APPENDIX M.
CPUC/CEC JOINT RECOMMENDATIONS

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Decision 08-10-037 October 16, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

FINAL OPINION ON GREENHOUSE GAS REGULATORY STRATEGIES

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FINAL OPINION ON GREENHOUSE GAS REGULATORY STRATEGIES

1. Summary

The Global Warming Solutions Act of 2006 (Assembly Bill (AB) 32) caps California's greenhouse gas (GHG) emissions at the 1990 level by 2020. Meeting this target will require an 11% reduction from current emissions levels and about a 29% cut in emissions from projected 2020 levels on a statewide basis. AB 32 directed the California Air Resources Board (ARB) to adopt a GHG cap on all major sources to reduce statewide emissions to 1990 levels by 2020.

The electricity and natural gas sectors will play a critical role in achieving this ambitious goal. Indeed, ARB's Climate Change Draft Scoping Plan envisions that the electricity sector will contribute at least 40% of the total statewide GHG reductions, even though the sector currently creates just 25% of California's GHG emissions. This is before considering the additional emissions reductions that are projected to result from a GHG emissions allowance cap-and-trade system, if such a system is adopted and implemented. The electricity sector is expected to reduce its emissions further due to its participation in such a market-based system. While this decision demonstrates a path to achieve a disproportionate share of emissions reductions from the electricity sector through programmatic measures, we urge ARB to pursue all cost-effective measures within other sectors.

The electricity and natural gas sectors are vital to California's economy and have many unique characteristics. The electricity industry has a particularly complex market structure and the California Independent System Operator (CAISO) is in the midst of developing and implementing significant changes to wholesale energy markets.

The California Public Utilities Commission (Public Utilities Commission) and the California Energy Commission (Energy Commission) have undertaken this collaborative proceeding to develop and provide recommendations to ARB on measures and strategies for reducing GHG emissions in the electricity and natural gas sectors. This effort provides ARB with the benefit of the two Commissions' collective knowledge of the electricity and natural gas sectors and experience implementing the programmatic measures that will be the cornerstones of emissions reductions: energy efficiency and mandates that increase California's reliance on renewable energy sources. We retained consultants (Energy and Environmental Economics (E3)) to conduct scenario analyses and modeling to assist in our understanding of the potential contributions from, and impacts on, consumers in the electricity and natural gas sectors, from both programmatic measures and market-based approaches. There has been extensive stakeholder participation through a series of workshops, en banc hearings, and symposia, with all parties provided opportunities to participate and to file several sets of comments and legal briefs during the proceeding.[1]

Today's decision is the second policy decision to be issued pursuant to this effort. In an earlier decision, Decision (D.) 08-03-018 issued in March 2008, we provided our initial GHG policy recommendations to ARB. We emphasized the need for both programmatic and market-based mechanisms to reduce emissions in the electricity and natural gas sectors. We also identified the appropriate point of regulation for the electricity sector, should the ARB decide that a cap-and-trade program for the State is warranted. Today's decision goes further

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1 Attachment A to this decision contains a list of parties that have filed comments in this

Footnote continued on next page

with information about the potential reductions and cost estimates associated with different policy scenarios, and the potential consumer cost impact of various cap-and-trade design scenarios.

We emphasize, as we did in D.08-03-018, that it is ARB's role to determine whether the implementation of a cap-and-trade program in California is the appropriate policy. The role of the two Commissions in this proceeding is to inform ARB regarding the potential impacts of various design elements on the electricity and natural gas sectors for the options ARB is evaluating, including additional programmatic mandates as well as cap-and-trade design. Our analysis is intended to inform and supplement, not supplant, ARB's AB 32 implementation process.

In today's decision, we make a set of interrelated recommendations to ARB regarding GHG regulations for the electricity sector and, to a lesser extent, the natural gas sector, which constitute our best judgement at this time, based on the extensive effort undertaken in this proceeding. However, our work is not finished and much remains to be done. We acknowledge that many uncertainties remain and the underlying analysis here, though extensive, is not definitive. We fully anticipate that new information will develop over time and that the current analysis may need to be updated to reflect innovations in technology, as well as revised assumptions for inputs such as forecasted fuel prices, demand forecasts, and technology costs. Moreover, additional modeling may be needed to evaluate market design elements and other factors not analyzed in the course of this proceeding.

collaborative proceeding, and the related acronyms used herein.

As discussed throughout this decision and summarized in Section 8 below, numerous important implementation details will require additional consideration. Further, as ARB examines other sectors of the California economy in more detail and the Western Climate Initiative continues to develop, we may find it appropriate to revisit some of the recommendations made herein.

If a comprehensive federal or international market-based program develops, the design elements and their impacts on California would also need to be analyzed carefully. While some modeling of regional energy markets was conducted in this proceeding, a thorough assessment of the impacts of the Western Climate Initiative cannot be undertaken until its membership and market rules are finalized. In addition, modeling being undertaken by ARB of a multi-sector carbon market will provide context for our assessment of the impact of cap-and-trade on electricity markets. Ultimately, a multi-state, multi-sector market should be measured against the principles that underlie this Decision: environmental integrity, equitable treatment of all market participants, and overall cost containment. Additionally, we cannot yet know the impact of the global financial crisis.

Therefore, we submit this Decision to the ARB with the recommendation that it be viewed, not as a static document, but rather our assessment based upon the best information and analysis available at this time. We recognize that both our analyses and the conclusions we draw from them may need to be revisited as new information emerges.

The two Commissions will continue to analyze collaboratively the issues related to AB 32 and, as further information becomes available, will assess whether any of the recommendations included herein should change. We will provide further recommendations to ARB, as appropriate, as its implementation process proceeds.

1.1. The Need for Both Mandatory Emission Reduction Measures and Market-based Regulations

In D.08-03-018, we stated that the most prudent avenue for addressing California's climate change issues is to pursue both regulatory and market approaches to achieve significant GHG reductions. We are in strong agreement with ARB's Draft Scoping Plan, which calls for aggressive energy efficiency programs, obtaining at least 33% of California's electricity from renewable sources, and increased reliance on combined heat and power (CHP) facilities as principal strategies for reducing GHG emissions. We agree with ARB that a multi-sector cap-and-trade program that provides access to additional GHG emissions reduction opportunities through linkage with a West-wide regional cap-and-trade system should also be considered. We emphasize that the foundation for success to reduce GHG emissions in the electricity sector is more energy efficiency and further development of renewable energy sources such as wind, solar, geothermal, and biomass.

The two Commissions are committed to this two-fold strategy. We will aid ARB with additional analysis and modeling on how market-based elements would impact the electricity sector. And we are already aggressively pursuing the mandatory emissions reduction measures envisioned in this Decision. We are actively and collaboratively expanding the energy efficiency, renewable, and CHP programs that are under our existing jurisdiction.

1.2. Energy Efficiency: The Cornerstone of our Approach

Energy efficiency is the least expensive strategy available to reduce GHG emissions significantly in the electricity and natural gas sectors. The State's efficiency standards and the utilities' energy efficiency programs have made a significant difference in California energy consumption. California's per-capita electricity use has remained almost flat over the last 30 years, demonstrating the success of a variety of energy efficiency programs and cost-effective building and appliance efficiency standards. We believe that, in order to meet the GHG reduction goals of AB 32, more energy efficiency is required. With intensified efforts in building and appliance standards and utility programs, and with new strategies and technologies, the State can capture all cost-effective energy efficiency.

In this decision, we reaffirm our commitment to a bold and aggressive approach to realize significant new reductions in energy consumption and GHG emissions via energy efficiency measures. Recent actions by both agencies demonstrate this commitment. In September 2008, the Public Utilities Commission established energy efficiency goals for the investor-owned utilities through 2020 that are consistent with the AB 32 goals. In D.08-09-040 issued in Rulemaking (R.) 08-07-011, the Public Utilities Commission adopted the California Long-Term Energy Efficiency Strategic Plan setting forth a statewide roadmap to maximize achievement of cost-effective energy efficiency between the years 2009 and 2020. The Energy Commission has endorsed the Strategic Plan's vision and strategies as consistent with and complementary to its own findings and recommendations in its 2007 Integrated Energy Policy Report. The two Commissions' policy determinations have set the stage for our overarching goal of achieving sustained market transformation in the major end-use sectors across the State. Achieving this goal will require continual evolution in utility program design. The Energy Commission's standards-setting authority and its development of new efficiency technologies are essential to attainment of this goal. The two Commissions will work together to achieve our energy efficiency goals in the coming decade.

1.3. Renewable Energy: Stepping Stone to 2050 Goals

Renewable resources are essential for reducing GHG emissions and reaching AB 32 goals, and are a crucial aspect of the future low-carbon economy that will be required to meet California's 2050 climate goals. Over the last three decades, the State has built one of the largest and most diverse renewable portfolios in the world. Currently, about 11% of the State's electricity is from renewable energy sources, including solar, wind, geothermal, and biomass. The investor-owned utilities have enough renewable energy under contract and in negotiation to deliver 20% of their electricity from renewable sources soon after 2010. We believe that a target of 33% of the State's electricity from renewables by 2020 is achievable if the State commits to significant investments in transmission infrastructure and key program augmentation.

Both Commissions, along with the CAISO and publicly-owned utilities, are members of the Coordinating Committee of the Renewable Energy Transmission Initiative, to identify and help develop bulk transmission to deliver renewable energy to consumers. In addition, we are working to overcome contracting, permitting, and grid integration challenges to ensure that 33% of our electricity from renewables becomes a reality.

1.4. Market-based Regulations Complement and Reinforce Mandatory Measures

In addition to aggressive regulatory measures that maximize energy efficiency and expand renewable energy development, D.08-03-018 recommended that ARB consider a complementary market-based approach – a cap-and-trade program – to capture additional cost-effective reductions of GHG emissions. The adoption of a cap-and-trade program would depend on ARB finding that the program would meet certain conditions as specified in Part 5 of

AB 32. In D.08-03-018, we also recommended that for the electricity sector the "deliverers" of electricity to the California grid – generally in-state power plant operators and entities that import power to California – have the compliance obligations under the cap-and-trade program.

In a cap-and-trade program, electricity deliverers would be responsible for surrendering permits (allowances) for emitting carbon dioxide (CO2) and other GHGs equal to their actual emissions. The deliverers would obtain allowances either through administrative distributions, through auctions, or through a combination of these approaches, as discussed further in this decision. We also expect that a secondary market would develop for allowance trading. The total supply of emission allowances would decline over time and this, in conjunction with the mandatory measures adopted by ARB, the two Commissions, and other governing entities, would ensure that the overall targets for 2020 and beyond are met. Under a cap-and-trade program, electricity deliverers would have the option of reducing their own GHG emissions or purchasing emission allowances from others who have made emissions cuts beyond their obligations, so long as the total emissions stay below the cap.

In D.08-03-018, we found that a well-designed cap-and-trade approach would have these attributes:

- Environmental integrity: The emissions cap ensures the targeted level of GHG emissions will be achieved with real reductions.
- Flexibility: Trading allows emitters to purchase additional emission rights, if they are needed.
- Incentive to reduce: Emitters may profit from aggressively reducing emissions by selling their excess allowances.
- Innovation: The program encourages creative approaches to achieving reductions at lower costs.

A cap-and-trade approach can reduce emissions at the lowest social cost by providing regulated entities with flexibility to procure the least-cost emission reductions available. However, such programs must be designed carefully and must include built-in safeguards, long-term monitoring, and strict enforcement to ensure a stable market and one which achieves real, verifiable, and permanent reductions in GHGs.

By recommending a combination of regulatory and market approaches, we seek to combine the best aspects of both regulation and market forces in a mutually reinforcing framework. While regulatory programmatic strategies are the foundation of our recommended strategy, a market would provide a backstop to the programs, should they fail to deliver sufficient GHG emissions reductions. Having a binding cap on emissions can ensure that the goals are met and that the ingenuity and creativity of the private sector are unleashed to find new and lower-cost alternatives to providing reductions.

1.5. This Decision's Recommendations for the Electricity and Natural Gas Sectors

As the next step in this collaborative proceeding, we build on our initial decision and ARB's Draft Scoping Plan to provide further recommendations to help achieve GHG targets in the electricity and natural gas sectors. In addition, this decision makes certain suggestions and outlines a variety of options for ARB to consider in deciding how to design a program and strategies to reduce emissions in these sectors. It focuses on the unique characteristics and needs of the electricity and natural gas sectors. The two Commissions have combined their expertise on the cost and feasibility of various aspects of the AB 32 framework as they relate to the electricity and natural gas sectors, in consultation with the CAISO, which is engaged in extensive wholesale market redesign for electricity, and with important assistance from E3, modeling consultants to the Public Utilities Commission.

1.5.1. Energy Efficiency and Renewables Resources

California's electricity and natural gas sectors will play a major role in meeting the State's GHG reduction goals for 2020 and beyond. The electricity sector produces about one-fourth of California's GHG emissions and is being asked, in ARB's Draft Scoping Plan, to contribute about 40% of the total GHG reductions that are expected to come from direct emission reduction measures. In addition, depending on the allowance allocation policy among sectors in the proposed cap-and-trade program, the electricity sector could be asked to contribute additional reductions.

To help achieve these ambitious cuts in GHGs, this decision reaffirms our commitment to energy efficiency standards and programs, and recommends an aggressive expansion of regulatory programs to pursue all cost-effective electricity and natural gas energy efficiency in the State, which represents nearly a doubling of efficiency goals. Energy efficiency is the cheapest and most effective resource for reducing GHG emissions in both the electricity and natural gas sectors. We recommend that ARB require comparable investment in energy efficiency from all retail providers in California, including both investor-owned and publicly-owned utilities, and assist in the implementation of the California Long-Term Energy Efficiency Strategic Plan to maximize savings opportunities Statewide.

We also recommend that California's reliance on renewables be expanded so that at least 33% of the State's electricity needs are met by renewable resources by 2020. It is not necessary that this goal be met exclusively through retail provider mandates. We support the California Solar Initiative and expansion of the Renewable Portfolio Standard (RPS) requirements, and also the exploration of other means of achieving increased renewables, including voluntary private sector investment and additional distributed renewables programs. To achieve the Statewide goal, we recommend that each retail provider be required to meet 33% of its electricity load using renewable energy sources by 2020. We believe that these goals are achievable with a serious commitment by the State to overcoming challenges such as transmission access and system integration.

Extensive modeling was conducted to calculate emissions, costs, and potential average rate impacts of multiple 2020 scenarios. Due to the substantial uncertainty associated with many of the model assumptions, we did not use the E3 model as a prescriptive tool but rather to obtain a general sense of the relative costs and emissions impacts of various policies, including efficiency, renewables, and several California–only (in-state electricity generation and imports) cap-and-trade allowance allocation options.

Overall, the electricity sector costs and rate impacts due to achieving 2020 GHG caps through more energy efficiency measures, greater use of renewable energy, and increased reliance on CHP may be significant but appear acceptable, against the backdrop of the economic and environmental costs of not acting to address the need to reduce GHG emissions. Total utility costs are expected to increase in excess of inflation between now and 2020 under all resource scenarios studied, including business as usual, due to load growth and expected real increases in capital and fossil fuel costs. At the same time, as described in Section 3.3.1, utility costs are actually expected to be less in the Accelerated Policy Case than under business-as-usual resource scenarios, largely due to the high levels of cost-effective energy efficiency we expect to achieve, which would offset the higher costs of renewable generation. However, with recognition of private customer costs, such as customer costs associated with the purchase of solar photovoltaic systems, the Accelerated Policy Case would be slightly more expensive than business as usual. This is all before taking into account the effects of a cap-and-trade program, which could have a large impact on consumer costs and rates, depending on the allocation of allowances or allowance value to the electricity sector as well as within the sector.

Average customer bills are estimated to be the lowest in the Accelerated Policy Case, consistent with the estimate of total utility costs. At the same time, average per-kilowatt-hour (kWh) retail rates would increase, because customers would purchase less electricity over which the utilities could recover their fixed costs. The actual impact of the rate increases would be felt differently by different types of customers: the rate increases may be more difficult for customers with little discretionary usage. However, customers with greater ability to take advantage of energy efficiency opportunities to manage their energy usage may see little or no bill increases.

The potential variability in customer impacts emphasizes the importance of well-designed programs, policies, and allowance allocation approaches to minimize overall consumer impacts.

1.5.2. Distribution of Greenhouse Gas Emission Allowances in a Cap-and-Trade Program

In considering how best to design a cap-and-trade program if one is adopted by ARB, we reviewed a number of approaches to the distribution of emission allowances, and considered extensive comments filed by the parties to the joint proceeding. Most of the focus of our work and parties' comments on allocation issues was on how to distribute allowances within the electricity sector.

Before turning to that issue, we address how allowances (or allowance value) should be allocated to the electricity sector in a multi-sector cap-and-trade program. We recommend that ARB assign allowances (or allowance value) to the electricity sector at the beginning of the cap-and-trade program in 2012 based on the sector's proportion of total historical emissions during the chosen baseline year(s) in the California sectors included in the cap-and-trade program (including emissions attributed to electricity imports). We recommend that, in subsequent years, allowance (or allowance value) allocations to each California sector in the cap-and-trade program be reduced proportionally, using the overall trajectory chosen by ARB to meet AB 32 goals by 2020. In this way, while the electricity sector may provide more than its proportional share of GHG emissions reductions through both mandatory programs and market-based reductions occurring due to the cap-and-trade program, the economic costs of the emissions reductions can be shared equally among all capped sectors.[2]

Turning to allocation policy within the electricity sector, the criteria used to evaluate each approach included the ability to minimize costs to consumers, treat all market participants equitably and fairly, support a well-functioning cap-and-trade market, and allow reasonable administrative simplicity.

We examined potential approaches that would distribute allowances to electricity deliverers in proportion to their historical emissions or in proportion to the amount of electricity they deliver to the grid. We also considered auctioning of allowances, with the distribution of allowances or allowance value to retail providers in proportion to the historical emissions of their generation portfolios or in proportion to their retail sales. Other approaches that were

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[2] As described in more detail in Section 4.3.2.1 below, it may be appropriate to increase allowance allocations to the electricity sector to reflect increased electricity demand and GHG compliance obligations due to electrification in other sectors, including the transportation sector.

considered include distributing allowances on the basis of economic harm (see Section 5.2.3 below) and distributing specified rights to purchase allowances at a set price (see Section 5.2.1.3). After considering the parties' arguments and the results of the analyses, we recommend that emission allowances be made available in a phased approach that allows parties to adjust their portfolios over time, minimizes wealth transfers, and ultimately has environmental integrity. This transitional process adds complexity, but better balances stakeholders' needs. We provide these recommendations to ARB:

- Beginning in 2012, 20% of the emission allowances allocated to the electricity sector should be auctioned, with 80% distributed administratively for free to electricity deliverers. The percentage auctioned would increase by 20% each year, so that by 2016, 100% would be auctioned.
- For the emission allowances distributed to electricity deliverers, the number of allowances given to individual deliverers should be determined using a fuel-differentiated, output-based allocation with distributions limited to deliveries from emitting sources, including unspecified sources. In determining the number of allowances for each deliverer, its output would be weighted based on the fuel source (such as coal or natural gas) of the electricity delivered.
- ARB may wish to retain a small portion of electricity sector emission allowances to fund statewide electricity programs consistent with AB 32.
- With the possible exception above, all of the electricity sector allowances that are to be auctioned should be given to the retail providers of electricity, on behalf of their customers. The retail providers should then be required to sell the allowances in a centralized auction undertaken by ARB or its agent. This would ensure open and equal access to allowances by all deliverers who require them.
- Each retail provider should receive all auction revenues from the sale of the allowances that were distributed to it. ARB should establish a centralized auction with safeguards to ensure that this

result is obtained. If ARB cannot design an auction that is legally separated from other State revenues, we suggest an alternate mechanism be designed.

- The distribution of allowances to individual retail providers for subsequent auctioning should transition over time from being based initially on historical emissions in the retail provider's portfolio to being allocated based on sales by 2020.
- All auction revenues should be used for purposes related to AB 32, and all revenue from the auction of allowances allocated to the electricity sector should be used for the benefit of the electricity sector, including the support of investments in renewables, energy efficiency, new energy technology, infrastructure, customer bill relief (possibly through rebates), and other similar programs.
- The Public Utilities Commission, for load serving entities, and the governing boards, for publicly-owned utilities, should determine the appropriate use of retail providers' auction revenues consistent with the purposes of AB 32.

As described below, issues that warrant further consideration include the fuel-based weighting factors to be used for allowance allocations to deliverers, and whether additional steps are needed to ensure that allowance distribution policies do not impede new entrants, the voluntary market, or the achievement of cost-effective energy efficiency.

1.5.3. Treatment of Combined Heat and Power Projects

We recognize the value of higher fuel efficiency provided by CHP projects. In this decision, we consider ways to encourage CHP installations as a way to reduce GHG emissions and the manner in which GHG emissions from CHP projects should be regulated.

CHP projects that produce both electricity and useful thermal output offer a viable GHG reduction option. When compared to generating usable thermal output and electricity separately, their co-generation achieves greater fuel efficiency and emits fewer GHGs. We considered a number of options for addressing CHP as a strategy for reducing GHGs. While certain efforts are underway, we recognize that further investigation is necessary regarding market and regulatory barriers for CHP. We commit to working to develop rules, programs, and policies to achieve higher CHP goals.

We also consider the manner in which GHG emissions associated with CHP-generated electricity should be regulated, but do not address the regulatory treatment of emissions associated with CHP's usable thermal output. We encourage ARB to consider treatment of GHG emissions related to CHP's thermal output in a manner consistent with its treatment of thermal output from other sources in the commercial and industrial sectors. To ensure equitable treatment of CHP compared to other entities in the electricity market, we recommend that emissions associated with CHP-generated electricity be included in the electricity sector for GHG regulatory purposes, subject to a minimum size threshold. Conceptually, we recommend that CHP facilities be treated like deliverers for all electricity they generate that is consumed in California, whether the electricity is delivered to the grid or used on-site, and that CHP facilities also be treated like retail providers for the portion of their electricity that is used on-site.

With this conceptual framework, we recommend that the deliverer of CHP electricity delivered to the grid and the CHP operator for CHP electricity used on-site (recognizing that they are likely to be the same entity) be responsible for surrendering allowances for the portion of CHP-generated electricity delivered to the grid and the portion used on-site, respectively. To the extent that allowances are distributed for free to deliverers, the deliverer for CHP delivered to the grid and the CHP operator for CHP electricity used on-site should receive allowances on the same basis as deliverers of electricity from other sources.

We also recommend that ARB treat CHP operators comparable to retail providers for the portion of CHP-generated electricity that is used on-site. To the extent that allowances are distributed to retail providers, the CHP operator should receive allowances on the same basis as retail providers and should be required to sell the received allowances through the centralized auction undertaken by ARB or its agent.

1.5.4. Market Design and Flexible Compliance

In this proceeding, we reviewed market design and flexible compliance options that ARB could consider if it implements a cap-and-trade program. Maintaining environmental integrity for achieving AB 32 GHG emission reduction goals is the primary driver for market design. The market design should also allow for transparent allowance trading with many participants.

A number of characteristics of the electricity sector, including unpredictability of emissions year-to-year due to variable weather and hydrologic conditions, make flexible compliance options particularly important for this sector. Flexible compliance options can reduce costs by allowing entities to pursue alternative means of meeting GHG emission requirements. Parties commented on a broad range of issues including price triggers and other safety valves, linkage with other GHG emissions allowance trading systems, compliance periods, banking and borrowing of GHG emissions allowances, penalties, and offsets.

Many uncertainties remain about the framework for GHG regulation. ARB is still in the process of determining many aspects of the overall GHG program as well as features of the potential cap-and-trade market design. Therefore, we cannot yet make specific recommendations on some aspects of market design, pending more detailed knowledge of the overall regulatory framework.

The market design and flexible compliance elements should maximize liquidity and transparency in a GHG emissions allowance market, while maintaining the integrity of allowances and the emissions cap. To achieve these goals, we support bilateral linkage of any California cap-and-trade program with other states in the Western Climate Initiative to create a multi-sector, regional cap-and-trade market. A regional or, better yet, national or international market is critical in order to broaden opportunities to find real, cost-effective emission reductions, to smooth the effects of localized weather and hydrologic variations, and to avoid leakage[3] and other potential drawbacks of a California-only system.

We encourage ARB to allow unlimited participation in the cap-and-trade system, with adequate safeguards to prevent market manipulation and anti-competitive behavior. To ensure environmental integrity of the system, no safety valves or price triggers — such as increasing the number of allowances automatically when a set price is reached — should be offered.

Overall, we conclude that flexible compliance mechanisms should be designed taking into account the scope of the GHG trading market and the emissions reductions required of market participants, elements that are not yet determined. More detailed rules and regulations for most flexible compliance options will be needed after the market details become known.

For now, to increase flexibility and reduce compliance costs, we encourage ARB, should a multi-sector, regional cap-and-trade market develop, to establish

[3] Section 38505(j) added to the California Health and Safety Code by AB 32 defines "leakage" to mean "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state."

three-year compliance periods to allow entities that deliver electricity from emitting generation resources time to implement emission reducing measures. We similarly encourage ARB to allow unlimited banking of GHG emissions allowances and offsets. We encourage ARB to allow limited use of high-quality offsets that comply with AB 32 requirements, without any geographic restrictions. To be acceptable, offsets should be real, additional, verifiable, permanent, and enforceable.

We recognize that further work is required in this area and propose that the Commissions work with ARB to evaluate the usefulness of other market design and flexible compliance features.

2. Background

In the Order Instituting Rulemaking (OIR) initiating R.06-04-009, the Public Utilities Commission provided that Phase 2 of this proceeding would be used to implement a load-based GHG emissions cap for electricity utilities, as adopted in D.06-02-032 as part of the procurement incentive framework, and also would be used to take steps to incorporate GHG emissions associated with customers' direct use of natural gas into the procurement incentive framework.[4]

On September 27, 2006, Governor Schwarzenegger signed into law AB 32, "The California Global Warming Solutions Act of 2006." This legislation requires ARB to adopt a GHG emissions cap on all major sources in California, including

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[4] In D.07-01-039 in Phase 1 of this proceeding, the Public Utilities Commission adopted a GHG emissions performance standard for new long-term financial commitments to baseload electricity generation. D.07-05-063 denied applications for rehearing of D.07-01-039. D.07-08-009 denied a petition for modification, but clarified how the adopted cogeneration thermal credit methodology will be applied to bottoming-cycle cogeneration. On February 12, 2008, SCE filed an amended Petition to Modify D.07-01-039, which is pending.

the electricity and natural gas sectors, to reduce statewide emissions of GHGs to 1990 levels.

A prehearing conference was held in Phase 2 on November 28, 2006. The Phase 2 scoping memo, which was issued on February 2, 2007, determined that, with enactment of AB 32, the emphasis in Phase 2 should shift to support implementation of the new statute. Because of the need for "a single, unified set of rules for a GHG cap and a single market for GHG emissions credits in California," the Phase 2 scoping memo provided that "Phase 2 should focus on development of general guidelines for a load-based emissions cap that could be applied … to all electricity sector entities that serve end-use customers in California,"[5] including both investor-owned utilities that the Public Utilities Commission regulates and publicly-owned utilities.

As detailed in the Phase 2 scoping memo, the Public Utilities Commission and the Energy Commission have undertaken Phase 2 on a collaborative basis, through R.06-04-009 and Docket 07-OIIP-01, respectively, to develop joint recommendations to ARB regarding GHG regulatory policies as it implements AB 32.

The Phase 2 scoping memo noted that the policies in D.06-02-032 were adopted prior to passage of AB 32. It placed parties on notice that, in the course of Phase 2, the Public Utilities Commission might adopt policies that would modify portions of D.06-02-032 as a result of AB 32, subsequent actions by ARB, or the record developed in the course of this proceeding.[6]

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[5] Phase 2 scoping memo, at 8.

[6] *Id.* at 10-11.

As Phase 2 has progressed, the Public Utilities Commission has modified the scope of Phase 2 through D.07-05-059 and D.07-07-018 amending the OIR.[7] D.07-05-059 specified that Phase 2 should be used to develop guidelines for a load-based GHG emissions cap for the entire electricity sector and recommendations to ARB regarding a statewide GHG emissions limit as it pertains to the electricity and natural gas sectors. To that end, D.07-05-059 also expanded the natural gas inquiry in Phase 2 to address GHG emissions associated with the transmission, storage, and distribution of natural gas in California, in addition to the use of natural gas by non-electricity generator end-use customers as originally contemplated in the OIR. The list of respondents to this proceeding was amended to include all investor-owned gas utilities, including those that provide wholesale or retail sales, distribution, transmission, and/or storage of natural gas.

D.07-07-018 amended the OIR further to provide for consideration in Phase 2 of issues raised by and alternatives considered in the June 30, 2007 Market Advisory Committee report entitled, "Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California," to the extent that they were not already within the scope of Phase 2. Thus, D.07-07-018 provided for consideration of alternatives to a load-based cap for the electricity sector, a deviation from the policies adopted in D.06-02-032. In its report to ARB, the Market Advisory Committee considered design of a market-based program to reduce GHG emissions, and described various options for the scope of a

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[7] On December 20, 2007, the assigned Commissioner issued a ruling modifying the Phase 2 scoping memo to specify the manner in which natural gas issues raised in the OIR and the issues added by D.07-05-059 and D.07-07-018 would be considered in Phase 2.

cap-and-trade program. For the electricity sector, the Market Advisory Committee recommended a "first seller" approach, with the entity that first sells electricity in the state responsible for meeting the compliance obligation.

ARB is taking the lead in developing reporting protocols and requirements for all parties covered by AB 32, including the electricity and natural gas sectors. In D.07-09-017 and a companion Energy Commission decision, the Public Utilities Commission and the Energy Commission recommended that ARB adopt proposed regulations contained in that decision as reporting and verification requirements applicable to retail providers and marketers in the electricity sector. The reporting requirements for the electricity sector approved by ARB on December 6, 2007 are consistent with the proposed regulations recommended by the two Commissions.

In D.08-03-018 and a companion Energy Commission decision, the Public Utilities Commission and the Energy Commission recommended that ARB adopt a mix of direct mandatory/regulatory requirements for the electricity and natural gas sectors and a multi-sector cap-and-trade program for GHG emissions allowances that includes the electricity sector. In particular, we recommended that ARB set requirements at the level of all cost-effective energy efficiency in the State. For electricity from renewable energy, we recommended that the requirements go beyond the current 20% requirement, consistent with State policy, but we left open consideration of exact percentage requirements or deadlines, pending further analysis. We concluded that any cap-and-trade program design for California should include a component for imported electricity. We recommended that ARB designate deliverers of electricity to the California grid, regardless of where the electricity is generated, as the electricity sector entities responsible for compliance with the cap-and-trade requirements. The recommended "deliverer" approach is a variation of the "first seller" approach recommended by the Market Advisory Committee. We recommended further that some portion of the emission allowances available to the electricity sector should be auctioned. An integral part of this auction recommendation is that the majority of the proceeds from auctioning of allowances for the electricity sector should be used in ways that benefit electricity consumers in California. In the same decision, we determined that additional record development was needed before recommendations could be made on the remaining issues in Phase 2 including GHG emissions allowance allocations, flexible compliance mechanisms, and the treatment of CHP facilities.

As part of our Phase 2 analysis, the Public Utilities Commission retained consultants E3 to conduct detailed modeling of the electricity sector impacts of potential GHG emissions cap scenarios. The modeling analysis has considered various policy options in order to analyze alternatives for cap design and implementation for the electricity sector. The consultants also considered the natural gas sector in their modeling process. However, separate, detailed modeling of the natural gas sector was not undertaken. The modeling effort has examined the level and costs of emission reductions that can be achieved by the electricity and natural gas sectors by the 2020 deadline set by AB 32. It has also addressed the rate at which these types of reductions can be achieved, in order to inform our recommendations for annual emissions goals for the electricity and natural gas sectors.

By an Administrative Law Judge (ALJ) ruling dated April 16, 2008, parties were asked to file comments on a joint Public Utilities Commission and Energy Commission staff paper that analyzed several potential methods for the allocation of GHG emission allowances, and to respond to certain questions addressing GHG emission allowance policies. On April 21 and 22, 2008, the

Public Utilities Commission and the Energy Commission held a workshop on emission allocation methodologies and preliminary model results.

By ALJ ruling dated May 1, 2008, parties were asked to file comments on a joint Public Utilities Commission and Energy Commission staff paper on CHP and to respond to a series of questions contained in the staff paper.

On May 2, 2008, the Climate Action Team Subgroup on Electricity and Natural Gas, ARB, the Public Utilities Commission, and the Energy Commission sponsored a workshop on regulatory strategies for the electricity and natural gas sectors. At the workshop, the agencies described present and future non-market based emission reduction measures. By ALJ ruling dated May 13, 2008, parties were asked to file comments on emission reduction measures and certain other issues, materials from previous workshops (May 2, 2008 and May 6, 2008) were incorporated into the record, and revised model results were provided to the parties.

By ALJ ruling dated May 6, 2008, parties were asked to respond to a series of questions regarding possible policies for flexible compliance in a cap-and-trade program as it may pertain to the electricity sector. The ruling also incorporated into the record two documents prepared by ARB and two documents prepared by the Western Climate Initiative that address flexible compliance mechanisms.

On June 26, 2008, ARB issued its June 2008 Discussion Draft of the Climate Change Draft Scoping Plan (Draft Scoping Plan). Pursuant to Rule 13.9 of the Public Utilities Commission Rules of Practice and Procedure, we take official notice of the Draft Scoping Plan and the Appendices to the June 2008 Discussion Plan issued shortly thereafter. The recommendations we have made in previous decisions in this proceeding, as well as the recommendations we adopt today are intended to guide ARB in developing rules and regulations and in its further activities implementing AB 32.

Today's decision is based on information presented at the workshops, the staff papers on allocation and CHP issues, materials incorporated into the record by ALJ rulings, and comments filed by the parties in this proceeding.

3. Greenhouse Gas Modeling of California's Electricity Sector

In June 2007, our consultant E3 began development of a model of GHG reductions in the electricity sector. The work was funded by the Public Utilities Commission and ARB as a component of the State's analysis to inform policy decisions surrounding implementation of AB 32. E3's GHG Calculator calculates the emissions, cost, and rate impacts of different scenarios relative to a Reference Case. The results can also be compared to a Natural Gas Only Buildout scenario, as further described below.

The GHG Calculator is a cost-based, bottom-up, scenario analysis model[8] of what it would cost seven groupings of California retail providers to achieve different levels of GHG emission reductions between 2008 and 2020, relying only on existing technologies.[9]

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[8] The GHG Calculator is a spreadsheet that simplifies the multiple possible outputs of the PLEXOS model into a few parameters; namely, the relationship between load and GHG emissions rates and the relationship between load and electricity prices.

[9] The groupings of retail providers modeled are: (1) PG&E, (2) SCE, (3) SDG&E, (4) SMUD, (5) LADWP, (6) a grouping of all other municipal utilities, direct access electric service providers, and other retail providers in Northern California called "Northern California Other," and (7) a grouping of all other municipal utilities, electric services providers, and other retail providers in Southern California, called "Southern California Other." The model also separates out the load and emissions associated with the California water agencies, including the Department of Water Resources, the Central Valley Project, and the Metropolitan Water Project, in a separate category.

In the Stage 1 GHG modeling effort (July 2007 through November 2007), the E3 team modeled the electricity and natural gas sectors assuming a load-based electricity and natural gas sector cap on emissions. Users of the GHG Calculator were able to select among demand-side and renewable energy resources for development, in order to bring GHG emissions in the electricity and natural gas sectors down to a target level in 2020.[10] The principal output of the Stage 1 model included the electricity and natural gas sector cost and rate impacts of reaching the GHG cap by developing the selected resource mix. The model also estimated the incremental cost of GHG emissions reductions resulting from the selected resource mix.

Key Stage 1 Questions:

- How much will various policy options reduce CO2 emissions?
- How will these policy options affect electricity rates?
- Underlying question: At what electricity sector target level do incremental improvements get expensive?

During the Stage 2 GHG modeling effort (February 2008 through May 2008), the E3 team refined model assumptions about retail provider-specific resources to reflect the Energy Commission and Public Utilities Commission recommendations to ARB on GHG regulatory strategies contained in

[10] The Stage 1 modeling default assumption was that the target emissions level for the electricity and natural gas sectors was equal to the 1990 sectors' emissions as reported in the preliminary ARB GHG emissions inventory, dated August 22, 2007. ARB revised the GHG inventory on November 19, 2007, which resulted in an adjusted 1990 emissions level for the electricity and natural gas sectors. This change to the ARB GHG inventory occurred after the Stage 1 model was released and so was not reflected in that version of the model.

D.08-03-018.[11] One of the major changes in the Stage 2 model enables users of the GHG Calculator to select the California-wide price of GHG emission allowances in terms of dollars per metric ton of CO_2 equivalent (CO_2e) emissions from 2012 – 2020. Users also have a number of other options in the GHG Calculator regarding potential GHG policy regulatory regimes. The GHG Calculator was designed to analyze different sets of rules for the auction or administrative allocation of emission allowances to the electricity sector, and for the use of GHG offsets.

Key Stage 2 Questions:

- What is the cost to the electricity sector of complying with AB 32 under different policy options for California (including different market-based program designs)?
- What is the cost to different retail providers and their customers of these options?
- Underlying question: What option has the best combination of cost and fairness?

3.1. Methodology and Approach: E3 GHG Calculator and PLEXOS

The GHG modeling analysis uses two tools in combination. The spreadsheet-based GHG Calculator was developed by E3 for use by staff and parties to evaluate alternative resource plans that can meet target GHG emissions levels. This simplified tool allows input values to be changed easily

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[11] Originally, E3 was required to provide estimates of GHG carbon dioxide equivalent (CO_2e) emission reductions under various "load-based" cap options, in which retail providers rather than deliverers would have the GHG compliance obligations. However, as result of D.08-03-018, the recommended point of regulation for GHG emissions in the electricity sector is the deliverer of electricity to the California transmission grid rather than the retail provider. This change required a number of significant modeling changes to the GHG Calculator.

with updated results displayed in seconds. In addition, all of the calculations are available to all stakeholders because all of the formulas are provided in the spreadsheet.

The second tool used by E3 is the production simulation model PLEXOS.[12] This tool contains a detailed zonal model of the entire Western Electricity Coordinating Council (WECC) area, including individual generators, transmission lines, loads, and fuel prices. The PLEXOS model dispatches the system at least cost using an optimization algorithm, subject to constraints such as transmission limits, and reports GHG emissions and generation for each plant in 2008 and 2020. The PLEXOS dispatch is used to estimate the least-cost transmission-constrained WECC dispatch that provides cost-based electricity market prices and emissions levels of generators. The PLEXOS dispatch is also used to verify that the dispatch is feasible and that sufficient resources exist on the system for reliable operation.

PLEXOS is used to provide underlying data that is then fed into the GHG Calculator in Microsoft Excel. In order for the GHG Calculator to be able to evaluate the many target cases chosen by users, it is designed to extrapolate from the PLEXOS dispatch model results over a large range of input assumptions. To check the validity of this extrapolation, the E3 project team tested an extreme case in the GHG Calculator, and found that the resulting statewide estimate of costs and GHG emissions were within 2% of California's emissions levels derived from PLEXOS results using similar input assumptions.[13] This

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[12] www.plexossolutions.com.

[13] For more detailed information on the cross-check, see the May 13, 2008 E3 presentation, Slide 39, Verification with PLEXOS.

"cross-check" of the GHG Calculator demonstrates that its results are in line with the results of a production simulation dispatch model.

3.1.1. Limitations of the Analysis and Scope of the Model

The purpose of the GHG Calculator is to estimate the key impacts of reducing GHG emissions in California's electricity sector on California electricity consumers. The GHG Calculator does not estimate the impacts of GHG policy choices on energy producers or entities other than the seven groupings of retail providers (and their customers) identified in the model.

The GHG Calculator is a high-level policy tool designed to test policy scenarios and not a resource planning tool with which to make specific resource planning or project choices. A number of trade-offs were made to accommodate the wide range of policy choices and carbon reduction approaches that the Energy Commission and Public Utilities Commission needed the GHG Calculator to model. A few of these limitations are highlighted here:

- The GHG Calculator does not dynamically solve or optimize resource selections based on policy criteria, least-cost criteria, the price of carbon allowances, offset prices, or any other criteria. The model simply provides the user the ability to select which resources to develop in creating a user-defined scenario.
- The GHG Calculator uses four time periods per year, which are fewer than would be used for a detailed planning study.
- The GHG Calculator uses summarized production simulation information for 2008 and 2020 and uses an interpolation approach in intervening years.

All of these choices make the GHG Calculator more flexible as a policy tool for evaluating GHG reduction strategies, but the results should not be used to make or advocate project-specific procurement decisions. In addition, the GHG Calculator does not directly inform questions relating to how the electricity sector might interact with other sectors of the California economy under a statewide GHG policy or market-mechanism regime. Similarly, the model does not evaluate macroeconomic impacts of emission reduction measures. These types of questions require a different set of tools to address.

There are many input assumptions in the model including numerous inputs that are specific to each retail provider. The E3 modeling team has sought to use as accurate information as possible in the GHG Calculator. The retail providers are expected to have better or more specific information on their individual resources and forecasts for their service territories contained within their individual utility resource plans. However, the GHG Calculator contains the best publicly available consolidated set of information for California's electricity sector.

The project team interacted both formally and informally with stakeholders while finalizing assumptions. Parties were given the opportunity to file two rounds of comments on E3's approach and methodology, and the assumptions have therefore been thoroughly reviewed and subject to comment. As a result of stakeholder input, many corrections and changes were made that have improved the analysis. Some stakeholders raised additional concerns about the input assumptions and methodology in the final round of comments, but these comments either were similar to comments submitted in the first round, or would not alter the final results significantly if implemented. As a result, the model was not modified following the second round of comments.

The strengths of the GHG Calculator are that it is non-proprietary and available to all interested parties, and includes only publicly-available information. It allows the user to choose a multitude of input variables. The intent was to create a transparent modeling process, allow interested parties to run their own cases, and avoid, to the extent possible, the perception that the results, and any resulting policy choices, are coming from a "black box." The model also benefits from the "bottom-up" detail of resource cost and potential contained within this portfolio approach to scenario analysis. In addition, the GHG Calculator is built on the foundation of production simulation dispatch modeling results for the entire Western grid. This level of detail helps validate and ensure that the simplified GHG Calculator produces a feasible and reasonable estimate of operations of the Western grid.

3.2. Key Driver Assumptions

Understandably, not all parties agree with all assumptions used by E3 because not everyone has the same view of the future in 2020. Fortunately, in this analysis, not every assumption is a "key driver" that has a significant impact on the modeling results, even among reasonable ranges of values. Thus, some assumptions matter more than others.

In any long-range forecast designed to guide policy choices, it is important to isolate the key drivers of results from the myriad issues that may be important in some contexts but can distract from the task at hand. Therefore, the analysis was focused on issues that are considered key drivers that are important to overall results.

The following table provides the key drivers that were identified and the default assumptions for each of these key drivers that are used in E3's analysis. The robustness of the results was verified for these key drivers through sensitivity analysis and alternative target cases.

Table 3-1
Key Drivers and Default Assumptions

Key Driver	Default Assumption / Approach
Resource Costs (both conventional and renewable generation)	Cost estimates reflect recent cost increases in generation.
Federal Tax Treatment: production tax credit, investment tax credit	Assume tax incentives are continued through 2020, except those limited to a specific quantity of new generation.
Market Transformation[14] Effects (including significant changes to the relative cost of energy resources or significant changes to the performance of energy resources)	Included as a sensitivity analysis.
Natural Gas Price (and other fuel prices)	Seams Steering Group of the Western Interconnect forecast for all fuels is scaled relative to the NYMEX futures markets for 2020 natural gas prices in March 2008.
Load Forecast	Energy Commission 2008-2018 forecast, extended to 2020 and adjusted for energy efficiency achievements.
Long-Line Transmission from California to distant renewable resources (*e.g.*, Wyoming, British Columbia, Montana, New Mexico)	These options were evaluated as a sensitivity analysis.
Energy Efficiency	Three energy efficiency scenarios were developed, modeled after the 2008 Itron Report, "Assistance in Updating the Energy Efficiency Savings Goals for 2012 and Beyond" written for the Public Utilities Commission.[15]

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[14] The following definition of market transformation generally captures its use herein: "Market transformation refers to a system of intentional actions to shift markets in terms of product availability and customer choice. It implies a greater consumer or demand-side influence on the development and dissemination of technology. It encompasses actions aimed at equipment performance (both stand-alone and in systems), market dissemination of products and actors' orientation towards new products. In the energy efficiency context, market transformation aims to shift away from products with inferior energy use patterns by moving improved products to market faster and widening their share of the market (IEA, 1997)." Source: International Energy Agency (IEA), *Energy Labels and Standards*, OECD, Paris, 2000. http://www.iea.org/textbase/nppdf/free/2000/label2000.pdf.

[15] Energy efficiency technologies included in the GHG Calculator consist primarily of technologies currently receiving incentives from investor-owned utility programs. Other off-the-shelf technologies are not included, and ARB's Draft Scoping Plan Appendices suggest a number of additional measures that are not included in Itron's set of measures. There are also many other delivery methods for energy efficiency that will require further analysis and evaluation. The Itron Goals Update report can be accessed

Footnote continued on next page

Key Driver	Default Assumption / Approach
Generation Additions from 2008 to 2020	The 2020 cases begins with the Transmission Expansion Planning Policy Committee (TEPPC) 2017 build-out of the WECC area, with generator additions based on utility long-term plans plus regional load / resource balance to meet 2020 estimated load and energy needs.
Generation Subtractions from TEPPC 2017 WECC-wide generation case for use in PLEXOS model	Meeting WECC-wide RPS levels in 2020 required adding additional renewable energy, leading to some conventional plants being removed because they were no longer needed to meet expected 2020 electricity demand (e.g., new Arizona coal).
Generation Retirements / Retrofit / Repowering	Use TEPPC 2017 WECC build-out assumption, which is essentially no retirements of existing plants.
Emission Intensity of Unspecified Imports	The Commissions' methodology for unspecified imports (1100 pounds (lbs) per megawatt hour (MWh)).
New Nuclear Power Plants	No new nuclear plants are assumed to be built between 2008 – 2020, although users can investigate this possibility as a sensitivity analysis.

3.3. Electricity Sector Resource Policy Scenarios

For analysis purposes, E3 developed three main resource policy scenarios that bracket the range of likely low-carbon resource portfolios in 2020 for the electricity sector, which are summarized below and described in more detail in Table 3-2:

- **Natural Gas Only Case.** This case assumes no new development of low-carbon resources beyond the 2008 level, and the addition of only new natural gas generation to meet load growth. There are no new energy efficiency, rooftop solar photovoltaics, or CHP programs in this scenario. The characteristics of this scenario are similar to those for the electricity sector in ARB's Business-as-Usual case,[16] and this scenario represents what would be referred to traditionally as a business-as-usual case.

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at: http://www.cpuc.ca.gov/NR/rdonlyres/D72B6523-FC10-4964-AFE3-A4B83009E8AB/0/GoalsUpdateReport.pdf

[16] There are three main differences between the Natural Gas Only Case and ARB's Business-as-Usual case: (1) ARB estimates a slightly higher rate of electricity load growth than that used by E3; (2) ARB assumes that no coal contracts expire between 2008 and 2020, whereas E3 assumes that California will not have responsibility for GHG emissions from coal contracts after their currently set expiration dates; and (3) ARB's Business-as-Usual case assumes a lower level of renewable energy in California than that included in the Natural Gas Only Case.

- **Reference Case.** This case assumes that existing State policies for the electricity sector (for example, the 20% RPS) are continued to 2020, and that the objectives of these policies are met for renewable generation, energy efficiency, demand response, rooftop photovoltaics, and CHP.
- **Accelerated Policy Case.** This case assumes substantially more aggressive targets and incentives than those included in the Reference Case, and a corresponding increase in low-carbon resource development. This is the case generally recommended in this decision, with some augmentation as detailed in subsequent sections.

All of these scenarios assume a mix of emission reduction measures for the electricity sector that result from regulatory requirements alone, separate from the introduction of any cap-and-trade system. Users of the GHG Calculator can also create their own scenarios by changing a variety of input assumptions, including resource portfolios, cost and performance assumptions, and emissions trading architecture.

Table 3-2

2020 Resource Portfolios for Three Key Resource Policy Scenarios

Inputs	Reference Case	Accelerated Policy Case	Natural Gas Only Case
Energy Efficiency	Energy Commission's load forecast, assume 16,450 gigawatt-hours (GWh) of embedded energy efficiency	"High goals" energy efficiency scenario based on Public Utilities Commission Itron Goals Update Study and publicly-owned utilities' AB 2021 filings: 36,559 GWh	No additional energy efficiency after 2008, 16,450 GWh added to Energy Commission's load forecast
Rooftop Solar Photovoltaics	Energy Commission's load forecast, 847 megawatts (MW) nameplate of rooftop photovoltaics installed	3,000 MW nameplate of rooftop photovoltaics installed	Existing nameplate photovoltaics only
Demand Response	5% demand response	5% demand response	Existing demand response only
CHP	CHP embedded in Energy Commission's load forecast only	1,574 MW nameplate small CHP, 2,804 MW nameplate larger CHP	CHP embedded in Energy Commission's load forecast only
Renewable Energy	20% RPS by 2010 (6,733 MW)	33% renewables by 2020 (12,544 MW)	Existing renewables only, which includes 1,000 MW of Tehachapi wind power currently under construction

3.3.1. GHG Reductions in the Resource Policy Scenarios

E3's analysis reveals that different resource policy scenarios result in very different levels of GHG emissions in 2020. Compared to 2008 electricity sector emissions of 107 million metric tons (MMT) of CO2e, the Natural Gas Only Case results in a 2020 emissions estimate of 129 MMT,[17] an increase of about 21 MMT relative to 2008 levels; the Reference Case results in a 2020 emissions estimate of 108 MMT, a nearly flat emissions profile; and the Accelerated Policy Case results in a 2020 emissions estimate of 79 MMT, a decrease of about 29 MMT relative to 2008 levels. These results are shown in Figure 3-1 and Table 3-3 below. These emissions estimates do not include the effects of a cap-and-trade system that includes the electricity sector.

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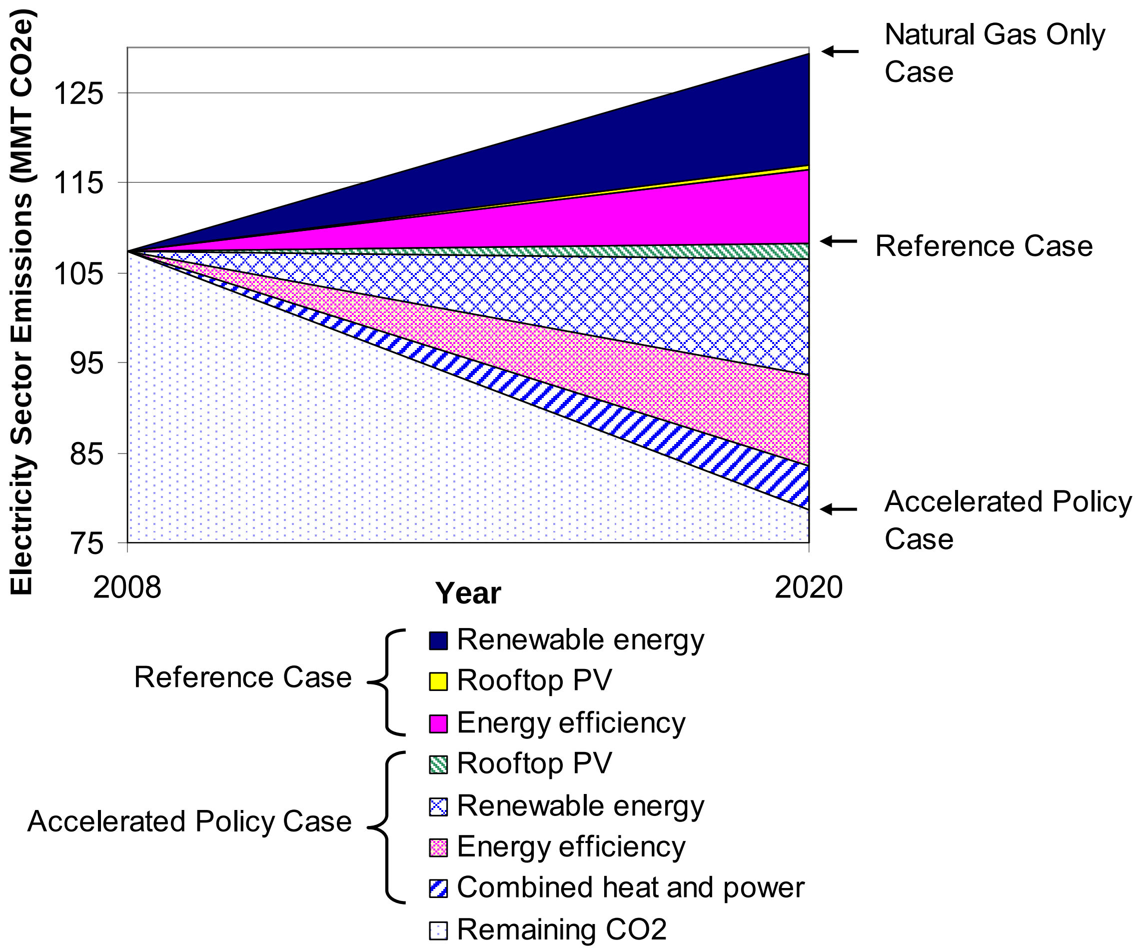
[17] The business-as-usual case in ARB's Draft Scoping Plan projects electricity sector emissions of 139 MMT in 2020, which is 7% higher than the 129 MMT obtained from the GHG Calculator's Natural Gas Only Case.

Figure 3-1

2020 GHG Emissions in Three Key Scenarios



The contributions of different low-carbon resources to the aggregate emissions reduction in the Reference Case and the Accelerated Policy Case are shown as "wedges" in Figure 3-1, with more detail provided in Table 3-3.

Table 3-3

2020 GHG Reductions in Reference Case and Accelerated Policy Case

(MMT)

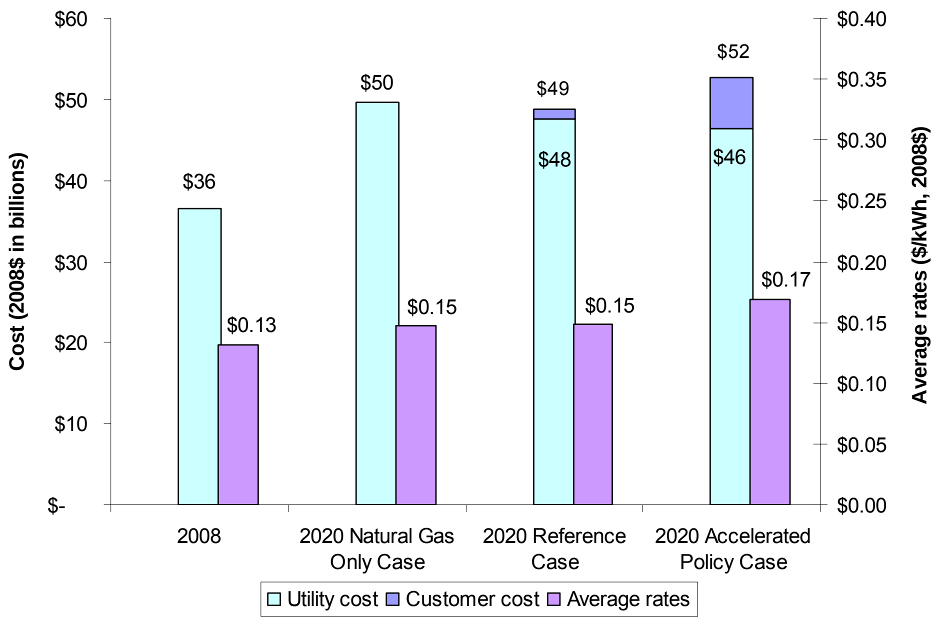
Low-carbon Resource	**Reference Case GHG Emissions Reductions Compared to Natural Gas Only Case**	**Accelerated Policy Case GHG Emissions Reductions Compared to Reference Case**
Energy Efficiency	**8.2**	**10.2**
Rooftop Photovoltaics	**0.5**	**1.7**
CHP	-	**4.9**
Electricity used on-site	-	*2.1*
Electricity delivered to grid	-	*2.8*
Renewable Generation	**12.4**	**12.8**
Biomass	-	*2.2*
Biogas	-	*1.1*
Wind	5.3	*2.9*
Geothermal	4.9	*2.9*
Solar Thermal	2.2	*3.7*
TOTAL	***21.1***	***29.6***

3.3.2. Impacts of GHG Reduction Policies on Costs and Average Rates

The E3 GHG Calculator estimates the impacts of GHG reduction policies on total retail provider costs (total revenue requirements for provision of electricity service to customers) and average rates, as shown in Figure 3-2 below for the Natural Gas Only, Reference, and Accelerated Policy scenarios in 2020. These cost and rate estimates do not include effects of a cap-and-trade system; those potential effects are addressed in Section 3.4, with more detailed discussion in Section 5 below.

Figure 3-2

Utility Costs, Customer Costs, and Average Rates in Three Key Scenarios



The GHG Calculator also estimates private customer costs in 2020 for the Reference and Accelerated Policy cases, as indicated for 2020 in Figure 3-2. Private customer costs are those costs that are not paid through utility rates but rather invested directly by electricity customers, such as the customer costs associated with the purchase of a solar photovoltaic system after receiving a rebate or incentive. The utility or retail provider costs of that system would include the portion covered by the rebate offered by the utility for the system. An analysis of private consumer costs is relevant for all of the policies that induce investment at customer premises, including rooftop solar photovoltaics, energy efficiency, and CHP investments. No customer costs are included in the Natural Gas Only Case, because no energy efficiency, solar photovoltaics, or CHP programs are included in this scenario. Customer costs in 2008 were not estimated and so are not reflected in Figure 3-2. The E3 estimates of consumer costs presented in Figure 3-2 are not reduced by the electricity bill savings that consumers will enjoy as a result of their investments in energy efficiency and other demand-side resources; instead, the related cost savings are reflected in the total utility cost calculations.

Potential impacts on utility costs, customer costs, and average retail rates based on the E3 estimates are summarized below, and are illustrative of potential future cost and average rate changes, not definitive forecasts.

- The modeling suggests that total utility costs will increase in excess of inflation in all three resource scenarios due to load growth and due to increases in the capital costs of renewable and conventional generation and of transmission and distribution facilities.
- The modeling suggests that total utility costs would be the highest in the Natural Gas Only scenario, with utility costs about about 4% lower in the Reference Case. In the Accelerated Policy Case, utility costs are estimated to be 7% lower than in the Natural Gas Only scenario. However, inclusion of incremental private customer costs indicates that the Accelerated Policy Case would be the most expensive (6% higher than in the Natural Gas scenario), and the Reference Case the least expensive of the three scenarios (2% lower than in the Natural Gas scenario).
- Average retail electricity rates also will vary depending on the electricity resource policies pursued. For the three scenarios studied, average electricity rates are estimated to be lowest in the Natural Gas Only case, with average rates about 1% higher in the Reference Case and about 14% higher in the Accelerated Policy Case.
- Energy efficiency is extremely important for limiting the economic impacts of GHG reduction on consumers and the economy as a whole.
- The modeling suggests that average utility bills would decline along with policies that reduce GHG emissions, reflecting the lower total utility costs estimated for the Reference Case and the

Accelerated Policy Case, even while average electricity rates may increase. With greater efficiency achievements, less energy is required to achieve the same level of energy services and economic productivity.

- Average customer bills are estimated to be the lowest in the Accelerated Policy Case because total utility costs would be reduced due to high levels of cost-effective energy efficiency and distributed resources, which offset the higher costs of renewable generation. Average retail per-kWh rates are estimated to increase under this scenario, however, because customers would purchase less electricity over which utilities could recover their fixed costs.[18] Because of energy efficiency investments at costs lower than supply-side alternatives, costs and average bills are actually lower when the aggressive levels of energy efficiency are achieved.

It is important to consider these costs in the context of the costs of reducing GHG emissions from other sectors of the economy. This analysis is being developed in ARB's Scoping Plan process, and will allow ARB to make informed judgements about the amount of energy efficiency, renewable energy, and other emission reduction measures that should be pursued meet the AB 32 goals.

3.3.3. Sensitivity Analyses

The cost and rate impacts of different GHG reduction portfolios are sensitive to changes in some of the key assumptions underlying these results. For California's electricity sector, the most important drivers are:

- Load growth,
- Energy efficiency achievement and cost, and
- Natural gas price forecast.

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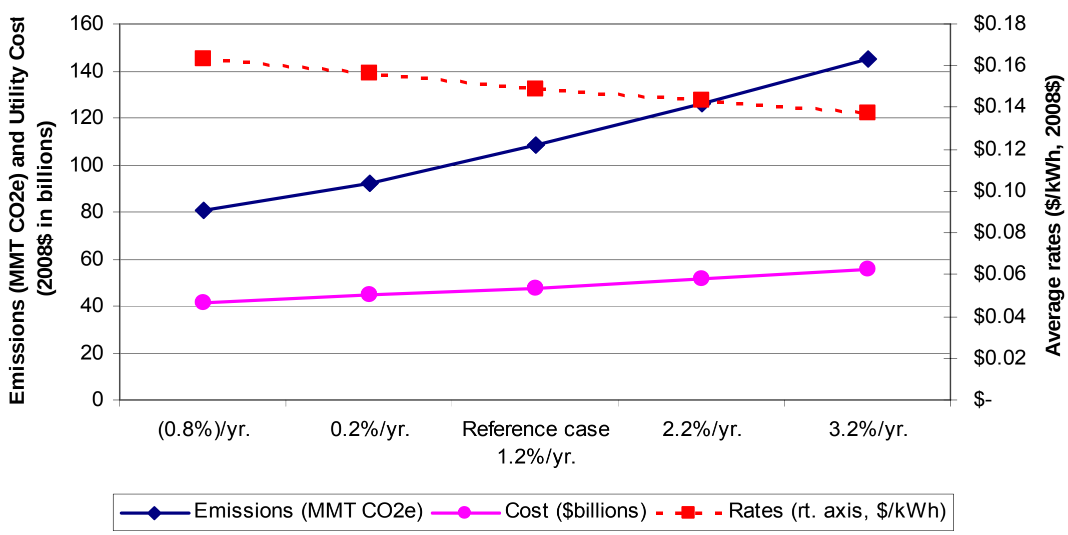
[18] Statewide retail electricity sales are estimated to total 277 terawatt-hours (TWh) in 2008, and to increase to 377 TWh by 2020 in the Natural Gas Only case. Statewide retail electricity sales in 2020 are estimated to be 321 TWh in the Reference Case and only 274 TWh in the Accelerated Policy Case (slightly less than the sales estimated for 2008).

In the E3 calculator, users can change the input assumptions for these values when developing their own scenarios. The results of an E3 sensitivity analysis for load growth are shown in Figure 3-3. Using Reference Case assumptions and varying only load growth, a 2% per year decrease from the Energy Commission's forecast that load will grow 1.2% per year results in an average decline in electricity demand of 0.8% per year, an emissions reduction of 28 MMT, and average rate increases of 10% after accounting for reduced capital investments. The reason rates increase at the same time that costs are reduced is that there are fewer sales over which to spread the utility revenue requirement. Increasing load by 2% per year above the Energy Commission's load forecast used in the Reference Case results in an average load growth rate of 3.2% per year, an emissions increase of 37 MMT, and a rate decrease of 8% after accounting for increased capital investments.

Figure 3-3

Sensitivity of 2020 Emissions, Utility Costs, and Average Rates to Load Growth Assumptions

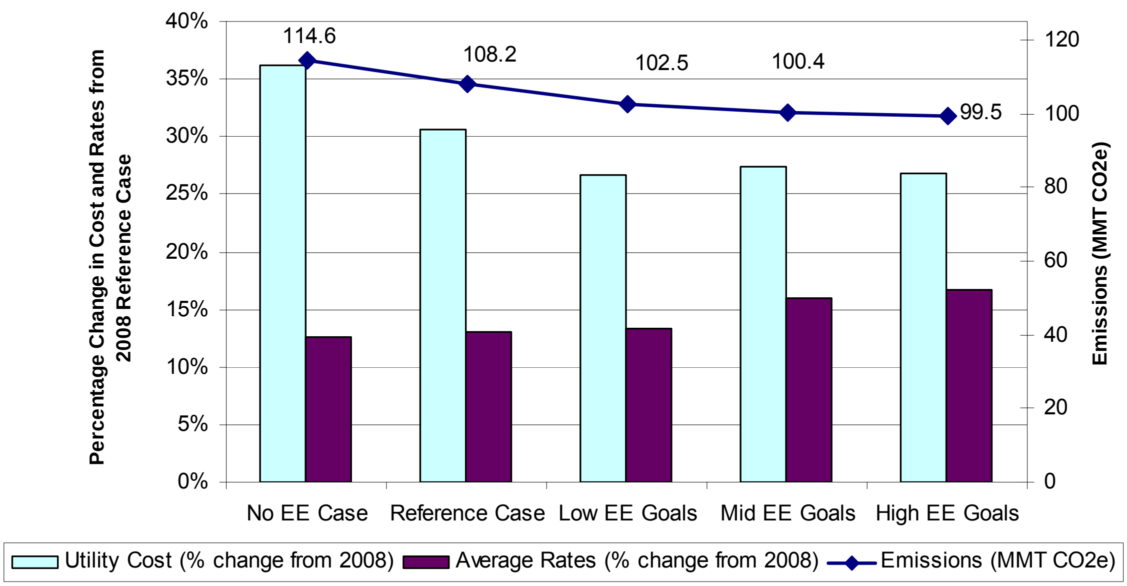


The results of an E3 sensitivity analysis for energy efficiency are shown in Figure 3-4. Using Reference Case assumptions and varying only the energy efficiency assumptions, emissions increase by 6 MMT in the case with no incremental efficiency, and decrease by 9 MMT in the high efficiency case. The "low goals," "mid goals," and "high goals" energy efficiency scenarios are based on the Itron Goals Update report for the three major investor-owned utilities in California. For the other entities in the state, energy efficiency achievements in these scenarios were extrapolated from AB 2021 filings to the Energy Commission.

E3 relied on the Itron scenarios in part because Itron was able to estimate the cost of achieving energy efficiency goals for those scenarios for the investor-owned utilities. Although the Commissions and the ARB are considering energy efficiency goals up to 100% of economic potential for energy efficiency, which is slightly higher than the Itron "high" scenario, currently no data or analysis exists to estimate the costs of achieving that level of energy efficiency.

Figure 3-4

Sensitivity of 2020 Emissions, Utility Costs, and Average Rates to Energy Efficiency Savings Assumptions



For a natural gas price sensitivity analysis, E3 tested 2020 prices between \$6 and \$12 per million British thermal units (MMBTU) in 2008 dollars. The original gas price assumption (\$7.85/MMBTU in 2008 dollars or \$10.56 in 2020 dollars) is based on the NYMEX forward price for natural gas as of March 2008. The prevailing market price approach is the best approach to develop an unbiased estimate of future natural gas prices because it is the price that a commodity trader could actually buy or sell gas today for future delivery. This price reflects all available information in the market by those with the best access to the information and ability to interpret it.

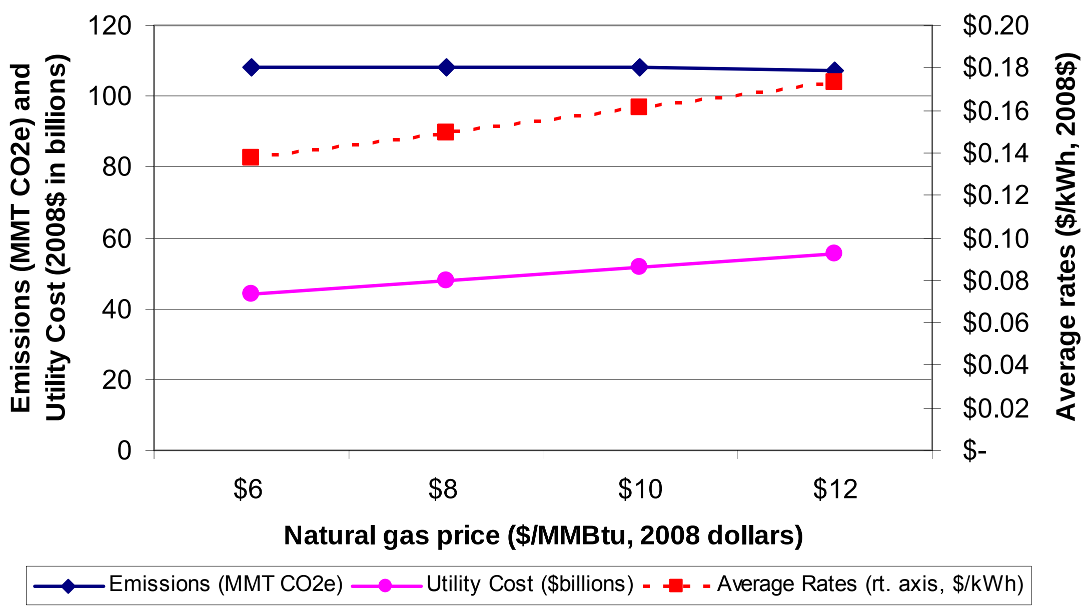
As of July 28, 2008, average NYMEX gas futures for 2020 delivery were trading at approximately \$9.86/MMBTU (2020 nominal) or approximately \$0.30/MMBTU less than in March 2008 when E3 established its input values for

2020. This fluctuation is well within the sensitivity ranges evaluated. Gas prices up to $12/MMBTU in real 2008 dollars (or $16/MMBTU in 2020 dollars) were evaluated.

Figure 3-5 below illustrates the findings of the natural gas sensitivity analysis. For each gas price, the cost-effective options in the resource plan were re-evaluated. The results across this range of natural gas prices at the reference costs of resources do not significantly affect carbon reductions in the electricity sector. In fact, at current resource prices, no additional clean energy resources are cost-effective until a price of $12/MMBtu in 2008 dollars enables some biogas to be cost-effective.

Figure 3-5

Sensitivity of 2020 Emissions, Utility Costs, and Average Rates to Natural Gas Price Assumptions



3.4. Modeling of Greenhouse Gas Cap-and-Trade Market

3.4.1. Modeling of Cap-and-Trade Design Choices

Within the broad cap-and-trade framework described in D.08-03-018, there are many potential design choices that would have an impact on California electricity consumers and the amount of carbon reduction achieved by the sector. The E3 GHG Calculator allows users to change some of these key cap-and-trade design assumptions and see the impact on key metrics, including utility costs and average rate impacts by retail provider; the impacts of a variety of GHG regulatory approaches on the electricity sector; and GHG emission levels both within California and in the entire WECC area.

Most of the cap-and-trade analysis was done assuming that the carbon market would initially be California-only, meaning that only in-state electricity generation and imports into California would face a carbon price, and not generation in the entire WECC area. This was the policy assumption in the GHG Calculator. Additional analysis was also done in PLEXOS with all generators in the WECC area facing a carbon price, simulating a regional or federal GHG policy. See Section 3.4.3 below for discussion of these results.

The GHG Calculator includes policy inputs that define the market price for carbon allowances and offsets, any limits on the amount of offsets allowed in the system, the method for distribution of allowances (auction, administrative allocation to deliverers, or some combination), and potential methods for distribution of auction revenue (or allowances – see Section 5.3 below) to retail providers.

If a user of the GHG Calculator chooses to model an auction for GHG allowances in a multi-sector cap-and-trade system, the user also chooses a market clearing price for GHG allowances. E3 did not endogenously model the market clearing price for GHG allowances in a multi-sector cap-and-trade program because the price would be the result of a number of policy and economic variables that fall outside the scope of this utility sector model, including the overall multi-sector cap on emissions, which sectors are included in the cap, the availability and price of qualifying offsets, the auction design, and other factors.[19]

Users of the GHG Calculator are also able to select whether, and how much, administrative allocation of emission allowances to deliverers would occur in the electricity sector. There are two steps to defining administrative allocation to deliverers: (1) the quantity to allocate administratively, and (2) the manner of the distribution of emission allowances to individual deliverers.

E3 modeled the distribution of allowances to deliverers using one or a combination of output-based and/or historical emissions-based allocation methods. In the case of output-based allocation, the output in the year allowances are granted is used as the basis of the allocation. In the case of historical emissions-based allocation, the emissions levels in 2008 are used as the basis of allocations. Both assumptions are simplifications for the purposes of modeling and do not constitute policy recommendations. In reality, the output-based allocations may be based on a prior year's output, and historical emissions may be determined by averaging over several years to reduce the volatility caused by hydro variations.

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[19] ARB is modeling different scenarios of multi-sector GHG regulatory regimes and how these scenarios affect the State using the Energy 2020 model. In contrast, the E3 GHG Calculator focuses exclusively on the impacts of GHG policies on the electricity and natural gas sectors.

If a user chooses a combination of both output-based and historical emissions-based allocations to deliverers, the model computes the administrative allocations by separating the available allowances into two pools based on the user-defined percentages and then allocating the allowances within each pool in proportion to the deliverers' output or historical emissions, as appropriate.

In addition, users can decide to model auction revenue (or allowance – see Section 5.3 below) distribution to retail providers. There are three steps to defining this policy in the model: (1) determining the amount of revenue to be distributed to retail providers, (2) selecting the basis for the distribution (sales-based or historical emissions-based), and (3) defining whether the auction revenue to return is a fixed share of the overall carbon market or is linked to the actual spending of the electricity sector in the carbon market auction. The model only considers distribution of auction revenue to retail providers, although in reality other alternatives are possible.

Similar to the market for GHG emission allowances, offset prices are also specified by the user. However, the model allows an additional control, limiting the percent of a deliverer's GHG compliance obligation that may be met with different types of offsets. The maximum amount of offsets that can be purchased by a deliverer is specified as a percentage of its total requirement. The offset prices and quantity limits are set independently for each of three types of offsets depending on origin: (1) a non-capped sector in California, (2) the region or the United States, or (3) international.

3.4.2. Modeling Results for a California-only Cap-and-Trade System

The GHG Calculator was used to analyze some of the impacts of a California-only multi-sector emissions allowance trading system, i.e., not a regional or federal system, but including allowances for emissions associated with imported electricity. By design, a California-only multi-sector cap-and-trade program (including electricity imports) would achieve emissions reductions to meet a pre-determined GHG cap. The trading component of the cap-and-trade policy would enable those GHG reductions to come from sectors or sources with lower marginal abatement costs than other capped sectors or sources. Analyzing the multi-sector impacts and interactions of such a multi-sector program lies outside the scope of E3's modeling, which was focused on electricity, primarily, and also on natural gas. Multi-sector modeling is being conducted by ARB.

E3 found that a California-only cap-and-trade system, modeled in the electricity sector with an exogenous price for GHG emissions on all electricity (including imports), is likely to increase costs in the electricity sector without achieving meaningful additional GHG reductions within the sector beyond the level of mandatory program reductions, unless one of the following or a combination of the following to a lower degree, occurs:

- Carbon prices reach high levels ($100/ton CO2e or more);
- Natural gas prices increase significantly (100% or more);
- Technology innovation drives down the cost of low-carbon electricity resources relative to natural gas or improves the performance of low-carbon technologies significantly; or
- Lower-cost opportunities are available from other sectors under the cap-and-trade program (though in this case the GHG reductions would come from those other sectors and not the electricity sector).

This finding assumes that lower-cost opportunities to reduce GHG emissions are available from other sectors under the cap-and-trade program, and underscores the critical need for including multiple sectors within the program and linking, to the extent possible, to trading systems beyond California's borders. A number of well-publicized analyses of carbon costs across sectors indicate that lower-cost opportunities may exist in sectors other than electricity. A multi-sector approach will be able to capture lower-cost opportunities in other sectors, but such results were not modeled by E3. Instead, E3's analysis focuses on the availability and costs of GHG reductions within the electricity sector.

Table 3-4 below shows the key findings of E3's simulation of the impacts on the electricity sector of a multi-sector cap-and-trade system implemented in California only.

Table 3-4

Impacts of California-Only Multi-Sector Cap-and-Trade Program on the Electricity Sector

Question	Key Findings
A. **Change System Operation?** Will cap-and-trade change how the existing fleet of California in-state generators operates, due to a GHG cost that changes the relative economics of plant dispatch?	a) No, because California plants are dispatched in emissions order already.
B. **Reduce Import Intensity?** Will cap-and-trade reduce the emissions intensity of electricity imports by increasing low-carbon imports and/or reducing high-carbon imports?	b) Possibly, but with risk of contract shuffling that would reduce California's apparent emissions responsibility while total emissions in the Western grid remain unchanged.
C. **Induce New Capital Investment?** Will cap-and-trade induce new capital investment, by adding a GHG cost that makes the all-in cost of low-carbon generation lower than the cost of fossil-fuel generation?	c) Possibly, if carbon prices exceed about $100/ton CO2e, based on current natural gas price and technology cost assumptions.
D**. Reduce Electricity Demand?** Will cap-and-trade reduce electricity demand, by adding a GHG cost that makes electricity prices higher?	d) Not much, because even a relatively high electricity demand elasticity (-0.3) does little to reduce emissions.
E. **Induce Technology Innovation?** Will cap-and-trade induce technology innovation, by increasing the market price for clean power?	e) Unknown. The E3 GHG model does not predict technology innovation.
F. **Have Distributional Allocation Impacts?** Will cap-and-trade result in distributional impacts due to allowance allocation policy choices and/or impact of the carbon market on electricity prices?	f) Yes, there will be winners and losers, affecting monetary flows between producers and consumers, and also different rate impacts for customers of different utilities.

3.4.3. Modeling Results for a Regional Cap-and-Trade System

In contrast to a California-only cap-and-trade system, linkage with trading systems on a regional basis, including all jurisdictions in the Western electricity grid, is more likely to result in a change in generator dispatch, with coal-fired generators operating less.

Under a cap-and-trade program, the prices of GHG allowances and offsets increase the variable cost of electricity generation. Currently, the lowest variable cost fossil-fuel units in the West are coal units, which also have the highest GHG emissions. If a carbon price were applied to all generators in the WECC area and if the carbon price became expensive enough, it would become more economic to dispatch existing natural gas units instead of existing coal-fired units. However, California's in-state generation mix contains very little coal-fired generation and includes mostly low-carbon, low-variable cost units (hydro, nuclear) and higher-carbon, higher-variable cost natural gas units. Therefore, including a carbon price would not change the dispatch order of generators in the State because the plants with the highest GHG emissions are already dispatched last.

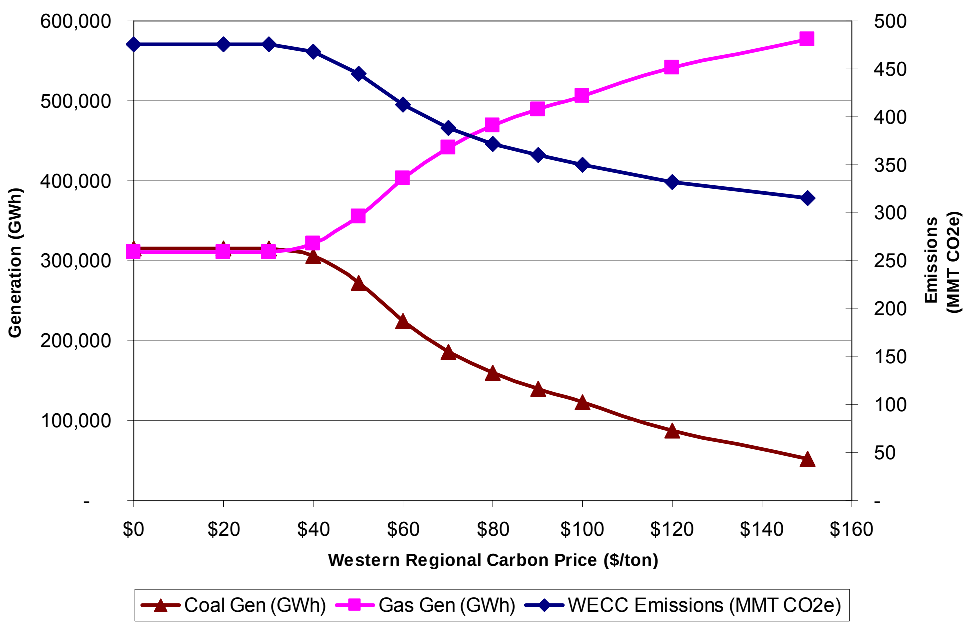
While the dispatch order of generators in California is not expected to change much under a cap-and-trade program, California imports a significant amount of coal-fired electricity. Under a California-only cap-and-trade policy, out-of-state generators would not pay for carbon allowances unless they deliver their power to California. Thus, the dispatch order of out-of-state generation is not expected to change based on the cost of California-only carbon allowances if the coal generation is still economic to serve non-California load. In the GHG Calculator, the user may select whether specified out-of-state coal contracts should be dropped if the price of carbon makes these contracts uneconomic. Unspecified electricity imports to California are modeled consistently with

D.07-09-017: the default assumption is that all unspecified imports are assigned a regional default emission factor of 1,100 pounds of CO2e/MWh produced.

To evaluate generation operational changes in a regional or federal GHG policy scenario, E3 ran several scenarios in PLEXOS in which the WECC-wide dispatch included a carbon price in the operating costs for all of the generators in the WECC area that emit GHG, with results shown in Figure 3-6 below. These PLEXOS scenarios included GHG allowance price assumptions from $0/ton to $100/ton of CO2e, in $10/ton increments, plus scenarios with prices of $120/ton and $150/ton. This analysis provides an estimate of the GHG reductions due to operational or dispatch changes of the 2020 WECC generator fleet due to a region-wide market for carbon allowances.

Figure 3-6

PLEXOS Results for WECC Dispatch with WECC-wide Carbon Price



This analysis found that, at the natural gas and coal prices assumed in the Reference Case, natural gas would begin to displace coal at a carbon price of about $50/ton CO2e, and that there would be a significant shift from coal to natural gas at a carbon price of around $60/ton. Higher coal prices relative to natural gas prices would be expected to reduce the required carbon price that would change operations. The answer to Question A in Table 3-4 above would change under a WECC-wide cap-and-trade program. This analysis was not built into the GHG Calculator; however, the results were presented at the workshop on April 21, 2008 and parties subsequently had an opportunity to file comments on the results.

In addition, a WECC-wide cap-and-trade program would significantly mitigate the "contract shuffling" concern raised in response to Question B in Table 3-4 above. A transparent, well-regulated regional system, with robust reporting and enforcement mechanisms, could eliminate incentives for contract shuffling and the resulting emissions reductions that are only on paper.

Finally, in a WECC-wide cap-and-trade program, new low-carbon generation may displace either coal- or natural gas-fired generation depending on time and location. Therefore, the relative price-point of carbon allowances needed to make new renewables cost-effective posed in Question C above depends on the relative variable costs and emissions rates of coal and natural gas. The responses to Questions D, E, and F would remain unchanged under a West-wide cap-and-trade program.

These findings only serve to underscore the critical importance of California's participation in a multi-sector and multi-state cap-and-trade system, to reduce costs and increase GHG reductions from the program.

3.4.4. Analysis of Effects of a Cap-and-Trade Program on Retail Provider Costs and Average Electricity Rates

A cap-and-trade program would add a GHG emissions cost to electricity generation, which could affect both wholesale and retail electricity prices. In a system with organized wholesale power markets such as California, all generators participating in the wholesale power market receive a single market clearing price for their electricity based on the bid of the last or "marginal" generator needed to meet electricity demand. The expectation is that, in most circumstances, the marginal generator would pass through its carbon cost in the market clearing price.[20] Retail providers would also be responsible for carbon costs associated with generation they own or have under long-term contract. These increased costs for both purchased and owned electricity would tend to increase retail rates, but could be offset to greater or lesser extents if allowances are distributed for free to deliverers and/or retail providers, as described briefly here and in more detail in Section 5 below. Cost savings arising due to the cap-and-trade program itself may also reduce bill impacts relative to other GHG mitigation approaches.

In this section, we provide a brief overview of E3's analysis of potential effects of a California-only cap-and-trade market on total utility costs and on average retail rates, depending on allowance allocation alternatives. We look at

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[20] A possible exception to this generality may occur in a GHG allowance cap-and-trade system with allowances allocated to electricity deliverers in proportion to some measure of output, which may not affect electricity prices, or not by as much as other approaches. However, the output-based allocation approach has never been implemented in practice, so the expected impacts of this approach have not been demonstrated empirically. For a more detailed discussion of the possible implications

Footnote continued on next page

E3's estimates of the effects of a cap-and-trade program assuming that the resource policies included in Accelerated Policy Case are implemented, because we are committed to pursuit of the resource policies in this scenario. The E3 analysis of cap-and-trade market alternatives assumes a carbon price of $30 per ton CO2e and no offsets.

Because of its focus on only the electricity sector in California, the E3 model does not capture the important potential financial benefits of a multi-sector cap-and-trade program and, thus, it tends to over-estimate electricity sector costs that may occur in a multi-sector cap-and-trade program. A multi-sector cap-and-trade program would allow entities with compliance obligations to identify least-cost GHG reduction opportunities among all of the covered sectors, which in turn could allow California to meet its emissions goals at considerable cost savings, relative to a GHG reduction approach that relied only on increased mandatory programs. A cap-and-trade program with a larger geographic scope could yield significantly greater costs savings, which also are not estimated by the E3 analysis. Nor does the E3 model quantify the additional emissions reductions that can be expected due to the presence of a price on GHG emissions, which would encourage additional conservation and investments in efficiency and low-GHG generation. Because of these limitations, we find E3's analyses of cap-and-trade scenarios most useful as a means to compare relative costs of various cap-and-trade design options, and less helpful regarding identification of total electricity sector costs in a multi-sector and/or regional cap-and-trade program.

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of output-based allocation approaches, see Section 5 of this decision, on allocation policy.

Figure 3-7 compares E3's estimates of utility costs for three cap-and-trade scenarios if the Accelerated Policy Scenario is implemented. The three cap-and-trade scenarios considered are (1) all allowances are auctioned and no allowances (or allowance value) are distributed to retail providers for the benefit of their customers; (2) all allowances are distributed at no cost to deliverers in proportion to their historical emissions; and (3) all allowances are auctioned, with either the allowances or allowance value distributed to retail providers for the benefit of their customers.

Figure 3-7

Estimates of Retail Provider Costs
With a California-only Multi-sector Cap-and-trade Program

(2008$ in Millions)

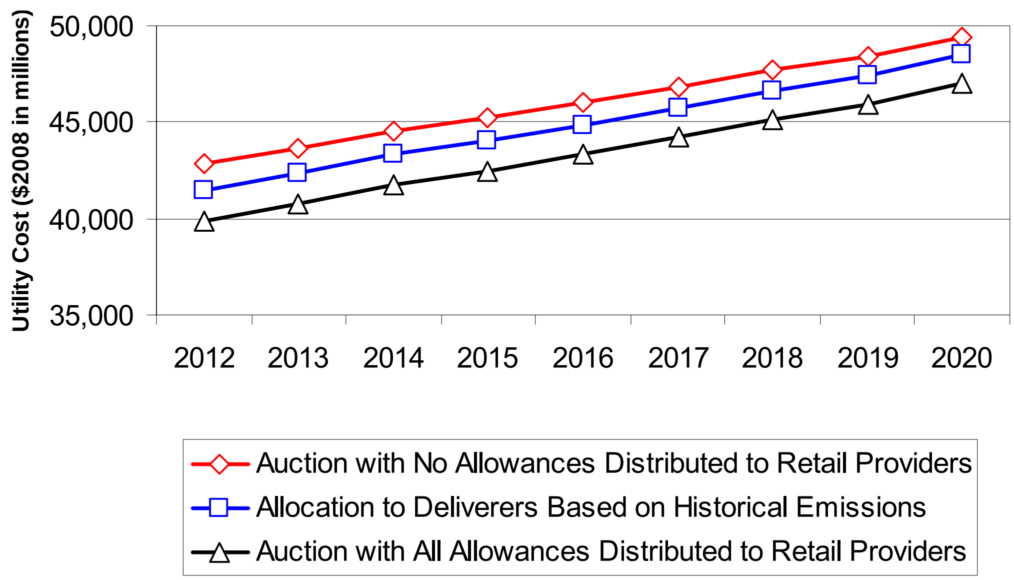
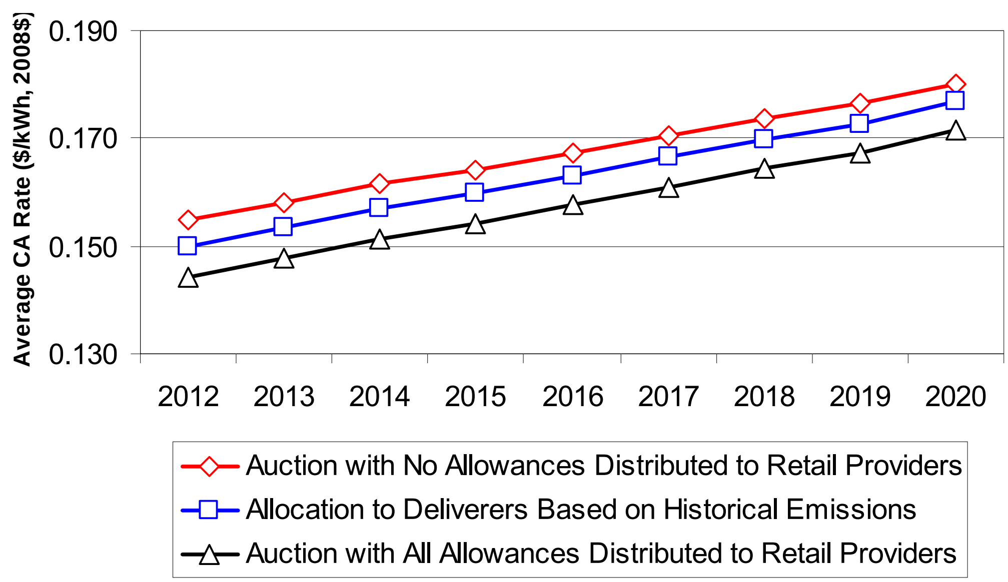


Figure 3-8 compares E3's estimates of statewide average retail electricity rates for the same three cap-and-trade scenarios.

Figure 3-8

Estimates of Average Retail Electricity Rates
With a California-only Multi-sector Cap-and-trade Program

($/kWh, 2008$)



Of the three cap-and-trade approaches considered, these figures indicate, as we would expect, that the most expensive approach from the retail provider and customer perspectives would be if all allowances are auctioned but no allowances or allowance value are distributed to the retail provider for the benefit of consumers. As indicated in Figure 3-7 and Figure 3-8, assuming $30 per ton allowance costs, such an auctioning approach could cost California retail providers approximately $2.4 billion more in 2020, with resulting increases in average retail electricity prices of about $0.009 per kWh, in 2008 dollars, compared to an approach in which all allowances are auctioned with retail providers receiving the auction revenues for the benefit of their customers. These results illustrate clearly why we believe it is crucial that all or almost all of the value of electricity sector allowances that are auctioned be distributed to retail providers, to fund emission reduction activities and mitigate these potential rate impacts.

The other cap-and-trade scenario presented in Figure 3-7 and Figure 3-8 would have all allowances distributed to deliverers at no cost in proportion to their historical emissions, which E3 calculated based on 2008 estimated emissions. As indicated in the figures, E3 estimates that this approach would cost retail providers approximately $1.5 billion more in 2020, with resulting increases in average retail electricity prices of about $0.005 per kWh in 2008 dollars, relative to auctioning with retail providers receiving the auction revenues for the benefit of their customers.

As illustrated above, auctioning with retail providers receiving auction revenues would largely mitigate the potential effect of carbon costs on total utility costs and retail rates while still providing powerful incentives to reduce emissions. As explained in more detail in Section 5, auctioning of allowances would create limited windfall profits in the form of "rents to clean generation," because the increase in the wholesale price of electricity paid to low-carbon resources that utilities purchase through the wholesale electricity market would exceed their compliance costs. The clean generation rents would constitute a wealth transfer from electricity customers to low-carbon electricity producers. Higher returns to clean generation would encourage further investment in low-carbon resources, principally renewable generation. Moreover, while the clean generation rents would tend to increase electricity rates somewhat, this potential increase might be outweighed by the cost savings benefits of a multi-sector cap-and-trade program, which are not captured by the E3 model.

As explained in Section 5 and illustrated above, distribution of allowances at no cost to deliverers would result in large windfall profits to independent generators and marketers, including allowance rents and clean generation rents. While clean generation rents have some offsetting benefits, as noted above, allowance rents are particularly worrisome. In Section 5, we recommend that historical emissions-based allocations to deliverers not be pursued, because of these unacceptably large wealth transfers and retail rate increases.

While not included in the above figures due to modeling limitations, output-based allocations to deliverers may reduce wholesale price increases and windfall profits, to the extent that output-based allocations would reduce the incentive for deliverers to pass through the carbon price in the wholesale energy market. (See Section 5.2.1.2.)

As explained in Section 5.4.2, we recommend that a fuel-differentiated output-based method be used to distribute a limited portion of allowances to deliverers in the early years of a cap-and-trade program, to be phased to 100% auctioning by 2016, with allowances distributed to retail providers and the auction revenues used to benefit customers.

3.5. Parties' Comments on Modeling Issues

Twenty-four parties filed comments that address modeling issues. The majority of modeling-related comments focus on input assumptions: integration costs,[21] transmission costs, resource costs, energy efficiency achievements, CHP operating characteristics, and penetration rates in the Accelerated Policy Case. There was also some discussion of the results. For example, SDG&E/SoCalGas and PG&E argue that the estimated rate and cost impacts are too low, while some of the advocacy groups argue that the estimated rate and cost impacts are too high.

Other modeling-related questions and issues raised in the comments include the following:

- What is the best metric for evaluating allocation scenarios: should we consider retail provider "normalized" cost impacts (such as utility costs relative to utility benefits, or relative to utility size) or cumulative impacts from 2008 or 2012 – 2020, rather than just annual costs in 2020? (SCE, SMUD)
- Does the model show any value to a cap-and-trade approach? (LADWP)
- How reliable is the theorized electricity market clearing price effect[22] of an output-based allocation, and what is the best estimate of the magnitude of this effect? (SMUD)
- How much uncertainty is there surrounding the key assumptions for the Reference and Accelerated Policy Cases?

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[21] Integration costs include the cost of reliably incorporating intermittent resources such as wind and include the costs of increased ramp and regulation, and increased capital costs to increase the ability of the system to accommodate larger variations in generation output.

[22] The "market clearing price effect" refers to the increase in wholesale electricity prices due to the introduction of a carbon allowance cost for electricity deliverers.

The following sections discuss model and input issues. Other modeling-related comments are discussed in other relevant sections of this decision.

3.5.1. Model Structure and Operation

3.5.1.1. Documentation

Several parties, including SDG&E/SoCalGas and SCE, state that the model documentation is insufficient and that the model is overly complicated. They also express concern with labeling within the model that they claim is poor, inconsistent, or misleading.

E3 made substantial improvements in the model interface in the final version, including consolidation of controls on the Resources and CO2 Market tabs, color coding of inputs, adding an input/output printable table, and including a map to the different tabs. On May 6, 2008, Public Utilities Commission staff held a WEB-EX workshop to educate stakeholders' technical staff on the model's architecture and how to run scenarios. E3 also made itself available via phone, email, and in-person to meet with various stakeholders to answer questions and address concerns about how to use the model. Even with those efforts, there is a degree of irreducible complexity in the model that reflects the subject matter and the types of analyses requested, and only familiarity through use, rather than documentation per se, will help users fully understand its function and results.

3.5.1.2. Price Elasticity of Demand

Some parties comment that the model does not dynamically account for the price elasticity of demand. As designed, the GHG Calculator has no feedback loop by which demand for electricity or natural gas is reduced in response to increasing electricity, carbon, or gas prices (or increased in response to lower prices). These price-induced demand effects will change the estimated cost effectiveness of carbon reduction measures. However, it was too complex to build the effects of price elasticity into the model. Instead, E3 handled this issue in the following manner.

E3 tested the sensitivity of results to average price elasticity assumptions and found that the impacts on emissions, costs, and rates are very small even with a fairly aggressive assumption for price elasticity (-0.3). While the model does not dynamically iterate to adjust demand interactively with price until an equilibrium is reached, if a user wants to see the impact of price elasticity, there is a control that can be used to adjust demand based on user assumptions about the price response.

We note that the effects of price elasticity at higher prices are not clearly understood and the differential impacts on energy-intensive elements of the economy have not been addressed in this assessment. While demand response to average prices may be low, the more energy-intensive elements of the California economy pay electricity rates well above the average rate. Hence, they would be more likely to notice and to respond to price increases. Similarly, a fundamental purpose of adding the price of carbon into the price of electricity (which is what a cap-and-trade system does) is to induce technology innovation throughout the economy. Users would not have to rely on utility programs to invest in technologies that would lower their bills; instead they are rewarded for searching out incremental efficiency improvements. Price elasticity is an economy-wide issue which ARB is working on modeling, and there is need for more analysis. As has been recently demonstrated in the transportation sector, it may take very high prices to induce individuals to make big shifts in their use of energy but, once started, the changes may snowball. On the other hand, high electricity rates can discourage high consumption from the grid (e.g., prohibitively high prices in the upper tiers of residential rates may encourage solar photovoltaic installations). We do not know these "tipping points" for different types of electricity users.

3.5.2. Input Assumptions and Results

GPI comments that, "the input assumptions used by E3 in both the reference case and the other cases it has prepared appear to us to be valid. E3 has done a good job of estimating inputs based on the current market, and it has done some good work in estimating future markets. One thing that may not be possible to model is a large change in the market, such as a change in technology. While E3 may not be able to model such a market change, it is important to keep in mind that such a change is possible, even probable given the amount of effort going into improving technology and finding new energy sources." (GPI Comments, p. 34).[23]

SMUD states that it "commends the Commissions and E3 for the Stage 2 modeling effort. Although the model has weaknesses at the specific [retail provider] level, the model nonetheless provides real information and allows participants to adjust parameters and view the impacts of those changes." (SMUD Comments, p. 12.)

PacifiCorp states that the E3 modeling results appear to support similar modeling performed by the Electric Power Research Institute that examined the effects of different CO2 prices on the WECC power market, including natural gas being dispatched ahead of coal once CO2 is priced closer to $60/ton (i.e., reducing coal electricity imports into California). (PacifiCorp Comments, p. 47.)

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[23] Cites to parties' comments are to their opening comments due June 2, 2008, unless indicated otherwise.

PG&E contends that "model results should always be represented in an uncertainty band." Regarding the Reference Case outcome of an emissions level of 108.2 MMT in 2020 for the electricity sector, PG&E comments that "slight changes in assumptions would change this figure. For example, if load growth continues at the 1990-2000 historic levels, 1.5%/year, then the 2020 electricity sector emissions projection becomes 114.5 MMT CO2. A few small, realistic changes in inputs change the emissions outcome substantially, and so the ARB's implementation of AB 32 must accommodate the uncertainty inherent in the sectors' 2020 emissions forecast." (PG&E Comments, p. 101.)

We agree that variations are likely in the key drivers over time, and it is important to recognize these as policy is developed. The GHG Calculator was developed to allow evaluation of the effects of changes in key drivers and exploration of policy decisions that would accommodate a range of actual conditions over time.

3.5.2.1. Electricity Prices and Natural Gas Heat Rates

Some parties (Solar Alliance and CalWEA/LSA) contend that the natural gas market heat rates and electricity market prices in the model are too low. Referring to the Accelerated Policy Case, they state that, "The electricity market prices used in the model average $54 per MWh. Assuming variable operations and maintenance of $2.50 per MWh in the market price and dividing the remainder by the gas price results in a market heat rate of approximately 6,600 Btu/kWh. This is 5% below the 'clean & new' heat rate of a new [combined cycle gas turbine] CCGT, and is inconsistent with typical market heat rates of 8,000 Btu per kWh observed in the California wholesale market in recent years." (Solar Alliance Comments, p. 10, and CalWEA/LSA Comments, p. 10.)

In the Accelerated Policy Case, electricity loads are approximately 88% of the forecast load levels in 2020. At these load levels, the PLEXOS model indicates that natural gas plants are not always on the margin, which causes the relatively low market heat rate that concerns these parties.

The "market prices" referenced above are based on the PLEXOS model output and include only the energy component of the electricity wholesale costs. Therefore, the reported average market prices do not include the costs of capacity. The model includes the capacity value of displaced new generation in the calculation of resource value and adds it to the energy values cited. The total value of new resources once capacity value is added for the Accelerated Policy Case is about $74/MWh annual average value of energy and capacity, which we believe is reasonable.

3.5.2.2. Wind Integration Costs

CEERT contends that the wind integration costs used by E3 are too high and recommends that we rely on costs produced by the Intermittency Analysis Project (IAP) and adopted by the Energy Commission. According to CEERT, "IAP estimated integration costs [are] at $0.69/MWh for wind in a 33% renewables by 2020 scenario [whereas] E3 assumes a range of $4.09 – 6.36/MWh." (CEERT Comments, p. 16.)

The E3 team evaluated the IAP project and found the wind integration costs at the extreme low end of the range in the studies available and used to develop wind penetration cost estimates. The IAP appears to assume that the State's hydro system can be used to provide increased ramp and regulation needs at zero cost. Said another way, in the IAP analysis there is no opportunity cost for redispatching the hydro system. In addition, the IAP only evaluates a single resource scenario and provides no mechanism to estimate differing integration costs for different renewable resource mixes as is required in the GHG Calculator.

EPUC/CAC contend that the renewable integration costs used by E3 may be too low because "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." (EPUC/CAC Comments, p. 19.)

The GHG Calculator includes incremental transmission costs attributable to new renewables in order to evaluate the relative impact of new renewables for any case defined by the user. In addition, the GHG Calculator adds an integration cost for wind that includes costs of system balancing, ramp, and regulation.

EPUC/CAC also question the ability of the electricity system to integrate large amounts of renewable generation. EPUC/CAC contend that reliability impacts have not been fully assessed: "… 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 [and …] the California grid could see too much generation in generation pockets and too little supply in load pockets." (EPUC/CAC Comments, p. 19.)

We reiterate that the GHG Calculator is a policy-level tool and not a detailed resource planning or system operations model suitable for evaluating renewable integration. While PLEXOS has the capability of performing detailed operations simulation, it was not run in a manner that would provide detailed renewable integration costs for all possible cases of potential interest. Such analysis is not possible in a tool that allows for such diverse system configuration and range of plans necessary for policy-level decisions. To estimate integration costs, the GHG Calculator adds a renewable integration cost as a function of wind penetration. E3 developed the integration cost function based on numerous intermittent cost studies that analyzed the details of system cost.

We acknowledge that there is a great deal of uncertainty regarding the integration costs for renewable energy and more work is ongoing. Factors contributing to the uncertainty include (1) the proportion of intermittent to firmed or baseload renewables developed for the state's renewable energy goals and voluntary Renewable Energy Credit (REC)[24] market; (2) changes made to the fossil fuel generators' ramping capabilities over the next 12 years; and (3) changes made to the amount of regulation support, short-term and long-term "storage," and the integration of Smart Grid technologies, among many other factors.

3.5.2.3. Resource Costs for Conventional and Renewable Generation

TURN contends that capital construction costs in the model may be too low and do not take into account recent cost increases.

The cost of new clean energy technology is important, but also hard to predict. In the GHG Calculator, the Reference Case assumption is that current capital costs stay the same in real terms between 2008 and 2020. Increased demand for raw materials or competition with other regions for clean technology could drive up clean generation capital costs, in real terms, between now and 2020. However, capital costs for clean technology could also decrease in real terms if the technology improves and/or production methods and manufacturing become more efficient over time. If the price of inputs such as steel rises for all technologies, the relative change in prices among technologies may be less pronounced than if some technologies make major efficiency improvements while others do not. However, if solar thermal technology capital costs were to fall 25% in real terms between 2008 and 2020 while other technologies' costs did not change, for example, far more solar thermal installations could become viable in the near term, reducing the cost to the electricity sector of compliance with GHG reductions policies.

NRDC/UCS state that the assumed capital costs for combined cycle gas turbines (CCGT) are too low:

> The E3 model documentation notes that the model escalated capital costs for all generating technologies "by 25% per year for two years to reflect recent rapid inflation in construction costs, with the exception of solar, thermal and wind." Because the model's CCGT capital cost assumptions are based on plants built in 2004 and 2005, they also appear to have been excepted from the 25% per year cost escalation applied to other resources. For consistency, and to ensure that CCGT capital cost assumptions reflect current market reality, the CCGT capital cost should be escalated by a similar rate to other resources, or by a widely used power industry price index such as the Handy-Whitman index. (NRDC/UCS Comments, p. 49.)

The CCGT capital costs were escalated to reflect recent capital cost increases using the same approach as adopted in Resolution E-4118 in the Market Price Referent proceeding, R.04-04-026. Furthermore, there is not an inconsistency introduced by using different escalation rates for the costs of CCGT and new clean resources because the data sources are different. The CCGT costs are based on actual plants built in California while the costs of clean energy technologies are based on planning level estimates used in the United

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24 The Public Utilities Commission has defined and characterized the attributes of a REC for California RPS compliance in D.08-08-028 in R.06-02-012.

States Department of Energy's 2007 Annual Energy Outlook. E3 found the 2007 Annual Energy Outlook costs to be lower than the range of costs reviewed and documented in the Stage 1 analysis and therefore applied higher inflation rates to provide an estimate of actual installed cost on the same basis as assumed in the Market Price Referent proceeding.

3.5.2.4. Natural Gas Price and Other Fuel Prices

A number of stakeholders claim that the natural gas prices used in the E3 scenarios are too low. According to CEERT, natural gas prices may be closer to $17/MMBTU by 2020, a price which it asserts would have implications for the cost-effectiveness of new renewable resources. Environmental Council and Solar Alliance prefer to assume $15/MMBTU in 2020 in 2008 dollars. In addition, they state that coal prices should be closer to $3.03/MMBTU in 2020, instead of $1.01/MMBTU.

Taking another view, TURN states that the assumed natural gas price is too low, but that "… it is not clear that a reasonable increase in gas prices will make renewable energy economic compared to natural gas anyway." (TURN Comments, p. 30.) However, CalWEA/LSA contend that an increased starting natural gas price would lead to a decrease in the cost of GHG reductions: "If the starting natural gas price is increased to $10 per MMBtu [from $7.85/MMBtu], the cost of GHG reductions from a 33% RPS decreases from $133 to $106 per tonne." (CalWEA/LSA Comments, p. 9.) NRDC/UCS also have concerns about the low prices used by E3 in its scenarios. However, they also believe that adding renewable energy might reduce demand for natural gas resulting in between 2% and 15% downward pressure on price levels in the future. (NRDC/UCS Comments, p. 46.)

According to CalWEA/LSA,

> "in the long-run, fossil fuel prices can be expected to exhibit a positive real escalation rate, as they become increasingly difficult to find and produce. In addition, the structure of the E3 model does not recognize the potential for renewable resource costs to decline over time, as renewable technologies improve. These differential escalation rates become particularly significant over the multi-decade timeframe in which the GHG reduction program will operate. Indeed, one of the primary benefits of renewables is that they substitute capital costs for fuel costs, and are a long-term hedge against future fuel price escalation. The E3 model's use of constant, 2008 dollar costs in all years ignores these significant benefits of renewables. CalWEA and LSA have re-run the E3 calculator, assuming that a natural gas price of $10 per MMBtu in 2008 increases at the historical long-term real escalation rate of 3.5%; using this rate, the natural gas price would exceed $15 per MMBtu in 2020 in 2008 dollars. This change in the profile of natural gas prices used in the E3 calculator results in a GHG mitigation cost for a 33% RPS of $43 per ton." (CalWEA/LSA Comments, p. 10.)

SCPPA asserts that "if gas prices are assumed to be at or beyond today's prices of nearly $12/MMbtu, even higher allowance prices would be required to alter the dispatch of coal-fired generation." (SCPPA Comments, p. 10.)

As discussed in the section on sensitivity analysis above, natural gas prices in 2020 are a key driver of model results. The Reference Case natural gas price forecast for 2020 is $10.56/MMBTU in nominal dollars (or $7.85/MMBTU in real 2008 dollars). This is the price of natural gas for 2020 that could be secured in the NYMEX forward market at the time of the analysis in March 2008. Spot prices could increase or decrease from this forecast, and E3 and other parties performed sensitivity analyses on natural gas prices. However, the NYMEX market prices reflect the best publicly available unbiased forecast of future gas prices. If 2020 natural gas prices were to reach the range of $19 - $21/MMBTU in nominal dollars (or $14 - $17/MMBTU in real 2008 dollars), the average all-in cost of wind would be competitive with the cost of installed natural gas units. Likewise, if

2020 natural gas prices were to reach the range of $21 - $24/MMBTU in nominal dollars (or $15 - $18/MMBTU in real 2008 dollars), the average all-in cost of solar thermal would be competitive with the costs of natural gas generators.

We note that, while increases in assumed natural gas prices make the cost of renewable energy more attractive, higher gas prices also make out-of-state coal generation relatively more cost effective. Likewise, higher gas prices increase overall utility costs, given the high degree of reliance that California utilities have on natural gas generation.

3.5.2.5. Energy Efficiency

Some parties are concerned about the achievability of the energy efficiency levels in the E3 scenarios and about the likely costs:

> [T]he EE values proposed for use in Phase 2 of the GHG modeling are more realistically achievable than the EE levels used in Phase 1. However, SCE has concerns about EE levels used in E3's Mid and High Cases because these cases assume utility incentive programs based on 100% of incremental cost[footnote omitted], an approach that has never been used on a comprehensive basis in the real world. Use of a scenario based on current incentive levels would be a more realistic assumption until the efficacy of the 100% can be demonstrated based on empirical results. (SCE Comments, p. 49.)
>
> The aggressive case is unprecedented, and ARB should not assume that these levels of EE and [renewable electricity] will be achieved in the scoping plan. Small changes to the load growth assumption change emissions substantially. (PG&E Comments, p. 101.)

Regarding energy efficiency modeling, SDG&E/SoCalGas state that, "non-intuitive results such as the aggressive energy efficiency case showing that utility costs of these programs may exceed the 'total resource cost' [footnote omitted] creates questions of modeling accuracy of these assumptions." (SDG&E/SoCalGas Comments, p. 41.) In fact, in the "mid" and "high" energy efficiency scenarios, utility costs are correctly higher than the total resource cost by a few tenths of a cent per kWh. This is because in a few cases the Itron analysis assumed that the current utility rebates exceed 100% of full incremental measure costs.

A number of current incentive programs administered by the investor-owned utilities have paid 100% of incremental cost for energy efficiency measures.[25] For example, several small business programs have paid incremental costs, and have paid more than incremental costs for certain qualifying customers. Furthermore, the low-income energy efficiency programs, although not incentive programs, may provide 100% or more of incremental costs, and generally are more comprehensive than investor-owned utility incentive programs, dealing with building envelope as well as lighting and heating, ventilation, and air conditioning systems. Additionally, retrofit programs, which provide incentives for the replacement of technologies before the end of their useful lives, often provide more than incremental cost; they may provide a high percentage or even 100% of total cost.

In general, assumptions about the penetration and costs of achieving energy efficiency in the model are among the largest uncertainties in the analysis, as discussed in the section above related to sensitivity analyses. Several parties also assert that there is insufficient documentation of the energy efficiency costs in the model. Cost assumptions are all "best estimates" based on analysis of investor-owned utility costs performed by Itron for the Public Utilities Commission's IOU Goals Update Study.

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[25] "Incremental cost" is the difference in cost between a "normal" inefficient product and the substitute high energy-efficiency product.

3.5.2.6. Interaction of Cap-and-Trade and Renewables Assumptions

Several parties express concern that a requirement to participate in a cap-and-trade system may not induce the development of new renewables, or may encourage renewables only at very high allowance prices exceeding \$100/ton CO2e:

> Given the E3 results showing the potential inefficacy of requiring the electric sector to participate in a multi-sector cap-and-trade program except at very high allowance prices and given the current absence of evidence about the cost of GHG reductions in other sectors, it would be premature to force the electric sector into a multi-sector cap-and-trade program. Thus, SCPPA recommends that the Commissions revisit their Interim Opinion and, upon reconsideration, defer recommending that the electric sector participate in a multi-sector cap-and- trade program. (SCPPA Comments, p. 3-4.)

> A comprehensive approach to renewables is fundamentally important if they are to play a significant part in GHG reduction. Renewables are a capital-intensive industry with long-term planning needs, both for the facilities themselves and the transmission infrastructure necessary to support them. It is unrealistic to expect the substantial investment needed for renewables to exceed the current 20% target based on a brand new pricing signal from a yet-to-be established cap-and-trade system, which, based on the experience of other markets, is certain to be somewhat volatile in its fledgling years. (CalWEA/LSA Comments, p. 2.)

Despite the relatively high cost of renewables based on current prices found in the E3 analysis, increased renewables development will remain a significant component in decarbonizing the California electricity sector to meet the AB 32 targets and more critically California's 2050 goal of 80% reductions below 1990 levels. Mandates for renewable energy will ensure that renewables are developed even if carbon allowance prices are lower than the level necessary to induce new renewables or if fossil generation is cheaper than renewable generation for other reasons.

As described in D.08-03-018, we recommend that the electricity sector be included in the cap-and-trade program because it could encourage greater innovation and cost reductions, including in the development of renewable generation. Additional development of renewables could occur in the voluntary market for RECs, if utilities surpass renewables mandates, or if there is increased self-generation using renewables that is not accounted for outside of a cap-and-trade market. Some parties ask that some number of allowances be set aside for the voluntary market, as discussed in Section 5.4.3.2 below. Although E3 took a conservative approach and assumed no market transformation , a higher market price for electricity and a higher carbon price could drive new technology innovation, resulting in new sources of emission reductions in the sector at lower costs. The GHG Calculator allows parties to model alternative future scenarios by substituting their own values for selected variables; a number of these scenarios were submitted in comments. On this point, the modeling itself or its methodology is not the issue; rather it is the differing assumptions about the future that drive different results. Will carbon prices reach and maintain a level of $100/ton CO2 or more? Will natural gas prices increase significantly? Will technology innovation drive down the cost of low-carbon resources or improve the performance of low carbon technologies? We believe that, over the long term, the potential opportunities that can be created by increased market pressure are likely to outweigh the costs to ratepayers imposed by including electricity within an emissions cap-and-trade system.

3.6. Scenarios Submitted by the Parties

Several stakeholders used the GHG Calculator to model different outcomes to inform their own comments:

- PG&E used the model to show the carbon impacts of its proposed alternative scenarios.
- IEP used the model to show the impacts of alternative producer surplus scenarios.
- SCE used the model to generate alternative metrics for evaluating the "economic harm" of allocation scenarios.
- WPTF used the model to submit alternative allocation scenarios.
- SMUD used the model to evaluate different allocation scenarios and developed its own metric for evaluating them.
- Environmental Council created a preferred set of input assumptions for the Reference Case.
- NRDC/UCS submitted alternative scenarios to support their comments.
- NCPA used the model to develop and verify its own allocation model developed by R.W. Beck.

These submissions are discussed where relevant in this decision.

4. Emission Reduction Measures and Overall Contributions of Electricity and Natural Gas Sectors to AB 32 Goal

ARB's Draft Scoping Plan calls for an "ambitious but achievable" reduction in California's carbon footprint. In order to achieve the statutory goal of returning statewide emissions to 1990 levels, the Draft Scoping Plan estimates necessary reductions of 169 MMT of CO2e. Both the electricity and natural gas sectors are expected to be key contributors in achieving that goal.

This section addresses the level of emission reductions that can be achieved by the electricity and natural gas sectors by 2020.[26] In addition, we indicate best estimates of the cost at which varying levels of sector-wide emissions reduction may be achieved, informing recommendations regarding appropriate distribution of emissions reduction responsibility across sectors of California's economy. Information presented in this section should also inform overall emissions cap levels (i.e., the total number of allowances allocated) for a cap-and-trade program inclusive of the electricity sector, if one is implemented.

4.1. Emission Reduction Measures

In this decision, an "emission reduction measure" describes a means by which the sector as a whole can achieve GHG emissions reductions. Our goal is to estimate, using best-available information, the overall level of reductions that may be expected from the electricity and natural gas sectors within AB 32's 2020 timeframe; which resource areas, generally, those reductions will derive from; and the associated costs. While the realization of certain reductions estimated herein may require support through the establishment of new or accelerated policies, it is not our intent to do so by way of this decision.

In basic terms, electricity sector emission reductions derive from the displacement of GHG-emitting generation. Such displacement can be achieved either through measures that work on the supply side to reduce the carbon intensity of electricity deliveries to consumers, or through demand-side measures that either reduce the overall demand for electricity from the

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[26] The natural gas sector, as defined in the amended scope for this proceeding, is described in D.07-05-059 and consists mainly of natural gas combustion chiefly in the residential and commercial sectors, plus fugitive emissions from natural gas pipelines and other infrastructure.

transmission and distribution grid or generate electricity on the customer side of the meter. For the natural gas sector, emission reduction opportunities are largely limited to demand reductions and solar hot water heating,[27] as natural gas demand is served by a uniform fuel source with fixed carbon content. However, some parties have suggested opportunities by which fossil natural gas supplies can be replaced by biogenic sources (biomethane), effectively reducing the net carbon intensity of servicing natural gas demand for certain end uses.

Considering GHG reduction measures within the electricity and natural gas sectors necessarily entails bringing together a host of efforts that have been underway in California for many years. Although not all of such measures have been motivated directly by climate concerns, they nonetheless contribute to achieving targeted GHG reductions.

The emission reduction measures examined in this proceeding include increased penetrations of the following:

- energy efficiency through codes and standards and a host of programs provided by utilities or other providers,
- utility-scale renewable generation by way of the State's RPS mandate and other potential options to ensure increased renewable investment,
- distributed photovoltaics through the Million Solar Roofs Initiative,[28] and
- CHP facilities.

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[27] ARB's Draft Scoping Plan has recognized solar hot water heating as an important measure that is also related to reaching the "zero net energy" goals of both Commissions in 2020 and 2030 for residential and commercial buildings, respectively.

[28] This program includes the California Solar Initiative, the New Solar Homes Partnership, and other photovoltaic programs.

Other measures suggested by parties, though not analyzed in depth in this proceeding, include solar hot water heating, biomethane, Smart Grid technologies, and carbon capture and storage.

Currently, the best available information regarding the quantified emission reductions stemming from the various measures examined in this proceeding comes from the work undertaken by E3 described in more detail in Section 3 above. In the scope of this work, E3 gathered detailed information regarding the market potential in each of the above-bulleted areas.

4.1.1. Energy Efficiency

In D.08-03-018, we recommended that ARB incorporate into its Scoping Plan a goal of achieving all cost-effective energy efficiency in the State, through a combination of utility programs and non-utility actions and initiatives, including mandatory standards. ARB's Draft Scoping Plan picks up on the D.08-03-018 recommendation and proposes an aggressive pursuit of energy efficiency opportunities to assist in meeting AB 32's emission reduction goals.

In particular, the Draft Scoping Plan would set new targets for statewide energy demand reductions of 32,000 GWh and 800 million therms from business-as-usual projections for 2020. These targets apply to both investor-owned and publicly-owned utilities, and are expected to be achieved through a combination of means, including enhancements to existing utility programs such as increased incentives, more stringent building codes and appliance efficiency standards, and a concerted effort to transform consumers' use of energy products.

In D.08-07-047, adopted on July 31, 2008 in R.06-04-010, the Public Utilities Commission adopted new energy efficiency goals for the years 2012-2020 for investor-owned utility service territories. The purpose of goal-setting on this time frame was in large part to assist in informing ARB in the development of its

Scoping Plan. The adopted goals, which were informed by Itron's most up-to-date assessment of energy efficiency potential within investor-owned utility service territories, take into account savings from the entire breadth of energy efficiency opportunities. In addition to direct savings from the investor-owned utilities' programs, they include recognition of State building and appliance standards and expected federal appliance standards, the Public Utilities Commission's Big Bold energy efficiency strategies, and AB 1109 (requiring improvement in general service lighting). The goals include total energy savings from new investor-owned utility programs of over 16,000 GWh and 620 million therms between 2012 and 2020. Including expected savings from current programs between 2008 and 2012, total electricity savings would exceed 26,000 GWh.

As mentioned above, we support a goal of achieving all cost-effective energy efficiency, through a combination of means. We recommend that ARB set electricity and natural gas energy efficiency requirements in its Scoping Plan at the level of all cost-effective energy efficiency, with energy efficiency goals for investor-owned utilities set based on those adopted in D.08-07-047, as may be revised and updated by the Public Utilities Commission from time to time. We recommend further that ARB consider leveraging the substantial analytic work and stakeholder input embodied within the recently adopted California Long-Term Energy Efficiency Strategic Plan as a roadmap to achieving these ambitious and unprecedented levels of energy savings across the State.

As part of its modeling, E3 has incorporated into its GHG Calculator scenarios the same underlying energy efficiency potential data that has informed the Public Utilities Commission's energy efficiency 2020 goal setting. While E3's Reference Case reflects business-as-usual with respect to energy efficiency savings, the Accelerated Policy Case reflects the achievement of Itron's "high goals" scenario. The E3 modeling results indicate that achieving Itron's "high goals" for energy efficiency would reduce GHG emissions in 2020 by an additional 10.2 MMT compared to business as usual and that these reductions would come at an incremental cost of $63 per ton.

4.1.1.1. Positions of the Parties

Several parties comment on the energy efficiency assumptions underlying E3's model. PG&E argues that, even after improvements between Stage 1 and Stage 2 to the model's representation of energy efficiency, energy efficiency costs assumed in the modeling are still "orders of magnitude" too low. As a result, PG&E suggests that E3 change the Accelerated Policy Case energy efficiency assumption to reflect Itron's "low" goals.

SCE is of the view that the Stage 2 energy efficiency scenarios are much better than the Stage 1 assumptions, but remains skeptical that Itron's "high" and "mid" goals are achievable. Due to uncertainty surrounding the unprecedented levels of energy efficiency program achievement in the Itron scenarios, PG&E argues that ARB should not assume in its Scoping Plan that either the "high" or the "mid" goals case will be achieved. PG&E suggests that, at the very least, the Commissions should conduct sensitivity analyses on energy efficiency costs and/or communicate model results to ARB with an acknowledgement of the uncertainty associated with different outcomes.

4.1.1.2. Discussion

In this decision, we reaffirm our commitment to achieving all cost-effective energy efficiency in California. Energy efficiency is, as always, the cheapest and most effective energy resource, and is now our best means to reduce GHG emissions in the electricity and natural gas sectors. Making this happen will require a focused effort and new, aggressive approaches to delivering efficiency options to consumers.

Given that current levels of investment in energy efficiency do not capture the entirety of what is cost-effective, we do not agree with those parties who argue that instituting a cap-and-trade program will make energy efficiency mandates unnecessary. Indeed, many non-price market barriers to energy efficiency investment exist today and will continue to exist even if a GHG emissions allowance cap-and–trade program is implemented.

In addition, as the cost of GHG mitigation is increasingly reflected in the cost of energy, more and more energy efficiency opportunities should become cost-effective over time. However, as more “low-hanging fruit” energy efficiency is achieved, incremental energy efficiency options may become more expensive. One of the biggest uncertainties associated with E3’s modeling work and our overall analysis is the anticipated cost of achieving extremely high levels of energy efficiency. Such scenarios will require activities and technologies that have not been accomplished with existing approaches; therefore, there is little empirical evidence to verify cost assumptions or verify successful delivery mechanisms.

In order to meet our aggressive goals, we will need to engage in new and innovative approaches to delivering energy efficiency. Although utility programs and building codes and appliance standards have been successful, we cannot expect that the existing mechanisms alone will deliver all cost-effective energy efficiency. The Public Utilities Commission engaged a wide array of stakeholders including builders, developers, local government, and other State agencies to develop the California Long-Term Energy Efficiency Strategic Plan as a means of identifying further mechanisms and approaches.

At a minimum, we expect to develop much higher requirements for building codes and appliance standards in California through the Energy Commission's ongoing processes. We also expect higher energy efficiency requirements for both investor-owned utilities and publicly-owned utilities. As explained in D.08-03-018, we recommend that the State require comparable investment in energy efficiency from both investor-owned and publicly-owned utilities. ARB may be able to require energy efficiency investments by publicly-owned utilities or it may seek additional Legislative authority to accomplish this objective. In either case, we do not mean to suggest that the investor-owned and publicly-owned utilities must choose the same programs or approaches to energy efficiency investment; we simply encourage similarly aggressive levels of investment and delivered savings expectations from all retail providers.

In addition, through the Energy Commission's Integrated Energy Policy Report process and implementation of the California Long-Term Energy Efficiency Strategic Plan, we expect to engage a number of additional approaches including, but not limited to, energy use benchmarking and disclosure requirements, building and industrial certification and labeling programs, time-of-sale upgrade requirements, comprehensive whole-house retrofit programs, new financing instruments, integrated marketing and awareness campaigns, Smart Grid innovations, quality installation, maintenance and branding programs for air cooling technologies, more comprehensive technical and regulatory assistance programs, expanded training programs, and federal and State tax incentives. These initiatives are expected to be carried out by a wide range of actors. They will accelerate achievement of long-term energy efficiency savings needed to reach energy efficiency goals for 2020, and will advance market transformation policies toward the "Big Bold" programmatic initiatives adopted by the Public Utilities Commission in D.07-10-032: that, "[a]ll new residential construction in California will be zero net energy by 2020; [a]ll new commercial construction in California will be zero net energy by 2030; and [t]he HVAC industry will be reshaped to assure optimal performance of HVAC equipment." (D.07-10-032, p. 38.)

We are aware that some sectors, including the industrial sector, may have AB 32 compliance obligations themselves as part of a cap-and-trade program or other AB 32 regulations. Therefore, monitoring of energy efficiency achievements in those sectors may require addressing complex issues including the tracking of cost contributions, e.g., whether ratepayer or private funds were used, and the attribution of energy savings and GHG reductions achieved, e.g., to the industrial entity, the utility, or the cap-and-trade market.

Over the next year, the Energy Commission will begin development of the next update to the mandatory Building Energy Efficiency Standards and development of advanced or "reach" standards for higher voluntary levels of energy efficiency, and will develop recommendations for the integration of renewable energy system requirements into future Building Energy Efficiency Standards. These efforts will assist with meeting AB 32 GHG emission reduction goals. The Energy Commission is also working closely with ARB on development of a GHG Performance Standard for supermarkets and other buildings with large refrigeration systems which will likely become part of the proposed 2011 Title 24 Building Energy Efficiency Standards.

In addition, we are interested in investigating the use of market-based approaches to achieve additional energy efficiency. Approaches utilizing "white certificates" or "white tags" have been employed in certain states and countries, and operate similar to RECs in areas with renewables obligations that can be met with tradable certificates. Such approaches may represent a supplemental, market-based mechanism for capturing emission reductions and encouraging additional energy efficiency investment in addition to that occurring through mandatory codes and standards, utility programs, industrial sector caps, and voluntary actions as energy efficiency becomes "business as usual."

Therefore, we reiterate our support of attainment of the goal of all cost-effective energy efficiency investment. We note that achieving that goal will require a continuation of existing direct regulatory/mandatory requirements, expansions of existing requirements and development of new ones where appropriate, and implementation of other innovative approaches such as the market-based strategies described above. We reaffirm our commitment to working with ARB on determining ways to deliver the most energy efficiency savings possible.

We expect that the level of savings to be achieved through augmented codes and standards will continue to be developed through Energy Commission efforts, while the mandatory minimum levels of energy efficiency achievement for investor-owned utilities will be developed through Public Utilities Commission processes. Many of the frontier strategies that will carry the State towards its goal of achieving all cost-effective energy efficiency, some of which are mentioned above, are identified in the recently adopted California Long-Term Energy Efficiency Strategic Plan (see D.08-09-040 in R.08-07-011). The strategic planning process that the Public Utilities Commission and the Energy Commission are conducting is ongoing and will continue to identify and develop additional strategies for achieving the most energy efficiency savings possible.

4.1.2. Development of Renewables

In D.08-03-018 we recommended that the requirements for retail providers to procure electricity from renewable sources be increased above the current 20% RPS mandate, consistent with State policy and as expressed in the Energy Action Plan. However, we left open consideration of exact percentage requirements or deadlines, pending further analysis.

ARB's Draft Scoping Plan calls for California to obtain 33% of its electricity from renewable resources by 2020, and includes emission reductions based on this level. We concur with this commitment.

E3 modeled the resource costs associated with achieving a 33% renewables target statewide. E3's Accelerated Policy Case reflects a resource scenario in 2020 which includes 33% of electricity from renewable sources. The E3 modeling results indicate that achievement of 33% electricity from renewables would reduce GHG emissions in 2020 by an additional 12.8 MMT more than the current 20% RPS mandate, a larger reduction than any other electricity sector emission reduction measure. E3 estimates that these reductions may come at an average incremental cost of $133 per ton.

As discussed below, a number of parties have demonstrated that model results regarding renewables in both the Reference and Accelerated Policy Cases are highly sensitive to input assumptions.

4.1.2.1. Positions of the Parties

A number of parties comment on the advisability of mandating that 33% of California's electricity comes from renewables as part of our package of recommendations to ARB.

LADWP claims that a 33% renewables mandate should be a "foundational strategy in achieving AB 32's goals" and CEERT asserts that a 33% renewables mandate "must be an integral part of the electricity sector's responsibility for reducing GHG emissions." However, PG&E and WPTF argue that to endorse a 33% renewables requirement in this proceeding would be premature and unreasonable.

In general, opposing parties suggest that to establish an unreachable renewables target would increase costs to a level that might incite a backlash against AB 32. They argue that adequacy of supply, availability of transmission, and integration concerns should be assessed before making 33% renewable electricity mandatory. PG&E and DRA argue that program set-asides should only be considered if a GHG abatement measure is low cost and other market failures exist, and that a 33% renewables mandate does not pass this test. WPTF cautions that increasing the renewables mandate to 33% would make it harder for other cheaper GHG control technologies to compete.

Several parties opposing a 33% renewables mandate state that the economic modeling by E3 supports their view, pointing to the incremental cost found by E3 of $131 per ton of GHG emissions saved by electricity from renewables. Furthermore, PG&E believes this number may be an understatement, asserting that the cost assumptions used in the 33% renewables scenario did not include costs of storage, ramping, regulation, over generation, and backup dependable capacity.

Different parties suggest that the public policy debate and technical evaluations needed to determine ability and appropriateness of increasing the RPS mandate above 20% would be very complex and should not be hurried (SMUD, DRA). In addition, SMUD argues that, because increasing the use of electricity from renewables would have a variety of benefits and costs, not just GHG reductions, it should be considered in a broader forum than this rulemaking.

Most commenting parties recognize the continued existence of significant barriers to renewable development in the State which will not be easily resolved. Parties arguing in favor of a 33% mandate, however, suggest that these barriers justify the need for an accelerated mandate.

More specifically, parties supporting a 33% renewables mandate suggest that:

- Such a policy statement would help build the certainty needed to encourage investor confidence that an aggressive renewable build-out will be supported by State policy (NRDC/UCS/GPI, CEERT, CalWEA/LSA).
- A higher renewables mandate would focus the efforts of government, utilities, and industry to overcome the transmission, siting, and other market barriers to developing electricity from renewables in the State (NRDC/UCS/GPI, CEERT).
- A higher renewables mandate would mitigate consumers' exposure to natural gas price risk likely to come as demand for natural gas intensifies and supply diminishes (NRDC/UCS/GPI, CEERT, Environmental Council).
- Pricing signals sent by a cap-and-trade program alone would be insufficient to ensure coordinated effort and achieve the penetrations of renewables desired (CalWEA, GPI, CEERT, SMUD, LADWP).
- A 33% renewables by 2020 mandate may be easier to meet than the current mandate of 20% RPS by 2010 (GPI).

CalWEA/LSA state that, "A comprehensive approach to renewables is fundamentally important if they are to play a significant part in GHG reduction. Renewables are a capital-intensive industry with long-term planning needs, both for the facilities themselves and the transmission infrastructure necessary to support them. It is unrealistic to expect the substantial investment needed for renewables to exceed the current 20% target based on a brand new pricing signal from a yet-to-be established cap-and-trade system, which, based on the experience of other markets, is certain to be somewhat volatile in its fledgling years." (CalWEA/LSA Comments, p. 2.)

Several parties supporting a 33% renewables mandate disagree with the cost assumptions used in the E3 model. In particular, they assert that E3 overestimates the cost of 33% renewables, by overestimating the cost trajectories of renewable technology (Environmental Council, CalWEA/LSA, CEERT, Solar Alliance, LADWP), underestimating the costs of natural gas (Environmental Council, CalWEA/LSA, CEERT, Solar Alliance, LADWP), and ignoring the potential risk of natural gas price volatility (NRDC/UCS, Environmental Council).

NRDC/UCS assert that, after making a number of changes to the model's input assumptions in these areas, the incremental costs of the 33% measure could reasonably be reduced to $45/ton. NRDC/UCS state that "at a natural gas price of approximately $13.50/MMBTU the 33% RPS/High-Goals EE scenario does not cost any more than the reference scenario. At natural gas prices of $14/MMBTU and higher, the 33% RPS/High-Goals EE scenario actually results in lower total costs. … At gas prices above $14/MMBTU the cost of carbon is negative. …[T]hese illustrative calculations are made using E3's own input assumptions, which, as discussed in the modeling section below, are highly conservative with respective to renewable energy cost and performance. Using more reasonable assumptions for these factors would reduce the 'break-even' natural gas price to a much lower amount." (NRDC/UCS Comments, p. 9.)

4.1.2.2. Discussion

In D.08-03-018, we reaffirmed our support for requiring retail providers of electricity to deliver more than 20% of their electricity from renewable sources in the future. We remain committed to additional renewable energy in California;

renewable build-out is a keystone element of meeting AB 32's 2020 goal, as well as the State's longer-term 2050 goal. In the 2008 Energy Action Plan Update, we committed to "evaluate and develop implementation paths for achieving renewable resource goals beyond 2010, including 33% renewables by 2020, in light of cost-benefit and risk analysis, for all load serving entities." Further, as mentioned earlier, the ARB's Draft Scoping Plan calls for achieving 33% renewables based on Governor Schwarzenegger's call for 33% of the State's electricity to be provided by renewable resources by 2020, and includes emission reductions based on this level. We pledge to use our best efforts and to support the efforts of others to achieve 33% renewables by 2020.

Renewable mandates will play an important role in achieving aggressive renewable energy penetration, since they provide a long-term signal that can lead to market transformation of new renewable technologies and potential cost reductions. Further, E3's estimated average cost of obtaining 33% of electricity from renewables statewide, $133 per ton, is much higher than the carbon prices seen in other markets such as the European Union Emission Trading Scheme or the Regional Greenhouse Gas Initiative. Therefore, we do not believe that a cap-and-trade market alone will result in 33% renewables, and additional policies are necessary. In addition, renewable energy provides important environmental and other co-benefits, including reducing other non-GHG pollutants, when sited in California, providing further justification for policies specifically encouraging renewables.

We know from our continued implementation of the current 20% RPS requirement by 2010 that significant implementation barriers exist to the continued deployment of renewable energy in California. There are many sources of risk for project deployment, including uncertainties associated with the continuation of federal production/investment tax credits, availability of transmission, siting, and permitting issues. We agree with the comment in ARB's Draft Scoping Plan that program complexity is another challenge that must be addressed.[29] We commit to work actively with other government agencies to overcome these barriers.

AB 32 requires that the emission reduction measures undertaken to achieve its target be both cost-effective and technically feasible. The 2007 Integrated Energy Policy Report states that, "scenario analysis indicates that… aggressive cost-effective efficiency programs, when coupled with renewable development, could allow the electricity industry to achieve at least a proportional reduction, and perhaps more, of the state's [carbon dioxide] emissions to meet AB 32's goals." It notes that "meeting the 33% goal in 2020 is feasible, but only if the state commits to significant investments in transmission infrastructure and makes some key changes in policy." Initial analyses of the cost-effectiveness of a 33% renewable mandate have been undertaken,[30] including by E3, and continue to be developed. Cost-effectiveness studies must incorporate existing State policies and priorities, including the loading order for meeting the State's electricity demand, as well as the need to set a course to achieve the longer-term GHG emission reduction targets set by the Governor of 80% reduction of GHG emissions below 1990 levels by 2050. The social costs and benefits of mitigating climate change must also be taken into account.

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[29] ARB Draft Scoping Plan, Appendices, p. C-77.

[30] In 2005, the Public Utilities Commission published a report prepared by the Center for Resource Solutions assessing the cost impacts of a 33% renewable electricity target. The findings of that report and other analyses were included in the 2007 Integrated Energy Policy Report.

E3's analysis provides preliminary estimates of the potential costs of achieving 33% renewables. However, before discussing E3's analysis further, we first note an error in PG&E's assertions about the E3 modeling assumptions for renewables. PG&E is incorrect in stating that E3 did not account for the costs of integrating renewable power onto the grid, including costs such as ramping, regulation, and backup dependable capacity. E3 did, in fact, estimate and account for those costs.

Several parties utilized the E3 GHG Calculator to support their positions, either for or against mandating 33% renewables. This illustrates that there continues to be a great deal of uncertainty regarding the assumptions underlying a 33% renewable mandate. Factors contributing to this uncertainty include: (1) the proportion of intermittent to firm or baseload renewables developed for the State's renewable energy goals and voluntary REC market; (2) retirement of existing generation due to once-through cooling requirements and other variables; (3) generation changes made to the fossil-fuel generators' ramping capabilities over the next 12 years; and (4) changes made to the amount of regulation support, short-term and long-term storage, and the integration of Smart Grid technologies, among other factors.

While a number of parties, including NRDC/UCS, assert that E3 overestimates the costs of renewables and that renewable technology and installation costs should decline over time, others such as PG&E believe that the costs of integrating this level of renewables into the electricity system are understated.

We believe that E3's assumptions regarding the costs of renewables are reasonable. On the one hand, theory and some historical experience suggest that costs of renewable technologies should decline over time. E3 did not include estimates of this effect because it is speculative and uncertain. On the other hand, E3's assumptions also do not reflect that contract prices for successful renewable projects have increased in recent years, and in some cases far exceed the cost assumptions in E3's model. All of this illustrates the significant uncertainty associated with modeling the costs of achieving 33% renewables, and the speed with which necessary system improvements can be achieved.

Using current estimates, E3's analysis suggests that the average costs for new renewable generation projects may reach approximately $130 per ton of GHG emissions abated. This is significantly higher than the price for carbon in any market currently operating (the European Union Emission Trading Scheme, or the initial auctions held for the Regional Greenhouse Gas Initiative in the Northeastern states) and would represent a significant cost to California ratepayers.

Significant work is underway in California and elsewhere to better understand what it will take to achieve 33% renewables. The Commissions, along with the CAISO, are participating in the Renewable Electricity Transmission Initiative. As part of that initiative, additional cost estimation is occurring. The CAISO may need to do additional analysis to fully understand the grid management changes, improved forecasting tools, and changes to the electricity grid infrastructure needed to integrate 33% renewables into the California electricity system.

In addition, the Public Utilities Commission intends to develop a 33% renewables analysis in the long-term procurement proceeding, adhering to four guiding principles: (a) ensuring reliability, (b) ensuring the lowest reasonable rates by continuing to encourage the development of functional competitive markets (or other market structures), (c) adhering to the Energy Action Plan loading order, and (d) anticipating AB 32 constraints on investor-owned utilities' electricity portfolios.[31] With these guiding principles, the 33% analysis should assess yearly renewables targets based on an implementation assessment of feasibility and a valuation of different generation characteristics including peaking, dispatchable, baseload, firm, and as-available capacity of renewable projects. We expect the 33% analysis to further inform our understanding of the cost and feasibility of achieving even higher renewables levels.

As with energy efficiency discussed above, a mandatory utility renewables program may be the best way to achieve the bulk of needed renewables investments, but we may also wish to explore other innovative options to achieving additional renewables in the State. In addition to RPS and the California Solar Initiative discussed below, there may be other ways to encourage innovation in renewables, such as through voluntary private sector investment and additional distributed renewables programs. We support expanding the RPS, but also advocate additional policies and mandates to achieve at least 33% renewables for California, which may be met through a variety of approaches including voluntary investments. Additionally, the existing RPS statutes and regulations should be reexamined to determine if there are opportunities to reduce complexity and make changes that will help the State achieve its GHG reduction goals at the lowest possible costs.

We expect that ARB will conduct additional analysis of GHG mitigation options and costs in other sectors of the economy. To date, all of the ARB analysis released in association with AB 32 has addressed only electricity sector costs. In order to meet the cost-effectiveness requirements of AB 32, the costs of

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[31] R.08-02-007 scoping memo, p. 8.

reducing GHG emissions through renewable investment should be compared to the costs of abatement in other sectors, including industry and transportation. As the ARB Scoping Plan and AB 32 implementation process progresses, we expect to learn more about the potential costs of GHG reductions in other sectors relative to the costs of measures that may be undertaken in the electricity sector.

We recognize that meeting California's longer-term 2050 GHG reduction goals will require significantly reducing the GHG footprint of the electricity sector. Policies and mandates that achieve 33% of California's electricity from renewables by 2020 are an important step in achieving this transformation, even if renewable energy investments represent relatively higher marginal cost abatement opportunities in the near term.

NRDC/UCS and other parties may be correct that the costs of at least some renewable technologies may decline between 2010 and 2020. However, we cannot project this outcome with any certainty in 2008.

Further, there are other reasons to support a 33% renewables mandate besides GHG emissions mitigation as required by AB 32. These include fuel diversity, economic development benefits for California, and air quality improvement in California, to name a few. These reasons may support a higher renewables mandate or a different program design than would be found reasonable for GHG reduction alone. These issues also require further analysis and discussion among policymakers.

For all of these reasons, we support requiring that all retail providers of electricity deliver 33% of their electricity from renewable sources by 2020. We also support ongoing analysis of the implementation path needed, the actions we can take to help ensure success, and the potential costs and benefits of renewables in the context of AB 32.

In response to comments on the proposed decision, we address the treatment in a cap-and-trade program of RECs and "null" power, the electricity from renewable sources that may be sold separately when RECs have been unbundled from the electricity. The Public Utilities Commission has not authorized load serving entities to use tradable RECs for RPS compliance, but expects to consider the possibility in an upcoming decision in R.06-12-012. In anticipation that tradable RECs may be authorized in the future, the Public Utilities Commission stated recently in D.08-08-028 that,

> [O]nce a REC is used for RPS compliance (either before or after a GHG cap is imposed), the REC cannot also be used as a GHG emissions offset. In addition, once a GHG cap is imposed, RPS-eligible generation subject to a cap never avoids emissions. The "avoided emissions" will continue to be included in the REC, but the avoided emissions will be zero; the balancing GHG emissions value of the null power will therefore also be zero. Thus—assuming that ARB adopts this analysis—our characterization of the REC will not require any RPS-eligible generation with zero GHG emissions to need allowances when delivered to the California grid [footnote omitted]. (D.08-08-028, mimeo. at p. 24.)

We recommend that ARB rely on and adopt the above analysis and conclusions in D.08-08-028, i.e., that RPS-eligible generation with zero GHG emissions would not need allowances when delivered to the California grid, regardless of whether RECs have been unbundled from the electricity such that the electricity is delivered as null power.

The analysis in D.0-08-028 did not address a scenario in which Public Utilities Code Section 399.16(a)(3) is modified to allow use for RPS compliance of unbundled RECs from electricity not delivered to the California grid. If such a revision occurs, the appropriate treatment of unbundled RECs from electricity generated in an uncapped state and not delivered to the California grid may require further consideration.

4.1.3. Other Emission Reduction Measures

While renewables and energy efficiency are by far the most effective and expansive emissions abatement opportunities for the electricity and natural gas sector currently available, other potential emission reduction measures have been addressed by E3 modeling, ARB Scoping Plan development, and party comments.

In its modeling of GHG scenarios, E3 included two other major areas of GHG reduction: rooftop photovoltaic installations realized through the California Solar Initiative, and increased CHP installations.

For rooftop photovoltaics, while E3's Reference Case includes the level assumed to be in the Energy Commission's load forecast (847 MW), the Accelerated Policy Case reflects the achievement of the California Solar Initiative program goal of 3,000 MW. The E3 modeling results indicate that achieving the California Solar Initiative goal would reduce GHG emissions in 2020 by an additional 1.7 MMT CO2e compared to the Reference Case.[32]

For CHP, while the Reference Case reflects what is assumed to be in the Energy Commission's load forecast (292 MW behind-the-meter CHP and no new CHP over 5 MW in size), the Accelerated Policy Case reflects the achievement of approximately 1,600 MW of new small CHP (smaller than 5 MW) and 2,800 MW of new large CHP (larger than 5 MW). The E3 modeling results indicate that achieving this CHP goal would reduce GHG emissions in 2020 by an additional 4.9 MMT compared to business as usual.

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[32] If tradable RECs from the California Solar Initiative are allowed in the RPS progam, care must be taken not to double-count the GHG emissions reductions. See D.07-01-018 in R.06-03-004.

The ARB Draft Scoping Plan includes one additional emission reduction measure that was not addressed in the E3 modeling: solar hot water heater installations. Solar hot water is included in the Draft Scoping Plan as a way to reduce natural gas use in homes and businesses. The Draft Scoping Plan assumes the installation of 200,000 solar water heating systems by 2020, saving 26 million therms of natural gas per year (a goal set forth in AB 1470, Huffman, Chapter 536, Statutes of 2007). The Draft Scoping Plan finds that achieving this goal would result in 0.1 MMT of GHG reductions.

4.1.3.1. Positions of the Parties

NRDC/UCS and SCE raise solar hot water heating as a measure worthy of consideration, particularly if the natural gas sector is not part of a cap-and-trade program initially, as recommended in D.08-03-018.

PacifiCorp suggests that California consider incentives for utilities to pursue grid applications that address electrical losses, electricity storage as an enabling technology for increasing utility scale renewable penetrations, and Smart Grid technology to accommodate distributed renewable resources and demand response. In addition, PacifiCorp suggests that California consider providing incentives for carbon capture and sequestration, and for repowering and retirement of high GHG-emitting fossil-fueled plants.

NRDC/UCS suggest a number of measures to reduce GHG emissions through efficiency gains, including time-of-sale energy efficiency requirements, appliance feebates, and water-use efficiency. In addition, NRDC/UCS suggest biomethane as a powerful abatement opportunity in the natural gas sector. According to their estimate, biomethane has the potential to save 7.2 MMT of GHG emissions by 2020 from dairies alone, with further potential savings from wastewater treatment facilities.

4.1.3.2. Discussion

In this section, we address each suggested additional mandatory emission reduction measure in turn and suggest an appropriate venue for additional analysis or policymaking. If a suggestion is not addressed, it is either because the measure was too vague or, in some cases, because an appropriate venue does not yet exist. We remain open, however, to ongoing suggestions for additional emission reduction measures that may be implemented to help support the AB 32 goals.

Rooftop Solar Photovoltaics

California already has an aggressive effort to encourage deployment of customer-sited photovoltaics, in the form of the Public Utilities Commission's California Solar Initiative and the Energy Commission's New Solar Homes Partnership. In those programs, we have set a goal of 3,000 MW of installed solar photovoltaic capacity in California by 2017. We believe this target is appropriately aggressive and do not suggest amending it at this time. However, should we decide to pursue additional initiatives for solar photovoltaics, our separate proceedings on these programs are the appropriate venue for such consideration. At the Public Utilities Commission, the California Solar Initiative rulemaking is R.08-03-008. The Energy Commission is responsible for policymaking for the New Solar Homes Partnership.

Solar Hot Water

We agree with ARB, NRDC/UCS, and others that solar hot water is worthy of inclusion in the Scoping Plan, with potential to go beyond current mandates. The Public Utilities Commission is in the process of implementing AB 1470 (Huffman), which requires consideration of the results of a pilot program in San Diego before implementing additional solar hot water heating incentives. Results of that evaluation are expected later this year in R.08-03-008.

Combined Heat and Power

In this proceeding, we address two fundamental questions about CHP systems. One question is how to regulate GHG emissions from CHP; this issue is discussed in Section 6 below. We address here the other question about CHP: whether and how to treat it as an emission reduction measure, as proposed in the Draft Scoping Plan.[33]

Properly designed and sited CHP systems can provide efficient co-generation of electricity and thermal heat. In addition, on-site generation avoids electricity transmission and distribution losses, thus avoiding more fuel consumption for the generation of electricity. Because it reduces the consumption of fossil fuels, CHP can reduce GHG emissions. Types of CHP systems are described in more detail in Section 6.1 below.

Parties were asked to file comments on whether CHP should be considered to be an emission reduction measure, and whether there should be efficiency requirements in order for CHP systems to be considered an emission reduction measure. The parties largely support the concept of encouraging additional CHP as an emission reduction strategy, as long as CHP units are efficient and sized appropriately. However, some parties raise certain concerns about treating CHP as an emission reduction measure.

PG&E contends that there will be a market for more efficient, less GHG-intensive electricity and, as a result, that there is no need to classify CHP as an

[33] The Draft Scoping Plan includes CHP as an emissions reduction strategy in the "energy efficiency category." In proceedings before the two Commissions, energy efficiency typically refers to demand-side strategies to save energy; CHP is inherently a supply-side fuel-efficiency measure. We note this distinction in order to avoid any confusion about the two classifications.

emission reduction measure. The logic behind PG&E's conclusion is that the market will inherently favor CHP's less GHG-intensive electricity.

Other parties, including EPUC/CAC and CCC, argue to the contrary that GHG regulation might create disincentives for CHP facilities whose GHG emission rate is higher than the average emission rate of the local utility's electricity portfolio. GHG costs embedded in a utility's retail electricity rates will depend on the utility's owned resources, its degree of reliance on the wholesale electricity market, and the carbon costs that are included in wholesale electricity rates. It is possible that a CHP facility's per-MWh compliance costs would be higher than the averaged compliance costs embedded in the utility's retail rates even though the CHP's emission rate might be lower than the emission rate of marginal generation sources used by the utility. In such circumstances, emissions would increase if the CHP owner chooses to purchase electricity from its local utility rather than produce electricity on-site, making attainment of GHG reduction goals more difficult. This problem is not unique to CHP, but could arise for any distributed generation facilities.

Both PG&E and SCPPA assert that classification of CHP as an emission reduction measure would result in a de facto subsidy. A related comment was filed by DRA, which supports including CHP as an emission reduction measure but cautions against setting a specific target level without careful consideration of the cost. As stated elsewhere in this decision, we agree that cost-effectiveness is a key criterion in the establishment of emissions reduction measures, and it is critical in setting targets going forward. DRA's point is well taken that the cost-effectiveness criterion will act as a safeguard against over-building the amount of CHP in the State; it will help ensure that there will be an increase, but that it will be done in a cost-effective manner. However, the assertion that classification of CHP as an emission reduction measure creates a subsidy is incorrect. We may, however, wish to consider incentives for CHP, if we determine that the cost-effective and economically-rational level of CHP investment in the State is not occurring due to identified barriers. This should be considered in another venue, as discussed below.

Most other comments about CHP as an emission reduction measure center around the idea of encouraging efficient CHP. We do not have enough information, however, to establish an overall level or method that should be used to achieve this efficiency. While encouraging a certain level of efficiency is an important policy goal, we do not believe it is necessary to set a particular threshold at this time.

Overall, we support the identification of CHP as an emission reduction measure, as already included in ARB's Draft Scoping Plan. This is primarily due to the ability of CHP to reduce overall GHG emissions by producing two products (heat and electricity) with one fuel input. Classifying CHP as an emission reduction measure would complement the market demand for less GHG-intensive electricity. As with other forms of efficiency, there may be barriers to the adoption of CHP that would prevent achievement of optimal levels of CHP through a market-based system.

The Draft Scoping Plan anticipates a level of 32,000 GWh of new CHP, which would lead to emission reductions of 6.9 MMT CO2e in 2020. This level translates to the installation of 4,000 MW of new CHP with an assumption of a capacity factor of 85%.

We support the treatment of CHP as an emission reduction measure and the goal to encourage cost-effective, fuel-efficient, and location-beneficial CHP. Several existing activities will help inform the amount of new and efficient CHP that California can expect. In compliance with AB 1613, the Public Utilities Commission recently opened a new rulemaking, R.08-06-024, which is addressing the policies and procedures for purchase of electricity from small CHP less than 20 MW. The Energy Commission plans to open a proceeding in early 2009 to develop operational standards and guidelines for AB 1613-eligible customer-generator CHP systems. These guidelines will ensure that new CHP systems that are eligible under this law meet all operational, fuel efficiency, and emission standards intended by the Legislature. These guidelines will apply to new CHP facilities in both the investor-owned and publicly-owned utility service territories. In addition, the recent Qualifying Facility decision issued by the Public Utilities Commission in September 2007 (D.07-09-040) applies to some CHP contracts with utilities.

Unlike other measures discussed in this section, there is not a strong policy framework in place for the development of new CHP and the evaluation of existing CHP. The best policy tools available to both investor-owned and publicly-owned utilities to encourage efficient CHP are not yet clear.

We are persuaded that further investigation is necessary regarding market and regulatory barriers for CHP. There is a clear need for a broader look at CHP policy (both for new and existing units, at various capacity sizes). The Public Utilities Commission intends to establish a new rulemaking to address these and other issues related to CHP in order to help maximize cost-effective GHG reductions from CHP. This rulemaking will explore removal of existing barriers to deployment of CHP and, on that basis, the setting of realistic targets for CHP contributions to the AB 32 goal. In addition, the Energy Commission plans to explore options with the publicly-owned utilities to accelerate CHP installation incentives that some publicly-owned utilities have already initiated.

Time-of-Sale Energy Efficiency, Appliance Feebates, Water Use Efficiency

NRDC/UCS suggest several efficiency initiatives to help increase savings of energy and water. These additional energy efficiency measures should be considered by both Commissions and, where advisable and within our jurisdictions, directly implemented. Some highly significant measures, such as time-of-sale efficiency upgrades, may need to be addressed by ARB or the Legislature. Regarding water conservation and efficiency, the Public Utilities Commission currently has a water conservation investigation (I.07-01-022). We also anticipate continuing to work with the Department of Water Resources and the State Water Resources Control Board on additional water efficiency measures as the Scoping Plan process goes forward.

4.2. Reliance on Mandates and Markets

Desired emission reduction outcomes can be achieved using a number of distinct policy approaches. Because ARB is considering a market-based cap-and-trade program inclusive of the electricity sector as part of its AB 32 implementation strategy, in conjunction with regulatory mandates, an important question for the electricity sector concerns the interaction of GHG reductions through direct mandatory or regulatory control measures with voluntary reductions, including those claimed through the potential market-based cap-and-trade program under consideration at ARB.

We in D.08-03-018 and ARB in its Draft Scoping Plan recognized the role for both mandatory measures and market-based approaches. However, the level at which mandates would be set and the way in which mandatory measures would interact with the potential cap-and-trade program have yet to be addressed. This section describes opinions of the parties as expressed in this proceeding.

4.2.1. Positions of the Parties

Most parties agree that existing regulatory mandates have served as a successful means of slowing the rate of growth of GHG emissions within the electricity and natural gas sectors to date. Parties have differing opinions, however, regarding the degree to which codes and standards, efficiency and solar programs, and RPS requirements should be expanded beyond current levels in order to achieve deeper reductions as required by AB 32.

Several parties assert a strong view that any additional reductions in the electricity sector to achieve reductions under AB 32 should be driven solely by a cap–and-trade market. Parties in support of this approach argue that such an approach would ensure that any further reductions from the sector would be cost-effective in the context of the statewide effort and relative to costs from other sectors (PG&E, Morgan Stanley, SCE, SDG&E/SoCalGas). A number of parties also point out that the more mandatory measures that are adopted, the less benefit there would be from a cap-and-trade system (SDG&E, DRA, TURN).

Other parties in support of a cap-and-trade-only approach to achieving additional reductions assert that, because a market rewards over-compliance and innovation, greater levels of emissions reductions would be realized more quickly by way of a cap-and-trade program than by using a programmatic or mandatory approach (Calpine, WPTF, SCE).

In addition, PG&E urges that the Commissions be extremely careful in assuming that further reductions will come from direct energy efficiency and renewable programs other than those programs already in place, because meeting existing targets has been challenging even at current levels.

A second group of parties advocate that the electricity sector should be left out of a cap-and-trade system entirely. Instead, they argue that the sector would be better-suited to pursue its emission reduction responsibilities by way of programmatic mandates only. This issue was addressed in D.08-03-018, in which we recommended a multi-sector cap-and-trade program including the electricity sector. However, we summarize these comments here, for completeness, with the benefit of new information and analysis by E3 as well as the issuance of the Draft Scoping Plan by ARB. These parties base their recommendation on the following arguments:

- A market-based approach would only add costs to overall compliance, with very limited added environmental benefit (SCPPA, LADWP, CUE).
- Allowance prices would have to be extremely high before a market would cause changes in dispatch and otherwise bring about incremental GHG reductions above aggressive policy mandates in the electricity sector (SCPPA, LADWP, CUE, IEP, TURN).
- Leakage and/or contract shuffling would negate any benefits of reduced emissions from imported coal in a California-only cap-and-trade system (TURN).

In most cases, parties draw heavily on the modeling results provided by E3 to argue that mandates can effectively achieve emission reduction goals within the sector and that the market would be a costly means to achieve incremental reductions within the sector. For instance, SCPPA, SDG&E/SoCalGas, LADWP, and SMUD point out that, according to E3's results, the electricity sector could meet the goal of 1990 emissions levels by 2020 through existing programmatic mandates including the 20% RPS goal and energy efficiency programs. NCPA asserts that the electricity sector is already below the 1990 benchmark level. Further, SCPPA points out that, according to E3's results, "nearly no emissions reductions would be derived from participation in a cap and trade program until very high levels of allowance prices -- $100 to $150/ton CO2—are reached." As discussed below, a number of parties suggest in reply comments that the conclusions reached by these parties relying on E3's results are flawed.

A third set of parties does not favor one approach over the other; they argue that it is not an "either or" scenario. Instead, they view mandatory regulations and market mechanisms as two complementary policy instruments with added value when used in concert. They support the conclusion in D.08-03-018 that a combination of additional mandates and a cap-and-trade program should be used to achieve incremental reductions within the sector.

Parties in support of this combined approach offer the following reasoning:

- While the GHG price established by a cap-and-trade program is essential, it would not overcome the various non-price market barriers that other regulatory programs can more effectively address (NRDC/UCS, GPI).
- While mandates can drive progress toward broad emission reduction targets, a cap-and-trade program would provide a back-stop and would capture any resulting shortfalls in expected emission reductions due to higher load growth or delayed RPS development (NRDC/UCS, PG&E, WPTF).
- While mandates can be effective in deploying existing technology, a cap-and-trade program would offer distinct benefits by accommodating and rewarding emerging GHG control technologies not embodied by current mandates (WPTF).

This position is supported by a number of reply comments rebutting the arguments of parties that utilize E3 model results to argue for a market-only or mandate-only approach.

PG&E and WPTF assert that, because the E3 model results are highly sensitive to input assumptions and because slight increases in load growth would yield higher emissions levels than suggested by E3's Reference Case, the Commissions should reject parties' conclusions based on E3 Reference Case results that a cap-and-trade program and other compliance options will be unnecessary. PG&E in particular offers an alternative reference case based on a set of modified assumptions which indicates that 2020 reference case emissions would be above 1990 levels.

Similarly, both PG&E and WPTF argue that conclusions based on E3's model that a cap–and-trade program would impose extra costs with no GHG benefits are flawed. They assert that cost efficiencies from a cap-and-trade program would stem from a number of factors that are unaccounted for in the model, including the ability to harness cross-sector abatement opportunities and innovation incentives provided by the system, which could drive the discovery of unforeseen opportunities for compliance by entities within the sector. These parties argue that, while these factors cannot be modeled quantitatively, they are qualitatively understood as better utilized by market instruments than by programmatic approaches and mandates.

On the other side, NRDC/UCS argue that conclusions based on E3's model that additional mandates are not cost-effective are flawed. NRDC/UCS submit that determination of these measures' cost effectiveness depends on there being low-cost abatement opportunities in other sectors, and sufficiently many to meet the cap before pursuing such aggressive in-sector measures. They assert that we cannot make judgements based on E3's model regarding the availability of lower-cost emission reduction measures in other sectors, and caution against the "false hope" of assuming their availability. While in support of a cap-and-trade program covering the electricity sector, they believe that a majority of emission reductions in this sector should be achieved through programmatic and regulatory measures. They suggest that any reduction in the effort to achieve significant direct, in-sector emissions reductions through the expansion of existing mandates would defer urgently needed investments in these areas, thereby increasing the overall cost of AB 32 compliance.

4.2.2. Discussion

In D.08-03-018, we recommended that ARB consider both mandatory/regulatory measures and a multi-sector market-based cap-and-trade program for the electricity and natural gas sectors in California. Nothing in parties' comments or in the E3 modeling work convinces us that we should reconsider our support of both additional mandatory measures, as discussed above, and a well-designed cap-and-trade system.

However, whether a cap-and-trade system achieves its desired results is highly dependent on its design. The E3 modeling results reveal specific areas of concern where careful monitoring and verification will be needed to ensure that the cap-and-trade system functions as anticipated. In particular, these include monitoring to ensure that the cap-and-trade program does in fact achieve real reductions in emissions at reasonable cost and that significant revenue shifts unrelated to emission reductions between customers of different retail providers, or from retail providers to generators, are avoided.

Since the issuance of D.08-03-018, the Western Climate Initiative draft design of a regional system that would link state-specific cap-and-trade programs throughout the Western United States has developed rapidly. Draft design principles were issued on July 23, 2008 that target an opening date of January 1, 2012 for the regional linked system. Given this, we strongly believe that partnership and linkage with other states in the Western Climate Initiative for the cap-and-trade system is critical in order to remove or mitigate the challenges and limitations of a California-only approach.

While the opportunities for emissions reductions within the electricity sector are bounded by economic and jurisdictional constraints, it remains within California's best interest to act aggressively and proactively to begin a large-scale transformation of its electricity infrastructure and demand patterns. Taking into account the lack of a national program at this time and the State's requirement to implement AB 32, we have carefully considered the best interim steps that California's electricity and natural gas sectors can take to meet the AB 32 requirements, and to support participation in a linked Western Climate Initiative system, while preparing to move toward a nationally and ultimately internationally integrated program.

In the near term, the cap-and-trade program can serve to supplement other policy tools in place by providing a backstop, in case the reductions from the mandatory programs do not fully materialize as expected. In addition, as we stated in D.08-03-018, a cap-and-trade program will likely provide a relatively small incremental portion of the overall emission reductions needed to meet the 2020 limit, above emission reductions achieved due to existing and expanded mandatory measures.

In the later years of AB 32 compliance, it is likely that a broader national market will be in effect, and GHG emissions abatement technology will have developed significantly. Under these circumstances, a market framework may become the preferred means to motivating increased emissions reductions throughout the economy.

If we were to pursue goals only through mandates, incentives, and other programmatic methods, the price effects could be inconsistent. Utility customers would pay for the costs of the recommended measures in ARB's Draft Scoping Plan. However, without a cap-and-trade program or carbon fees, there would not be a price incentive for the fossil-fired portion of the electricity sector to become more efficient. There would be no market to reward clean-burning fossil technologies or to provide incentives for the incremental efficiency changes that can be made in a host of fossil fuel-using facilities. Enlisting the generation community in the effort to reduce emissions makes sense as a policy tool. Utility customers would likely pay most of the costs of energy efficiency, renewable, and CHP programs, although with carbon fees or allowance revenues under a cap-and-trade program, those costs can be allocated more broadly in the economy.

As a result, we reiterate the recommendation in D.08-03-018 that the electricity sector pursue a two-pronged approach to achieving emission reductions using both current and expanded mandates, under which programmatic strategies dominate in the short term, and a market-based approach, which would provide increasingly powerful incentives for emission reductions over time, allowing reductions to be achieved in the most cost-effective manner possible.

E3 modeling confirms that, through aggressive regulatory measures, the electricity and natural gas sectors can reduce emissions substantially between now and 2020, provided that utility programs are extended in a binding manner to the publicly-owned utilities, and provided that incremental building and appliance standards, as well as new innovative program design methods, are enacted.

Furthermore, as evidenced by the modeling, many of our targeted technology solutions – central station renewables, rooftop solar photovoltaics, and carbon capture and storage – arguably would not occur at any reasonably large scale if we rely only on market forces unless the price of carbon rises to some point significantly above $60 per ton. If we were to use a market-based approach alone, we may not be able to keep program costs low or support market transformation of desired technologies.

Accordingly, our recommendation in D.08-03-018 that California pursue a two-pronged approach to GHG regulation in the electricity and natural gas sectors – continuation of regulatory mandates designed to accelerate development and deployment of specific low-carbon technologies in the near term, and a market-based approach to leverage the potential for discovery of emission reduction measures currently unknown to regulators—in order to achieve incremental emissions reductions at least cost and over the longer term is supported by E3's analytics.

We recognize that achieving the goals set by current and expanded mandates will require significant expenditures by utilities and likely will result in increased rates for utility customers, although reductions in customer energy usage due to energy efficiency achievements may allow average customer bills to decrease at the same time. Significant co-benefits for California may also be achieved. The success of these mandatory programs will require dedication, creativity, and will but, once achieved, will result in significant contributions to the state's overall GHG reduction goals. It is important to recognize that some delays or other failures may occur for some of the programs considered here, including both the regulatory mandates and the cap-and-trade program. However, the overlay of a cap-and-trade mechanism on mandatory programs serves as an insurance policy to make sure the emission reductions occur, and to supplement enforcement mechanisms by providing additional economic benefits for achievement of the mandates. Similarly, the incorporation of the mandates provides additional assurance that the overall program will deliver tangible, near-term results.

We acknowledge potential downsides to our two-part strategy, as follows. First, any significant shortfall in meeting aggressive mandates could result in upward pressure on allowance prices in a cap-and-trade market, due to the fact that additional allowances may be needed by entities with compliance obligations on short notice due to the failure of mandates. By the same token, unanticipated problems in the cap-and-trade market, such as larger-than-expected shifts of revenue between retail providers without productive emissions reductions, larger-than-expected windfall profits, and costs incurred by retail providers due to unexpectedly high or volatile allowance prices may undermine the ability of some retail providers to achieve their goals. We emphasize the need for continuous monitoring and updating of all programs implemented in the electricity sector in support of AB 32, and their interactions, in order to ensure that we achieve the goals of AB 32.

4.3. Contribution of Electricity and Natural Gas Sectors to AB 32 Goals

This proceeding was scoped to include making recommendations to ARB regarding the total contribution that the electricity and natural gas sectors can reasonably make toward meeting the AB 32 emissions reduction goals, and the setting of annual GHG emissions caps for the electricity and natural gas sectors.

There are a number of bases upon which ARB could allocate GHG reduction responsibility among sectors, including the relative cost-effectiveness of identified emission reduction measures in the individual sectors and the potential impacts on consumers, including rate impacts for electricity and natural gas customers, of varying levels of emission reductions responsibility among the sectors.

It is challenging at this point to determine the cost-effective level of electricity and natural gas sector emission reductions because we have very little sense of the abatement opportunity and costs in other sectors.

If there is a multi-sector cap-and-trade program, sector-specific emissions caps would not be set. We expect that there would only be a single emissions cap that would apply to the aggregate emissions from all the sectors under the cap. In this multi-sector scenario, if allowances were administratively allocated, ARB would still need to determine how many allowances (or how much allocation value) would be allocated to the electricity and natural gas sectors, assuming that ARB's cap-and-trade program design includes the allocation of allowances or allowance value among the sectors. ARB policies regarding both the scope of mandated emission reduction programs and the allocation of GHG emission allowances or allowance value to each sector would determine the extent to which individual sectors bear the cost responsibility of the emission reductions necessary to reach AB 32 goals. We discuss this in more detail below.

An important consideration regarding the appropriate level of emissions reductions from the electricity and natural gas sectors is the associated rate and cost impacts on utility customers. E3's modeling results provide some guidance on the relative rate and cost impacts of emissions reductions responsibilities of varying stringency within the electricity and natural gas sectors.

4.3.1. Positions of the Parties

Several parties assert that there is no need to recommend annual caps or sectoral targets, based on their view that the market will determine cost-effective distribution of emission reductions among the sectors (WPTF, SCE, GPI). Other parties (SMUD, DRA, NCPA, MID, TURN) suggest that additional information is needed regarding the relative cost of abatement opportunities in other sectors, before the desirability of additional mandates or sectoral responsibility can be determined. CEERT and NRDC/UCS emphasize their view that allocation of responsibility to the sectors and annual cap recommendations are important aspects of our recommendations to ARB. IEP suggests that the sectors should bear responsibility proportional to their contribution to statewide emissions.

GPI anticipates that the electricity sector will be required to make reductions below 1990 levels, with proportional reduction requirements in excess of its proportion of contribution to statewide emissions. GPI suggests that sector caps should be treated as rough guidelines, used only for planning purposes and crafting policy measures, and distinct from AB 32's statewide mandate which is obligatory and absolute.

A number of parties comment on the trajectory of annual caps, including PacifiCorp, Dynegy, IEP and SCE. These parties suggest that cap setting should be gradual, in step with the lead times necessary for renewable and other investments to run their course, and should reflect the limited GHG abatement opportunities available to deliverers in the short term.

CMUA submits that the two Commissions should recommend principles, and ARB must implement regulations, that encompass an equitable proportionality of reduction obligations among the different sectors.

PG&E recommends that, in advising ARB regarding what the electricity sector emissions will be and the reductions expected from current programs, the Commissions should be mindful of communicating realistic levels and should not double count savings. PG&E believes that targets for California can be based on "stretch" goals, with agencies supporting technological innovation in the marketplace and research and development to reach those goals, rather than "command and control" mandates.

In addition, PG&E states that statutory criteria in AB 32 for setting emissions reduction targets should be applied to the annual emissions caps to be set for the 2012–2020 period. These include technological feasibility; economic efficiency; cost and rate impacts on consumers, businesses, and governments; and impacts on low income communities and ratepayers. PG&E suggests that the trajectory of emissions targets for 2012-2020 should take into account a rigorous and full peer- and public-reviewed economic model of the impacts of the targets on each sector of the California economy, including an assessment of abatement costs and availability of emissions abatement measures in each sector.

PG&E further submits that assumptions regarding the electricity generating resources that will remain in operation during the 2012-2020 period, including coal-fired and other high-emitting generating resources, should be evaluated in setting interim 2012-2020 targets for the electricity sector.

PG&E also states that the emissions trajectory should be gradual. It asserts that it will be many years before emissions reductions are achieved by new long-term capital investments. Citing an inability for energy consumption to change greatly in the short term, PG&E recommends that the emissions trajectory should allow for growth in the short term, followed by gradual reductions.

Finally, PG&E states that the allowance value apportioned to the electricity sector should be fair and should recognize the lengthy history of investments in energy efficiency and renewables. PG&E believes that electricity customers should not subsidize emission reductions in other sectors.

SDG&E/SoCalGas recommend that electricity and natural gas sector caps should be based on the mandatory measures ARB finds to be cost-effective, with the cap-and-trade program designed to provide the same level of reduction as would be projected to occur if ARB had adopted the mandatory measures that were deemed to be cost-effective. SDG&E/SoCalGas agree with PG&E that entities subject to the cap should not pay for any shortfalls in reductions in other sectors.

SMUD states that the Commissions are in the best position to determine what levels of renewables and energy efficiency are possible, and the cost-effectiveness of achieving those levels. SMUD emphasizes its view that, in considering whether to require the electricity sector to reduce emission below its 1990 levels, ARB must weigh the cost relative to reductions in other sectors.

According to CEERT, the Commissions should recommend to ARB specific cost-effective and prudent levels of energy efficiency and renewables to be obtained in the electricity sector. GPI, on the other hand, as summarized above, recommends that any identification of sector caps should be considered as rough guidelines only for planning purposes.

PacifiCorp and SMUD recommend that we defer any recommendations on sector responsibility or annual caps until we have a better sense of opportunities available in other sectors.

4.3.2. Discussion

We agree with parties who suggest that the level of responsibility or "burden" under AB 32 should be proportional and fair to consumers in all sectors of the economy. However, defining what is fair or proportional is difficult particularly because, as noted by several parties, while we have a great deal of information about the opportunities and costs for GHG mitigation in the electricity sector provided by E3, we do not have equivalent information about the other sectors.

One approach would be to analyze the GHG mitigation cost curve for measures available in all sectors of the economy, and choose the least costly options such that the desired reductions are obtained, regardless of the sector(s) in which the emission reductions occur. This is similar to E3's analysis for the electricity sector, but would be performed on a multi-sector basis. A second approach, apparently being utilized by ARB, is to identify feasible or achievable measures and strategies available in each sector and choose some for adoption as regulations while allowing others to be achieved through a market-based approach, without prioritization based on relative cost-effectiveness. In either approach, it does not follow that the cost burden of each chosen mandatory measure should be borne within its own sector. Under a combined market-based and regulatory strategy, the responsibility for the cost burden can be separated from the obligation to reduce GHG emissions.

E3's analysis of potential emission reduction measures for the electricity and natural gas sectors represents the best available information upon which the Commissions can base a recommendation regarding emission reduction measures in these sectors. As discussed at length above, this analysis is subject to a great deal of uncertainty, but represents a significant advancement in our understanding of what is feasible in the sectors as well as the overall magnitude of potential costs.

The best use of the E3 results is to inform policymaking through highlighting differing outcomes across a range of inputs. We present below a scenario designed to represent a reasonable potential outcome, as analyzed by E3.

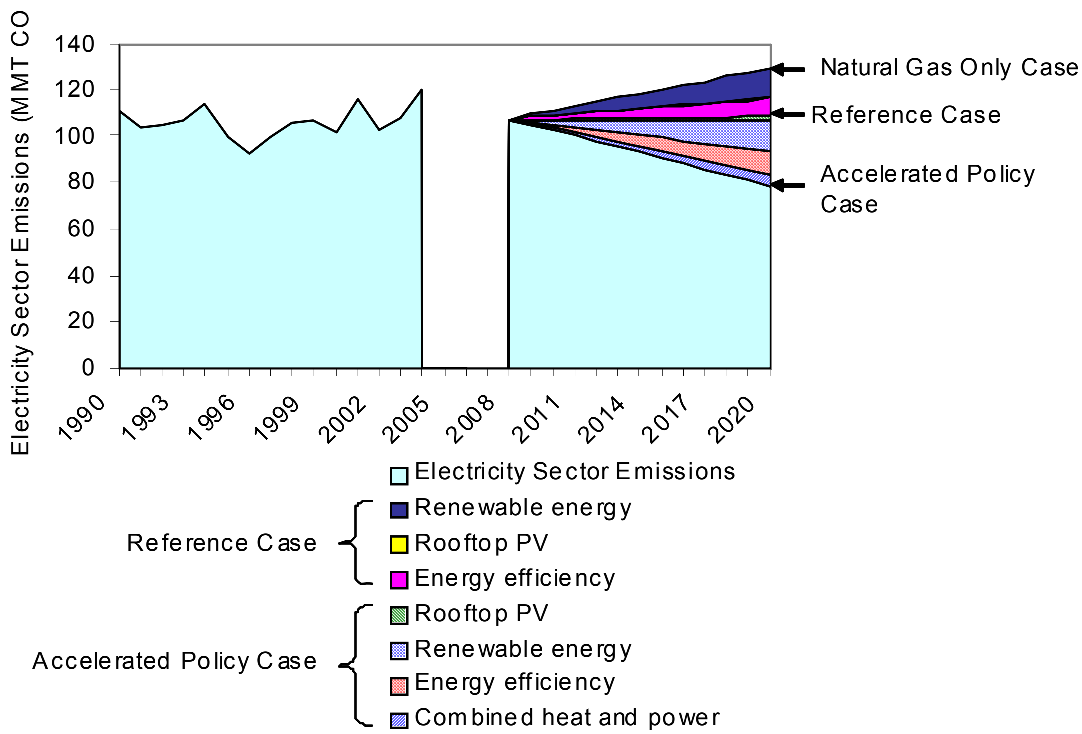
Section 3 above discusses in detail E3's assumptions and approach. We will not reiterate that discussion here, except to say that, on balance, we find E3's approach and analysis to be reasonable to inform our recommendations.

4.3.2.1. Electricity Sector

Figure 4-1 shows a reasonable scenario of potential achievable emissions reductions in the electricity sector compared to its historical emissions levels. In this scenario, all emission reduction measures contained in E3's Reference Case and Accelerated Policy Case would be achieved, including energy efficiency, renewables, and CHP implementation as discussed above. More detail on the emission reductions that may be obtained through these measures is described in Section 3.3.1 above, including Figure 3-1 and Table 3-3. Historical emissions data for 2005-2007 are not yet verified, and are therefore not included in Figure 4-1.

Figure 4-1

Electricity Sector Emissions Reduction Potential Compared to Historical Electricity Sector Emissions



As discussed above, we are committed to the policies and GHG emission reductions contained in the Reference Case and the Accelerated Policy Case. We recognize that these policies may result in slightly more or slightly less emissions reductions, depending on actual progress during the 2020 timeframe. All of the emissions reductions shown above result from assumed levels of direct or programmatic approaches and mandates and not from a cap-and-trade system. As described in Section 3.3.1 above, these emissions reduction measures, before consideration of a cap-and-trade program, would result in 2020 emissions in the electricity sector of approximately 79 MMT, about 27% below its 1990 emissions level. This projected 2020 emissions level under the Accelerated Policy Case would be approximately 38% lower than the 129 MMT estimate resulting from "business as usual" in the absence of any climate change policy in California, in which additional growth in electricity demand is met solely with natural gas-fired resources (the Natural Gas Only Case).

ARB's Draft Scoping Plan would assign approximately 40% of the economy-wide responsibility for mandatory emissions reductions to the electricity sector, even though electricity represents only 25% of the statewide emissions. Using ARB's assumptions, this requirement would result in electricity sector emissions in 2020 roughly equal to the level that E3 estimates under the Accelerated Policy Case. If electricity is included in the cap-and-trade program contemplated in the Draft Scoping Plan, and were to achieve the additional emissions reductions that ARB expects from the cap-and-trade program, the electricity sector could, in total, deliver as much as 55% of the required emission reductions in the State (if the electricity sector were to deliver the majority of the additional 35 MMT of reductions that ARB projects will need to come from the capped sectors).

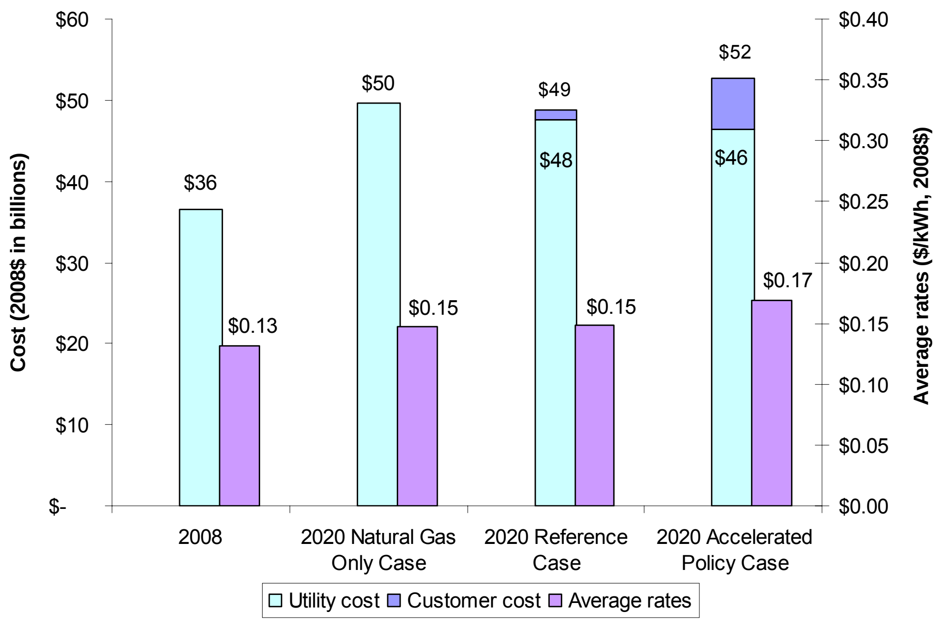
We fully expect that, as the second largest contributor to California's GHG emissions after transportation, the electricity sector will bear a large share of the emission reduction responsibility under AB 32. The electricity sector is a sector in which techniques for reducing emissions are already known and generally fairly quantifiable and feasible. However, we caution that the temptation to assign as much responsibility as possible to this sector should be avoided.

We are mindful of the responsibility to ensure cost-effectiveness of AB 32 measures, as well as to keep costs to consumers at a reasonable level. As noted above, the responsibility for reducing emissions can be separated from the recovery of the cost of the emission reductions.

Electricity is a somewhat unique commodity in modern life in that it is necessary both to sustain quality of life for individuals, and for the production of other necessary goods and services. Unlike many other goods and services, there are no ready substitutes for electricity in the economy (except for natural gas or other fuels, in some instances), and low-income consumers rely on electricity in their daily lives. In the territories of some investor-owned utilities, up to one-third of the customers are low-income. The proportion of low-income customers may be even higher in particular areas of investor-owned or publicly-owned utilities' territories. Therefore, we must be concerned about overburdening the sector as a whole, and low-income electricity consumers in particular, when designing AB 32 regulations for the electricity sector.

Figure 3-2 in Section 3.3.1 above, which we duplicate for convenience as Figure 4-2 below, contains E3's estimates of the total utility costs occurring in the three resource policy scenarios it examined: the Natural Gas Only Case, the Reference Case, and the Accelerated Policy Case scenarios. As can be seen from this figure, utility costs are projected to increase from current levels (above inflation) under all scenarios, largely because of generally increasing costs of natural gas and increasing capital costs of renewable and conventional generation as well as transmission and distribution facilities. The Accelerated Policy Case has more aggressive energy efficiency, renewables, California Solar Initiative, and CHP requirements. However, total utility costs would be higher in 2020 without those more aggressive policy options, with the data underlying Figure 4-2 indicating that total utility costs would be 4% higher in the Reference Case and 9% higher in the Natural Gas Only Case. This is chiefly because of the high levels of cost-effective energy efficiency assumed to be achieved in the Accelerated Policy Case. If those high levels of energy efficiency are not achieved, utility costs would go up commensurately.

Figure 4-2
Utility Costs, Customer Costs, and Average Rates in Three Key Scenarios



Some costs associated with increased levels of energy efficiency and other demand-side resources will be borne by individual consumers purchasing equipment, rather than by utility ratepayers. E3's estimates of those private costs in 2020 are included in Figure 4-2 above. E3 did not estimate consumers' private costs in 2008.

The average rates in Figure 4-2 mask significant variations in current rates (see Table 5-1 below) and potential rate impacts that may occur for individual retail providers. Larger rate increases are anticipated for some retail providers, while others will likely see more modest increases. In addition, individual retail provider results will be heavily influenced by the allowance allocation policy under a cap-and-trade program, if implemented, as discussed further below and in Section 5 of this decision.

It is important to point out that the estimated percentage rate increases are uniformly higher than the percentage cost increases shown in Figure 4-2 due to energy efficiency. If energy efficiency is successful, utilities will need to recover their fixed costs while selling less electricity, which causes per-kWh rates to increase by larger percentages than costs.

We also note that these forecasted rate impacts are averages for all customers; we did not ask E3 to estimate the rate impacts on particular types of consumers owing to the inherent complexity and variation in tariff structures for various types of customers of each utility. The actual impact of rate increases will be felt differentially by different types of consumers; the rate increases may be more difficult for consumers with little discretionary usage. Customers with greater ability to take advantage of energy efficiency opportunities to manage their energy usage may see little or no bill increases.

Our discussion to this point has focused on the cost and average rate impacts that will result from programmatic mandates. We also are concerned about the additional costs that may be borne by the electricity sector and its consumers as part of a cap-and-trade program. Therefore, we discuss next and make recommendations regarding cap design and allowance allocation.

As discussed above, while we agree that the electricity sector should contribute to emissions reductions through the programmatic strategies described in this decision, we do not necessarily agree that electricity sector consumers should bear all of the costs of the electricity sector programs or any or all of the additional costs associated with a cap-and-trade system. The design of the cap-and-trade system, and its associated allowance allocation policy, can have a significant positive or negative impact on the costs borne by electricity consumers.

As a starting point, we assume that ARB will set an emissions cap for the covered sectors as a whole that takes into account projected emissions levels throughout the entire economy of California. In fact, we believe this is required, since AB 32 requires attainment of 1990 emissions levels for the State as a whole, and not just in capped sectors.

As ARB conducts a sector-by-sector bottom-up analysis, we urge ARB not to assume or project additional emission reductions from the electricity sector beyond the levels contemplated by E3's Accelerated Policy Case, with one exception. As discussed in Section 4.1.1.2 above, we are committed to achieving all cost-effective energy efficiency in California. However, this level could not be modeled by E3 due to unavailability of reliable cost estimates for the more expensive energy efficiency measures approaching the cost-effectiveness threshold. With achievement of the Accelerated Policy Case and this additional commitment to all cost-effective energy efficiency, the electricity sector will bear a burden of reductions exceeding its proportional contribution to 1990 emissions and potentially at very high marginal costs for some measures. While emissions in this sector have been stabilizing due to aggressive current policies, emissions in other sectors have been growing steadily. This sector has already done a great deal and has incurred significant costs to mitigate GHG emissions in California and should not be further burdened beyond the levels contemplated here.

In order to minimize the potential additional burden on electricity consumers, we recommended in D.08-03-018 and ARB has already acknowledged in its Draft Scoping Plan that as many sectors of the California economy as possible should be capped and participate in the cap-and-trade program. We also support linkage of California with a regional and/or national cap-and-trade system, in order to open up further opportunities for GHG mitigation at lower cost than may be possible within California, so long as the programs with which California links are sufficiently stringent to meet AB 32 requirements. We also make additional recommendations in Section 7 related to flexible compliance, to ensure that the electricity sector participants in the cap-and-trade program have essential flexibility to keep costs low for electricity consumers. In addition to mandatory programs, the design of the cap-and-trade system has the potential to have a large impact on consumer costs.

We recommend that any further electricity sector reductions required as part of a multi-sector cap-and-trade program should be justified based on detailed analysis of the costs of GHG mitigation in other sectors. Until that additional analysis is conducted, we recommend that the electricity sector not be required to reduce its emissions below the approximately 79 MMT CO2e estimated in E3's Accelerated Policy Case.

As noted in Section 3.4.4 above, some additional costs would be borne by the electricity sector consumers as a result of inclusion in a cap-and-trade system, since the inclusion of a carbon price would result in higher wholesale electricity market prices, whether or not additional GHG reductions are achieved in the sector.

In a cap-and-trade system where some allowances (or allowance values) are administratively allocated, ARB will need to determine the proportion of allowances (or allowance value) to allocate to the electricity sector as a whole. This decision will have a potentially large impact on electricity consumer costs and rates.

While E3 did not analyze inter-sectoral cost and equity issues, we can make some general recommendations about how ARB's allowance allocation policy should treat the electricity sector. Section 5 of this decision contains our intra-sectoral allocation recommendations.

We do not know enough about ARB's potential cap-and-trade program design or about emission reduction opportunities in other sectors to make precise recommendations regarding the specific level of allowances that should be allocated to the electricity sector. However, we can make some general recommendations regarding the allocation approach that ARB should follow absent convincing information justifying a different approach. We recommend that ARB assign allowances (or allowance value) to the electricity sector at the beginning of the cap-and-trade program in 2012 based on the sector's proportion of total historical emissions during chosen baseline year(s) in the California sectors included in the cap-and-trade program, including emissions attributed to electricity imports. [34] We recommend that, in subsequent years, allowance (or allowance value) allocations to each California sector in the cap-and-trade program be reduced proportionally, using the overall trajectory chosen by ARB to meet AB 32 goals by 2020.

As an example of this allocation recommendation, if ARB creates allowances in a specified compliance year equal to 90% of the historical emissions in the sectors in the cap-and-trade program (including emissions attributed to electricity imports) during a chosen historical baseline period, the electricity sector would receive allowances equal to 90% of its actual emissions (including those attributed to imports) in the chosen baseline year(s).

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[34] We recognize that certain deliveries of imported power might be excluded from California's cap-and-trade system if they are included in comparable cap-and-trade programs elsewhere, which might happen as a result of Western Climate Initiative implementation. If that occurs, the historical baseline for calculating the allocation of allowances to and within California's electricity sector might need to be revised to reflect the reduced scope of the California cap-and-trade system.

With this allocation recommendation, while the electricity sector may provide more than its proportional share of GHG emissions reductions through both mandatory programs and market-based reductions occurring due to the cap-and-trade program, it would bear a roughly proportional share of emission reduction costs under the cap-and-trade system as compared to other sectors in the cap-and-trade program. Also, this approach would recognize early actions that entities in the capped sectors have taken to reduce emissions after the baseline period.

We also recommend that the trajectory of the multi-sector cap and the required annual reductions be generally a straight-line reduction between 2012 and 2020 for all sectors in the California cap-and-trade program, including electricity. In general, we favor steady progress toward the 2020 goals, which implies equal reductions annually between 2012 and 2020. However, development through the Western Climate Initiative of regional emission reduction programs, which may include transportation and other sectors, may affect the schedule for implementing reductions.

Regardless of whether ARB chooses a straight-line trajectory for the multi-sector cap, we emphasize the need to allocate the allowances proportionally among the sectors in the cap-and-trade program, based on relative emissions during an historical baseline period. Whether there are multi-year compliance periods will affect the electricity sector greatly, due to annual weather variations (as further discussed in Section 7 on flexible compliance below). If the annual cap reduction trajectory is not linear, we will need to examine carefully the impact on the electricity sector.

We note that during the first phase of the European Union Emission Trading Scheme, non-electricity sectors generally were allocated allowances to cover their expected emissions, while the allowance shortfall fell entirely on the electricity sector. For the reasons stated earlier about the impact on consumer cost in the electricity sector, we cannot support such an allocation policy in California. Because we are committing to aggressive policy mandates in the electricity sector, further reductions should not be required of the electricity sector, though we recognize that there may be some efficiencies available by generators within the 2020 period. Any further decisions about allowance allocation to the electricity sector should, at a minimum, be based on some analysis of the proportionality of the burdens being borne by each sector of the California economy. The additional reductions necessary to meet the AB 32 goal should not rest solely or even primarily on the electricity sector, given how much has already been achieved in the sector. If ARB determines that additional emission reduction measures should be mandated for the electricity sector, ARB should distribute additional allowances or allowance value to the electricity sector, so that the related costs would be shared among the sectors rather than borne by the electricity sector alone.

We continue to emphasize the need for careful monitoring of the performance of all electricity sector programs, including the cap-and-trade program, to ensure the program goals are achieved and that performance and cost information is obtained.

We have not addressed in this proceeding other emission reduction measures that may reduce overall California GHG emissions but increase emissions in the electricity sector. Chief among these is likely to be the electrification of transportation through, for example, electric vehicles and plug-in hybrids. This area will require further work as we coordinate with ARB on the development of the Low-Carbon Fuel Standard and the Scoping Plan. In order not to create a disincentive for the electrification of transportation, ARB may need to allocate extra allowances to the electricity sector to account for the increase in emissions and the increased sectoral GHG compliance obligations expected as a result of these and other potential policies. We do not know enough about the magnitude of the expected impact, but expect to work closely with ARB as these policies and technologies develop.

4.3.2.2. Natural Gas

ARB's Draft Scoping Plan indicates a desire to phase in inclusion of the natural gas sector (residential and commercial natural gas combustion) in the cap-and-trade program during the 2012 to 2020 timeframe. This is generally consistent with our recommendation in D.08-03-018 to consider later inclusion of natural gas in the cap-and-trade system. At this time, our analysis of the potential for natural gas sector contributions to the AB 32 2020 reduction goals is limited to the potential for energy efficiency, including utility programs, building codes, and appliance standards, affecting natural gas use, and solar hot water. Thus, we do not make recommendations regarding the natural gas sector contribution to GHG reductions, except that we recommend that ARB set natural gas energy efficiency requirements in its Scoping Plan at the level of all cost-effective energy efficiency, with energy efficiency goals for investor-owned utilities set based on those adopted by the Public Utilities Commission in D.08-07-047, and as may be revised and updated by the Public Utilities Commission from time to time.

We also note that, similar to the potential for electrification of vehicles as described above, natural gas is a potential alternative fuel to gasoline for transportation. We will need to work closely with ARB to estimate the potential impact on the natural gas sector of increased use of natural gas as a transportation fuel.

5. Distribution of GHG Emission Allowances in a Cap-and-Trade Program

If ARB determines that there will be a cap-and-trade program in California, ARB must determine how to distribute allowances to emit GHG. A GHG "allowance" is an authorization to emit a specified amount, generally one ton of CO2e of GHG emissions. At the end of a compliance period, entities with compliance obligations would be required to surrender the number of allowances equal to the amount of GHG they emitted, or meet their obligations through offsets or other flexible compliance mechanisms to the extent they are permitted. Any shortfall would subject the entity to penalties and/or other enforcement actions. Cap-and-trade market design and flexible compliance options are discussed in Section 7.

Because allowances could be traded in the cap-and-trade program, allowances would have financial value, even if distributed for free. The value would be determined by the supply of allowances, the demand to emit GHG, and the availability and cost of flexible compliance mechanisms. Because of this value, the method of allowance distribution could have a large impact on the costs to individual deliverers, retail providers, and ultimately electricity customers.

In D.08-03-018, we considered the issue of allowance distribution within the electricity sector in a multi-sector cap-and-trade program with deliverers as the point of regulation. In that decision, we recommended to ARB that "some portion of the GHG emission allowances available to the electricity sector be auctioned."[35] We stated further that:

[35] D.08-03-018, p. 8.

> An integral part of this auction recommendation is that the majority of the proceeds from the auctioning of allowances for the electricity sector should be used in ways that benefit electricity consumers in California, such as to augment investments in energy efficiency and renewable energy or to provide customer bill relief.[36]

We determined at that time that additional record development was needed in order to allow us to make more complete recommendations on allowance distribution issues. Building on our recommendations in D.08-03-018, and with the benefit of the extensive record developed subsequent to that decision, we address in this section the following aspects of allowance allocation policy for the electricity sector in a multi-sector cap-and-trade system:

- The proper mix between auctions and administrative allocations of emission allowances to deliverers, including transitioning between the two approaches;
- Whether allowances to be auctioned should be distributed to retail providers, which would then sell their distributed allowances through the auction;
- The manner in which auction proceeds should be used for the benefit of electricity customers; and
- The manner in which administrative allocations should be made to individual deliverers and retail providers.

In Section 6, we consider allocation of allowances to CHP facilities.

While it is critically important to design auctions in a way that prevents collusion and abuse of market power, we do not make detailed recommendations to ARB regarding auction design at this time. We expect that, if ARB includes auctions in its scoping plan, detailed auction design will occur during a subsequent rulemaking process. We expect to make further

[36] Id., at 9.

recommendations to ARB regarding auction design and other remaining allocation issues as part of that process.

We recommend that the allocation process occur in steps for the electricity sector. First, ARB would determine the total number of allowances to create for each year (or other appropriate time period) for all of the sectors included in the cap-and-trade program, with the number declining over time to meet the multi-sector GHG emission reduction goals. ARB would then determine the number of allowances (or the amount of auction revenue rights if there is a multi-sector auction with the distribution of auction revenue rights) to allocate to the electricity sector. Then, the electricity sectoral allocation would be divided through a second allocation process among the relevant entities within the electricity sector. In this section, we address the allocation of allowances or auction revenues within the electricity sector. In Section 4.2 above, we address the broader determination of the amount of allowances, or auction revenue rights, to be allocated to the electricity sector.[37]

5.1. Evaluation Criteria, Principles, and Goals

While determining in D.08-03-018 that further record development was needed to make complete recommendations to ARB regarding allowance allocation, we provided some broad direction for the more detailed recommendations on allocation policy that we make today:

> In addressing allocation issues, we keep in mind that some deliverers of electricity to the California grid are also retail providers of electricity for consumers. We also recognize that allocation policy will have an impact on consumer costs. Our intent in developing additional allocation policy recommendations is to ensure that GHG

[37] We recognize that ARB may develop a different method of distributing allowances for other covered sectors.

> emissions reductions are accomplished equitably and effectively, at the lowest cost to consumers. While we may wish to reward early actions to reduce GHG emissions in advance of 2012 when the AB 32 compliance period begins, it is not our intent to treat any market participants unfairly based on their past investments or decisions made prior to the passage of AB 32.[38]

A staff paper on allowance allocation discussed criteria to use in evaluating allocation options based on the goals discussed in D.08-03-018. Additionally, parties were asked to comment on appropriate evaluation criteria. Based on the discussions in the staff paper and parties' comments, we believe that the following criteria and goals provide useful guidance as we evaluate the various possible allocation approaches:

- Minimize costs to consumers.
- Treat all market participants equitably and fairly.
- Support a well-functioning cap-and-trade market.
- Align incentives with the emission reduction goals of AB 32.
- Administrative simplicity.

We address each of these criteria in turn.

5.1.1. Minimize Costs to Consumers

This criterion is grounded in AB 32 (Section 38652(b)(1) and Section 38652(b)(2)[39]) and is a key goal guiding AB 32 implementation. Several parties that propose evaluation criteria, including NRDC/UCS and PG&E, include consumer cost in their criteria. NRDC/UCS include a broad category ("Benefit consumers") that contains four subcriteria: avoid windfall profits,

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

[39] Unless indicated otherwise, citations to statutory Sections refer to California Health and Safety Code sections added by AB 32.

minimize costs/maximize benefit for consumers, benefit disadvantaged communities, and improve technology investment. The first criterion we identify focuses on the first three of these subcriteria. Morgan Stanley suggests a broad category ("[develop] a system that is of the least cost to California") that is similar.

We identify three key goals in the quest to minimize costs to consumers, which we address in turn:

Minimize increases in average retail rates and bills statewide. While the next goal considers distributional impacts, this goal seeks to allocate allowances in a manner that reduces average costs to electricity customers statewide. This goal focuses on the overall cost of the emissions reductions realized via the cap-and-trade program and on how those costs are distributed between consumers and producers of electricity.

Minimize wealth transfers among customers of different retail providers. This goal focuses on the differential impacts on retail providers of the various allocation approaches and promotes equity among electricity customers throughout California. The staff paper included a similar criterion ("Equity Among Customers of Retail Providers"), which several parties support in their comments. As we describe below, California's retail providers currently have widely differing average emissions levels. Additionally, the retail providers have varying levels of exposure to the wholesale electricity market. This goal recognizes the importance, to the extent that these characteristics are due to decisions made before AB 32, of not devising an allocation methodology that would create large transfers of wealth between customers of different retail providers.

California's generation mix differs substantially from much of the rest of the United States. Coal is the dominant source of electricity for most of the

United States, while less than 10% of California's electricity is produced by coal. As a result, natural gas generation generally is the price-setting generation in California, rather than coal. Additionally, California has a larger percent of non-emitting sources than found in other parts of the United States. Over one-quarter of California's electricity is produced by non-emitting generation.

Within California, retail providers have a range of generation profiles. The majority of California's customers are served by large utilities: three investor-owned utilities (PG&E, SCE, and SDG&E/SoCalGas) and two publicly-owned utilities (LADWP and SMUD). Table 5-1 below lists the generation characteristics of retail providers in California. PG&E has the lowest average emissions rate among California's large retail providers, primarily due to its high levels of non-emitting sources. Of the five largest providers, LADWP has the highest average emissions rate due to the large amounts of coal in its generation mix. Some of the smaller publicly-owned utilities have larger percentages of coal in their generation mix. Anaheim Public Utilities, for example, serves 78% of its load with coal-generated electricity, according to the Energy Commission's 2007 Integrated Energy Policy Report.

Table 5-1

Load and Sales Data for California's Retail Providers (Based on E3 2008 Modeling Data)

	Total Retail Sales (GWh)	Average Retail Rate ($/KWh)	% of Load from Coal*	% of Load from Natural Gas*	% of Load from Non--emitting Sources*	% Market Purchases and Other Generation	Average Emission Rate (MMT CO2e Per MWh)
PG&E	89,042	.14	0.4%	21.1%	40.0%	38.5%	.26
SCE	87,966	.147	7.1%	22.7%	32.9%	37.3%	.32
SDG&E	18,685	.145**	3.1%	46.3%	19.6%	31.0%	.35
LADWP	28,004	.101	40.7%	17.9%	21.2%	20.2%	.56
SMUD	11,887	.106	0.0%	47.7%	26.3%	25.9%	.32
Northern Cal. Other	23,583	.099	6.1%	4.3%	0%	89.6%	.44
Southern Cal. Other	28,479	.123	24.5%	8.5%	17.7%	49.4%	.48
Water Agencies	12,761	.060	11.0%	0%	0%	89.0%	.47
California Average/ Total	300,408	.131	9.5%	20.5%	27.4%	42.7%	.35

* These categories include generation by resource type that is utility-owned or under long-term contract. The Non-emitting Sources category includes generation from nuclear, large hydropower, and renewable sources.

** SDG&E Comments, June 2, 2008.

Unless great care is taken, carbon regulations inadvertently could have disparate customer impacts due to the different generation mixes. Customers of retail providers with small amounts of coal generation or large amounts of non-emitting generation in their electricity portfolio would tend to see lower price impacts due to compliance obligations under carbon regulations since the emissions levels of power serving them are lower. On the other hand, retail providers with larger amounts of coal generation or smaller amounts of non-emitting generation in their portfolio would tend to have higher rate impacts because their generation sources have higher carbon regulation compliance costs. An additional consideration is that retail providers have differing practices regarding the extent to which they own generating sources and their degree of reliance on market purchases. Customers of retail providers that obtain much of their electricity from the wholesale market would be affected by increases in wholesale prices more than would customers of retail providers that own or have long-term contracts with most of the generating assets used to serve their load. A significant focus of inquiry in this proceeding has addressed ways in which allowance allocation policies could help moderate these potential price impacts.

One important measure of potential impacts of GHG regulations on customers is the effect on the average rate levels of the various retail providers. Table 5-1 above shows current average retail rates and emission rates for retail providers in California. These rates differ significantly among the retail providers. PG&E's average retail rate is $0.14 per kWh, slightly above the average rate in California, while PG&E has the lowest average emissions rate. LADWP has the lowest retail rates among the large retail providers, with average retail rates of only $0.101 per kWh. However, LADWP has the highest average emissions rate among California's large retail providers.

One of the challenges of this proceeding is the development of allowance allocation policies that treat retail providers with such widely disparate emissions, procurement policies, and rate profiles equitably and fairly.

Avoid undue windfall profits for independent deliverers. This goal focuses on the potential for different allocation approaches to redistribute wealth from electricity consumers to independent generators and other deliverers. For the purposes of this decision, we define windfall profits as any increase in profits to deliverers that results from the establishment of an emissions cap-and-trade program and the manner in which allowances are distributed.

PG&E and several other parties support this goal. The staff paper describes how the allocation methodologies could provide differing amounts of windfall profits, which would lead to increased costs for consumers. In evaluating potential allocation methodologies, we pay close attention to the potential for windfall profits and the resulting effects on consumer costs.

Most of the allocation approaches that we have considered would increase wholesale electricity prices by an amount up to the allowance cost of the marginal generator, where allowance cost equals the market value of allowances times the number of allowances that must be surrendered for each unit of electricity from that resource. Using terminology suggested by the Market Surveillance Committee of the CAISO,[40] we distinguish two ways in which independent deliverers may obtain windfall profits due to a cap-and-trade system:

- "Allowance rents" are windfall profits obtained due to the free distribution of allowances. All deliverers that sell into the wholesale market would realize increased revenues as a result of higher wholesale electricity prices, while consumer costs would increase to the extent that individual retail providers rely on wholesale electricity purchases. Allowance rents would be a direct transfer from consumers to deliverers, with the increase in the deliverers' "producer surplus" matched by a corresponding loss in consumer surplus.
- "Clean generation rents" reflect the increase in producer surplus, and thus windfall profits, that occurs for generation with emission rates lower than the emission rate of the marginal unit that sets the wholesale market price. If the wholesale market price increases due to cap-and-trade by more than the compliance cost of other generators selling into the market, they realize clean generation rents. Conversely, if the wholesale

[40] CAISO Comments, December 3, 2007.

market price increases by less than the compliance cost of other generators selling into the market, their clean generation rents would be negative.

Figure 5-1 presents a stylized example that illustrates these two types of rents for several types of independent generators selling into the wholesale electricity market.[41]. In this example, gas-fired combustion turbines are the marginal source of generation and set the market clearing price P_0 before the cap-and-trade system is implemented. Once cap-and-trade is in effect, the wholesale market clearing price rises to P', reflecting the allowance cost of the gas-fired combustion turbines, which remain the marginal resource.

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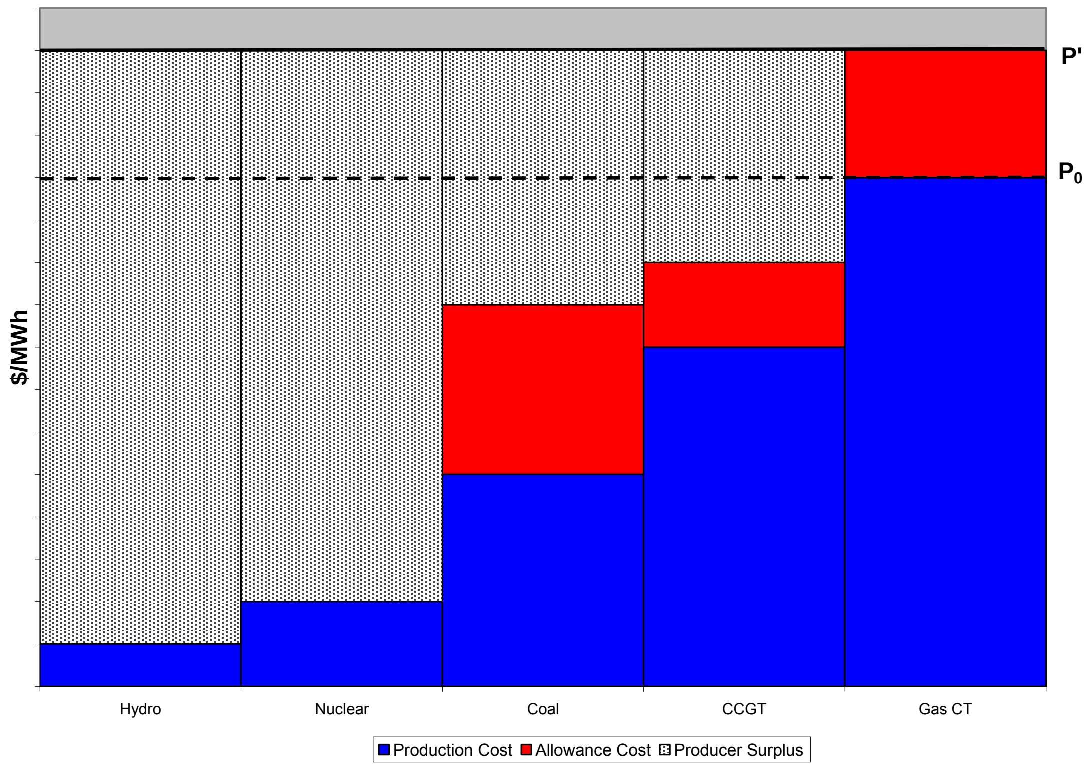
[41] For simplicity, we assume in this example that the independent generators are the deliverers of their electricity to the grid.

Figure 5-1

Stylized Example of Effects of GHG Compliance Costs on Producer Surplus



As illustrated in the example in Figure 5-1, allowance costs per MWh are lower for more efficient combined cycle gas-fired plants, higher for more carbon-intensive coal-fired generation, and zero for carbon-free hydropower and nuclear facilities. If generators receive all of the allowances they need for free, they will realize allowance rents equal to ($P' - P_0$) on each MWh they sell into the market. These rents represent an increase in the producer surplus that was already being received by inframarginal generators. Clean generation rents would accrue to some producers even with 100% auctioning. With 100% auctioning, emitting generators would actually incur the allowance costs shown in Figure 5-1, and the producer surplus each realizes would increase or decrease depending on whether it is less or more carbon-intensive than the marginal resource. In this example, the hydroelectric, nuclear and CCGT units all receive clean generation rents because the wholesale electricity price increase exceeds their allowance cost. The reverse is true for coal-fired generators, so their producer surplus declines. There is no change in producer surplus for the gas-fired combustion turbines on the margin. The wholesale energy price increase reduces consumer surplus, but this loss may be partially compensated by distributing the auction revenues in a way that benefits retail electricity customers.

While different parties have used somewhat different terminology, we find the CAISO's terminology to be useful for our purposes. It is generally accepted that only independent deliverers would actually receive either category of windfall profits. For generation owned by or already under long-term contract to retail providers, we assume that regulators and local governments would not allow pass-through of the opportunity costs of free allowances or clean generation rents, so that for such generation only actual compliance costs would be passed on to retail customers.

SCE submits that the profits that the Market Surveillance Committee calls rents to clean generation are unavoidable, and arguably are desirable in that they create incentives to build additional low-emission generating units. It finds allowance rents to be more problematic.

While supporting a relatively quick transition to a full auction in part because of concerns about windfall profits, DRA asserts that the extent of the overall windfall would be limited, for several reasons. First, DRA states that pre-existing procurement contracts are not susceptible to generator windfalls to the extent that the generator is not able to adjust the contract price to reflect increases in wholesale market prices. Second, DRA suggests that new procurement contracts may shift the carbon risk from the generator to the utility.

WPTF asserts that the E3 GHG calculator greatly overestimates potential windfall profits by independent deliverers. First, WPTF takes issue with E3's assumption that all generation currently under contract will be procured from the market upon expiration of the contract. Second, WPTF believes that E3 overestimates the extent to which renewable facilities would sell their power through the wholesale market and thus be positioned to reap windfall profits. Upon review of WPTF's concern, we find that WPTF states incorrectly that the marginal clearing price effect modeled in the E3 calculator is the difference between the effect of allowance costs on wholesale prices and the deliverers' cost of allowances. In fact, the market clearing price effect calculated by the E3 model is the total increase in wholesale prices, which is not reduced by deliverers' compliance costs.

EPUC/CAC assert that windfall profits by independent deliverers would be limited because of qualifying facilities and other power that is sold through long-term contracts. We agree that the administrative determination of prices for qualifying facilities may reduce the potential for windfall profits for such generation. However, it seems unlikely that generators entering into bilateral contracts would forego all of their potential windfall profits in exchange for the certainty of a long-term purchase agreement. We expect that wholesale prices in new contracts will reflect, to some extent, the profits that generators would expect if they chose to sell their power through bidding into the wholesale market.

5.1.2. Treat All Market Participants Equitably and Fairly

This criterion is grounded in Section 38562(b)(1). We recognized this guidance in our statement in D.08-03-018 that, "[I]t is not our intent to treat any market participants unfairly based on their past investments or decisions made prior to the passage of AB 32." (D.08-03-018, p. 18.) We recognize that retail providers and generators have made historical investments in emitting technologies and that allowance allocation methodologies could have significant financial impacts on investors and customers that rely on these technologies. Similarly, potential impacts on retail providers that have developed procurement strategies with greater reliance on wholesale markets should be considered when assessing the desirability of different allowance allocation approaches.

We also recognize the importance of providing appropriate recognition of early actions that entities may take to reduce GHG emissions. SDG&E/SoCalGas and PG&E argue that past energy efficiency and renewable energy investments by retail providers should be reflected in the allocation of allowances or auction revenue rights. While recognizing that early actions will provide an automatic benefit by reducing compliance obligations, we also consider how the various allowance allocation methodologies would recognize early actions.

Another consideration is the extent to which an allocation methodology would provide revenues to deliverers or retail providers to help fund compliance obligations or investments in GHG emission reduction measures, or to reduce customer rate impacts. Reducing GHG emissions consistent with AB 32's goals will require long-term investments in low-emitting technologies. As we discuss in Section 5.5 below, auction revenue intended for the benefit of consumers could be used in many ways, including investments in emission reduction measures and compensation for potential increases in electricity rates. We consider the impact that various allocation options would have on providing entities with revenues that they could use in adjusting to the new GHG reduction requirements.

An important goal is to ensure that the chosen allocation approach does not have inadvertent and unfair competitive impacts. While the need for emission reductions inherently will encourage the development of lower-emitting technologies and business practices, we should take care to avoid unintended consequences that favor certain technologies or entities for reasons other than their effectiveness in helping California achieve the goals of AB 32. Some parties have expressed particular concern that no entity should have preferential access to allowances.

Finally, while we agree that there is value in recognizing the past investment and business planning decisions that entities undertook before the need to reduce GHG emissions was understood fully, equity considerations require that we recognize and encourage entities that take aggressive steps to reduce emissions. While a transition period is reasonable, equity dictates that we move to a market in which "the polluter pays."

5.1.3. Support a Well-functioning Cap-and-Trade Market

We see three aspects of potential allowance allocation approaches as being particularly important to ensure the smooth functioning of the cap-and-trade market. First is the degree to which the distribution methodology leads to accurate price signals, to guide the activities and choices of market participants.

Second, market participants stress the need for some reasonable degree of predictability and certainty in the market. Market certainty would help companies plan future investments, particularly because many GHG-reducing strategies require significant long-term investments. Under a cap-and-trade program, certainty and predictability would be furthered by stable, long-term carbon prices. Additionally, it would be beneficial for entities to have some assurance regarding the level of allowances that will be available in the market and, in particular, the number of allowances that they may expect to receive. This concept is embedded in the "planning predictability" criterion that DRA proposes. We note that planning predictability will hinge on the value of allowances, not just the number available in the market or distributed to individual entities. A cap-and-trade program that would prevent or discourage allowance hoarding or other market manipulation practices would help foster accurate and more stable price signals. Third is the extent to which potential allocation methods might be vulnerable to market manipulation, a concern expressed in several parties' comments.

5.1.4. Align Incentives with the Emission Reduction Goals of AB 32

AB 32 provides guidance to the State agencies in developing GHG regulations to reduce GHG emissions. Of particular relevance in assessing allowance allocation options is the guidance in Section 38560 that regulations should "achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions." In evaluating allocation options, we consider the extent to which they provide incentives that will further the reduction of GHG emissions in California.

5.1.5. Administrative Simplicity

This criterion is included in the staff's criteria and is supported by several parties, including DRA and NRDC/UCS. In addition to improving the feasibility and ease of implementing the adopted GHG regulations, administrative simplicity would help stakeholders "reasonably predict the consequences of the program." (Staff allocation paper, p. 12.)

5.1.6. Additional Considerations

In addition to the most important criteria and goals listed above, we evaluate each allocation option to assess its desirability if California links to a regional and/or national cap-and-trade program. We recognize that future success in reducing GHG emissions will involve increasing coordination at the regional and national levels. In August 2007, several Western states (including California) and Canadian provinces established the Western Climate Initiative, an agreement to reduce GHG emissions through coordinated cap-and-trade programs. California is a full and supportive participant in the Western Climate Initiative. We also are following closely federal legislation that would establish a federal cap-and-trade program. We do not see that any of the allocation proposals considered would impede linkage with a federal or regional cap-and-trade program. Commission staff are coordinating with other Partner governments in the Western Climate Initiative to ensure that program design recommendations support the goals of the Western Climate Initiative and would contribute to a smooth transition to regional coordination and linkage.

SMUD and other parties (IEP, Dynegy) suggest that grid reliability be included as an allocation criterion, arguing that reliability was not considered adequately in the staff analysis. While grid reliability is of paramount importance, we do not find merit in these parties' arguments that allowance allocation policies could have a detrimental effect on grid reliability. Entities with a compliance obligation would be allowed to acquire allowances through auctions or from other parties. With proper design to curb the potential for market manipulation, the cost of allowances in the secondary market should reflect the supply and demand for allowances. Markets for allowances should provide generators and retail providers with appropriate price signals to guide long-term investments. Flexible compliance options, such as offsets, banking of allowances, and multi-year compliance periods, would help ease potential allowance demand spikes, as well as reduce the impact of abnormal hydropower years or other anomalies that may affect electricity generation or demand.

Some parties suggest accommodation of new entrants as a factor to consider in evaluation of the various allocation proposals. Based on the record, it appears that all allocation proposals could be structured in ways that would allow new entrants to obtain allowances equitably. By their structure, some allowance allocation approaches, in particular auctioning, would treat all deliverers equally, so that new deliverers would be on the same footing as other deliverers regarding their ability to obtain allowances. Other allocation approaches, particularly if used exclusively, may need specific provisions to accommodate the allowance needs of new entrants. For example, an approach in which allowances would be made available to deliverers in proportion to their historical emissions could, at the same time, set aside a number of allowances for new deliverers, so they would not be disadvantaged by such a general historical emissions-based approach. If an allocation approach appears desirable for other reasons, the complexity of devising and maintaining such a set-aside provision would need to be considered in deciding whether the approach should be pursued.

Finally, legal issues that parties have raised regarding allocation alternatives are addressed in Section 5.6. We do not find any convincing legal concerns with the allocation-related recommendations that we make to ARB.

5.2. Description of Allowance Distribution Options

The issue of allowance distribution is fundamentally a question of allocating the value that allowances represent. Allowance values could be distributed either by administratively allocating the actual allowances themselves or by first auctioning allowances and then distributing the resulting revenues, for example, according to a previously established structure of auction revenue rights. One party, GPI, has suggested making some or all of the allowances available for sale to deliverers at a predetermined price.

Allowances could be distributed to the entities with compliance obligations, or to other entities. In the electricity sector, allowances could be distributed to deliverers, which would have the compliance obligations under the deliverer approach that the Commissions have recommended to ARB. Allowances or auction revenues also could be distributed to retail providers on behalf of their ratepayers.

The staff paper on allowance allocation explored the impacts of several methods of allocation, including distribution to deliverers based on their historical emissions (both of in-State generation and imported electricity) during a fixed baseline period, distribution to deliverers based on the amount of electricity they currently or recently delivered to the California grid, and auctioning with allowances or auction revenues distributed to retail providers based on the retail providers' historical emissions, or on sales periodically updated to reflect more recent sales levels. The staff paper also describes various combinations of these approaches, which could be crafted to improve the extent to which various evaluation criteria are met.

We describe next the basic allowance distribution approaches that staff examined and also two other approaches suggested by parties.

5.2.1. Distribution of Allowances to Deliverers

5.2.1.1. Distributions in Proportion to Deliverers' Historical Emissions

One option would distribute allowances to deliverers in proportion to their historical emissions in a fixed prior baseline year or multi-year period. This approach is sometimes referred to as "grandfathering." Basing allocations on periodically updated emissions levels is generally not considered, because such updating would provide incentives for deliverers to increase, rather than reduce, the emissions associated with their electricity. Instead, the fixed proportion of yearly allowances that each deliverer would receive would be determined based on relative emissions during the baseline period. These fixed proportions then would be applied to the total number of allowances allocated to the electricity sector for each year to determine the number of allowances to distribute to individual deliverers. Allowances would continue to be distributed in the same proportion to individual deliverers, but deliverers would receive proportionately declining numbers of allowances each year as the overall number of allowances allocated to the electricity sector declines.

A primary drawback of historical emissions-based allowance distributions to deliverers is that there could be large windfall profits to independent generators and marketers. This approach would allow allowance rents and clean generation rents.

The expectation is that, with an historical emissions-based distribution mechanism, electricity sold through the wholesale market would reflect the full expected opportunity cost of allowances, even though deliverers were given allowances for free. This is because, if they did not operate, they would not incur compliance obligations and could sell their allowances at a profit. Because of the loss of allowance value entailed by the operation of an emitting facility, deliverers would tend to incorporate the opportunity cost of their allowances into their bids just as if the allowances had been purchased. As a result, wholesale prices would reflect the full opportunity cost of the marginal generators setting the wholesale market price. Deliverers of electricity from emitting generation resources (including deliverers from unspecified sources) would realize allowance rents because they would receive the higher wholesale electricity price while avoiding the cost of purchasing some or all of the allowances they need. Independent deliverers that receive free allowances could also reduce deliveries compared to the baseline period and sell the allowances; the resulting profits would also be considered an allowance rent. Carbon-free deliverers selling into the market also would receive the higher wholesale price without needing to purchase allowances. In this case, the resulting increase in profits would represent a clean generation rent.

These windfall profits would occur at the expense primarily of customers whose retail providers are dependent on competitive wholesale markets, which includes the investor-owned utilities and certain publicly-owned utilities. Electric service providers would be disadvantaged, to the extent they rely on the wholesale market. The windfall profits would result in wealth transfers to independent deliverers. A comparable wealth transfer would not occur for utilities that own most of their resources, because their regulatory boards presumably would prevent them from passing on the full opportunity cost of the freely received allowances to their customers.

An advantage of an historical emissions-based distribution approach is that it would avoid wealth transfers from customers of retail providers whose portfolios have higher GHG emission rates to customers of utilities with portfolios with lower GHG emission rates. Because sources that provide power to each utility are unlikely to change radically over a short time frame, the sources of power serving a retail provider's load should not be particularly short or long on allowances, particularly during the early years of an historical emissions-based approach.

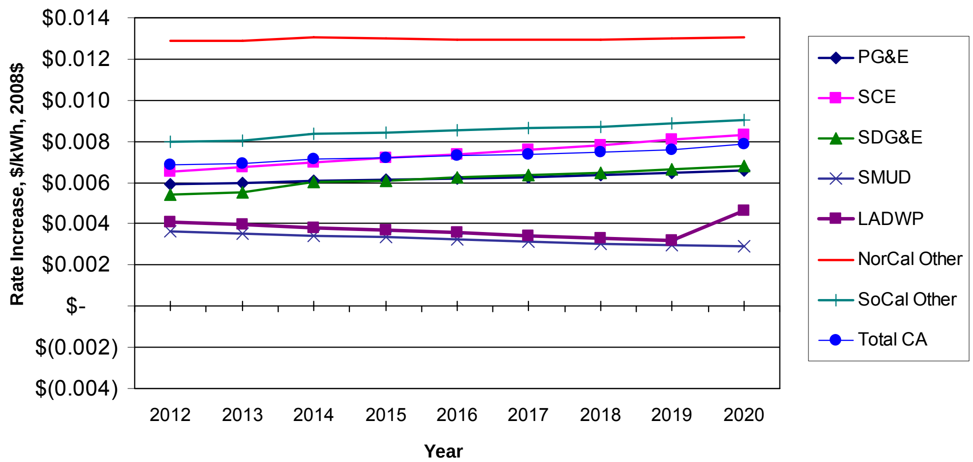
Figure 5-2 provides an illustrative example of the potential effects on retail providers' rates of historical emissions-based distributions of allowances to deliverers.[42] Recognizing that this scenario using the E3 calculator is based on only one set of modeling assumptions, we find this scenario useful because it provides a general indication of the effects that historical emissions-based distributions to deliverers could have on retail electricity rates. A comparison of the results in Figure 5-2 to results for other distribution options presented below indicates that, of the administrative allocation options we consider, historical emissions-based distributions of allowances to deliverers could have the largest impact on retail rates. While distributions on the basis of historical emissions would tend to protect retail providers like LADWP with relatively high-emitting portfolios, the large windfall profits would increase rates significantly for retail providers that are more dependent on the wholesale market.

[42] All E3 scenarios in Section 5 are based on the Accelerated Policy Case, including 33% renewables and "high" levels of energy efficiency. They also assume $30/ton allowance costs and no offsets. For simplicity, E3 assumes that the number of allowances allocated to the electricity sector each year matches the level of emissions projected for that year. The E3 auction scenarios also assume that all allowances to be auctioned would be distributed to retail providers, i.e., that ARB does not retain any allowances to be auctioned with the revenues used for other purposes.

Figure 5-2

Estimates of Effects on Average Retail Electricity Rates Due to Historical Emissions-Based Distributions of Allowances to Deliverers

($/kWh, 2008$)



To prevent new entrants with emissions from facing a competitive disadvantage relative to existing generators, an allowance set-aside or other steps would be needed to accommodate new entrants.

A shortcoming, compared to auction alternatives, is that this approach would generate no revenues to fund GHG emission reduction efforts by entities other than deliverers, or for customer bill relief. In its favor, the historical emissions-based approach would provide revenues to those deliverers with the largest compliance obligations and potentially with the most opportunity to reduce their emissions.

The extent to which historical emissions-based distributions to deliverers would recognize voluntary early actions that deliverers have taken to reduce emissions depends on the base period used in establishing the level of historical emissions to be used in determining the number of allowances each deliverer would receive. If, for example, the base period used for determining historical emissions were a period immediately prior to the enactment of AB 32, deliverers would be rewarded for any early action they take to reduce emissions after that base period. These deliverers would receive credit for their early action because their allowances would be based on their higher (pre-AB 32 enactment) historical emissions, but they would only need enough allowances to cover a level of emissions that had been reduced by the actions they took after enactment of AB 32. The receipt of the additional allowances would reward the deliverers for their voluntary early actions.

An advantage of historical emissions-based distributions to deliverers is that the number of free allowances that each deliverer would receive would be predictable.

An historical emissions-based distribution of allowances to deliverers would be relatively simple to administer. It would require administrative determinations regarding the baseline year(s). A multi-year average baseline could be used to smooth normal variations in emissions, e.g., due to varying hydro and temperature conditions and due to varying lengths of outages. Additionally, for electricity delivered from outside of California during the baseline period, the sources of generation would need to be identified and appropriate emissions factors applied to unspecified purchases. Because of the significant volume of unspecified purchases from out-of-state sources, this would entail a substantial value. The need to develop some method to set aside or otherwise provide allowances to new entrants would add administrative complexity.

The distribution of allowances in proportion to historical emissions would provide a strong incentive for deliverers to reduce emissions, since the deliverer could sell any unused allowances. A deliverer could reduce its emissions in various ways, including increases in the efficiency of its facilities, switching to lower-emitting sources, or decreasing deliveries. Since allowances would continue to be distributed in perpetuity, high-emitting facilities in particular might have an incentive to shut down in order to free up allowances to sell in the market.

5.2.1.2. Distribution in Proportion to Amount of Electricity Delivered

In this approach, allowances would be distributed to deliverers in proportion to the amount of electricity they deliver to the California grid in a specified period. This approach is often referred to as "output based." The proportions of allowances distributed to individual deliverers would be updated periodically, either annually or perhaps less frequently, to reflect relative changes in production. These updated proportions would be applied to the total number of allowances allocated to the electricity sector for the year in question to determine the number of allowances to distribute to individual deliverers.

In a pure output-based approach, the number of allowances distributed to each deliverer would be proportional to the total amount of electricity it delivers in the specified period, regardless of its emissions levels. As a variation on the output-based approach, allowances could be distributed instead in proportion to the delivery of electricity from generation with emissions. As another variation, staff suggests a fuel-differentiated approach, as explained more fully below.

Table 5-2 provides a simplified illustration of how an output-based allocation mechanism would work, along with the two variations described in the staff paper. This example assumes that the electricity sector consists of four generation sources – coal, natural gas, unspecified, and non-emitting – and that each source delivers 100 GWh to the grid. It also assumes that the total electricity sector carbon allowances equal the total sector's emissions, in tons CO2e.

Table 5-2

Illustration of Output-based Allowance Distribution Methodologies

Generation Fuel Type	Deliveries in Prior Period (GWh)	Emissions (tons CO2e)	Allowances, Pure Output-based	Allowances, Output-based to Emitting Deliverers	Assumed Weighting for Each Fuel Type	Allowances, Fuel-Differentiated Output-based
Coal	100	100,000	50,000	66,667	2	100,000
Gas	100	50,000	50,000	66,667	1	50,000
Unspecified	100	50,000	50,000	66,667	1	50,000
Zero-emission (Renewable, large hydro, nuclear)	100	0	50,000	0	0	0
Total Emissions/ Allowances		200,000	200,000	200,000		200,000

As Table 5-2 illustrates, in a pure output-based approach, deliverers with non-emitting or relatively low-emitting generation resources would benefit relative to those with higher-emitting resources.[43] As a result, a pure output-based approach likely would result in large wealth transfers from customers of coal-dependent retail providers and would advantage customers of retail providers with low emissions in their electricity portfolios.

Staff and certain parties suggest variations to the output-based approach, aimed at moderating this wealth transfer. With an output-based allocation

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[43] In the example, the deliverer of zero-emission electricity would receive the same number of free allowances as the coal-based deliverer. The zero-emitting deliverer would have no compliance obligation, whereas the coal-based deliverer would have a compliance obligation twice as large as the number of allowances it received.

restricted to emitters, deliverers with emissions would receive a larger share of allowances than under a pure output-based allocation. As Table 5-2 illustrates, allowances would be divided among entities that deliver electricity from emitting resources (including unspecified sources) based on their portion of emitting deliveries. Because allowances would be targeted to deliverers with emissions, the wealth transfer from customers of retail providers with high levels of emitting generation would be reduced. However, there still would be wealth transfers from customers of retail providers with disproportionate amounts of coal generation to customers of largely natural gas-dependent retail providers.

With a fuel-differentiated output-based allocation, allowances would be allocated only to deliverers of electricity from emitting resources, using weighting factors based on fuel type. As illustrated in Table 5-2, the use of weighting factors would reduce, and could largely eliminate, wealth transfers from customers of coal-dependent retail providers to customers of natural gas-dependent retail providers. This reduction of wealth transfers would be accomplished by providing emitting deliveries with allocations that more closely reflect their emission levels.

Staff and certain parties argue that output-based distributions of allowances to deliverers may tend to hold down consumer costs compared to historical emissions-based distributions to deliverers, due to what they call a "market clearing price effect."[44] In an output-based approach, deliverers would have an incentive to maintain or increase sales levels, since the number of

[44] See, Burtraw, D., Palmer, K., and Kahn, D., "Allocation of CO_2 Emissions Allowances in the Regional Greenhouse Gas Cap-and-Trade Program," Resources for the Future Discussion Paper 05-25, June 2005, attached to the April 16, 2008 staff paper on allowance allocation.

allowances they receive would depend on continued generation levels. Because of this incentive to maintain sales and generation, generators may have an incentive to not include the full value of allowances in wholesale bids or in negotiated prices in power purchase agreements. Essentially, there would be no opportunity cost for the allowances because the allocation depends on continued deliveries. If emitting sources reduce generation in order to free up and sell allowances in one period, they would lose allowances in the future period. If wholesale energy bids reflect this theorized incentive, wholesale market prices in an output-based approach would be lower than in an historical emissions-based approach. In theory, wholesale prices would increase only if, and to the extent that, the marginal generator setting the market clearing price does not receive free allowances sufficient to meet its compliance costs. Although this line of reasoning is somewhat persuasive, we note that this allocation approach has never actually been used in practice.

Staff recommends that the output-based approach, if chosen, distribute allowances only to deliveries from GHG-emitting resources, since including all generation would provide free allowances to deliverers that use non-emitting resources including nuclear, hydro, and renewable sources that do not need them. Staff recommends further that allocations be made on a fuel-differentiated basis, with more allowances provided to high emitters. In this fuel-differentiated approach, a weighting factor would allocate more allowances per MWh to deliveries from coal-fired sources. Staff states that this fuel-specific approach should be designed to produce virtually no wealth transfers among retail providers at the start of the program.

The potential effects of output-based distributions to deliverers on average retail rates depend heavily on the extent to which allowance values are reflected in wholesale market prices. The following figures provide illustrative examples of potential average rate impacts of output-based allocation approaches for the different retail providers. Because of current modeling limitations, the fuel-differentiated option has not been modeled in this proceeding. Figure 5-3 and Figure 5-4 below illustrate potential average rate impacts for retail electricity customers under a pure output-based allocation, with Figure 5-3 assuming that the full value of allowances is included in wholesale market prices while Figure 5-4 assumes that 25% of the value of allowances is included in wholesale market prices. As mentioned previously, these figures and all other figures in Section 5 assume 33% renewables, "high" levels of energy efficiency, $30/ton allowance costs, and no offsets.

Figure 5-3

Estimates of Effects on Average Retail Electricity Rates Due to Pure Output-Based Allocation of Allowances to Deliverers, With Inclusion of Full Value of Allowances in Wholesale Prices

($/kWh, 2008$)

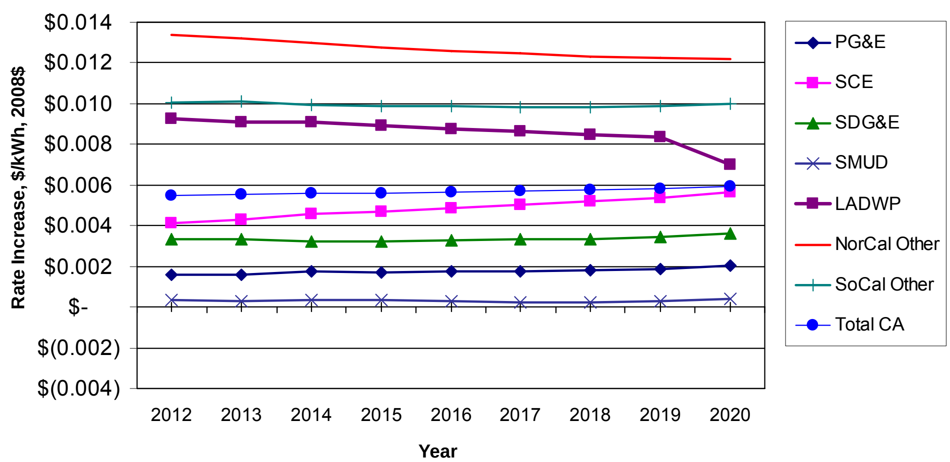
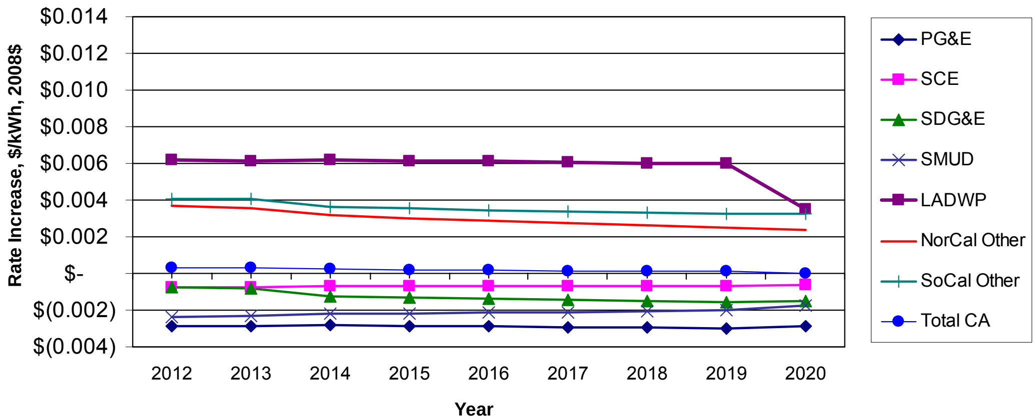


Figure 5-4

Estimates of Effects on Average Retail Electricity Rates Due to Pure Output-Based Allocation of Allowances to Deliverers, With Inclusion of 25% of Allowance Value in Wholesale Prices

($/kWh, 2008$)



Relative to an historical emissions-based allocation (illustrated in Figure 5-2), an output-based allocation to all generation would have smaller rate impacts for retail providers with large percentages of non-emitting generation. PG&E and SCE, both with large shares of non-emitting sources, would experience lower costs with an output-based allocation to deliverers, relative to their costs with an historical emissions-based allocation to deliverers. Retail providers with relatively small amounts of non-emitting generation, such as LADWP, would experience higher rate impacts with an output-based allocation to deliverers relative to an historical emissions-based allocation. These findings apply regardless of the extent to which the value of allowances is reflected in wholesale market prices.

If, as theorized, an output-based approach suppresses the inclusion of allowance values in wholesale prices (illustrated in Figure 5-4), the differences in rate impacts for retail providers with lower-emitting portfolios compared to those with higher-emitting portfolios could be even more pronounced. The scenario illustrated in Figure 5-4, with only 25% of the allowance value reflected in wholesale prices, indicates the possibility that lower-emitting retail providers could see rate decreases in such situations.

Figure 5-5 and Figure 5-6 below illustrate potential average rate impacts for retail providers with an output-based allocation limited to emitting generation deliverers.

Figure 5-5

Estimates of Effects on Average Retail Electricity Rates Due to Output-Based Allocation of Allowances to Emitting Deliverers, With Inclusion of Full Value of Allowances in Wholesale Prices

($/kWh, 2008$)

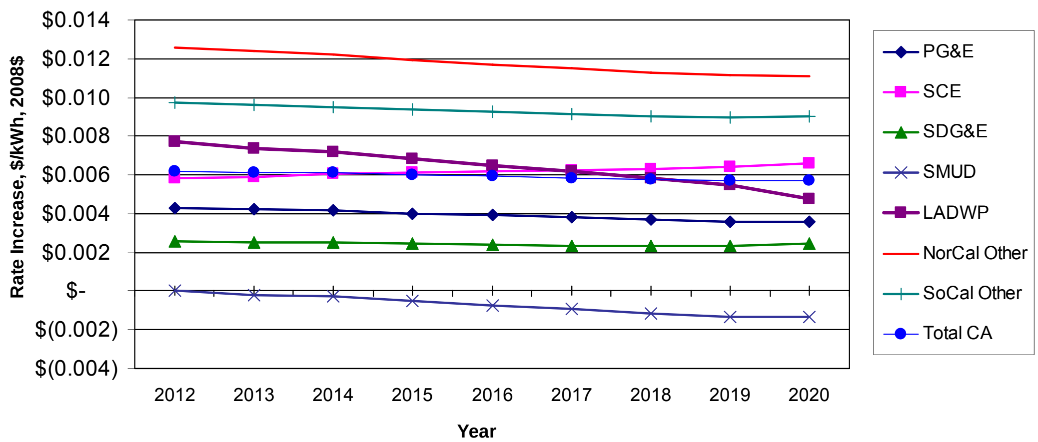
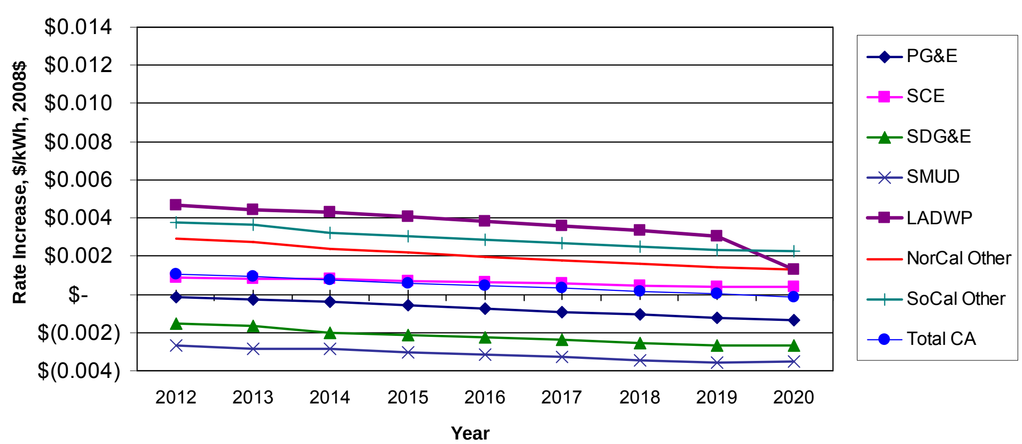


Figure 5-6

Estimates of Effects on Average Retail Electricity Rates Due to Output-Based Allocation of Allowances to Emitting Deliverers, With Inclusion of 25% of Allowance Value in Wholesale Prices

($/kWh, 2008$)



While average statewide rate impacts may be about the same for either a pure output-based approach or an output-based approach limited to deliverers of electricity from emitting generation resources, wealth transfers among customers of different retail providers would be moderated somewhat if the output-based allocation is limited to emitting generation deliverers, as can be seen by comparing Figure 5-5 and Figure 5-3.

A pure output-based allocation approach would provide an incentive for increasing generation from low-or non-emitting resources, to the extent that allowances would be received in excess of the number needed for such resources. At the same time, there may be an incentive to decrease production from high-emitting resources such as coal.

Output-based allocations restricted to emitters would not provide an incentive to increase generation from non-emitting sources. Under this approach, it appears that natural gas generators still would receive more allowances than they would need, particularly in the early years, and, thus, would have an incentive to increase production. Coal, on the other hand, would receive fewer allowances than it would need, which could act as an incentive for decreased coal production.

A fuel-differentiated output-based allocation could largely eliminate the incentives to increase generation from natural gas or decrease coal production, if the weighting factors approximate deliverers' emission rates.

A pure output-based allocation methodology would benefit renewable and other low-emitting generators in that they would receive free allowances that they could sell, with resulting windfall profits in the form of allowance rents. However, the variations on the output-based approach that staff considered would provide no allowances to zero-emitting generators. Generators selling into the market would be affected by the theorized characteristic that output-based methodologies might suppress the pass-through of allowance opportunity costs in market clearing prices. To the extent that occurs, clean generation rents would be less than would occur in allocation methodologies that lead to full reflection of allowance opportunity costs in the market clearing price.

An output-based approach with frequent updating would accommodate new entrants. However, to avoid a competitive advantage to existing deliverers, it may be desirable to have a small set-aside of allowances for a new entrant's first year of operation, if allowances were allocated exclusively through output-based distributions to deliverers.

Like the historical emissions-based approach, a shortcoming of an output-based distribution to deliverers is that it would not generate revenues to fund GHG emission reduction efforts by entities other than deliverers, or for customer bill relief.

If allowances were distributed to deliverers on an output basis, deliverers would obtain a benefit from any early action they had taken to increase their generating efficiency. For example, the number of allowances needed for a natural gas generator would decrease if the generator increases its efficiency, while the number of allowances it would receive would not change based on that early action.

Output-based allowance distribution approaches would not provide as much certainty for deliverers as would an historical emissions-based approach. This is because the number of allowances that an individual deliverer would receive would be determined based on its proportional share of deliveries to the grid in the previous period and therefore would depend on the output of all of the allowance-eligible deliverers. Consequently, its allocation in future periods could not be known in advance.

A pure output-based allocation approach would be fairly transparent and easy to administer, because it would provide a simple formula for allocating allowances, based on generation levels during a specified period. An output-based approach limited to emitting sources would be more complex, because the sources of the electricity would need to be identified. A fuel-differentiated approach would require development of appropriate weighting factors for each fuel type, adding some additional administrative complexity.

5.2.1.3. Distribution of Rights to Purchase Allowances at a Fixed Price

GPI asserts that giving emissions allowances away without charge would be equivalent to giving away public assets or resources and would not be in the public interest. GPI maintains that free distributions would provide a form of windfall to the recipient, whether retail sellers or generators, at the expense of electricity consumers. GPI supports the auctioning of a small fraction of allowances initially, transitioning to increased reliance on auctions as the market develops, matures, and stabilizes.

GPI submits that, to the extent that allowances are not auctioned, the proper approach is to administratively allocate to deliverers the right to purchase allowances at a pre-determined, administratively set price. GPI states that the administrative allocation to deliverers of purchasing rights for the GHG emissions allowances can be done using the same methods as have been discussed for the administrative allocation of free allowances to deliverers.

GPI asserts that its proposed approach would prevent windfalls, and would ensure that the value of emissions allowances could be applied to benefit consumers. GPI submits that its approach would provide some amount of price stabilization, at least in the early stages of the program.

GPI asserts that distribution of allowances by sales rather than without charge would provide some important market protections and benefits, including that market participants that purchase allowances rather than receive them for free would be less likely to exhibit manipulative, speculative, or hoarding behavior. It also asserts that this approach would impose greater operating costs on fossil generators, and greatly reduce the risk of windfall profits.

GPI states that the market clearing price for allowances likely would be achieved in the secondary market although the authorities "ought to be able" to set a price that is reasonably close to the market clearing price for allowances.

GPI expects that the administrative allocation of the rights to purchase allowances at a fixed price would be phased out gradually with increased auctioning.

5.2.2. Auctioning with Distributions to Retail Providers

In this approach, auctions of GHG allowances would be conducted by ARB or its agent. Deliverers, which would have the compliance obligation, would buy allowances according to anticipated need through the auction and/or in the secondary market.

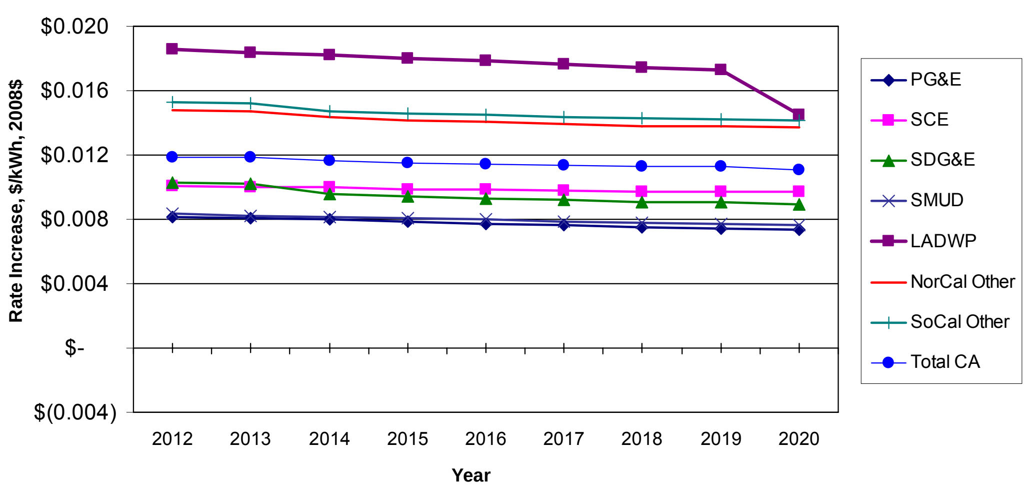
With auctioning, deliverers would buy allowances (or utilize offsets or other flexible compliance options to the extent allowed) for all emitting electricity that they deliver, and would need to recover these costs. We expect that, with auctioning, wholesale electricity prices would increase to reflect allowance costs of marginal generation that sets the market clearing price. This would generally flow through to retail rates. Resourced retail providers similarly would be able to pass their allowance costs through to consumers, assuming approval by regulatory or other governing authorities.

The net effect on costs to customers and wealth transfers among customers of different retail providers would depend on how the money raised by the auction is used. If no allowances or auction revenues were distributed to retail providers, we expect that retail rates would increase statewide, with the largest increases for retail providers with generation portfolios with relatively high emission rates. Figure 5-7 illustrates potential rate impacts if allowances are auctioned without retail providers receiving any allowance value.

Figure 5-7

Estimates of Effects on Average Retail Electricity Rates of Auctions If Retail Providers Receive No Allowances

($/kWh, 2008$)



Because of the significant rate impacts that would occur otherwise, as illustrated in Figure 5-7, we recommended in D.08-03-018 that the majority of revenues from the auctioning of allowances for the electricity sector be used for the benefit of electricity consumers. In one formulation of this approach, ARB would auction the GHG allowances and the State would receive revenues from the auction. In another formulation, ARB would distribute some or all of the allowances to retail providers and/or other entities that ARB determines should receive the value of the allowances. As discussed in Section 5.3 below, we recommend that ARB distribute allowances to retail providers, with a requirement that they then sell the allowances distributed to them through a centralized auction. This requirement would mitigate potential anti-competitive effects due to the distribution of allowances to retail providers.

Auctioning would treat all deliverers, including new entrants, equally.

Auctioning would provide a strong incentive for deliverers to reduce emissions associated with their power. In this regard, auctioning would perform on par with emissions-based allocations to deliverers and somewhat better than output-based allocations, which would provide less incentives for deliverers to shut down high-emitting plants or take other steps to reduce the emissions of the power they deliver.

An auction could be complex to develop and administer. There also would be a need to develop and implement a method for allocating allowances or auction revenue to individual retail providers. Allocating allowances or auction revenues to retail providers on a sales basis would be relatively simple, whereas an historical emissions-based approach would be somewhat more complex.

Because of the potential otherwise for large retail bill impacts, we recommend that ARB distribute all, or almost all, of the electricity sector allowances that are to be auctioned to retail providers, for the purposes of GHG emission reductions and customer bill relief. This could be done in a number of ways, including distributions in proportion to historical emissions in the retail provider's portfolio in a baseline year, or on a sales basis. We next describe these two alternatives.

5.2.2.1. Distribution in Proportion to Retail Providers' Historical Emissions

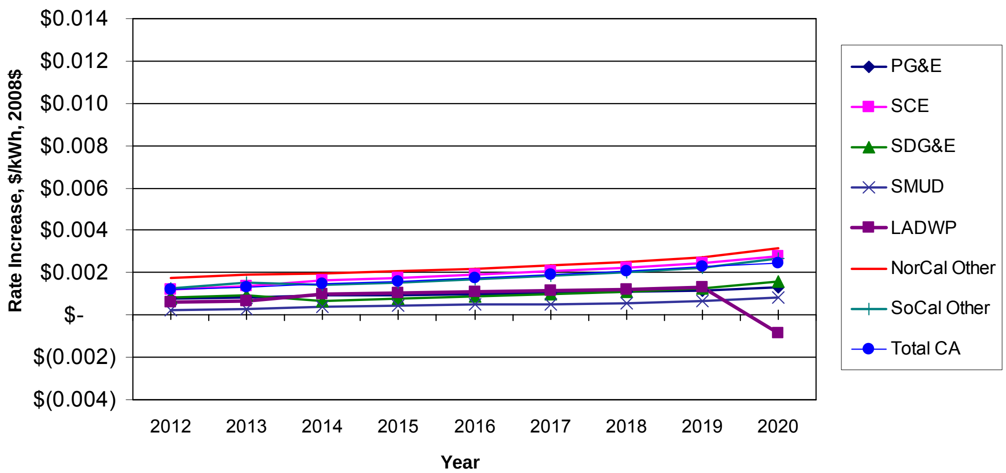
In this approach, allowances would be distributed to retail providers (for subsequent auctioning) in proportion to the historical emissions of sources and purchases used to serve each retail provider's load in a prior baseline year or multi-year period. The fixed proportions would be used to determine allowance allocations in subsequent years, with the actual amounts distributed to each retail provider depending on the total number of allowances allocated to retail providers each year. This approach is conceptually similar to distributions to deliverers on the basis of historical emissions, but the effects on average customer costs would be much less, largely due to the elimination of allowance rents to deliverers.

Figure 5-8 provides an illustrative example of the potential rate impacts for different retail providers due to a 100% auctioning approach, with all allowances distributed to retail providers in proportion to historical emissions of their portfolios.

Figure 5-8

Estimates of Effects on Average Retail Electricity Rates Due to Allowances Distributed to Retail Providers on the Basis of Historical Emissions

($/kWh, 2008$)



As illustrated clearly in Figure 5-8, the distribution of allowances to retail providers based on the historical emissions of their electricity portfolios would have much lower rate impacts than distributions to deliverers, and with much less variation among retail providers throughout the study period. Of course, greater variations may appear over time if individual retail providers modify their resource portfolios at different paces than assumed by E3. Larger rate impacts would also be expected if the number of allowances allocated to the electricity sector declines faster than emissions decline. While these generalizations about the potential effects of variations in resource portfolios and disparities between emission levels and available allowances also would apply to other allowance distribution approaches, we mention them in this context because of the marked similarities in modeled results for the various retail providers.

The extent to which historical emissions-based distributions to retail providers would recognize early actions that retail providers may have taken to reduce emissions would depend on the base period used.

Once the relative proportions based on the historical emissions of individual retail providers are established, retail providers would know in advance the number of allowances they could expect to receive each year. This would provide some certainty as retail providers plan for the use of auction revenues, though the auction proceeds could still vary widely depending on allowance prices.

5.2.2.2. Distribution in Proportion to Retail Providers' Sales

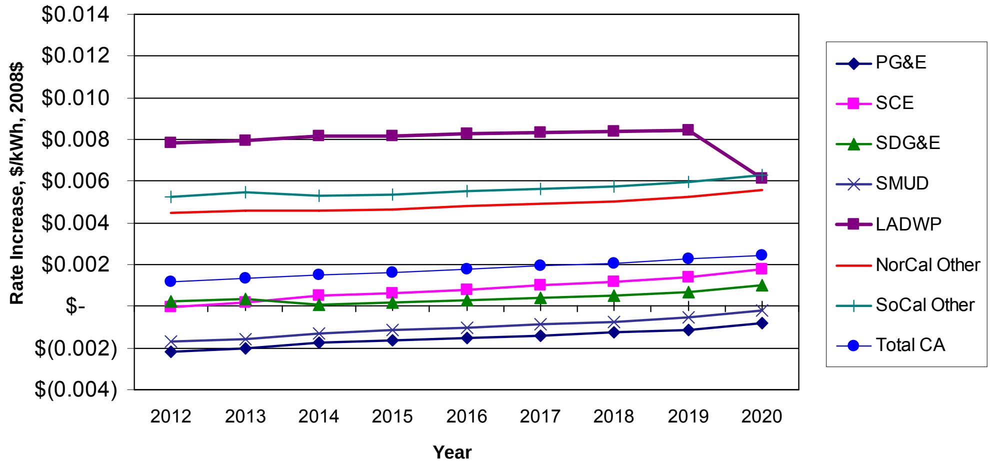
In this approach, allowances would be distributed to retail providers (for subsequent auctioning) in proportion to their sales during a specified period. The proportions of allowances distributed to individual retail providers would be updated periodically, to reflect relative changes in sales. This approach is conceptually similar to distributions to deliverers on the basis of output. A beneficial aspect of this approach is that it would accommodate and reflect differing growth rates in different retail providers' service territories.

Figure 5-9 provides an illustrative example of the potential rate impacts for different retail providers due to a 100% auctioning approach, with all allowances distributed to retail providers in proportion to their sales.

Figure 5-9

Estimates of Effects on Average Retail Electricity Rates Due to Allowances Distributed to Retail Providers on the Basis of Sales

($/kWh, 2008$)



As Figure 5-9 indicates, rates would increase more for customers of retail providers with relatively high-emission portfolios and would increase less, or could even decrease, for customers of retail providers with relatively low-emission portfolios, with a resulting wealth transfer from customers of high-emitting retail providers to customers of retail providers with lower-emission portfolios.

Sales-based allocations to retail providers would provide incentives for retail providers to increase reliance on cost-effective renewables and other low-emitting generation. Some parties have argued that sales-based allocations would provide incentives for retail providers to increase sales rather than invest in energy efficiency, and that a measure of energy efficiency should be included in the sales calculation to reward early actions and to avoid incentives to increase sales. This matter is discussed in Section 5.4.3.

Compared to an historical emissions-based allocation, retail providers would have less certainty about the number of allowances they would receive, because the proportional distributions would depend on the sales of all retail providers.

5.2.3. Distribution of Allowances in Proportion to Economic Harm

SCE proposes that the allowance allocation methodology be devised to mitigate the economic harm caused by implementation of AB 32. SCE describes economic harm as the difference in an entity's economic outcome under a cap-and-trade system as opposed to business-as-usual conditions. In SCE's approach, allowances would be given to those entities that otherwise would experience economic harm due to the implementation of a GHG reduction program.

SCE asserts that this approach would be consistent with the equity guidance in AB 32 and would ensure that windfall profits are not created.

SCE submits that economic harm could occur in the electricity sector in the following situations:

- When an independent generator that sells power in a wholesale electricity market has an emissions rate that is higher than the emissions rate of the marginal generating unit that sets the market clearing price in that market. SCE submits that, in such a circumstance, the independent generator would incur emissions costs greater than the increased revenue it receives.
- When a retail provider owns generation that has GHG emissions or is responsible for the emissions costs of generation it has purchased by contract. In such a circumstance, the generation would not receive any market revenues because it directly serves load, and SCE expects that the emission costs would be recovered from the retail provider's customers, who would suffer resulting economic harm.

- When a retail provider purchases power from the wholesale electricity market but the market price has increased as a result of GHG regulation. Retail rates would be expected to increase as a result, with economic harm to customers.
- When an independent power producer has sold its output forward into the period of GHG reduction regulation without any contractual provisions to recover the new GHG costs.

If allowances are auctioned, SCE proposes that auction proceeds be distributed according to its economic harm-based methodology. SCE does not support targeting auction revenues to fund energy efficiency or renewables. It argues that the expected increases in market prices would make greater levels of energy efficiency and renewable energy projects cost-effective, and that no additional incentives would be needed. SCE points out further that, under its proposed economic harm-based allocation mechanism, a significant portion of allowances or auction revenue rights would be allocated to retail deliverers based on the economic burden of GHG regulation on their ratepayers, and would be available to mitigate increases in the revenue requirement resulting from an emissions cap. In SCE's view, the precise distribution of auction revenues by customer class should be determined by the Public Utilities Commission during an investor-owned utility's cost recovery proceedings.

5.3. Should Allowances or Auction Revenues be Distributed to Retail Providers?

With auctioning, the value of some or all of the auctioned allowances could be distributed to benefit consumers through at least two different ways:

- Direct centralized auction by ARB or its agent, with retail providers given auction revenue rights for some or all of the auctioned allowances; and
- Distribution of allowances to retail providers, with the provision that they must sell those allowances in a centralized auction undertaken by ARB or its agent, and receive the proceeds.

5.3.1. Positions of the Parties

SCPPA and PG&E prefer that allowances be distributed directly to retail providers with subsequent monetization of the allowances through an auction and a return of auction revenues in proportion to the number of allowances distributed to each retail provider. In SCPPA's view, this procedure could help to address its concerns about whether auction revenues would actually be returned to retail providers instead of being "siphoned off to other purposes." DRA expresses a similar concern that auction proceeds under the control of a State agency may be vulnerable when there are shortfalls in the State budget.

Calpine, Dynegy, WPTF, AReM, FPL, and IEP oppose distributing allowances directly to retail providers. These parties argue that such a step would raise a number of competitive fairness issues:

- Calpine is concerned that this would give control of the auction process to a certain segment of market participants, and that liquidity in the allowance market would be reduced, making it more difficult for the market to find the most cost-effective means for reducing emissions.
- Calpine states that distributing allowances to retail providers would raise market power concerns if retail provider-owned generation assets would have preferential access to allowances to the detriment of independent power producers and power marketers.
- Dynegy and IEP are concerned that retail providers could impose unreasonable conditions on allowance purchases or withhold them from the market altogether. Dynegy suggests that a retail provider could condition the availability of allowances to a supply agreement, and thus reap an unfair advantage over independent power producers. Dynegy argues further that such a system would create a price advantage for the retail providers, and would create an incentive for them to build their own generation rather than seek needed generation through competitive solicitations.

- WPTF argues that jurisdictional retail providers would have an inherent conflict of interest as the recipient of allowances because, in most instances, they also own generating resources and/or are in direct competition with independent entities for providing electricity to retail load. WPTF and AReM argue that a direct allocation of allowances to jurisdictional retail providers potentially would confer an unfair competitive advantage to utility-owned resources in procuring allowances, and create a concentration of market power.
- FPL describes that retail providers might have a competitive advantage in development of new generation projects if they have obtained the needed allowances for free.

These parties take the general position that the market structure must treat all similarly situated market participants in a non-discriminatory manner.

5.3.2. Discussion

The distribution of allowances to retail providers with the provision that they must sell those allowances in a centralized auction undertaken by ARB or its agent would satisfy both SCPPA's request for assurance that retail providers receive the anticipated revenues, and the independent providers' concerns that they not be disadvantaged due to the retail providers' access to allowance value for the benefit of retail customers.

Parties appear to be unified in their views that retail providers that receive allowances should be required to sell them through auction. As noted above, independent producers are concerned that allowing retail providers to use allowances that were given to them at no cost to meet compliance obligations while other entities are required to purchase allowances for their delivered electricity could have competitive consequences, including difficulties by independents in obtaining allowances and the unfair encouragement of more utility-owned generation. No party has voiced objection to the recommendation that retail providers should be required to sell at auction any allowances they receive.

We are aware of the anti-competitive concerns that the independent producers have raised regarding the distribution of allowances to retail providers. We agree that retail providers should be required to provide nondiscriminatory access to the allowances they own.

At the same time, having the retail providers rather than the State own the allowances at the time they are auctioned would simplify the auctioning and revenue distribution process, in that auction revenues would pass directly to the retail providers rather than being deposited first in State-controlled accounts and then redistributed to the retail providers through an auction revenue rights mechanism.

For these reasons, we recommend that ARB establish a centralized auction process, to be run by ARB or its agent. For the portion of allowances whose value ARB deems should be distributed to retail providers for the benefit of their customers, ARB should distribute the allowances directly to the retail providers with a requirement that they in turn sell the allowances in the centralized auction. Utility owned generation would then have the opportunity to purchase allowances on the same basis as other deliverers. Each retail provider should receive all auction revenues from the sale of the allowances that were distributed to it. ARB should establish the centralized auction with safeguards to ensure that this result is obtained. If ARB cannot design an auction that is legally separated from other State revenues, we suggest an alternate mechanism be designed.

In response to a question raised in comments on the proposed decision, we clarify that our recommendation that retail providers be required to sell the allowances they receive applies only to allowances received in their role as a retail provider, not to any allowances that a vertically-integrated entity that is both a retail provider and a deliverer may receive based on its deliveries to the grid.

5.4. Recommended Structure of Allowance Distributions in the Electricity Sector

In D.08-03-018, we determined that, if a multi-sector GHG cap-and-trade program is implemented in California, some portion of the emission allowances available to the electricity sector should be auctioned. We found, however, that additional record development was needed to allow us to make recommendations regarding the proper mix between auctions and administrative allocations of emission allowances to deliverers for the electricity sector.

As described above, the allowance distribution methods that we consider include:

- Auctioning: distribution of allowances to retail providers for subsequent auctioning;
- Distributions to deliverers, either free or at a set price;
- SCE's harm-based proposal; and
- Transitions, in particular, from mainly distributions to deliverers to greater amounts of auctioning, and from emissions-based to sales-based distributions to retail providers.

5.4.1. Positions of the Parties

5.4.1.1. Auctioning vs. Distribution to Deliverers

Most parties support initial auctioning of only a portion of allowances, either commencing immediately or within a few years after a cap-and-trade program begins, with a transition to auction larger numbers of allowances over time. As a complement to their views regarding auctioning, most parties support initial distribution of a portion of allowances to deliverers, with that portion declining as increased auctioning is phased in. Some parties support 100% auctioning from the beginning of the cap-and-trade program.

Some parties continue to argue against any auctioning. While we do not revisit our determination in D.08-03-018 that some portion of allowances should be auctioned, we consider those parties' cautions against auctioning in determining the amount of auctioning to recommend to ARB.

Low Initial Auction Levels/High Distributions to Deliverers

Some parties take the position that all allowances should be distributed to deliverers for free, with no auctioning (CMUA, Calpine, EPUC/CAC). An additional set of parties favored auctioning only a small number of allowances initially (SMUD, DRA, Dynegy, WPTF). Those parties that support no or small amounts of auctioning initially make the following arguments:

- Independent power producers would not have a guarantee of carbon cost recovery (EPUC/CAC). EPUC/CAC cite the presence of administratively determined prices, the scope of utility solicitations, and implementation of the CAISO's Market Redesign and Technology Upgrade (MRTU)[45] as factors that may affect a generator's ability to recover its carbon cost from the market.
- Independent power producers may have contracts with utilities that extend beyond 2012 for which there is no clear provision for recovery of new GHG costs. SDG&E/SoCalGas respond to this concern by suggesting that retail providers should give allowances to generators with fixed-price contracts signed prior to AB 32 that do not contemplate a GHG market.

[45] EPUC/CAC submit that 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." They describe that MRTU prices will be subject to a system-wide cap and that MRTU will cap a supplier's bid under certain circumstances.

- Auctioning may raise reliability concerns (IEP, Calpine, SMUD). Calpine argues that if third parties purchase large quantities of allowances and withhold them from the market, reliability could be threatened if insufficient allowances are available for generation to meet the load.
- Auctioning could create volatility in prices and auction revenue, making it difficult to plan effective infrastructure and programs (SMUD and CMUA). Calpine is concerned that volatility may make it difficult for generators to recover their compliance costs in the wholesale energy market.
- Uncertainty regarding allowance prices would make it difficult for entities with compliance obligations, especially publicly-owned utilities with deliverer responsibility for a significant portion of their portfolio, to plan their cash flow requirements if they must purchase allowances.
- Dynegy and SMUD assert that distribution of allowances to deliverers is needed to provide them funds for emission reduction investments.
- SCPPA raises market power and manipulation concerns about the conduct of auctioning, and general concerns about the complexity of an auction process.

Several parties favor transitioning to increased amounts of auctioning over time. DRA and WPTF submit that a transition period would provide time for deliverers to plan for compliance and make necessary adjustments to their financial plans to account for the impacts of GHG compliance obligations on their operating cash flow. DRA recommends that 25% of allowances be auctioned initially and that all allowances be auctioned by 2017. Powerex supports up to 25% auctioning initially, transitioning to 100%. These parties argue that a transition is needed for the following reasons:

- WPTF states that a transition period would enable generators to retain the resources needed for long-term investment in cleaner technologies and fuels.

- Transitioning from auctioning a small portion to auctioning a larger portion of the allowances would protect ratepayers from potential problems/market dysfunctions stemming from a sudden regulatory shift and the lack of familiarity with auctions in a regulatory context, while also ensuring adequate market liquidity for allowances.

Other parties express concern about a rapid transition to auctioning, such as the five-year transition to 100% auctioning as suggested by staff and DRA. These parties argue in favor of a slow transition to allow entities time to adjust to new market conditions. Dynegy suggests a 15-year transition to ensure that older generation needed for reliability stays online and older facilities have time to identify ways to reduce GHG emissions. Calpine recommends that a phase-in to auctions conclude around the year 2031. EPUC/CAC suggest a small two-year trial auction beginning in 2014, with future increases in auctioning phased in to avoid industry disruption. GPI supports auctioning a small fraction of allowances initially, with transitioning to increased reliance on auctions as the market develops, matures, and stabilizes.

High Initial Auction Levels/Low or No Distributions to Deliverers

Several parties (PG&E, NRDC/UCS, TURN, SCPPA, FPL, Johnson, CARE) recommend that, in the electricity sector, all or most emissions allowances be auctioned. SDG&E/SoCalGas support allocation of all allowances to retail providers, with appropriate measures to ensure that allowances are made available to the market on a non-discriminatory basis. They state that this proposal is equivalent to an auction approach with auction revenue rights allocated to retail providers, using the terminology of the staff paper.

These parties argue, variously, that auctioning would improve market liquidity (PG&E, Johnson, NRDC/UCS (joined by GPI)), reward early action (NRDC/UCS, GPI), and create a transparent price signal for the market (PG&E,

Johnson). PG&E submits that retail customers will bear the ultimate costs of meeting GHG reduction goals and, therefore, should receive the value of the allowances to help mitigate their compliance costs. LADWP expresses similar views. Johnson states that whatever allocation benefits are desired could be achieved by allocating auction revenue rights, and that 100% auctioning may be simpler than a combination of auction and allocation to deliverers. NCPA argues that retail providers would have the best opportunities to mitigate carbon emissions, especially during the early years of the program.

While continuing to oppose inclusion of the electricity sector in a multi-sector cap-and-trade program, TURN states that most, if not all, allowances should be auctioned, and that it could support no more than an initial 20% allocation to deliverers based on emissions, to be phased out by 2016.

Several parties (PG&E, NRDC/UCS, GPI, TURN, SCPPA, Johnson, CARE) argue that giving allowances to deliverers would result in windfall profits to independent deliverers, with significant transfers of wealth from consumers to those deliverers. NRDC/UCS and TURN assert that most independent deliverers could recover the cost (or the opportunity cost) of allowances in their wholesale electricity prices. TURN cites information in the record that GHG emission reduction costs are likely to be much less than 50% of the value of the allowances. TURN points to a fairly low elasticity of demand for electricity, the absence of cheaper substitutes, and the lack of foreign competition as reasons why independent deliverers would be able to increase wholesale prices to recover GHG compliance costs. It states that only at certain breakpoints in allowance prices would there be a major change in the relative profitability of different production technologies. The supporters of free distributions to deliverers respond that the extent of any windfall profits would be limited, for various reasons, with DRA and WPTF arguing further that a quick transition to

100% auctioning would ensure that any windfall profits would be short-term and declining in nature.

Other

Under SCE's economic harm-based allocation proposal, deliverers and retail providers would receive allowances only to the extent that they otherwise would incur economic harm due to implementation of AB 32. SCE asserts that independent generation would incur economic harm if it sells electricity with an emissions rate higher than the emissions rate of the marginal unit that sets the market clearing price, or if it has long-term contract obligations to sell its output forward into the period of GHG regulation without contractual provisions to recover the new GHG costs. SCE submits that customers of retail providers would be harmed when a retail provider owns generation that has GHG emissions or is responsible for the emissions costs of generation it has purchased by contract, or when a retail provider purchases power at a market price that has increased as a result of GHG regulation. SCE concludes that independent generators and retail providers should receive allowances in these circumstances.

SCE asserts that, if its economic harm proposal is not adopted, capital investments made prior to AB 32 under laws and rules that did not require pricing of GHG emissions may have to be abandoned prematurely, raising questions of equitable treatment and imposing significant costs to the California economy.

5.4.1.2. Historical Emissions-based Distributions to Deliverers

Several parties (Dynegy, DRA, TURN) state that allocations to deliverers should be based on historical emissions. DRA proposes emissions-based distributions to deliverers, so that the relative proportion of free allowances allocated to each deliverer would remain constant until 2017, when all allowances would be auctioned under DRA's proposal. TURN states that it could support no more than an initial 20% allocation to deliverers based on emissions, to be eliminated by 2016. These parties offer the following arguments for historical emissions-based allocations to deliverers:

- An historical emissions-based allocation system would recognize the reliability benefits conferred by such sources, provide funding for emission reductions investments, and offset some of the expected loss of market value of emitting resources (Dynegy).
- An historical emissions-based allocation would protect the value of current resources occurred in compliance with all then-existing regulatory requirements (Dynegy).
- An historical emissions-based allocation approach would provide a predictable amount of free allowances to individual deliverers, which would be desirable from a business planning perspective (DRA).

Other parties (PG&E, SCE, NRDC/UCS) oppose historical emissions-based allowance allocations to deliverers. These parties provide the following arguments against this allocation procedure:

- An historical emissions-based approach would penalize entities that have already invested in low-GHG technologies and fuels (NRDC/UCS and Calpine).
- This approach would not provide an incentive for efficiency improvements or investments in cleaner and more-efficient generating technologies (Calpine).
- Necessary assumptions regarding emissions rates of market purchases and non-unit-specific contracts would result in an inaccurate allowance allocation (PG&E).
- Some generators would receive an unearned windfall of the allocation value (NRDC/UCS and SCE).
- An historical emissions-based allocation of allowances to deliverers would result in transfers of wealth from consumers to producers or deliverers (SCPPA).

- Clean utilities could pay twice under an emissions-based allocation: once for clean investments and a second time to generate what are more expensive emission reductions to meet the cap or obtain allowances (NRDC/UCS).

Though supporting initial allocations to deliverers based on historical emissions, DRA recognizes that an historical emissions-based allowance allocation methodology for deliverers would disadvantage customers of utilities that purchase most of their power from independent producers, relative to customers of utilities that are vertically integrated, but states that this disadvantage would be eliminated by 2017, when all allowances would be auctioned under DRA's proposal.

5.4.1.3. Output-based Distributions to Deliverers

Parties provide general comments on output-based allocation methodologies, with some also commenting on specific output-based variations, including limiting distributions to only deliverers with emitting sources, and fuel-based differentiations, as described in the staff paper.

Output-based allocations to deliverers using all or most generation types are supported by three parties (Calpine, Solar Alliance, and CRA). Solar Alliance and CRA both favor some allocation to new renewable generation, although neither comments on whether there should be allocations to deliverers using existing non-emitting sources. These parties offer the following arguments in favor of output-based allocation to deliverers:

- Output-based allocations to deliverers would reflect current market conditions and provide incentives for investment in low-GHG technologies and fuels (Calpine).
- This approach would recognize early actors since the quantity of allowances received would be based on the entity's output rather than historical emissions, and would not create perverse incentives to extend the life of dirty, inefficient generators or contracts with these generators (Calpine).

Parties that oppose an output-based allocation methodology for deliverers provide the following arguments:

- Output-based allocations would provide valuable allowances to non-emitting entities that have no need for them because they do not have a compliance obligation (Dynegy). These deliverers would already see an increase in profits as the wholesale price of power rises.
- An output-based allocation methodology might give generators the perverse incentive to increase output in order to increase their share of allowances (DRA). Calpine responds to this argument by asserting that an output-based approach would only provide incentives for cleaner technologies to increase production. Calpine asserts that the expected yearly declines in the number of allowances granted would place downward pressure on emission levels.
- This approach would create a wealth transfer from high-emitting entities to low-emitting resources (SCE, LADWP).
- An output-based approach would not help high-emitting resources receive the allowances necessary to transition to a carbon-constrained economy (SCE).
- Uncertainty regarding the level of year-to-year distributions to individual deliverers would create risk for deliverers and would make it difficult for entities to predict compliance costs (SCE and DRA).
- An output-based method for distributing allowances to deliverers should not be considered until a more robust modeling analysis of the proposal can be completed, to assess the impact of an output-based approach on bidding behavior (SCPPA).

Some parties oppose the staff proposal to limit output-based allocations to only deliverers that use emitting generation. SCE and GPI assert that this approach would result in windfall profits for natural gas generators at the expense of coal generation.

SMUD supports a fuel-differentiated output-based allocation of allowances and would include new renewables and energy efficiency after AB 32 became law, but would not grant allowances for non-emitting resources existing before passage of AB 32. SMUD asserts that this would be a simple, cost-effective method to reward early action for adding clean resources while acceptably reducing regional imbalances due to historical resource ownership. SCPPA states that a fuel-differentiated output-based allocation to emitting deliverers would merit further examination. It asserts, however, that the output-based allocation of allowances to deliverers should not be pursued without undertaking further modeling to determine whether the claimed market clearing price mitigation would actually occur.

Some parties offer arguments against fuel-differentiated output-based allocations to deliverers. These parties make the following arguments against fuel-differentiated allocations:

- Allocation to deliverers on a fuel-differentiated basis could make it more expensive for a relatively inefficient GHG gas-fired generator to run than an efficient coal-fired generator (SDG&E/SoCalGas).
- Applying a weighting factor to resources based on the fuel type would complicate an output-based allocation methodology and could be gamed (DRA).

SCE argues that an assumption that market clearing prices would not increase under an output-based approach would ignore the fact (so SCE alleges) that a marginal generating unit (which sets the market-clearing price) would not receive allowances sufficient to cover its emissions. SCE sees such a shortfall occurring in two ways. SCE contends that there would be a shortfall of allowances to emitting generators, first, if allowances are allocated to non-emitting resources and, second, because the allowance cap would decline each year. SCE maintains that generators would include these shortfalls in their bids and also would increase their bids to recover the risk uncertainty related to the number of allowances they receive. SCE also explains that, because the State's total generation fluctuates each year, the number of allowances that a deliverer would receive would vary depending on variables such as temperature and hydro levels. SCE argues further that an output-based approach would be less efficient than other approaches because entities could alter their allowance allocation through current or future behavior.

5.4.1.4. Transition from Emissions-based to Output-based Distributions for Deliverers

EPUC/CAC support a hybrid historical emissions/output-based allocation that gradually transitions to full output-based by 2020. They recommend that the output-based approach distribute allowances to deliverers based on the lower of their actual or an average emissions benchmark, and that a five-year baseline be used for output determination in the output-based approach.

5.4.1.5. Allowances for New Deliverers

EPUC/CAC submit that a new entrant reserve should be set aside for new generation, sized sufficiently to accommodate new generation needs and taking into account load growth, anticipated plant retirements, and increased efficiency from repowering. In their view, CHP and other low-carbon generation should be given priority in a new entrant reserve to recognize their efficient fuel use and carbon reduction benefits.

DRA recommends that, given the relatively short transition it proposes to 100% auction, new deliverers should purchase all of their allowances in the auction.

5.4.1.6. Historical Emissions-based Distributions to Retail Providers

SCPPA states that, if auctioning with the distribution of auction revenues to retail providers is undertaken, the distributions should be based on the emissions associated with each retail provider's total portfolio. It asserts that this approach would have little or no potential for creating wealth transfers among retail providers.

PG&E disagrees, arguing that an allocation methodology based on historical emissions associated with a retail provider's load would not recognize prior investments made in zero or low-carbon generation and energy efficiency. PG&E asserts that use of historical emissions associated with load would require assumptions regarding emission rates of market purchases and non-unit-specific contracts, which would result in an inaccurate allowance allocation. PG&E also contends that allowance allocation options such as those based on historical emissions or which fail to provide credit to sources or categories of sources for emissions reductions prior to implementation of AB 32 would violate the express requirement in AB 32 that sources of emissions receive credit for early actions (Section 38562(b)(3)).

SDG&E/SoCalGas argue similarly that allocation of allowances to retail providers based on emissions rather than sales would be inconsistent with the mandates of AB 32 in Sections 38562(b)(1) and (3) to "encourage early action" and give "appropriate credit for early voluntary reductions." They assert that emissions-based allocations would punish customers of retail providers that already have incurred significant costs to reduce their emissions, and would reward retail providers that have delayed reducing their emissions. They argue further that emissions-based allocations would fail to reflect the costs imposed on society by high-emission deliverers.

5.4.1.7. Sales-based Distributions to Retail Providers

PG&E supports distribution of all allowances to retail providers on the basis of sales, and suggests an updating metric such as current retail electricity sales adjusted for verified customer energy efficiency savings. PG&E supports this approach on the basis that it would recognize and encourage early action and would also encourage aggressive deployment of energy efficiency and investments in low- and zero-emissions generating technologies. PG&E states that its proposal would be equitable to retail providers with varying emissions rates, arguing that, while a utility's current emissions are one element that determines the average cost to customers, low-emitting utilities will have fewer low-cost GHG reduction opportunities and high-emitting utilities may have more lower-cost emission reduction opportunities within their own portfolio. PG&E argues further that equity goals support its proposal, asserting that those entities with high-emitting resources in their portfolio should be responsible for the cost of those emissions and that those costs should not and lawfully may not be assigned and shifted to customers who do not receive the benefits of the electricity from these higher-emitting resources.

SDG&E/SoCalGas similarly support allocation to retail providers on the basis of sales adjusted for cumulative energy efficiency savings. They state that updating allowance allocations to retail providers based on sales may introduce some inefficiency by creating incentives to increase sales, if verified energy efficiency is not included. They submit that including cumulative energy efficiency savings would reduce this potential inefficiency while accounting for higher growth in some areas.

SDG&E/SoCalGas state that mandatory GHG reduction measures would not require retail providers with a high GHG-emitting portfolio to undertake any more actions than low-emitting retail providers and argue, as a result, that it makes sense to fund the mandatory measures with allocation of allowances or auction revenue rights on a sales basis. They contend that higher-emitting retail providers have the "headroom" in rates necessary to incur costs similar to those that have been realized already by the lower-emitting retail providers in reducing their emissions. They expect that GHG-reducing strategies such as energy efficiency currently available to publicly-owned utilities are, in large part, less expensive than opportunities currently available to investor-owned utilities, because of the energy efficiency achievements already attained by investor-owned utilities.

SCE and SCPPA oppose a sales-based allocation of auction revenue rights to retail providers, because of its tendency to result in wealth transfers from more carbon-intensive retail providers to less carbon-intensive retail providers.

SCPPA states that basing retail provider allocations on net load (gross retail provider load less load served by legacy hydroelectric and nuclear resources), as suggested by staff, would mitigate somewhat the wealth transfer effect of a sales-based allocation, and that allocation to retail providers on a fuel-differentiated basis, so that there would be proportionately higher allocation of allowances or auction revenue rights to coal-served load, would further mitigate the wealth transfer.

5.4.1.8. Transition from Historical Emissions-based to Sales-based Distributions for Retail Providers

SMUD supports allocation of auction revenue rights to retail providers based on emissions initially, and sales later. SMUD supports retail providers receiving auction revenue for renewable energy and energy efficiency.

PG&E asserts that, if a sales-based distribution approach is not implemented immediately, there should be a short transition to this approach, so that all utilities are held to the same benchmark emissions rate as quickly as possible.

SCPPA opposes a transition to sales-based allocations for retail providers because of the wealth transfers that would occur. It states that such a transition would fail to recognize that various retail providers, including SCPPA members, have existing contracts with coal plants that will not expire until later years (including 2019 for the LADWP contract with the Navajo coal plant and 2027 for various SCPPA members' contracts with Intermountain Power Project). SCPPA argues that there should be, at most, a minimal transition by 2020 from an emissions-based allocation of auction revenue rights among retail providers toward a sales-based allocation.

While not making firm recommendations, NRDC/UCS suggest that auction revenue distributions to retail providers in 2012 based partly on emissions and partly on sales adjusted for verified energy savings would provide some accommodation for those carbon-intensive retail providers that need to reduce their emissions the most, but at the same time would reward and not penalize those utilities that took early actions prior to the start of the program in 2012. They recommend that the distribution approach for retail providers transition to 100% sales-based, adjusted for verified energy efficiency savings, by 2020 or earlier. In their view, this would provide long-term incentives for retail providers to reduce the overall emissions associated with serving their customers. They recommend that any sales-based distributions should use sales that are adjusted for verified energy efficiency savings, in order to provide proper incentives for emissions reductions and adherence to the State's loading order. NRDC/UCS urge the Commissions, in determining allocation policies, to focus on the equity impacts for all entities involved. They recognize that the most carbon-intensive retail providers in the State would need to make significant investments in order to clean up their systems. At the same time, they are concerned that distributions to retail providers on an emissions basis would tend to reward the dirtier utilities while penalizing the cleaner utilities; they submit that sales-based distributions would have the opposite effect.

CARE supports the staff proposal to distribute auction revenues to retail providers using a transition from an historical emissions basis to a sales basis, with the sales determination including renewables but excluding nuclear and large hydro.

5.4.2. Discussion

We determined in D.08-03-018 that some allowances allocated to the electricity sector should be auctioned. Today, we address other issues regarding the structure of allowance distributions in the electricity sector, including what portion of the allowances allocated to the electricity sector should be auctioned.

We evaluate the various alternatives for structuring allowance distributions in the electricity sector using the evaluation criteria and goals discussed in Section 5.1, as follows:

- Minimize costs to consumers.
- Treat all market participants equitably and fairly.
- Support a well-functioning cap-and-trade market.
- Align incentives with the emission reduction goals of AB 32.
- Administrative simplicity and feasibility.

We find it useful to address the allowance distribution proposals brought forward by GPI and SCE first, before turning to the other alternatives before us.

5.4.2.1. Distribution of Rights to Purchase Allowances

GPI proposes that, to the extent that allowances are not auctioned, ARB should administratively allocate to deliverers the rights to purchase allowances at a pre-determined, administratively set price. GPI's proposal is described in more detail in Section 5.2.1.3 above.

According to GPI, the allocation of purchase rights would have significant advantages over distributing free allowances. GPI states that, by granting purchase rights to entities with compliance obligations, ARB would ensure that these entities have access to the allowances they need to meet their compliance obligation. At the same time, selling these allowances at a fixed price would ensure that the State generates revenue from the allocation. GPI argues further that the sale of allowances would limit the windfall profits realized when allowances are distributed for free on an emissions basis.

We recognize the potential benefits that might be obtained by an allocation of purchase rights, as described by GPI. However, in practice, any relative benefits of this proposal would hinge on the setting of the administrative price of the allowances. Setting a "well-determined price," as GPI suggests, would determine how successful this allocation would be at limiting windfalls and generating revenue for the State.

The risks of not setting a "well-determined" price may outweigh any benefits that could be derived from this allocation method. If the administratively set price turned out to be higher than the market value of the allowances, the allocation of purchase rights at that price would provide no value to the entities with purchase rights. In such a situation, entities with purchase rights might chose not to exercise their purchase right, but instead buy allowances at market prices in the auction or secondary market. This would eliminate one of the benefits of free allocations to deliverers, that is, that free allocations would help entities avoid negative impacts due to investment and procurement decisions made prior to GHG regulation.

If the administratively set price was less than the market value of the allowances, entities with purchase rights could still derive some windfall profits from the allowances, while the State would obtain a limited share of the value of allowances for consumer purposes.

Additionally, it is not clear what relationship a "well-determined price" would have to the market price. And even if the ideal relationship were known, it is not clear what basis the State would have for administratively setting the purchase price during the initial years of the program, before experience has been gained regarding market prices.

We conclude that these risks and administrative problems make GPI's proposed method less desirable than the administrative allocation of free allowances to deliverers, to the extent that such administrative allocations are deemed appropriate.

5.4.2.2. Harm-based Distribution of Allowances

SCE asserts that the most effective way to design an equitable and low-cost cap-and-trade program is by identifying entities that would suffer economic harm under the program and allocating free allowances to such harmed entities. As described in Section 5.2.4 above, SCE identifies four types of situations in which generators or retail customers in the electricity sector could be harmed.

Some parties (SDG&E/SoCalGas and WPTF) criticize the SCE harm-based allocation approach. SDG&E/SoCalGas object to all fuel-specific allocation methods for failing to provide "near-term incentives" for high-emitting entities to reduce their emissions. WPTF argues that, because most of the specified coal in California's generation mix is utility-owned, SCE's proposal would create an unfair benefit for utilities. PG&E also opposes SCE's proposal, asserting that it would result in an ongoing inefficiency and unfairness that can create a significant cost to the economy and sustain excess profits for coal generators.

SCE's economic harm concept provides a useful perspective as we consider the various allocation proposals. The proposal that allowances should be distributed in a method that compensates for economic harm resulting from the GHG regulatory scheme has value, and is generally consistent with the equity criterion, grounded in AB 32, that we have identified and that we apply in today's decision. However, there are several shortcomings to SCE's proposal that prevent us from recommending it.

The first situation of economic harm that SCE identifies would occur if an independent generator that sells power in a wholesale electricity market has an emissions rate that is higher than the emissions rate of the marginal generating unit that sets the market clearing price in that market. While we agree in general with SCE's characterization, SCE has not suggested, and we do not readily see, how an allowance allocation mechanism could be devised that would pinpoint with any accuracy the situations and generators for which such economic harm would occur, or the amount of economic harm that would occur.

The second situation that SCE identifies is that retail rates would be expected to increase to reflect GHG costs of electricity that the retail provider either owns or is responsible for through a purchase contract. This would include, in particular, coal and other fossil resources owned by the retail provider. The third situation that SCE identifies is that retail rates would increase due to a retail provider's wholesale electricity purchases when the market price has increased as a result of GHG regulation. We agree that an equitable allocation mechanism should take into account the economic harm to consumers arising from GHG compliance obligations for such resources and market purchases.

Finally, SCE is concerned that independent producers may have long-term contracts, extending into the period of GHG regulation without contractual provisions to recover the new GHG costs.

As described in more detail below, the combined recommendations that we make to ARB regarding the appropriate allocation and distribution of allowances within the electricity sector, taken together, would achieve results generally consistent with SCE's proposal, particularly in the short term. We believe that our recommendations, however, would provide stronger incentives for deliverers and retail providers to reduce GHG emissions in the longer term than would SCE's approach. By compensating entities indefinitely, SCE's approach would not provide incentives for the long-term modifications to the resource mix that we believe are crucial to meet the goals of AB 32.

In an allocation workshop presentation, SCE suggested what it characterized as a modified version of its harm-based approach. SCE identified coal generators and ratepayers as the primary entities in the electricity sector that would be harmed by a cap-and-trade program. SCE suggested that allowances be allocated to coal generators using an historical emissions-based allocation, with remaining allowances allocated to retail providers on a sales basis. Sales would be determined net of sales from coal generation, because economic harm for this fuel source would already be addressed through the separate allocation to coal generators.

As described below, one of our recommendations to ARB is that the method of distributing allowances to retail providers transition from an historical emissions-based methodology to a sales-based methodology. With the anticipated expiration of existing coal contracts, the approach we recommend is similar to that suggested by SCE in the allocation workshop. We believe the approach we recommend is preferable, however, because it recognizes the range of past investment and procurement decisions, not just coal investments, that could cause economic harm in a GHG regulatory structure.

5.4.2.3. Comparison of Allowance Distribution Alternatives

With rejection of the GPI and SCE proposals, we now consider how the remaining allowance distribution alternatives considered in this proceeding would perform relative to the criteria and goals described in Section 5.1.

Minimization of Costs to Consumers

As we describe in Section 5.2, free distributions of allowances to deliverers in proportion to historical emissions would be the most expensive distribution option, on average, for customers, other than auctioning with no distribution of allowances to retail providers. This is due to the windfall profits in the form of allowance rents that independent deliverers would enjoy, in addition to full reflection of GHG compliance costs in market prices and the accompanying clean generation rents.

The average retail rate impacts due to free distributions to deliverers based on the amount of electricity they deliver to the California grid would depend on the extent to which the allowance value would be included in wholesale market prices. If the full allowance value was included in wholesale market rates, average retail rate increases would approach those expected with distribution to deliverers based on historical emissions. On the other hand, if no or almost no allowance value was included in wholesale market rates, average retail rate impacts would be minimal, with the possibility of average rates actually declining if distributions to deliverers were structured such that deliverers of the marginal generation that sets market prices receive allowances in excess of their compliance needs. This might happen, for example, with an emitter-only output-based allocation that leaves deliverers of coal generation short and deliverers of gas generation long on allowances.

Auctioning with distribution of all allowances to retail providers would have average statewide rate impacts resulting from reflection of full GHG compliance costs in market prices and the resulting clean generation rents. While there would be distributional effects among customers of different retail providers, the average statewide rate impacts would vary only minimally among the methods considered for distributing allowances to retail providers.

In addition to average rate impacts due to the various allowance distribution options, there would be variations in rate impacts among customers of different retail providers due to differences both in the resource mix of utility-owned or controlled resources, and in the extent to which the retail providers rely on market purchases. As our analysis in Section 5.2 indicates, auctioning with distribution of allowances to retail providers based on historical emissions would cause the least variation in rate impacts among the retail providers. Sales-based distributions to retail providers would have the largest distributional impacts among customers of different retail providers, unless and until retail providers adjust their resource mix to reduce the emissions of their portfolios.

Historical emissions-based distributions to deliverers would minimize wealth transfers from customers of retail providers with relatively high emitting portfolios to customers of retail providers with cleaner portfolios. However, there would still be distributional variations based on the degree of the retail providers' reliance on market purchases.

Fuel-differentiated output-based distributions to deliverers of electricity from emitting generation resources (including unspecified sources) would perform similarly to historical emissions-based distributions to deliverers in terms of minimizing wealth transfers based on the emissions characteristics of the retail providers' portfolios. There would still be distributional variations based on the degree of the retail providers' reliance on market purchases. On the other hand, a pure output-based distribution would provide allowance rents to independent deliverers of zero- and low-emission electricity, including those under contract to retail providers. This would result in wealth transfers from customers of retail providers with relatively high-emitting portfolios to customers of retail providers with relatively low-emitting portfolios. Limiting output-based distributions to only deliverers of electricity from emitting generation resources would moderate the allowance rents and resulting wealth transfers.

Equitable and Fair Treatment of Market Participants

One of the measures of equity is whether an allocation methodology would cause negative impacts to market participants due to investment and procurement decisions made prior to GHG regulations. For retail providers, this concept is addressed above in the discussion of wealth transfers among customers of different retail providers.

Independent deliverers are concerned about whether they would have an opportunity to recover their carbon costs. The record identifies at least two types of situations in which independent deliverers may have trouble recovering compliance costs, to the extent the costs are not mitigated through (free) allowance distributions: (1) independent deliverers with emissions rates higher than the emission rates of the marginal generator whose allowance costs are reflected in the market price, and (2) contracts that extend beyond 2011 and do not provide for recovery of carbon costs. The distribution of allowances to deliverers could help such deliverers, whereas auctioning would not.

A related concept, but with different proponents, addresses the extent to which entities that cause GHG emissions are held responsible for the compliance costs of those emissions, which has been characterized as the "polluter pays" argument.

A related equity consideration addresses the extent to which an allowance distribution method recognizes early actions that have reduced an entity's GHG emissions.

Free distributions to deliverers based on their historical emissions or fuel-differentiated output-based metrics would reduce the compliance costs of high-emitting sources. Free distributions to deliverers based on their historical emissions would reward early actions that the deliverers take after the baseline period to reduce the emissions of the electricity they deliver to the California grid, as described in Section 5.2.1.1. Distributions using output-based metrics also would also benefit deliverers that take early actions to reduce their emissions, as described in Section 5.2.1.2. Conversely, pure output-based distributions to deliverers, and sales-based distributions to retail providers would reward the development of renewable sources. As we discuss in Section 5.4.3, a sales-based distribution to retail providers could be modified to reward emission reductions due to energy efficiency. Distributions to retail providers based on their historical emissions would benefit retail providers that take early actions after the baseline period.

We also assess the extent to which allowance distribution approaches provide revenues to fund emission reductions, compliance obligations, and/or customer rate reductions. Auctions with the distribution of allowances to retail providers would provide such funds to retail providers. Distributions to deliverers based on historical emissions, or based on a fuel-differentiated output-based metric, would roughly match deliverers' compliance obligations and needs for funding emission reductions. The continued sufficiency of such funds would depend on the extent to which the number of allowances allocated to the electricity sector diverges from the sector's emissions over time. Distributions based on deliverers' output or retail providers' sales would reduce the allowances available to deliverers or retail providers with the highest compliance obligations.

As we establish in Section 5.3, retail providers that receive allowances should sell them through a centralized auction, to avoid potential competitive concerns. An important benefit of auctioning is that it would allow equal access to allowances for both established deliverers and new delivers seeking to enter the market. Auctioning with allowance distributions to retail providers based on sales would provide allowances to new retail providers on an equal basis with existing retail providers, although perhaps with a short time lag. A similar result would hold for allowance distributions to deliverers based on their output. Allowance distributions based on historical emissions of retail providers, or historical emissions of deliverers, would place new retail providers or new deliverers, respectively, at a competitive disadvantage unless appropriate set-asides were established for them.

Align Incentives with the Emission Reduction Goals of AB 32

Auctioning would provide strong incentives for all deliverers to reduce GHG emissions, in order to reduce their compliance costs. The reflection of the full cost of GHG compliance in wholesale rates would also provide incentives for retail providers to serve their customers through lower-emission means. Allowance distributions to deliverers on the basis of historical emissions would provide a stronger incentive to reduce emissions than would distributions on an output basis because the historical emissions approach would provide allowances that deliverers could sell if they reduce their emissions. Additionally, if an output-based approach results in lower wholesale market prices, as theorized, that would prompt less end-use efficiency than would the higher prices expected with historical emissions-based distributions to deliverers.

Support a Well-functioning Cap-and-Trade Market

Auctioning of allowances would improve market liquidity, which could improve the accuracy and reduce the volatility of price signals in the market.

With auctions, deliverers would have reliable access to allowances without having to rely on secondary markets, but they would not know the price they would have to pay. With free allowance distributions to deliverers, they would have a degree of certainty about the availability of some number of free allowances to help meet compliance obligations. With distributions based on historical emissions, deliverers may know the number of allowances they would receive ahead of time whereas, with distributions based on output, the number of allowances distributed to an individual deliverer would depend on its output as well as the output of other deliverers. In all distribution options, the entities that receive allowances would not know the value of the free allowances or the cost of any other allowances they may need to purchase in the secondary market.

Administrative Simplicity

Auctions could be complicated to design and implement. One concern voiced by many parties is the lack of experience with auctioning of GHG allowances in California. The various methods of distributing allowances to either retail providers (for subsequent auctioning) or to deliverers would have differing challenges but (aside from the GPI and SCE proposals which we have rejected) appear to be administratively feasible.

5.4.2.4. Conclusions

First, we consider what amount of allowances should be auctioned for the electricity sector. There are strong arguments in support of auctioning all or most allowances. Auctioning of allowances would provide market liquidity, which would improve the accuracy of price signals in the market. A centralized auction undertaken by ARB or its agent would ensure that all deliverers have equal access to allowances, and would reduce or avoid the need for a set-aside or other administrative accommodation for new entrants. We expect that, with auctioning, GHG compliance costs would be internalized in wholesale electricity prices, sending more accurate price signals that would encourage participants in the electricity sector to reduce emissions. Entities with compliance obligations would bear full financial responsibility for the emissions associated with the electricity that they deliver to the California grid. At the same time, unlike free allowance distribution to deliverers, auctioning would preclude windfall profits due to allowance rents received by independent deliverers. However, the inclusion of allowance costs in wholesale prices would allow independent deliverers of relatively low-emission electricity to earn clean generation rents. As SCE points out, such increased profits for clean generation would be expected as a normal part of a functioning market, and should help spur additional investment in clean generation technologies. For all of these reasons, we believe it is desirable to move quickly to full auctioning.

We are persuaded, however, that auctioning should be phased in, with a fairly brief transition period. We anticipate that any cap-and-trade program that ARB implements will be linked to a regional, and ideally national, market. A transition to auctioning would help protect ratepayers if problems arise as this new mechanism is implemented and experience is gained with the auctioning process. A phased approach would begin the auctioning process so that California can reap initial benefits and, at the same time, would provide some protection and stability while the cap-and-trade market develops and matures.

As another reason for phasing in auctioning, the distribution of some free allowances to deliverers would be beneficial as an interim measure. Distributing some free allowances to deliverers would reduce short-term impacts on generating resources, and would help generators adapt to the new regulatory environment. Such distributions would provide time and financial resources that deliverers may need to make necessary adjustments to their financial and investment plans to account for the impacts of GHG compliance obligations. This need for free allocations to deliverers would decline over time.

In its allocation paper, staff suggests a six-year transition to 100% auctioning. Several parties, including WPTF (recommending an 8-year transition), Dynegy (recommending 15 years), and Calpine (recommending 19 years), argue that a longer transition period is needed because of the long lead time required for new infrastructure to become operational and in order to provide more time for generators to recover their current costs and to make plans for the transition. EPUC/CAC suggest a small two-year trial beginning in 2014 with future increases phased in to avoid industry disruption.

We conclude that free allocations to deliverers should transition to an auction of 100% of allowances by 2016. By increasing auction levels over this five-year period (and recognizing the advance notice that the industry is already receiving), entities with existing high-emitting resources would have time to adjust their generation investments before they face the full cost of their emissions. At the same time, a five-year transition would ensure that any undue windfall profits to deliverers would be short-term and declining in nature, as suggested by DRA and WPTF.

We conclude that in 2012 there should be 20% auctioning and 80% free allocation of allowances to deliverers, with a transition to 100% auctioning by 2016, as shown in Table 5-3.

Table 5-3

Recommended Transition for Auctioning and Distribution of Allowances to Deliverers

	Percentage of Allowances Sold through Auction	Percentage of Allowances Allocated to Deliverers
2012	20	80
2013	40	60
2014	60	40
2015	80	20
2016	100	0

This transition schedule would, in our judgement, allow California to gain experience with auctioning and fine-tune the auctioning structure, if needed, while ensuring that market participants receive a correct price signal regarding the cost of GHG compliance and have time to adjust their operations and investments. The knowledge that 100% auctioning would begin in a few years would give deliverers a strong incentive to move quickly to complete their preparations in a timely way.

We turn now to the manner in which allowances should be distributed to deliverers during the transition to auctioning, and also the manner in which allowances to be auctioned should be distributed to retail providers.

As discussed in Section 5.5 below, we recommend that all, or almost all, of the electricity sector allowances to be auctioned be distributed to retail providers. ARB may choose to retain a small percentage of allowances to be owned by the State in order to use the related auction revenues for various purposes consistent with AB 32, but we recommend that all auction revenues from allowances allocated to the electricity sector be used for the benefit of the electricity sector.

As the percentage of allowances distributed to deliverers phases down, the percentage distributed to retail providers would increase by comparable amounts, lacking only those allowances that ARB retains for statewide purposes.

Because of this interrelationship between distributions to deliverers and distributions to retail providers, we find it helpful to consider together the manner in which allowances should be distributed to individual deliverers and to individual retail providers. This approach makes it easier for us to ensure that the policies for distributions to deliverers and retail providers are coordinated in a manner that best meets and balances the allocation criteria and goals that we establish in Section 5.1.

The first criterion, aimed at minimizing costs to consumers, can be viewed as a subset of the second criterion regarding equitable and fair treatment of all market participants. There is no single measure of equity. We attempt to reach a reasonable balance among the competing interests and goals, so that each entity is treated fairly and each deliverer has reasonable options to ensure compliance.

Equity among customers of different retail providers would be affected by policies for distribution of allowances to both deliverers and to retail providers. The impact on customers of allowance distributions to deliverers would depend on how much of its power a retail provider owns or purchases, the emissions profile of the retail provider's electricity portfolio, and the extent to which GHG allowance cost (or opportunity cost) is reflected in market prices.

Some parties argue, on the basis of equity, that deliverers should receive allowances in proportion to their output, or similarly that retail providers should receive allowances in proportion to their sales, with several supporters of sales-based allocations requesting that the assessment of sales include a measure of energy efficiency. These parties assert that such an approach would recognize early actions appropriately and would encourage investment in low-and zero-emitting technologies. PG&E argues that its customers should benefit from its relatively low-carbon footprint and that PG&E should not be required to reduce carbon emissions as much as other retail providers that have undertaken less energy efficiency and have a more carbon-intensive resource mix.

Other parties argue that historical emissions-based allocation methods would be more equitable because they would match more closely the deliverers' compliance obligations and would help protect customers of retail providers with high-emission portfolios from economic harm. LADWP asserts that a fair allocation policy would direct allowances toward high-emitting entities with incentives to increase their low- and non-emitting resources.

In weighing the evaluation criteria, we find that a primary consideration in the early years of a cap-and-trade program is to ensure that economic harm is mitigated to the range of market participants in the electricity sector, including customers, retail providers, and deliverers. For customers and retail providers, that goal would be met through the combined policies for distributions to retail providers and distributions to deliverers. For independent producers, that goal would be met through policies for deliverer distributions. Because of the need to prevent economic harm in the short term while market participants undertake the steps necessary to align their operations to a GHG regime, we conclude that, in the early years, allowances should be allocated in a manner that reflects compliance obligations.

While always important, in the longer term greater emphasis should be placed on the provision of strong incentives for both deliverers and retail providers to reduce GHG emissions, both through reductions in the emissions profile of electricity that is delivered to the grid and procured by the retail providers, and through aggressive actions by retail providers and others to improve the efficiency with which electricity is used. While the transition to these longer-term distribution policies will be phased in, and strong programmatic measures to require energy efficiency and renewable energy gains will be in place, it is still helpful to send a clear message to all market participants that they need to make plans, commencing well before the cap-and-trade program begins, to undertake the capital investments and other changes that may be needed to protect their financial interests and customers in the longer term.

Allowance Distributions to Deliverers

For the portion of allowances distributed to deliverers, we recommend a fuel-differentiated output-based approach with distributions limited to deliverers of electricity from emitting generation resources (regardless of whether the electricity is generated inside or outside of California). This approach would provide all deliverers with allowances roughly in proportion to the amount they need.[46] The fuel-differentiated distribution of allowances to deliverers, with regular updating, would focus allowances on the deliverers that would need them most for compliance purposes, thus reducing the potential for

[46] We note that the fuel-differentiated output-based approach would provide assistance to the two categories of independent deliverers that have been identified in particular as potentially having difficulty recovering GHG compliance costs: deliverers of relatively high-emitting electricity whose emission rates and thus compliance costs may be larger than reflected in wholesale market prices, and those with existing contracts continuing into the cap-and-trade period without GHG cost recovery provisions. We note further that standard offer contract terms for electricity purchased from Qualifying Facilities are being developed in R.04-04-003/R.04-04-025, and expect that treatment of GHG compliance costs for electricity purchased through standard offers will be considered in that forum.

windfall profits due to excess free allowances ("allowance rent"), compared to other output-based approaches or the historical emissions-based approach.

It has been suggested that fuel-differentiated and other output-based allocation distributions to deliverers may limit the increase in wholesale electricity prices, because they would provide generators with an incentive to maintain or increase their output. We do not know the extent to which that may be the case, although the reasoning seems somewhat persuasive. At the same time, as some parties point out, deliverers with the marginal generating units (which set the market clearing price) may or may not receive allowances sufficient to cover their compliance obligations. To the extent they do not, their allowance shortfalls would be a cost that they could be expected to include in their market bids. This amount may be considerably less than the full cost they would incur if they had to pay for all of their allowances. The theorized moderation of wholesale market prices could act to constrain consumer costs, which could be viewed as beneficial but would mute the price signal. Regardless, we do not rely on such an outcome in endorsing the fuel-differentiated output-based allocation approach for deliverers.

The fuel-differentiated output-based approach would not provide as much certainty to individual deliverers as an historical emissions-based approach regarding the number of allowances that they could expect, since a deliverer's proportional allocation would depend on both the level and fuel mix of its own deliveries and the level and fuel mix of electricity produced by other deliverers. However, in light of the limited time (four years) that we recommend for distributions to deliverers, deliverers should be able to estimate likely distribution levels adequately.

A central rationale for utilizing a fuel-differentiated output-based approach is to avoid undue economic harm to California electricity consumers whose retail providers are currently locked into a certain degree of dependence on coal. This raises the question of whether the higher weighting factor to be used in determining allowance distributions for coal-fired electricity should apply to all coal deliveries or should be restricted to only electricity from coal plants owned or under long-term contract to California retail providers. The concern is that the higher allocation rate might provide incentives for additional short-term deliveries of coal-fired electricity or for coal-fired generation that was previously sold on an unspecified basis to sell on a specified basis instead, in order to receive the higher number of allowances for coal. We recommend that the higher weighting factor be applied for all coal generation delivered to the California grid. Any generation that reports as specified coal would also have a higher per-MWh compliance obligation than unspecified power. Thus, there would be little to be gained by a short-term deliverer specifying as coal.

In order to implement a fuel-differentiated distribution to deliverers of electricity from emitting sources, additional work will be needed regarding the specific weighting factors to be used for the fuel-differentiated distributions and details on how to update the deliverer-specific output-based proportions used in the distribution process, *e.g.*, the time period to use. A related issue that will require further consideration is whether a small number of allowances should be set aside for new deliverers' first year of operation, as described in Section 5.2.1.2 above.

If, counter to our recommendations regarding auctioning, ARB does not implement 100% auctioning by 2016, an important longer-term goal of deliverer distributions should be to provide strong incentives for GHG reductions. If ARB adopts less auctioning than we recommend (either less than 100% as the ultimate goal, or 100% phased in later than 2016), we recommend that distributions to deliverers transition toward a pure output-based approach, to be reached by

2020 if 100% auctioning is not achieved by that time. A pure output-based approach would be more effective than a fuel-differentiated approach in providing strong incentives to develop lower-emitting resources.

Distributions to Retail Providers

Following similar principles, we recommend that the allocation of allowances to retail providers (with a requirement to sell the allowances at auction) initially be in proportion to the historical emissions of the retail providers' portfolios, transitioning to a 100% sales basis by 2020. Allocating allowances to retail providers based on historical emissions in the initial years would accommodate carbon-intensive retail providers that may face relatively high compliance costs. At the same time, as emphasized by NRDC/UCS, transitioning to a sales basis would provide long-term incentives for retail providers to reduce their reliance on high-emitting generation sources.

We do not recommend at this time that the sales calculation be performed on a "net load" sales basis (excluding large hydro and nuclear), as suggested by staff. Some parties have raised concerns that a pure sales-based approach, unadjusted to exclude large hydro and nuclear, would distribute allowances to retail providers with non-emitting legacy hydro power and nuclear generation out of proportion to the financial impact of GHG compliance on their customers. However, we conclude that a transition to allowance allocations made in proportion to unadjusted sales by 2020 would provide strong incentives for increased reliance on all low- and non-emitting resources, including legacy generation, and would not have unacceptable impacts on customers of individual retail providers, based on existing modeling results. Should further modeling reveal that this allocation approach would result in larger distributional impacts than estimated in this proceeding, we may revise this recommendation to ARB.

Additional work will be needed to implement our recommendations regarding distributions of allowances to retail providers, including how to calculate and update the sales-based proportions used in the distribution process as sales-based distributions are phased in and how to allocate allowances to new retail providers. As discussed in Section 5.4.3, additional work also will be needed to address whether and how allowances should be distributed for verified energy efficiency.

Summary of Recommendations

To summarize, we recommend that auctions of allowances be phased in for the electricity sector, beginning with 20% of allowances in 2012 and reaching 100% in 2016. We recommend that the allowances that are not auctioned be distributed on a fuel-differentiated output basis to deliverers of electricity from emitting generation resources (including unspecified sources). Allowances that are to be auctioned should be distributed to retail providers, with a requirement that they then sell the allowances through a centralized auction undertaken by ARB or its agent. The allowance distributions to retail providers should be made on the basis of historical emissions in 2012, transitioning to a 100% sales basis by 2020.

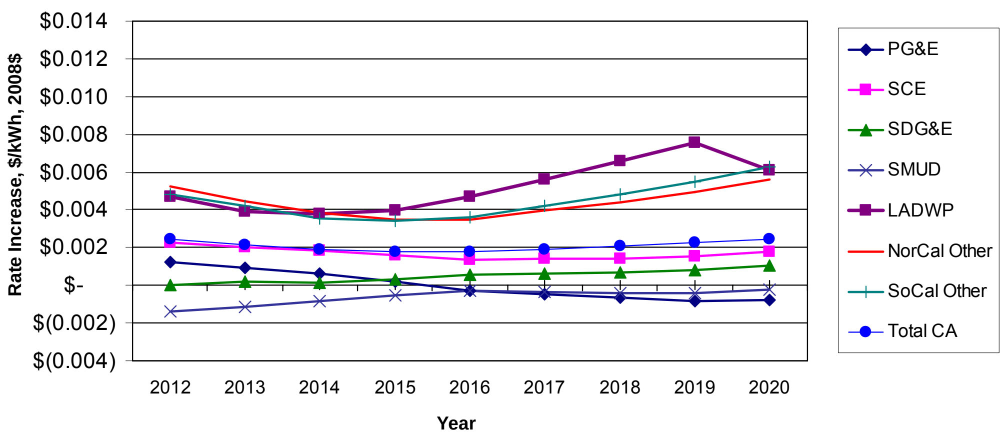
Figure 5-10 illustrates the potential impacts of these recommendations on the rates of individual retail providers. Because of modeling limitations, the allowance distributions to deliverers are modeled as non-fuel-differentiated output-based distributions to deliverers of electricity from emitting resources. The figure assumes that market clearing prices include 50% of the value of the allowances distributed to deliverers. If a fuel-differentiated output-based allocation to deliverers of electricity from emitting resources, which we recommend be implemented, were modeled, it would show a cost spread among retail providers in the 2012-2015 period somewhat less than indicated in

Figure 5-10 with, at the extremes shown in Figure 5-10, high-coal LADWP's costs decreasing and low-coal SMUD's costs increasing somewhat.

Figure 5-10

Estimates of Effects on Average Retail Electricity Rates Due to Recommendations Regarding Auctioning and Allowance Distributions to Deliverers and Retail Providers

($/kWh, 2008$)



While stressing that Figure 5-10 is presented for illustrative purposes only, we believe it provides a useful conceptualization of the possible effects of our recommendations to ARB.

We submit our allowance allocation recommendations to ARB as the allocation approach for the electricity sector that we find strikes a reasonable balance among the policy objectives that we have considered here. We recognize that, in contrast to our exclusive focus on the California electricity sector, ARB faces the challenge of deciding how to allocate allowances within California for a multi-sector cap-and-trade program that may be linked to a regional and/or national system. We also recognize that our modeling of the impacts of these allocation recommendations has limitations, as discussed above. Additionally, ARB will have to analyze any allocation methodologies that it considers in light of its interpretation of the specific statutory guidance in AB 32.

5.4.3. Should Allowances be Allocated to Support Emission Reduction Measures?

In this section we consider the proposals by some parties that allowances or auction revenues should be allocated as an incentive for certain activities that contribute to reducing GHG emissions. These proposals have in common the deliberate distribution of free allowances on the basis that the activities are either non-emitting (energy efficiency and renewable energy) or lower emitting than certain other sources of energy (CHP). Thus, these allocation methods would serve to encourage energy sources or measures that avoid or reduce emissions, and thus help to meet an emissions cap. Underlying these proposals is the belief that additional incentives may be needed because the GHG cap-and-trade market and other available incentives may not achieve the cap with an optimal mix of energy efficiency, renewables, and other low-carbon ways to meet energy needs.

Both the Public Utilities Commission and the Energy Commission have long supported the development of renewable energy, CHP, and energy efficiency to meet California's energy needs, and California has been a national leader in the development of these resources. All three sources have contributed substantially to reducing California's GHG emissions and, as the Energy Action Plan and ARB's Draft Scoping Plan indicate, the State is counting on all three sources to play a central role in meeting the State's future energy needs and the 2020 GHG cap. However, we are not prepared at this time to endorse any proposals to distribute free GHG allowances as an explicit incentive mechanism for these sources.

Several questions need additional analysis before we can definitively recommend any such proposals. A decision to distribute free allowances preferentially to certain activities should not be undertaken lightly, because such preferential treatment may skew the market with unintended consequences and may divert allowance value from other, potentially more valuable uses. Before we can determine whether to make this choice, two basic questions must be answered for each of these resources: (1) whether additional incentives are needed and (2) if so, whether the distribution of free GHG allowances is an effective and appropriate way of providing such incentives. The record in this proceeding has not been adequately developed to answer these questions. Below, we discuss some issues pertaining to two proposals that have been raised in this proceeding: allocation to retail providers for achieved energy efficiency and allocation to renewable energy producers for MWhs delivered. We also provide some preliminary guidance on the additional analysis required before a decision can be made. Allowance allocations to CHP are discussed in Section 6.

5.4.3.1. Energy Efficiency

Allocating allowances to retail providers on a sales basis that includes verified energy efficiency savings has been advocated by PG&E, NRDC/UCS, DRA, SMUD, and SDG&E/SoCalGas. These parties contend that any sales-based allocation of allowances to retail providers that does not include energy efficiency would deter energy efficiency savings because it would reduce the distribution of allowances to the retail provider for every megawatt-hour saved. In their view, allocating allowances for verified energy efficiency would help foster the development of feasible and cost-effective energy efficiency.

However, several questions remain about the desirability of allocating allowances on the basis of energy efficiency that have not been adequately addressed in this proceeding. SCE argues that, since generator bids are expected to internalize GHG costs, the higher energy prices in a cap-and-trade system would encourage additional energy efficiency automatically and no special treatment is necessary. AReM argues that allocating allowances to retail providers for verified energy efficiency would be unfair to ESPs. There are also uncertainties about how free allowance allocations would interact with existing energy efficiency mandates and incentives, and whether verified energy efficiency should receive allowances at the same rate as actual sales or be weighted less than actual sales. We also would want to ensure that all retail providers are held to consistent verification standards. We intend to consider these issues further, to ensure that allowance distribution policies do not impede achievement of cost-effective energy efficiency, and may make further recommendations to ARB at a later date.

5.4.3.2. Renewable Energy

Several parties support the allocation of allowances to deliverers of renewable electricity, including Solar Alliance, CRA, and SMUD. In Section 5.4.2.4. above, we recommend that deliverers of electricity from emitting generation resources receive allowances on a fuel-differentiated output basis, to be phased out by 2016. Deliverers of electricity from renewable sources that emit GHG would be eligible for such distributions, whereas deliverers of electricity from non-emitting sources would not receive allowances. In this section, we address whether there should be additional allowances distributed to or set aside for deliverers of renewable electricity to provide incentives for renewables development.

There are two issues to consider regarding the desirability of allocating allowances for deliverers of non-emitting renewable energy: the competitiveness of renewables in the market and the need for incentives for the voluntary renewables market to contribute to GHG emission reductions. We address the competitiveness concerns first.

A cap-and-trade program with an allowance allocation method that internalizes emission costs in wholesale electricity prices inherently enhances the competitiveness of renewables. Either historical emissions-based allocations to deliverers or auctioning would have this effect. However, output-based allocation to deliverers may suppress the pass-through of GHG costs in wholesale prices. To the extent that wholesale prices do not reflect GHG costs, the market would not bestow to renewables the full advantage of their lower GHG emissions. Based on the assumption that GHG costs would not be reflected fully in market prices with an output-based allocation of allowances, the Resources for the Future study of RGGI implementation attached to the staff allocation paper concluded that output-based allocations restricted to emitting sources would result in less addition of renewables than either auctioning or historical emissions-based allocations to sources.

Since we recommend that most allowances in the electricity sector be distributed initially through a fuel-differentiated output-based allocation to deliverers, an argument could be made that some complementary allocation of allowances to renewable sources may be desirable to avoid inadvertently disadvantaging those sources in the market. However, given our recommendation to rapidly transition the allocation method to 100% auctioning, any potentially deleterious effect on the competitiveness of renewables would be short-lived. This fact, coupled with the State's current, and potentially increasing, mandates for development of renewables, leads us to question whether including renewables in fuel-differentiated output-based allocations would be warranted. As discussed in Section 5.4.2.4. above, if the transition to full auctioning does not occur by 2016, we would support a transition to pure output-based allocations of allowances, which would include deliverers of renewable electricity.

The distribution of free allowances for renewables participating in the voluntary market potentially could serve another purpose. Currently, buyers in the voluntary market pay a premium for renewable electricity (or the RECs representing that electricity) for various environmental reasons: to be sustainable, to be carbon-neutral, to promote energy independence, or to contribute to reducing emissions of GHG and other pollutants. Once pollutants in the electricity sector are subject to a cap, purchases of voluntary renewables do not contribute to further reductions because the cap determines the allowable levels of emissions. In other words, once a cap is instituted, new renewables would not reduce emissions; instead, the replacement of fossil-based generation by renewables would free up allowances to be used elsewhere in the capped sectors. Solar Alliance characterizes this scenario as allowing fossil generators to free-ride on the emission reduction activities of others.

In order to allow the voluntary market to continue contributing to emission reductions, Solar Alliance recommends the creation of a set-aside of allowances for the voluntary market. Rather than sell the allowances, ARB could retire allowances from the set-aside reserve at some rate for each MWh sold (or REC retired) in the voluntary market. By this mechanism, voluntary purchases of renewable energy would reduce emissions essentially by ratcheting down the cap: ARB would retire allowances rather than issue them for use by an emitting source. Solar Alliance expresses concern that the voluntary market would collapse without a set-aside.

Currently, we do not have enough information to determine the desirability of allowance set-asides for the voluntary renewable market. We certainly do not want to damage the opportunity for voluntary contributions to GHG reductions. AB 32 directs ARB to "adopt rules and regulations…to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions…" (Section 38560). As part this effort, AB 32 directs ARB to "identify opportunities for emission reductions measures from all verifiable and enforceable voluntary actions. . . " (Section 38561(f).) AB 32 also directs ARB to "adopt methodologies for the quantification of voluntary greenhouse gas emission reductions. . ." (Section 38571.)

While we support continuing opportunities for voluntary reductions, consistent with the cited provisions of AB 32, we do not recommend the creation of a set-aside for the voluntary market at this time. A number of questions would need to be answered about the design of the cap-and-trade market and the RPS compliance market that may include provisions for RECs. We would need to investigate the types of RECs that would count under a set-aside, including whether RECs from capped and uncapped electricity markets should count. In addition, we would need to investigate how to assign emission reduction values to the RECs that would be counted. These issues will be further complicated in a regional cap-and-trade system. For all of these reasons, we need further investigation and analysis before recommending a set-aside for the voluntary renewables market.

5.5. Use of Auction Proceeds

In supporting some amount of auctioning in D.08-03-018, we cautioned that:

> As an integral part of this recommendation, we conclude that the proceeds from the auction of allowances for the electricity sector should be used primarily to benefit electricity consumers in California in some manner, in order to minimize costs of GHG emission reductions to consumers and assist with emissions

> reduction opportunities. Possibilities include use to augment investments in energy efficiency and renewable power or to maintain affordable electricity rates. Allocating the value of allowances and/or auction revenues primarily to benefit consumers recognizes the importance of electricity as a vital commodity. Thus, we believe that reservation of allowances or allowance value for consumers in this sector is warranted regardless of what may be done for other sectors. (D.08-03-018 at 98-99.)

We address the use of auction revenues in further detail in this section.

5.5.1. Positions of the Parties

Purposes Related to AB 32

Most parties commenting on this issue support the policy we articulated in D.08-03-018 regarding the use of auction revenues. Several parties specifically support the use of auction revenues to fund energy efficiency, renewable energy, and research and development activities, as well as to maintain affordable electricity rates. NRDC/UCS recommend further that such investments be subject to oversight and verification that the investments meet appropriate criteria, with forfeiture of the revenues to the State if a retail provider does not use the revenues in appropriate ways and within a specified time limit. Dynegy stresses its view that the expenditure of auction revenues must not advantage investor-owned utilities relative to independent power producers.

Several parties (PG&E, SDG&E/SoCalGas, SMUD, IEP, GPI, WPTF, NRDC/UCS, and FPL) support using auction revenue to support energy efficiency and renewable development programs. SMUD supports this use of auction revenue as a way to reduce electricity rates. GPI submits that all revenues raised by auctions and through its proposed direct sales of allowances to deliverers at predetermined prices should be used to invest in new, zero-emitting generating resources and efficiency, in order to benefit consumers by providing the infrastructure needed for living in a carbon-constrained world.

PG&E submits that, to the extent that auction revenues are used to fund energy efficiency and renewables programs that are currently funded in utility rates, this funding source should reduce current funding needs for these programs in order to avoid double counting.

PG&E states that auction revenue could be dedicated toward utility procurement and development of carbon-free technologies, if targeted toward applied technologies most likely to benefit California's electricity consumers directly. PG&E suggests tax credits, rebates, or incentives to energy users or producers for demonstration of new technologies or applied research, but not grants or pure research, in order to focus on the development of new, commercially-available "green" technologies for the benefit of utility customers. EPUC/CAC submit that any 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, and that any programs encouraging technology development should be made available to all potential competitors on an equal basis. IEP asserts that, in the first five years, 50% of auction revenues should be directed to renewable investment, 30% toward clean or low-emitting alternative resources such as clean coal or low-emitting natural gas, and 20% toward energy efficiency not otherwise covered by building and appliance standards and other existing requirements.

Many parties consider supporting consumer cost reductions to be a priority. However, parties differ in their approaches to providing auction revenues to customers.

Some parties (EPUC/CAC and AReM) favor using auction revenue to reduce customer electricity rates. ICC argues for applying auction revenue to reduce the revenue requirement of retail providers in a manner that does not shift costs among customer classes.

Several parties (PG&E, WPTF, FPL, Morgan Stanley, Powerex, CARE, Dynegy, GPI, Calpine, ICC, SCE, and Powerex) recommend that the value of allowances used to mitigate customer costs be applied in a way that preserves a carbon-based price signal. Dynegy and FPL oppose the use of auction revenues for general ratepayer assistance, arguing that ratepayers should not be insulated completely from the costs of GHG reductions and that auction revenues should not be used to dampen the price signals associated with GHG costs. PG&E, WPTF, Morgan Stanley, and CARE all suggest that any direct bill reductions be designed in a way, such as periodic bill credits or refunds, that is not tied to the volume of electricity used, in order to preserve the price signal benefits of a cap-and-trade program.

SCE and SDG&E/SoCalGas submit that the distribution of allowances or auction revenue rights to retail providers should be used to mitigate increases in the revenue requirement resulting from a GHG emissions cap. SCE maintains, however, that precise distribution is best determined by the Public Utilities Commission during an investor-owned utility's cost recovery proceedings. SDG&E/SoCalGas suggest that a reduction in overall revenue requirements would retain the flexibility to use revenues to pay for existing GHG measures or to benefit one rate classification or another. They maintain that the "use it or lose it" requirement that NRDC/UCS propose would be impractical to implement, foreseeing that such an approach would be hampered by rules for carry-over spending and arguments about how much of the capital cost for rate-based investments in renewables, photovoltaics, demand response, and CHP should be counted for GHG reduction versus electricity supply.

Targeting auction revenue toward low-income households was advocated by Dynegy, TURN, PG&E, SDG&E/SoCalGas, and Powerex. While TURN continues to oppose including the electricity sector in a multi-sector cap-and-trade system, it states that it could support the use of a capped system if all, or almost all, allowances are auctioned and the proceeds allocated to retail providers to benefit lower-income customers and to offset the costs of emissions reductions in the electricity sector. NRDC/UCS would support programs that reduce costs to consumers, particularly low-income consumers, for example, by supplementing funding for existing low-income energy efficiency and bill assistance programs, and also would support providing economic opportunities for low-income and disadvantaged communities. Dynegy supports the use of auction revenues to provide assistance to low-income customers, to offset that portion of those customers' bills associated with GHG programs.

WPTF, NRDC/UCS, and FPL believe that consumer interests would be served better by dedicating a substantial portion, if not all, of the auction revenues to specific programs that develop and deploy GHG control technologies, rather than providing direct or indirect short-term rate relief.

Use for Purposes Other than AB 32

PG&E, DRA, and NRDC/UCS are concerned that use of auction revenues for purposes unrelated to AB 32 could be construed as a tax, which they say is not authorized by AB 32 and would require approval by a two-thirds vote of the Legislature. NRDC/UCS argue that deposit of auction revenues in the General Fund to be used for any purpose that is not reasonably related to the purposes of AB 32 would be considered a tax. SDG&E/SoCalGas submit likewise that placement of auction funds in the State's General Fund could conceivably be challenged as a new tax.

5.5.2. Discussion

We addressed the use of auction revenues in D.08-03-018, recommending that proceeds from the auction of allowances allocated to the electricity sector be used primarily to benefit electricity consumers, either by supporting activities that reduce GHG emissions or by reducing the rate impact to California electricity consumers. We reiterate and refine that recommendation herein.

Most parties voice support for using auction proceeds in the electricity sector for purposes related to AB 32. Almost all parties agree that a portion of the auction revenues should be spent on energy efficiency and renewables. Some also recommend that auction revenues be used to support carbon-reducing infrastructure technologies. Parties comment on whether general bill relief should be implemented in a way that mutes the price signal, and whether any bill relief should be limited to low-income consumers. Other recommendations address the following:

- The type of rate relief, e.g., to low-income ratepayers and/or through rebates rather than usage rate decreases;
- The types of investments, e.g., a preference for applied/commercially proven technologies and applied research, compared to pure research and technology development; and
- Whether ARB should adopt a "use it or lose it" policy for retail provider uses of auction revenues.

We continue to support the development of energy efficiency and renewable energy, as articulated in the Energy Action Plan 2008 Update. We believe that retail providers receiving auction revenues should be required to spend such proceeds in a manner consistent with the Energy Action Plan loading order and the goals of AB 32. To meet the goals of AB 32, California is preparing to implement the most ambitious energy efficiency programs in the world. Meeting the targets for the electricity sector outlined in ARB's Draft Scoping Plan will require significant additional expenditures on energy efficiency measures.

California investor-owned utilities currently have sufficient renewable electricity under contract and in negotiation to deliver 20% of their electricity from renewable sources soon after 2010. California's support of renewable energy through the RPS and California Solar Initiative programs demonstrate that renewables can supply a large share of California's energy needs. The Draft Scoping Plan recommends that the State adopt a mandate of 33% electricity from renewable sources by 2020. Bringing that level of new renewables online will require substantial expenditures by California electricity consumers.

For these reasons, and to meet the emission reduction goals in AB 32 through a variety of means, it is critical that California's retail providers devote auction revenues toward cost-effective means of complying with AB 32. While most parties are in general agreement on this point, parties have differing options regarding the degree of oversight that should be applied to the use of the auction proceeds. Parties offer several suggestions about how the funds should used as well as what roles the Commissions and ARB should play in directing the use of those funds. Some parties appear to suggest that ARB mandate with considerable specificity the use that retail providers may make of auction revenues, whereas other parties recommend that the regulatory bodies, e.g., the Public Utilities Commission for investor-owned utilities, oversee the use of auction revenues.

We agree with parties that all auction revenues should be used for purposes related to AB 32. Such a requirement would further the goals of AB 32 and avoid the questions raised about the legality of use of auction proceeds for other purposes. In our view, the scope of permissible uses should be limited to direct steps aimed at reducing GHG emissions and also bill relief to the extent that the GHG program leads to increased utility costs and wholesale price increases. It is imperative, however, that any mechanism implemented to provide bill relief be designed so as not to dampen the price signal resulting from the cap-and-trade program.

We believe that it may be appropriate for ARB to retain a small portion of allowances for the electricity sector, to be owned by the State, in order to use the related auction revenues for statewide electricity-related purposes consistent with AB 32. With that possible exception, ARB should distribute all electricity sector allowances to be auctioned directly to retail providers, in a manner that we discuss in Section 5.4.2. The retail providers would then be required to sell the distributed allowances through a centralized auction, as we describe in Section 5.3. We recommend that all auction revenues from allowances allocated to the electricity sector, whether owned by the retail providers or resulting from the sale of allowances that ARB has retained, be used to finance investments in energy efficiency and renewable energy or for bill relief, especially for low-income customers.

Subject to this directive, the loading order and other statutory and ARB guidance, the Public Utilities Commission for load serving entities and the governing boards for publicly owned utilities should determine the appropriate use of retail providers' auction revenues. The Energy Commission should have broad review authority of publicly-owned utilities' expenditures, with the publicly-owned utilities required to demonstrate annually to the Energy Commission that their expenditures of auction revenues during the prior year were consistent with the requirements outlined herein. While we do not today adopt the "use it or lose it" approach advocated by NRDC/UCS, we recommend that ARB, in consultation with the Public Utilities Commission and the Energy Commission, specify that free distribution of allowances to each retail provider will be conditioned on a demonstration of adequate progress in complying with energy efficiency and renewable energy procurement targets established for the retail provider.

An alternative method for distributing allowance auction revenue has been proposed, in which all California residents would receive annual dividends funded by allowance auction revenues. A GHG cap-and-trade program is expected to increase the cost of energy throughout the capped sectors, and dividends would serve to mitigate the impacts of this cost increase on consumers. The dividend level could be constant for all consumers, or could be based on the proportional economic impact to consumers (with lower-income Californians perhaps receiving higher dividends), but would not be based on the level of energy used. This would preserve the price signal for consumers to reduce their energy use, since by reducing energy use they would decrease their costs without affecting their dividend. Payments would be automatic. Such an approach potentially would be similar to the annual dividends received by Alaska residents from oil revenues associated with Alaskan oil leases. While we do not recommend this approach, it may be appropriate for ARB to further explore this policy tool as part of its statewide cap-and-trade design process.

5.6. Legal Issues Related to Allowance Allocation

Several parties raise legal arguments about our recommended point of regulation for the electricity sector, the legality of auctioning allowances, and other matters covered in our prior decisions in this proceeding. These arguments have been raised previously and concern issues that have not been left open for further consideration in this decision. Accordingly, we do not discuss them here.

5.6.1. Issues of Permissibility Pursuant to AB 32

IEP argues that "[w]hile rate reduction is a worthy goal, it is not specifically authorized by AB 32 and it may conflict with the achievement of the goals [of] AB 32; for that reason, its legality is questionable." (IEP Reply

Comments at 12.) IEP notes that the paramount purpose of AB 32 is to reduce the emission of GHGs, and argues that a decrease in rates may actually cause an *increase* in GHG emissions. (IEP Reply Comments at 13.) However, IEP views the goals of AB 32 too narrowly. It ignores, for example, the provision in Section 38561(a) requiring ARB to consult with the Public Utilities Commission and the Energy Commission concerning "the provision of reliable and *affordable* electrical service" (emphasis added). Furthermore, Section 38562(b)(1),(2) directs ARB to design the regulations "in a manner that is equitable" and to "[e]nsure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities." Thus, the goals of AB 32 include the provision of affordable electricity service and ensuring that there is not a disproportionate impact on low-income communities. Accordingly, using auction revenues to provide bill relief to customers generally, or to low income customers who spend a larger proportion of their incomes on utility services, does further the goals of AB 32, and IEP's assertion that the legality of this use of auction revenues is questionable is without merit.

In its comments on the proposed decision, FPL argues that distributing allowances to deliverers on a fuel-differentiated output basis is biased against lower emitting resources, citing *North Carolina v. EPA*, 531 F.3d 836 (D.C. Cir., 2008). That case, however, provides no basis for rejecting the use of a fuel-differentiated output basis for distributing allowances under AB 32. In that case, the federal Environmental Protection Agency (EPA) had allocated nitrous oxide emission credits among states using a "fuel adjustment." "Fairness" was the EPA's only reason for adjusting the allocation of credits based on the kind of fuel used to generate electricity. The court concluded that "fairness" was not one of the factors that the EPA was authorized to consider under the federal Clean Air Act, and that in doing so the EPA had violated requirements of that statute.

Here we are recommending the distribution of allowances on a fuel-differentiated output basis for reasons of equity and to help assure reasonable rates. As pointed out in the preceding paragraph, AB 32 specifically directs ARB to design the regulations "in a manner that is equitable" and to consult with the Public Utilities Commission and the Energy Commission concerning "the provision of …affordable electrical service." Thus, allocating California GHG allowances based on the kind of fuel used to generate electricity is consistent with the authorizing statute, AB 32.

Several parties, including PG&E and NCPA, argue, without further explanation, that allocating allowances on the basis of historical emissions fails to further the goal stated in Section 38562(b)(3) to "[e]nsure that entities that have voluntarily reduced their greenhouse gas emissions prior to the implementation of this section receive appropriate credit for early voluntary reductions." We recommend that the distribution of allowances to retail providers should be made initially on the basis of historical emissions. We fail to see why this is inconsistent with the goal of giving credit for early voluntary reductions. The extent to which historical emissions-based distributions to retail providers would recognize voluntary early actions which these retail providers have taken to reduce emissions depends on the base period used. If, for example, the base period used for determining historical emissions were a period immediately prior to the enactment of AB 32, retail providers would be rewarded for any early action they take to reduce emissions after that base period. These retail providers would receive credit for their early action because their allowances would be based on their higher (pre-AB 32 enactment) historical emissions, but they would only need enough allowances to cover a level of emissions that had been reduced by the actions they have taken after enactment of AB 32. The receipt of these additional allowances would reward the retail providers for their voluntary early actions.

PG&E also argues, without citation to any particular provision of AB 32, that the only lawful method of allocating allowances is one under which the GHG compliance costs for high GHG-emitting resources must be paid by the customers who receive the electricity from those high-emitting plants. (PG&E Comments, at 28.) PG&E does not explain how this would be achieved under a deliverer point of regulation, since retail providers buy much of their electricity from others, and the market price for that electricity is set by a number of factors, such that the cost of allowances will not always be passed through. More generally, PG&E appears to argue that a "polluter pays" approach is the only lawful approach. However, there is no provision in AB 32 that requires a "polluter pays" approach. Indeed, as noted earlier in this section, AB 32 requires ARB to balance a number of goals, which sometimes may conflict. (See, e.g., Section 38562(b) and Section 38580(b).) Moreover, under the GHG regulatory system we recommend, the deliverers, not the customers of retail providers, should be considered the polluters. As the program transitions to 100% auction, deliverers will pay for all of their allowances. Thus, the polluters will be paying. The methodology for allocating free allowances to retail providers, for subsequent auction, answers a different question: who will receive the proceeds of the auction. As explained elsewhere in this decision, we have balanced the numerous goals of AB 32 and conclude that our proposal for allocating allowances to retail providers best balances those goals.

5.6.2. Commerce Clause Issues

Parties briefed the issue of whether the allowance allocation methods considered, including the methods proposed in this decision, raise concerns under the "dormant" Commerce Clause. Under the dormant Commerce Clause, a state's law or regulations may be unconstitutional if there is a differential treatment of in-state and out-of-state economic interests that benefits the former and burdens the latter. We have considered the parties' filings and conclude that allocation to deliverers using a fuel-differentiated output-based standard does not violate the Commerce Clause. We also note that this allocation methodology works within the deliverer point of regulation, which we have previously found not to be in violation of the Commerce Clause.

The allocation method we are proposing is facially neutral and does not have a discriminatory purpose or effect. In other words, allocation on a fuel-differentiated output basis does not on its face, or in effect, discriminate against interstate commerce in favor of intrastate commerce, nor is there any purpose or intent to favor intrastate commerce over interstate commerce. The allowances are allocated on a fuel-differentiated output basis alone, whether generation of the electricity occurs in California or elsewhere.

When a state law or regulation is not facially discriminatory and does not have a discriminatory purpose or effect, the courts apply the *Pike* balancing test. Under *Pike*, a state enactment "will be upheld unless the burden imposed on [interstate] commerce is clearly excessive in relation to the putative local benefits." (*Pike v. Bruce Church, Inc*. (1970) 397 U.S. 137,142.) Here, the burdens on interstate commerce, if any, are purely incidental to the local benefits to California of reducing GHG emissions and the impact of global warming. As detailed in D.08-03-018, the benefits to California are clear and well established.

PG&E argues that a fuel-differentiated output-based allocation methodology may create an undue impact on out-of-state generation because fuel type is a non-environmental criterion on which to base allocation, which would have a disproportionate impact on out-of-state generation. (PG&E

Comments, p. 33.) PG&E appears to be arguing that there is no relationship between any burden on commerce and local benefit if a fuel-based allocation is used and that the only allocation method that is likely to survive a Commerce Clause challenge is one based solely on the GHG emissions of the regulated entity. We disagree. First, a fuel-based approach relies on an environmental criterion and has a direct relationship to the harms of GHG that AB 32 seeks to reduce. Simply put, certain fuels produce more GHG than other fuels. An allocation of allowances using a fuel-differentiated output-based criterion is a narrowly-tailored solution to a California problem and the burden on interstate commerce, if any, is purely incidental. Second, we note that under a fuel-differentiated output-based allocation coal, which is most often used in out-of-state generation, will receive a more favorable treatment than it would under a pure output-based approach.

Accordingly, we conclude that any burdens on interstate commerce that may result from the implementation of AB 32 under the allocation methods that we recommend to ARB are incidental and not excessive in relationship to the local benefits to California.

We also conclude that the fuel-differentiated output-based allocation methodology does not regulate extraterritorially in violation of the Commerce Clause. A state statute or regulation may be struck down as impermissibly extraterritorial if it regulates commerce that occurs wholly outside the state. The fuel-differentiated output-based allocation methodology is implemented through the deliverer point of regulation and does not reach over the California border and regulate commerce that occurs wholly outside the state.

Additionally, auctioning allowances would not violate the Commerce Clause. Like administrative allocation, auctioning is facially neutral and does not have a discriminatory purpose or effect, and the burden on interstate commerce, if any, is not excessive and is purely incidental to the local benefit. We recommend that auction revenues be used in a manner that will not discriminate against interstate commerce.

Lastly, we find that our recommendation to allocate allowances to retail providers for subsequent auctioning transitioning over time from being based initially on historical emissions of the retail providers' portfolios to being allocated based on sales by 2020 does not violate the Commerce Clause. It is facially neutral and does not have a discriminatory purpose or effect, and the burden on interstate commerce, if any, is not excessive and is purely incidental to the local benefit.

5.6.3. Issues Regarding the Levying of a Tax

Parties have briefed the issue of whether allowance allocation methods, including the methods proposed in this decision, raise concerns about whether they involve the levying of a tax and, therefore, would require approval by a two-thirds vote of the Legislature. Under the California Constitution, Article XIII A, Section 3, a tax can only be enacted by not less than a two-thirds vote of the Legislature. AB 32 was enacted by less than a two-thirds vote of the Legislature. We have considered the parties' filings and conclude that neither allocations nor auctions violate the California Constitution, Article XIII A, Section 3.

There is an important distinction between a tax and a regulatory fee. A regulatory fee does not require a Legislative vote of not less than two-thirds, because it is enacted under a state's traditional police power, not its taxing authority. Taxes are imposed for revenue purposes, while fees are imposed *inter alia,* to pay for the expenses of a regulatory program or to defray the actual or anticipated adverse effects of the payer's action. (See *Sinclair Paint Co. v. State*

Bd. of Equal., (1997) 15 Cal. 4th 866, 874-876.) The imposition of such "mitigating effects" fees is designed to deter the undesired conduct and to stimulate alternative behavior or products. (*See id.* at 877.) Fees must also "bear a reasonable relationship to those adverse effects." (*See id*. at 870.)

So long as any revenue generated from an allowance allocation option is used to further the purposes and goals of AB 32 and not deposited in the state's General Fund for non-AB 32 uses, and is reasonable in relationship to the adverse effects caused by the corresponding emission of GHGs, there is no levying of a tax. We recommend that all auction revenues be used for purposes related to AB 32. We urge that auction revenues not be used for General Fund purposes.

5.6.4. Other Legal Issues

LADWP argues that Article XIII, Section 19 and Article XVI, Section 6 of the State Constitution may be violated by an allowance allocation option. Article XIII, Section 19 requires that taxes or license charges be imposed on public utilities in the same manner in which they are imposed on private entities. However, LADWP has not shown that the requirement that deliverers of emitting power purchase some allowances at auction would establish "license charges" as that term is used in Article XIII, Section 19 of the State Constitution. Moreover, we recognize that Article XIII, Section 19 "does not release a utility from payments … required by law for a special privilege…. (CA. Const. art. XIII, Section 19.) Additionally, LADWP's argument that the cost of programmatic measures is an additional tax or license charge that utilities will pay while other sectors will not, and thus is a violation of Article XII, Section 19 of the State Constitution, is unconvincing.

LADWP argues that the requirement for public entities to purchase allowances at auction violates Article XVI, Section 6 of the State Constitution. That section addresses public finances and does not allow the legislature to gift or lend public funds to private entities. LADWP fails to show how a requirement to purchase an allowance constitutes a gift.

6. Treatment of CHP in a Cap-and-Trade System

This section addresses three issues related to the treatment of CHP in a GHG cap-and-trade system. First, we consider whether CHP should be included in the cap-and-trade system and, if so, what thresholds or exemptions should apply. Second, we discuss what sector or sectors should be used to regulate CHP GHG emissions. Third, we consider the appropriate emission allowance allocation method for CHP, taking into consideration our other recommendations to ARB. Consideration of CHP installations as an emissions reduction measure is addressed in Section 4.1.3 above.

Our recommendations focus on GHG emissions associated with electricity generated by CHP facilities. We encourage ARB to consider treatment of the GHG emissions related to thermal output from CHP facilities in a manner that is consistent with its treatment of thermal output from other sources in the industrial and commercial sectors.

6.1. Background

CHP is a technological process that generates both electricity and useful thermal output from a single fuel source. Because of this co-generation, the potential exists for fuel efficiency gains relative to processes that provide electricity and useful heat separately. This efficiency potential can reduce total fuel use and therefore decrease GHG emissions.

Several technologies are used in CHP facilities, including gas turbines, microturbines, spark ignition reciprocating engines, steam turbines, compression ignition reciprocating engines, and fuel cells. These technologies can either combust fuel or, in the case of fuel cells, catalyze fuel. CHP systems can be divided into two basic classifications: topping-cycle and bottoming-cycle. In a topping-cycle CHP system, the primary purpose is to generate electricity on-site, with waste heat from that generation then captured for use in a secondary on-site process. A bottoming-cycle CHP application captures waste heat from an industrial or commercial thermal process and uses it to generate electricity. Electricity produced from a bottoming-cycle CHP unit has no or relatively small amounts of GHG emissions associated with it, depending on whether there is any supplemental firing.

In California, there are presently about 940 CHP units. Over 600 of these are units of less than 1 MW capacity, which fall below ARB's current reporting threshold. While these small units account for nearly two-thirds of the number of CHP units, they constitute just over 1% of all CHP capacity. Table 6-1 provides further information regarding CHP units in California.

Table 6-1

Summary Statistics of CHP Plants in California

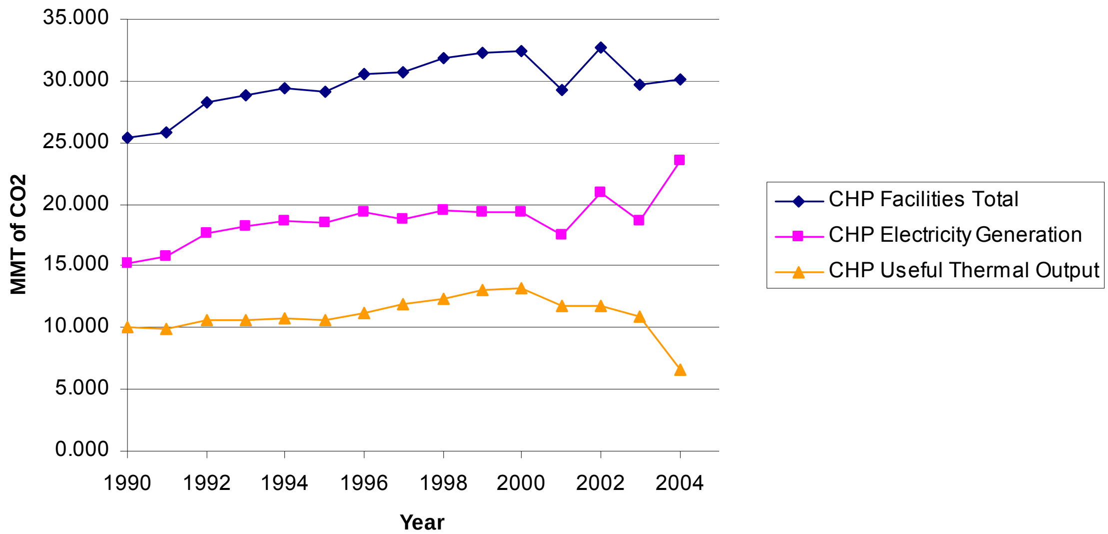
Size	**Total Capacity**	**% of Total Capacity**	**Number of Plants**	**% of Plants**
Less than 1 MW	102	1.1%	604	64%
Greater than 1 MW	9,126	98.9%	336	36%
Total	*9,228*	-	*940*	-

According to the current California Greenhouse Gas Inventory,[47] electricity production at existing CHP facilities emitted between 15 and 24 MMT CO2e each year between 1990 and 2004. GHG emissions associated with useful thermal output were between 7 and 13 MMT CO2e each year. Total CHP facility GHG emissions ranged between 25 and 33 MMT CO2e, approximately 6-7% of California's total GHG emissions during the period. CHP total and disaggregated GHG emissions are represented graphically in Figure 6-1.

[47] Inventory data available at http://www.arb.ca.gov/cc/inventory/data/data.htm, November 2007.

Figure 6-1

GHG Emissions from CHP in California
(Source: California Greenhouse Gas Inventory, November 2007)



Regardless of technology type or classification, most CHP produces three separate outputs: thermal output consumed on-site, electricity consumed on-site, and electricity delivered to the grid. Thus, GHG emissions from a CHP facility may be associated with more than one sector for GHG regulatory purposes. The on-site thermal output generally would be produced by a boiler if not for the CHP installation, and would be associated with the commercial or industrial sector, as appropriate. The electricity delivered to the grid would be associated with the electricity sector (as previously defined), while the proper sector for the electricity used on-site has not previously been determined.

6.2. Regulatory Treatment of CHP Emissions

6.2.1. Inclusion of CHP in the Cap-and-Trade System

In this section, we address whether all, some, or no portion of the three CHP components (electricity delivered to the grid, electricity consumed on-site, and thermal output consumed on-site) should be included in the cap-and-trade system, if ARB determines that cap-and-trade should be implemented.

Most parties support inclusion of all GHG emissions from CHP in the cap-and-trade system. EPUC/CAC argue that including CHP GHG emissions in a cap-and-trade system may create a disincentive for CHP because on-site emissions of a CHP facility are larger than they would be if the needed thermal output was obtained through other means and no electricity was produced on-site.

Electricity delivered to the grid is indistinguishable from electricity delivered from non-CHP sources. In the absence of a CHP installation, the electricity used on-site would be purchased from the grid. To provide comparable and equitable treatment for both CHP-generated electricity and electricity generated from non-CHP sources, we recommend to ARB that the emissions associated with all electricity consumed in California that is generated by CHP facilities in excess of a minimum size threshold (see Section 6.2.2 below), whether it is used on-site or delivered to the grid, be included in the cap-and-trade system. Whether inclusion of CHP in a cap-and-trade system would produce a disincentive is in large part a function of the allowance allocation method. This issue is discussed in more detail in Section 6.4 below. The allocation method we recommend in Section 6.4 for emissions associated with the electricity produced by CHP facilities would not create a disincentive for the installation of CHP.

The proposed decision did not include recommendations regarding CHP systems for which all electricity is used exclusively on-site with no deliveries to the grid. In comments on the proposed decision, EPUC/CAC recommend that all CHP facilities that meet the minimum size threshold be provided comparable GHG regulatory treatment regardless of whether they deliver electricity to the grid or solely serve on-site load. We agree with EPUC/CAC that there is no policy basis for differential GHG regulatory treatment of CHP facilities on the basis of whether they deliver electricity to the grid and, further, that differential treatment on this basis could have unintended and harmful competitive impacts. As a result, our recommendations to ARB regarding the GHG regulatory treatment of CHP facilities apply to all CHP facilities that meet the minimum size threshold, regardless of whether they deliver electricity to the California grid or solely serve on-site load.

EPUC/CAC also ask for clarification regarding our meaning in discussing electricity that is generated by CHP facilities for "on-site" consumption or use. We use this term to mean use for those purposes that are specified in Public Utilities Code Section 218(b)(1) and (2).

EPUC/CAC raise an additional concern in their comments on the proposed decision that warrants discussion. They describe that whether a CHP facility is importing electricity from or exporting electricity to the grid typically is determined at a single "net" meter at the facility's site boundary, with electricity produced and load served on-site being netted before reaching the meter at the point of interconnection. They describe other arrangements, however, in which generation and load may be interconnected to the grid through separate meters, and assert that, for purposes of determining GHG emissions, the result of these two configurations is the same. We agree with EPUC/CAC that GHG regulatory treatment of CHP facilities should be comparable regardless of the metering configuration used.

Another question arises concerning the treatment of electricity that may be delivered to the grid in California from out-of-state CHP. Under Section 38505(m), "Statewide greenhouse gas emissions" means "the total annual emissions of greenhouse gases in the state, including all emissions of greenhouse gases from the generation of electricity delivered to and consumed in California . . . whether the electricity is generated in state or imported." Under AB 32, ARB will track all GHG emissions resulting from the generation of electricity delivered to and consumed in California, whether the electricity is generated in California or imported. However, for CHP units located outside California, the thermal output and the electricity consumed on-site or at other locations outside California is not subject to AB 32. The scope of any cap-and-trade program under AB 32 can be no broader than what is encompassed within AB 32. Accordingly, for a CHP unit located outside California, we recommend that only the electricity delivered to the California grid and consumed in California be included in the California cap-and-trade program.

6.2.2. Applicable Thresholds/Exemptions

In this section, we address what, if any, size threshold should be established below which CHP facilities should not be included in the cap-and-trade system. Parties agree that very small CHP facilities should not be included in the cap-and-trade system, but do not agree regarding the size threshold. Some parties support a threshold based on the type of use made of the process heat. Other parties argue that, under the deliverer framework, non-CHP deliverers do not have distinctions based on size other than some minimum. Most of the parties agree that either 1 MW or some other *de minimis* threshold would be appropriate.

Since one of our goals is to create equitable GHG policy among all electricity market participants, we recommend that ARB adopt the same minimum size thresholds for CHP electricity generation as for all other deliverers included in the electricity sector for purposes of GHG regulation.[48] The size threshold would not distinguish between electricity used on-site and electricity delivered to the grid.

Some parties advocate that more efficient CHP facilities should be exempt from the cap-and-trade system. Most parties agree that efficient CHP should be used and encouraged. However, no other deliverer is subject to an efficiency threshold. Therefore, we do not recommend that any efficiency threshold be used to determine whether a CHP facility is subject to the cap-and-trade program, if one is implemented. Efficiency criteria may be useful, however, in determining if a CHP facility qualifies as an emissions reduction measure (see Section 4.1.3.2 above).

ARB may want to treat GHG emissions associated with thermal output from a CHP facility in a manner that is parallel to its treatment of other sources in the industrial and commercial sectors. In such an approach, the total emissions that determine if a CHP facility is subject to reporting or compliance obligations in the industrial or commercial sector, as appropriate, could include emissions associated with useful thermal output but would exclude emissions associated with electricity generation.

6.3. Attribution of GHG Emissions to Appropriate Sectors

Several parties advocate the creation of a separate sector for CHP for GHG regulatory purposes. Some of these parties argue that it would be arbitrary to divide GHG emissions between sectors and that doing so would make it difficult

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[48] ARB's current reporting regulations require reporting by all electricity generating facilities that both have a capacity greater than or equal to 1 MW and emit 2,500 metric tons of CO2 per year or more..

to design appropriate regulatory mechanisms. Other parties argue that a separate CHP sector is not needed as long as all of the outputs that CHP produces (electricity and thermal output) are included in the cap-and-trade system. These parties assert that if all emissions associated with both outputs are included in the cap-and-trade system, "where" the emissions are assigned is not important. Some parties believe that a benefit of a separate CHP sector would be that it would ensure that all CHP emissions are included in the cap-and-trade framework. As other parties note, no other technological process is currently defined as a separate sector.

Consistent with our recommendations in D.08-03-018 regarding the treatment of other electricity delivered to the grid and to ensure equitable treatment of CHP-generated electricity, we recommend that (subject to a minimum size threshold discussed above) CHP electricity that is delivered to the grid and consumed in California be included in the electricity sector for GHG regulatory purposes. The deliverer, that is, the entity that delivers the CHP electricity to the grid, would be responsible for the associated emissions. In order to also provide equitable treatment for CHP electricity used on-site, we recommend that CHP electricity that is used on-site also be included in the electricity sector, even though it is not delivered to the grid. While there is no "deliverer" for CHP electricity used on-site, it would be reasonable to treat the CHP operator as comparable to a deliverer for purposes of GHG regulation of CHP electricity used on-site, e.g., the CHP operator would be responsible for surrendering allowances for CHP electricity used on-site.

It is possible that in some instances the deliverer of CHP electricity to the grid is not the operator of the unit, in which case two entities would be responsible for surrendering allowances for different portions of the CHP unit's emissions associated with its electricity generation, i.e., the deliverer for the CHP electricity delivered to the grid, and the CHP operator for CHP electricity used on-site. We do not know if there are any cases where this will actually occur.

If ARB wants to attribute the GHG emissions from thermal output in a manner that is parallel to our recommended treatment of emissions associated with GHG-generated electricity, we expect that ARB would attribute those emissions to the industrial or commercial sector as appropriate.

6.4. Allocation of Allowances for CHP Facilities

6.4.1. Positions of the Parties

EPUC/CAC recommend that allowances should be distributed for free to topping-cycle CHP facilities using a double benchmark mechanism. A double benchmark would set reference emissions rates for each of the two outputs associated with CHP, useful thermal output and electricity. The reference emissions rates would be in the form of metric tons of emissions per unit of energy output. In essence, the double benchmark would allocate allowances based on what the emissions *would have been* if the thermal output and the electricity were efficiently generated separately. EPUC/CAC present the basic concept of a double benchmark and offer various different modifications to their proposal should we conclude that modifications are needed to coordinate their proposal with our recommended allowance distribution methodology for deliverers and retail providers. These options include use of a reference emissions rate based on average fossil generation or a CCGT, establishing the reference emissions rate based on a specific vintage of generation technology, and the allocation of allowances for avoided transmission losses. EPUC/CAC also describe modifications to their proposal that would apply if some allowances were distributed through an auction to CHP facilities. EPUC/CAC argue that any extra allocation that would occur due to the reference emissions rate being larger than the actual emissions rates of CHP facilities would compensate CHP facilities for the potential disincentives resulting from the increased on-site emissions due to CHP electricity production.

EPUC/CAC submit that there is no need to utilize a double-benchmark approach for bottoming-cycle CHP because the production process is fundamentally different than in a topping-cycle CHP facility. EPUC/CAC and Indicated Cement state that, in many bottoming-cycle CHP facilities, the level of GHG emissions is not changed by the presence of CHP and, further, that where supplemental firing is used to generate electricity, the incremental GHG emissions are much less than from a standard gas-fired generator. As a result, EPUC/CAC's position is that, when there is no supplemental firing in a bottoming-cycle unit, there is no need to allocate allowances for the electricity generated. When there is supplemental firing with a resulting compliance obligation, EPUC/CAC recommend that allowances be distributed for the electricity production based on an average or marginal emissions rate for fossil resources or for natural gas-fired generation. EPUC/CAC do not recommend use of a benchmark mechanism for the distribution of allowances for a bottoming-cycle CHP's thermal output.

Several parties generally support EPUC/CAC's double-benchmark proposal. These parties have differing opinions about the appropriate reference emissions rate. DRA prefers using an auction to distribute allowances, but states that special consideration such as a double benchmark may be required for CHP units if free allowances are allocated to other generators.

As discussed above, we consider in today's decision how, for CHP facilities that meet a minimum size requirement and are included in the cap-and-trade program, emission allowances should be distributed for the electricity generated by the CHP facility, not for the thermal output. As a result, in the remainder of this decision, we refer to EPUC/CAC's proposal as the "EPUC/CAC benchmark proposal," which recognizes that ARB may consider allowance allocations for the thermal output.

PG&E proposes that allowances should be distributed to CHP facilities in the same manner that they are distributed to other deliverers. PG&E argues that the inherent fuel savings of CHP would create an economic incentive to install CHP, and that any unintended negative consequences created by distributing allowances to CHP facilities on the same basis as all other deliverers would not be substantial enough to deter installation of CHP facilities. PG&E recommends that the method for distributing emission allowances for thermal output from CHP be consistent with the method ARB adopts for other sources of thermal output in the industrial sector. SDG&E/SoCalGas generally support PG&E's recommendation.

CCC contends that treating CHP facilities the same as other deliverers for allocation purposes could result in CHP facilities being economically disadvantaged if their role as a self-provider is not also accounted for. In its opinion, CHP facilities act essentially as their own retail provider. CCC argues that distribution of auction revenues to retail providers in proportion to the loads they serve without a comparable distribution of auction revenues to CHP facilities would treat CHP inequitably, and that this inequitable treatment would reduce the economic incentives for installing CHP facilities.

6.4.2. Discussion

Our recommendation that, for CHP facilities that meet a minimum size requirement, emissions associated with all electricity generated by the CHP facility and consumed in California be included in the cap-and-trade program and included in the electricity sector for GHG regulatory purposes allows separate consideration of the appropriate allowance distribution methodologies for thermal output and electricity generated by CHP. The separate consideration of allowance distribution methodologies for the two CHP outputs does not preclude adoption of any of the distribution options proposed by parties. As an example, if we were to recommend that allowance distribution for CHP electricity be based on a CCGT benchmark and ARB were to utilize an allocation method for thermal output that distributes emissions allowances based on a benchmark, the resulting distribution of emission allowances to CHP could be comparable to EPUC/CAC's double benchmark proposal.

In the development of the record, parties were asked about regulatory and legal barriers to the development of CHP, particularly in the context of whether CHP should be treated as an emissions reduction measure. Several parties suggest that allocation policies be used to compensate for what they perceive as regulatory barriers to CHP. In Section 5.4.3 above, we address a similar issue regarding whether extra allowances should allocated to renewables and to energy efficiency.

As discussed in Section 4.1.3, we commit to investigate market and regulatory barriers for CHP with the goal of maximizing the State's reliance on cost-effective CHP as an emissions reduction measure. Consistent with our discussion in Section 5.4.3, we do not determine at this time that it would be appropriate to use favorable distribution of GHG allowances to provide an extra incentive for CHP technologies. This issue may warrant revisiting as part of our further examination of CHP barriers, as discussed in Section 4.1.3.

The EPUC/CAC benchmark proposal would provide on-going allocations of free allowances to CHP based on reference emissions rates that would attribute more emissions to CHP facilities than they would actually create. Some parties argue that the resulting extra allowances would be warranted because

CHP facilities would experience increased on-site compliance obligations while contributing to an overall decrease in emissions statewide. However, we are not convinced that such favorable treatment and extra incentives for CHP through inflated allowance allocations are warranted. As a result, we do not recommend the EPUC/CAC benchmark proposal at this time.

One of the parties' concerns, articulated by CCC in particular, is that allocation policies would treat CHP inequitably if they do not recognize that CHP facilities act as their own self-provider of electricity used on-site. We agree that allowances should be made available to CHP facilities in an equitable manner that recognizes that CHP functions in ways that are comparable to a deliverer for all of its electricity, and comparable to a retail provider for the portion of its electricity used on-site.

To ensure equitable treatment for all market participants, we recommend that the allowance distribution policies that we recommend in Section 5 apply to CHP-generated electricity. We recommend that, for CHP facilities that meet a minimum size requirement, all CHP-generated electricity that is consumed in California, whether delivered to the grid or used on-site, receive allowances on the same basis as other deliverers, and that CHP-generated electricity used on-site receive allowances on the same basis that they are distributed to retail providers. These recommendations apply to both topping-cycle and bottoming-cycle CHP installations.

For purposes of GHG regulation, acknowledging the dual roles that CHP plays as both a deliverer for all of its electricity and a retail provider for on-site usage would treat CHP facilities on the same basis as other deliverers and retail providers. We recommend that CHP receive the same benefits of free allowance distributions and have the same obligations, including a requirement to purchase any additional allowances or offsets needed to meet GHG compliance obligations.

As described in Section 6.3 above, there may be situations in which the deliverer of CHP electricity to the grid is not the operator of the unit. Recognizing this, we recommend that, to the extent that allowances are distributed administratively to deliverers, the deliverers for CHP electricity delivered to the grid and consumed in California, and the CHP operators for CHP electricity used on-site, receive allowances on the same basis as deliverers of electricity from other sources.

All CHP electricity consumed in California should be included in determining free distributions to individual deliverers. In Section 5.4, we recommend that distribution of free allowances to individual deliverers be based on a fuel-differentiated output-based approach, with distributions limited to deliverers of electricity from emitting resources. Free distributions to deliverers would be phased out by 2016. We recommend that these same policies apply to CHP in its role as an electricity deliverer. For topping-cycle CHP, we recommend that the same fuel-based weighting factors be used that are used for other delivered electricity. Because no emissions would be attributed to bottoming-cycle CHP that does not use supplemental firing, it would not receive free allowances as a deliverer. We believe that additional work will be needed regarding the specific weighting factors that should be used when there is supplemental firing in bottoming-cycle CHP, in order to account for the resulting emissions.

We recommend similarly that ARB treat CHP operators comparable to retail providers for the portion of CHP-generated electricity that is used on-site. All CHP electricity consumed on-site should be included in determining the amount of free distributions to individual providers. Our recommendation in

Section 5.4 that allowance distributions to retail providers be based initially on historical emissions of their electricity portfolios, transitioning to a sales basis by 2020, should apply equally to CHP-generated electricity used on-site. Equity goals dictate that CHP operators receive allowances on the same basis as retail providers and similarly be required to sell through a centralized auction the allowances they receive as a result of their role comparable to a retail provider for the portion of CHP-generated electricity used on-site.

Our recommendation in Section 5.5 that auction proceeds should be used for purposes consistent with AB 32 also applies to CHP facilities. Operators of emitting CHP facilities could use auction proceeds to offset their compliance obligations under the cap-and-trade program, a use that would be consistent with AB 32. ARB may choose to require CHP facilities to report on their use of auction revenues.

7. Cap-and-Trade Market Design and Flexible Compliance

7.1. Introduction

In this section, we outline some of the characteristics specific to the electricity sector that ARB should bear in mind as it considers market design and flexible compliance mechanisms for a multi-sector cap-and-trade system that may link to a regional and/or national program. We stress the importance of a liquid and transparent allowance trading system and sufficient flexible compliance options to help market participants meet their obligations while maintaining the environmental integrity of the emissions cap. We make our suggestions and recommendations based on the unique characteristics of the electricity sector as discussed below.

7.2. Unique Characteristics of the Electricity Sector

Parties point to a number of unique characteristics in the electricity sector that should be recognized in the design of a cap-and-trade market.

EPUC/CAC, SCPPA, and CUE argue that, in the electricity sector where the thing regulated is a commodity of necessity, it is particularly important to make a wide variety of flexible compliance tools available.

PG&E notes that, absent government approval, California's investor-owned utilities cannot choose to withdraw voluntarily from the electricity or natural gas business or move their business or facilities to another state or location. Likewise, PG&E points out that, because electricity utilities are relatively capital-intensive and subject to natural economies of scale for their transmission and distribution facilities, utility customers do not have the same choice to buy electricity or natural gas services from out-of-state suppliers or manufacturers as they have for other consumer products and services.

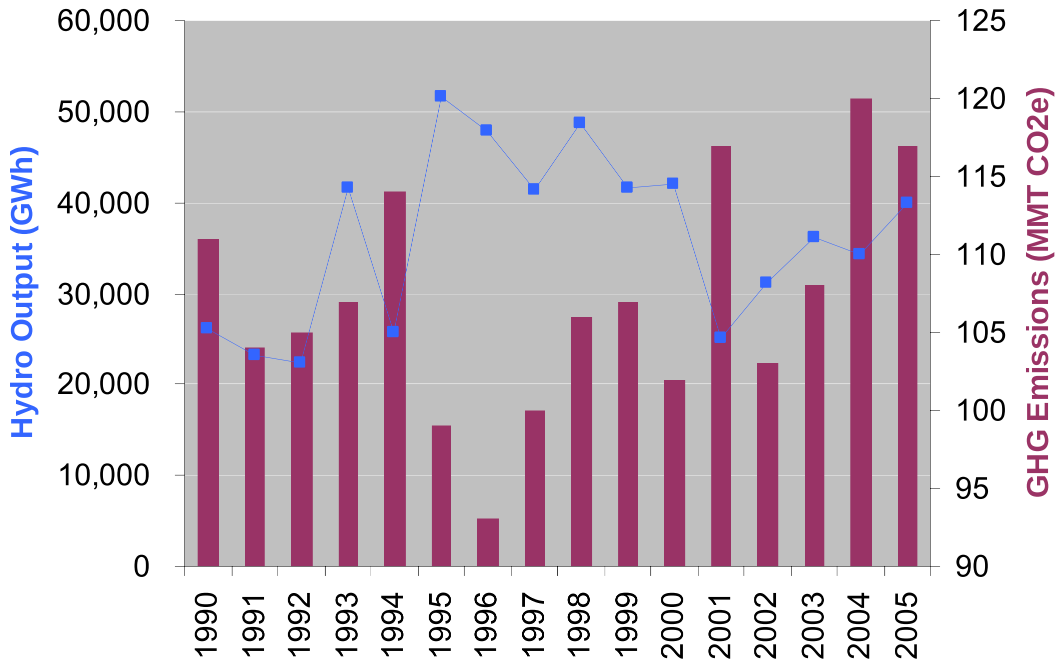
IEP cautions that electricity cannot be stored efficiently to any significant degree, and that most generators do not have 100% control over their operations in all hours.

SDG&E/SoCalGas suggest that GHG compliance obligations could cause price spikes in the electricity market due to inelastic demand for allowances by deliverers, which may be able to pass on the cost in the market price, as well as inelastic supply of allowances in the short term, since most emissions reductions will depend on investments that will take years to move from design to operation.

Several parties assert that the demand for allowances will be subject to annual variability due to the effects of weather on both the demand for electricity and the sources of energy. SMUD notes that over the past 18 years, while electricity sector emissions have remained relatively flat on average, annual variations in emissions of 15% and 2-year swings of 25% have occurred a number of times. Annual temperature variations lead to electricity demand variability, due in part to the increased demand associated with air conditioning on hot days. Weather also affects electricity supply, partially due to the relatively large role of hydroelectric generation in California's resource mix. Figure 7-1 illustrates the variation in California's hydropower generation during the period 1990-2005 and shows that the electricity sector's GHG emissions tend to be higher in years when hydroelectric output is low. Of particular concern is the potential for extended droughts to drive up the sector's demand for allowances as fossil-fired generation is substituted for carbon-free hydropower. Lengthy droughts are not uncommon in California. PG&E cites data from the Sacramento Valley Water-Year Index (Index), calculated by the California Department of Water Resources, which is closely correlated with the State's hydroelectricity supply. PG&E observes that "since recordkeeping began in 1906" the Index has been below normal for five periods lasting four years or more. In the worst sequence, the Index was at least 28% below normal for the first six years of a nine-year drought that began in 1929.

Figure 7-1

Correlation of Electricity Sector Emissions and In-state Hydro Production



PacifiCorp notes that electricity may be used as a substitute fuel by other regulated sectors to reduce their own GHG emissions reduction obligations. PacifiCorp argues that switching from direct fossil fuel combustion in manufacturing and production processes, and fuel switching as a result of technology advancement (i.e., the plug-in hybrid electric vehicle technology), are very likely to be environmentally beneficial and cost-effective, but that the outcome would be to increase the electricity sector's overall compliance burden.

We agree that the electricity sector faces certain constraints due to its unique characteristics and that some of these factors increase the year-to-year variability of annual emissions, in addition to the effects of macroeconomic forces that influence all sectors. Of particular note are the requirement that retail providers provide electricity to customers on demand regardless of price; the fact that some retail providers hold long-term contracts for high-emitting power; the relatively long time-frame for planning, permitting, and construction of transmission and generation facilities needed to significantly change California's electricity supply mix; relatively inelastic demand; and annual variations in demand and in zero-emitting hydroelectric supplies. Because of these constraints, we believe that the electricity sector has a compelling need to be able to access low-cost emissions reductions commensurate with the size of the market and the extent of required reductions, and to manage their compliance options over time. Moreover, as ARB refines its market design and develops criteria for allowance allocation, it should take into account the potential for emissions to migrate across sectors as a result of fuel switching, vehicle electrification, and other shifts.

7.3. The Need for Flexible Compliance Options

Several parties submit that a narrow allowance market with few participants and difficult emissions targets likely would require more flexibility than would a broader market with less ambitious targets. Calpine and WPTF argue that greater participation in the market would increase the liquidity of the market and encourage emissions reductions in the least cost-intensive sectors. Similarly, SMUD maintains that additional flexibility is necessary in a market that requires steeper emissions reductions. SMUD contends that, if the electricity sector is required to reduce emissions only to 1990 levels, limited flexible compliance options could suffice. SMUD states that if, instead, the electricity sector is required to reduce its emissions to 30% below 1990 levels as indicated in the E3 Accelerated Policy Case, the electricity sector would need more flexible compliance options. Calpine argues that the rate at which the cap ratchets down over time also will influence the need for flexible compliance options.

PacifiCorp states that a cap-and-trade program with flexible compliance options would be, by necessity, more complicated to administer than one without flexible compliance options, but that this additional complexity would be a reasonable trade-off for avoiding unnecessary economic harm and ensuring equity.

GPI asserts that the appropriateness of many of the flexible compliance tools depends on the basic compliance system itself, as well as on the suite of other flexible compliance tools that are employed. For example, GPI submits that the need for banking and borrowing provisions is intricately related to the length of the compliance period that is adopted.

Some parties warn against the excessive use of flexible compliance options. NRDC/UCS maintain that trading in a cap-and-trade program is itself a flexible compliance option. Calpine asserts that flexible compliance options must be limited in order to ensure that new technologies are deployed and real emissions reductions are achieved within the covered sectors.

We agree that the need for flexible compliance options is tied directly to the size of the market, the emissions targets, and the trajectory of required reductions toward those targets. As discussed in Section 4.3.2.1, we favor equal annual reductions in the multi-sector emissions cap between 2012 and 2020.

7.4. Market Design

As discussed above, we believe that it is necessary to have a more complete picture of key market design elements in order to make specific decisions about the best approach to flexible compliance. The mix of flexible compliance mechanisms that is ultimately implemented should ensure a liquid and transparent allowance trading system, limit rate increases to consumers, and provide a reasonable range of compliance options for the electricity sector while also maintaining the environmental integrity of the emissions cap. While all aspects of the market design may potentially affect the electricity sector, we confine our recommendations to areas in which unique characteristics of the electricity sector raise concerns that we urge ARB to consider.

7.4.1. Market Scope

Several parties emphasize the need for a broad allowance trading market. WPTF states that the scope and design of the cap-and-trade system is the most effective tool for cost containment, on the basis that a broader market is likely to have a larger supply of low-cost options and lower compliance costs. PG&E and SCE argue that a broad market is likely to be more active, providing a sustained price signal to drive investment in low-carbon strategies. Similarly, IEP asserts that no amount of flexible compliance can make up for a poorly designed, narrow, and illiquid market. The Market Advisory Committee Report recommends that ARB should seek to expand the cap-and-trade program over time so that it covers as many sectors, sources, and gases as practicable.

In its Draft Scoping Plan, ARB supports the development of and linkage with a regional cap-and-trade market through the Western Climate Initiative. Multi-state trading opportunities would likely provide a broad and liquid market due the number of states and provinces participating, as well as the number of sectors and industries expected to participate, including the electricity sector, natural gas sector, refineries, cement, and transportation.

We agree with those parties that favor linkage with a broad trading market, and we strongly urge ARB not to pursue a California-only program, but rather to continue working with the Western Climate Initiative to help create and participate in a broad, liquid, multi-sector, regional cap-and-trade market that includes the electricity sector, major industrial sources, and the transportation sector. Such a broader program will provide greater market liquidity and price stability, as well as additional opportunities for low-cost GHG reductions. As some parties have noted, a broader program may also reduce the need for flexible compliance options relative to a program with narrower scope.

7.4.2. Unlimited Market Participation

Parties are divided on whether to limit who can buy and sell allowances and offsets in the cap-and-trade system. Some parties assert that unlimited participation would increase market liquidity, increase efficiency within the cap-and-trade system, and decrease price volatility. These parties support broad participation by financial institutions, hedge funds, private citizens, and other non-obligated entities, in addition to entities with compliance obligations.

DRA submits that unlimited participation in cap-and-trade systems has not harmed other cap-and-trade programs. Morgan Stanley and other parties assert that there are operational advantages from having a broader range of participants. Morgan Stanley argues that intermediaries can offer many useful services in an open market, such as warehousing allowances and/or offsets, providing explicit and de facto financing, creating derivative instruments such as swaps and futures that provide flexibility and hedging opportunities, and making markets in the underlying instruments. Morgan Stanley also claims that, without speculators, forward prices could become distorted by the different risk tolerances of market participants. In addition, Morgan Stanley notes that commercial trading in allowances would be subject to applicable state and federal oversight.

PacifiCorp and CUE express concern that financial institutions and hedge funds could distort market operation by exerting market power to drive up prices. Several parties agree with IEP that the distribution of allowances, including auctions, should be limited to parties with compliance obligations. Dynergy and SCPPA argue that parties without compliance obligations should be prohibited from banking allowances, in order to discourage "hoarding."

DRA, Morgan Stanley, SCE, and WPTF argue that limiting participation in the emissions allowance market is impractical since it would be difficult to determine which parties have compliance obligations. This is because the definition of a deliverer potentially encompasses the entire array of entities--including financial institutions and power marketers-- that regularly deliver energy into the California electricity markets.

DRA, PG&E, and Powerex argue that developing different rules for different classes of participants as a means to prevent market manipulation would create an overly complex market to administer and monitor, and could give participants an incentive to work around the rules.

We are convinced that a broad allowance market with a wide spectrum of participants would result in more liquidity and greater access to tools for managing risk. We also note the difficulties of developing and applying different sets of rules for market participants versus non-market participants, especially given the expansive definition of a deliverer. However, we are also troubled by the concerns raised about the risk of market manipulation and anti-competitive behavior. The very characteristics of the electricity sector discussed above that justify the need for ample provision of flexible compliance opportunities in this sector also argue for serious precautions – and careful oversight – to prevent market manipulation.

We encourage ARB to closely evaluate the benefits of providing full market access in light of the adequacy of safeguards under consideration to reduce the risk of market manipulation and anti-competitive behavior. Provided that ARB is satisfied that adequate safeguards are in place, we encourage ARB to allow unlimited participation in the cap-and-trade system. We encourage ARB to develop one set of rules for all classes of participants. We agree with DRA, PG&E, and Powerex that creating different rules for different parties could result in an overly complex market to administer and monitor, and could give participants an incentive to work around the rules.

7.4.3. Bilateral Linkage with Other Trading Systems

Many parties support linking the California cap-and-trade system with other cap-and-trade markets to further encourage liquidity and potentially reduce compliance costs. PG&E argues that linkage would broaden trading opportunities, making the market more efficient. SDG&E/SoCalGas contend that trading with other systems could reduce compliance costs in California. The Market Advisory Committee Report recommends linkages with other mandatory cap-and-trade systems, commenting that program linkages can increase market liquidity and cost-effectiveness and improve the functioning of the cap-and-trade program without sacrificing environmental integrity. EPUC/CAC assert that linking with other programs is likely to discourage leakage and thus promote environmental integrity. They submit further that linking with trading systems in different regions will also help smooth the impact on allowance prices of localized variations in weather, rainfall, and economic activity.

Some parties advise caution when contemplating linkage with other trading systems. CUE argues that linkage would subject the California system to the market rules of the other systems, including some with which we might not agree. NRDC/UCS and GPI point out that use of allowances from other systems could transfer economic activity and co-benefits outside of the State. GPI also suggests that some limits on the use of allowances from other systems might make sense, especially at the beginning of the program when new rules are being tested and confidence in the verifiability of out-of-state allowances has not been established.

Many of the parties supporting linkage favor a bilateral approach, in which the allowances from one system would be fully fungible with the allowances from the other system. GPI states that bilateral linkages are preferable because each program could guarantee through a formal agreement that its own allowances would meet the minimum criteria established by the other program. Dynergy and Powerex submit that bilateral linkage can moderate price volatility if there are no limits on allowances obtained in other jurisdictions. The Market Advisory Committee Report states that the terms for linking with other programs will need to be negotiated individually with the specific jurisdiction(s) involved.

SCE, SDG&E/SoCalGas, and PacifiCorp argue for unilateral linkage, in which the allowances from other systems would be treated as offsets in California. SCE asserts that the offset approach would be the simplest and most straightforward manner for California to develop regulatory links with other regions. Morgan Stanley and IEP argue that California should use this approach if bilateral linkages are not possible.

Many parties support linking only with cap-and-trade systems that have equally stringent rules. NRDC/UCS argue that California should consider linkage only if the other system has a similarly tight cap, comparable verification and reporting requirements, and equivalent limits on offsets. DRA explains its view that, if penalties and other sanctions are not comparable between two linked systems, non-compliance is likely to be exported to the system with the lowest penalty level.

Some parties contend that allowance prices in linked systems are likely to converge. PG&E states that bilateral linkage might reduce or increase allowance prices in California, depending on the relative prices in California and the other system. However, PG&E states that unilateral linkage to another system might decrease, but would not increase, allowance prices in California.

We agree with the parties that state that linkage with other trading systems would add liquidity and efficiency to California's trading market. We also are convinced that bilateral linkage is the right approach to ensure that any allowances accepted by California entities from other systems are of comparable quality to California allowances. While we recognize the possibility that certain design features of other systems, such as price triggers or inadequate enforcement provisions, could affect environmental integrity adversely if linked with California's program, we believe that these issues can be worked out in advance through negotiations for bilateral linkage. We strongly support ARB's effort to link California's cap-and-trade system with the Western Climate Initiative. We recommend that ARB continue this effort and also pursue bilateral linkage with other local, regional, national, and international GHG cap-and-trade systems, as they emerge and are rigorously studied to establish that they have comparable stringency, monitoring, compliance, and enforcement provisions.

7.4.4. No Borrowing

Borrowing would allow obligated entities to use allowances from their allotments in future compliance periods to meet current compliance obligations. Parties are divided on this issue.

Several parties argue that borrowing should be allowed. GPI asserts that borrowing would allow obligated entities to fall behind in their requirements, to a limited extent, in order to supply electricity needed during shortfalls, while ensuring that they do not fall so far behind that they can never make it up. SCPPA argues that borrowing would permit market participants to alter their "glide path" to emissions reductions through successive compliance periods. SCPPA contends that this is important because substantial lead times might be necessary to finance and install electricity infrastructure that may result in a sharp drop in emissions in later years.

DRA, NRDC/UCS, and CARE argue that borrowing should not be allowed. DRA asserts that borrowers might end up defaulting on their allowance debt, jeopardizing the program's ability to meet the overall reduction goals. The Market Advisory Committee Report recommends that borrowing should not be allowed.

NRDC/UCS, SDG&E/SoCalGas, and Calpine argue that borrowing, if allowed, should be limited. NRDC/UCS support limitations on the percentage of an entity's compliance obligation that could be borrowed, how often a single entity would be allowed to borrow over the life of the program, and how many compliance periods ahead an entity could borrow from. NRDC/UCS, SDG&E/SoCalGas, and Calpine argue that borrowed allowances should be paid back with interest, which SDG&E/SoCalGas assert would discourage entities from taking advantage of the time value of money and speculating on prices across compliance periods. SDG&E/SoCalGas state that borrowers should be subject to similar creditworthiness requirements as counterparties in energy trades.

Morgan Stanley, SDG&E/SoCalGas, and PacifiCorp suggest that borrowing possibly should be allowed only during the early years of the program. Morgan Stanley argues that emitters will not have had any significant opportunity for contingency planning at the outset of the program, and thus that an anomalous first compliance period could be problematic.

At this time, we do not recommend that ARB permit borrowing, because we are persuaded by the comments that borrowing could delay emission reductions and make it more difficult to achieve the program's emission reduction goals. Other flexible compliance measures discussed herein offer the potential to aid emitters in managing their compliance obligations with less risk to the program's environmental integrity.

7.4.5. No Price Triggers or Safety Valves

Parties do not agree on the use of a price trigger or safety valve in the cap-and-trade program. A price trigger or safety valve would be engaged when allowance prices reach pre-determined levels, and additional allowances would be introduced into the market in order to guide prices downward. Several parties argue that such a mechanism could provide relief if the program proves to be excessively costly. SCE states that the program administrator should retain the option of offering additional allowances at a predetermined price in the event that the markets demonstrate economically burdensome price swings. SCPPA argues that a price trigger could be important to prevent a "market meltdown." Some parties, including PacifiCorp, suggest an approach in which additional allowances would be taken from the allotments to be distributed in future years, thereby maintaining the same level of emissions reductions over time.

Other parties argue that a price trigger or safety valve would threaten the effectiveness of the program. NRDC/UCS argue that such mechanisms would have the potential to break the emissions cap, undermining the purpose of the State's emissions reduction law. The Market Advisory Committee Report recommends against a safety valve, stating that total emissions within the program should not exceed the cap. Morgan Stanley asserts that safety valves would create uncertainty in the market, discouraging investments in new or existing emissions reduction technologies. Powerex and WPTF argue that including a safety valve or price trigger would make it more difficult for California to link with other trading systems that are not designed to have a similar mechanism. NRDC/UCS submit that a safety value is unnecessary because the Governor already can suspend any part of the program under the authority of AB 32 in the event of extraordinary circumstances.

PG&E asserts that a price trigger for allowing additional offsets into the trading system, such as that adopted by the Regional Greenhouse Gas Initiative might be ineffective because participants would not have adequate confidence or notice to actually make investments in potential offsets that they will be unable to sell into the market unless the price trigger is reached.

PG&E and FPLE argue for a "price collar" approach, in which a minimum price of allowances would be set along with a maximum price, giving investors in emissions reduction technologies and offset projects some degree of confidence that their product would have value in a future market. DRA opposes this approach, asserting that a minimum price for allowances would operate at the expense of ratepayers.

We are convinced that price triggers and safety valves could very likely distort or defeat the cap-and-trade market by creating uncertainty that investments in emissions reduction technologies would achieve returns commensurate with the level of reductions needed to meet the State's emissions reduction goals. Market certainty is important because the knowledge that allowance prices are likely to rise as the cap ratchets down over time is necessary to encourage long-term investments in emissions reductions that may not pay off in the short-term but that would be profitable in the long-term as a result of prices going up. We disagree with Powerex and other parties that a system-wide mechanism that borrows allowances from future periods, when allowances are likely to be in scarcer supply, would necessarily maintain the same level of emissions reductions over time. Such a mechanism would make allowances in these future periods even scarcer and could seriously jeopardize the State's ability to meet emissions limits during those periods. We find that this form of cost containment is not necessary, provided that the system contains other design elements such as multi-year compliance periods, unlimited banking, and a well-designed offset program. These design features would allow covered entities to manage their costs in a manner more likely to preserve the environmental integrity of the cap throughout the life of the program. Likewise, we disagree with those parties that argue for a price floor for allowances, because low prices are likely to indicate that the market is working to drive sufficient investment toward the required emissions reductions. We therefore recommend that ARB, in developing a cap-and-trade system, avoid creating any price triggers, ceilings, floors, or safety valves.

7.5. Flexible Compliance Options

The following options would introduce a useful degree of flexibility into the cap-and-trade market, while also satisfying other goals such as electricity system reliability and fostering reductions outside of the capped sectors. We encourage ARB to include these options in the cap-and-trade system.

7.5.1. Three-Year Compliance Periods

Several parties argue that multi-year compliance periods (in which covered entities would have to surrender allowances at the end of the period) would facilitate compliance with emissions limitations. No parties argue against the adoption of multi-year compliance periods. SCE suggests that multi-year compliance periods would help reduce the volatility of supply and demand in the electricity sector due to dynamic changes in weather patterns. SCPPA asserts that longer compliance periods such as three years would help regulated entities smooth the impact of capital-intensive emissions reduction improvements that might result in a significant step decrease in the entity's emissions. The Market Advisory Committee Report recommends a compliance period of approximately three years.

Morgan Stanley suggests that it might make sense for the initial compliance period to be relatively long, with subsequent compliance periods of shorter duration. It argues that this would prevent an early anomalous event from causing a major disruption before emitters have had time to develop and implement contingency strategies to manage such situations. Over time, however, Morgan Stanley believes that emitters should expect that anomalous events will occasionally occur, and that it would be reasonable to expect emitters to have a contingency plan in place to manage such events.

Several parties suggest that staggered compliance periods could improve liquidity within the allowance market. SMUD argues that there would be value to having compliance periods that do not end at the same time, in order to avoid a rush for allowances at the end of each compliance period. SCE argues that electricity sector entities could be especially vulnerable to manipulation of allowances prices since the sector's compliance obligations would be well-known due to the regulated nature of the industry. SCE and PacifiCorp suggest that, to discourage market manipulation, individual regulated entities should have the option to end their own compliance periods early. WPTF and Calpine suggest a system of rolling compliance periods. In their proposal, entities subject to the cap would be required to surrender allowances annually to cover emissions in the previous year, but in exchange would be able to use a limited quantity of allowances from the next year.

Several parties agree with PG&E that compliance extensions could help regulated entities respond to unanticipated, extraordinary events. However, DRA, Morgan Stanley, and WPTF argue that extensions would be unnecessary, and could undermine the effectiveness of the program by discouraging investments in new technologies and emissions reductions.

We are convinced that multi-year compliance periods could provide compliance flexibility and reduce price volatility due to potential effects such as weather-driven variations in electricity supply and demand. It would be appropriate for ARB to adopt multi-year compliance periods during the early years of the program. However, we are also concerned that longer compliance periods could make it difficult to discern shortages or surpluses of allowances due to underlying characteristics of the market, and we agree with Morgan Stanley that emitters eventually should have plans in place to deal with anomalous events that may lead to price volatility. We encourage ARB to establish three-year compliance periods for the early years of the cap-and-trade program, and to consider the possibility of shorter compliance periods as the program matures. We believe that staggered or rolling compliance periods potentially could reduce price volatility further, but we do not have enough information to determine how these devices would work in practice. We therefore encourage ARB to give further evaluation and consideration to staggered or rolling compliance periods. Finally, we find that compliance extensions would discourage emissions reductions, and therefore encourage ARB not to grant extensions of compliance periods in the cap-and-trade system.

7.5.2. Unlimited Banking

Many parties support a market feature that would allow parties to bank allowances and offsets for use in future compliance periods. Powerex argues that allowance banking would improve market liquidity, provide incentives for greater reductions during the early years of the program, and potentially allow covered entities to reduce their compliance costs. Powerex also suggests that banking could give covered entities that hold allowances due to early reductions a greater long-term commitment to the allowance trading system. SCPPA argues that banking would provide entities within the electricity sector with insurance against market illiquidity, including illiquidity that might be caused by market manipulation and abuse. DRA and EPUC/CAC comment that banking would help smooth out price variations in the market for allowances. EPUC/CAC argue that the allowance price volatility that was experienced by the European Union Emission Trading Scheme was due in large part to the lack of banking options between Phase I and II in that system. The Market Advisory Committe Report recommends that California issue allowances that do not expire and which may be banked for use in any subsequent compliance period.

No parties oppose allowance banking under all circumstances, but some argue for restrictions in order to discourage allowance "hoarding" and market manipulation. NRDC/UCS, GPI, and SMUD suggest that the number of allowances an entity is allowed to bank should be limited. NRDC/UCS, GPI, and TURN suggest limitations on the length of time that entities would be allowed to hold banked allowances. Dynergy and SCPPA argue that parties without compliance obligations should not be allowed to bank allowances.

Morgan Stanley argues against market restrictions intended to prevent "hoarding," contending that it almost always would be impossible to distinguish between a party holding allowances for "legitimate" purposes and one engaged in "hoarding." Morgan Stanley also asserts that banking large numbers of allowances for "hoarding" purposes likely would be prohibitively expensive.

We agree with those parties that suggest that allowance and offset banking likely would lead to greater market liquidity and compliance flexibility. Moreover, as discussed in Section 7.4.2, the deliverer definition renders efforts to differentiate between market participants and nonparticipants impractical. We also believe that banking would be an effective strategy to counter the uneven nature of the emissions in the electricity sector due to weather-driven variations in energy consumption and the supply of zero-emitting hydropower. However, we recognize the concerns about "hoarding" and market manipulation, and strongly encourage ARB to ensure that there are adequate safeguards to reduce these risks. With such safeguards, we suggest that ARB allow unlimited banking of allowances and offsets by all market participants.

Similarly, we recognize the point made by EPUC/CAC that restrictions on banking between phases of a program could increase market volatility, and therefore suggest that ARB consider recognizing allowances and offsets banked during the program from 2012 to 2020 in any post-2020 trading system as well.

7.5.3. High-Quality Offsets

Offsets are emission reductions or sequestration activities that are not otherwise required by regulation or created in common practice. They are a potentially valuable tool for covered entities to use to manage their compliance obligations and may help to limit rate increases to retail electricity customers. We recognize, however, that any cost saving realized by the use of offsets would prove a false economy if the underlying project did not actually produce the requisite emissions reduction. In the following discussion, we address the risks and benefits of allowing the use of offsets. We also identify several issues that we encourage ARB to consider in its evaluation of the potential establishment of a credible and reliable offset program.

7.5.3.1. Allowing Offsets for Compliance

Most parties support the use of offsets for compliance under certain circumstances. Morgan Stanley argues that the utilization of offsets that meet California's quality criteria would serve a useful cost containment function without impairing the environmental integrity of the program. The Climate Trust submits that offsets can stimulate GHG reductions in sectors that either are not covered by or are not appropriate for an emissions cap.

IEP points out that Section 38505(k)(2) requires that offsets must "result in the same greenhouse gas emission reduction, over the same time period as direct compliance with a greenhouse gas emission limit or emission reduction measure."

One party, CUE, argues that offsets should not be allowed. NRDC/UCS argue that an offset program should be approached with "an abundance of caution." CUE and NRDC/UCS assert that offsets would reduce incentives for investments in emissions reductions in sectors within the cap, and that ensuring that offsets actually achieve the reductions that they claim would be difficult and expensive. These parties also suggest that emissions in sectors outside the cap can be directly regulated or covered by another program.

Several parties argue that offsets should be allowed in unlimited quantities. Dynergy points out that there currently are no commercial technologies than can remove carbon dioxide from fossil fuel-fired electricity generators' exhaust gases. SCE asserts that limits on offsets would place a financial burden on covered entities that would reduce their ability to invest in technological changes needed to meet long-term emissions reduction goals. Other parties, including NRDC/UCS, argue that if offsets are allowed, they should be limited to a small percentage of each source's compliance obligation, in order to ensure that meaningful reductions occur within the capped sectors.

DRA argues that quantity limits on offsets should be eased over time as California gains confidence in the integrity of offsets.

The Market Advisory Committee Report recommends that offsets should be allowed as part of the cap-and-trade program. The committee's members were divided on whether there should be a limit on the quantity of offsets that can be used for compliance purposes. Most, but not all, members of the committee believe that quantity limits are not the best way to promote GHG reductions by sources within the cap. In contrast, some other members believe that only with quantity limits on offsets will industry make the investments necessary to ensure that long-term GHG reduction goals are achieved.

We are convinced that sources within the electricity sector may have limited opportunities to make short-term GHG reductions at levels significantly larger than those associated with the programmatic energy efficiency and renewable energy measures recommended elsewhere in this decision. For these sources, the use of high-quality offsets could provide an alternative compliance option while also creating incentives for sources outside the cap to make GHG reductions that otherwise would not have occurred. However, we also note that the need for offsets for the electricity sector is directly related to the level of the overall cap, the quantity and method of allowance distributions within the electricity sector, the size and liquidity of the allowance market, and many other factors. If, for example, the cap-and-trade program does not require reductions in the electricity sector below what is expected from programmatic energy efficiency and renewable energy measures, there may be no need for a large pool of additional offset opportunities. On the other hand, in a significantly short or illiquid market, offsets may be one of the few compliance options available to covered entities, especially in the short run.

We therefore encourage ARB to allow covered entities to use offsets at levels that are appropriate given other program design parameters. Of course, the requirements of AB 32 must be met.[49] As IEP argues, offsets should result in the same GHG emissions reductions over the same time period, and must be real, additional, verifiable, permanent, and enforceable, to ensure the integrity of the emissions reduction program. ARB's Draft Scoping Plan includes a provision to allow covered entities to use high-quality offsets for not more than 10% of their compliance obligation. We agree that, while we expect programmatic energy efficiency and renewable energy measures to be the primary driver for emission reductions in the electricity sector, a quantitative limit on the use of offsets may be desirable to ensure additional reductions from sources subject to the cap. We believe that the appropriate level of offsets should be determined relative to the scope and liquidity of the cap-and-trade market, as well as the emissions targets. Additional modeling work may be needed to determine an appropriate level of offsets for the cap-and-trade program.

7.5.3.2. Design of an Offset Program

Parties provided extensive comments on the merits of various proposals to restrict the use of offsets and to ensure that only high-quality offsets are used for compliance in California. These include whether there should be geographic limits on the sources of offsets, use of credits from the Clean Development Mechanism, discounting of offsets, requirements that offsets produce co-benefits,

[49] Section 38562(d) specifies that: "Any regulation adopted by the state board pursuant to this part or Part 5 (commencing with Section 38570) shall ensure all of the following: (1) The greenhouse gas emission reductions achieved are real, permanent, quantifiable, verifiable, and enforceable by the state board." Part 5, Section 38570 (a) states that: "The state board may include in the regulations adopted pursuant to Section 38562 the use of market-based compliance mechanisms to comply with the regulations."

third party verification of reductions from offsets, and periodic external review of the offset program. For the most part, these issues are generic to an offset program without particular unique considerations for the electricity sector. We therefore take no position on the design of a prospective offset program at this time. We do, however, encourage ARB to avoid overly narrow limitations on the geographic sources of offsets.

Most parties argue that no geographic limits should be placed on offsets. PG&E asserts that limiting offsets based on location would increase the cost of the cap-and-trade program by not allowing entities to pursue possible low-cost emissions reduction opportunities. PG&E and SCE argue that offsets offer a way for California to exercise global leadership and engage uncapped regions in the challenge of reducing emissions. EPUC/CAC assert that geographic limits on offsets could impede California linkage with other programs. In support of geographic limits, NRDC/UCS and CARE argue that only projects within California would provide co-benefits to the State and would ensure that California's high standards for quality are met. However, DRA points out that projects outside of California may have different co-benefits that may advance other social or environmental goals.

Parties offer different perspectives on whether California should accept offsets from the Clean Development Mechanism. NRDC/UCS and GPI assert that the Clean Development Mechanism fails to guarantee that its offset projects provide real, truly additional, verifiable, permanent, and enforceable GHG reductions. However, the Climate Trust argues that, while not without its problems, the Clean Development Mechanism is evolving rapidly and is moving to address many of the concerns raised regarding the issue of business–as-usual projects earning offset credits.

We are convinced that geographic limits are not consistent with the underlying goals of the offset program to contain costs and encourage reductions beyond those that are covered by an emissions cap. We note that all offsets projects are likely to produce some co-benefits, and that projects located outside California could potentially reduce the "carbon footprint" of products imported into the State, and possibly provide out-of-state markets for clean technology products manufactured in California. We therefore encourage ARB to consider accepting high-quality offsets for compliance purposes without any geographic restrictions, provided that each offset from outside California meets the requirements of AB 32. We also support participation by the State of California, as feasible, in efforts to secure a post-2012 international climate agreement, and encourage ARB to consider accepting offsets from any offset program established pursuant to such an agreement for compliance with the California program, provided that ARB is satisfied that these credits meet high-quality standards and do not weaken the GHG emission reductions associated with the voluntary REC market.

7.6. Legal Issues Related to Market Design and Flexible Compliance

7.6.1. Statutory Issues Concerning Linkage and Offsets

7.6.1.1. The Requirement that ARB Monitor Compliance with, and Enforce, its Rules

CUE argues that linkage to carbon-trading systems outside California (or the acceptance of out-of-state offsets) would be illegal because Section 38580(a) requires ARB to "monitor compliance with and enforce any rule, regulation, order, emission limitation, emissions reduction measure, or market-based compliance mechanism adopted . . ." CUE further argues that ARB would not have the authority or ability to oversee and enforce trading occurring outside of California and therefore such trading cannot legally be included as part of the implementation of AB 32.

CUE, however, ignores the apparent purpose of Section 38580, which is to ensure that regulated entities comply with the regulations that are adopted. If, for example, ARB adopts a regulation that permits credits from certain specified trading systems with comparable stringency, monitoring, compliance, and enforcement provisions to be used in California, ARB should still be able to monitor and enforce its requirement contained in the regulation that the credits must be issued by the specified trading systems and not by some other carbon-trading system with which linkage has not been authorized. CUE does not explain why ARB would not be able to track the credit back to the originating trading system,[50] nor why ARB would be unable to take enforcement action against a regulated entity that attempted to use a credit issued by a carbon-trading system with which linkage has not been authorized. Similarly, if ARB authorizes offsets from outside California, and requires that they conform with specified protocols and have been verified by authorized verifiers, ARB ought to be able to monitor and enforce compliance with such a regulation. Such monitoring and enforcement could be performed by reviewing the regulated entity's submission of verification reports showing (i) that the offsets come from a project that meets one of the authorized protocols and (ii) the amount of GHG emissions being offset. Nothing in Section 38580 requires that ARB itself be able

[50] Contrary to CUE's argument, Section 38580(a) does not require ARB to "oversee" every trading system that can be used to acquire credits for AB 32 compliance. It only requires ARB to monitor compliance with and enforce any market-based compliance mechanism that ARB adopts.

to inspect the offset project to determine its compliance with the protocol or the amount of emissions being offset. In short, we agree with SDG&E/SoCalGas that nothing cited by CUE "even remotely suggests that the Legislature wanted to prohibit linkages to other systems, although it clearly could have so stated, if that was its intent." (SDG&E/SoCalGas Reply Comments at p. 15.)

Furthermore, CUE's argument ignores Section 38564, which states, in pertinent part:

> [ARB] shall consult with other states, and the federal government, and other nations to . . . facilitate the development of integrated and cost-effective regional, national, and international greenhouse gas reduction programs.

This statutory encouragement for the development of integrated regional, national, and international GHG-reduction programs further supports our conclusion that AB 32 permits linkage to other GHG reduction programs and the use offsets from outside California.

7.6.1.2. The Definition of "Statewide Greenhouse Gas Emissions"

IEP notes that Section 38505(m) defines "statewide greenhouse gas emissions" as "the total annual emissions of greenhouse gases in the state, including all emissions of greenhouse gases from the generation of electricity delivered to and consumed in California . . . , whether the electricity is generated in state or imported." IEP submits that this definition could be interpreted to require a narrow focus on reducing GHG emissions "in the state" and thus could limit or prevent linkage or the use of out-of-state offsets.

IEP, however, concludes that it makes more sense to read the definition in Section 38505(m) as an effort to ensure that jurisdictional boundaries are respected, i.e., to ensure that AB 32 is not read as authorizing an encroachment into the jurisdiction of other states or the federal government. IEP also argues that it would be pointless for ARB to "consult with other states, and the federal government, and other nations to . . . facilitate the development of integrated and cost-effective regional, national, and international greenhouse gas reduction programs," as directed by Section 38564, if ARB were prohibited from participating in such regional, national, or international programs. Accordingly, IEP concludes that the definition of "statewide greenhouse gas emissions" should not be read to restrict ARB's ability to incorporate appropriate out-of-state carbon trading systems or offsets into its flexible compliance options.

No party supported the view that the definition of "statewide greenhouse gas emissions" prevents California from linking with other carbon trading systems or accepting out-of-state offsets. Section 38562(b)(1) directs ARB to design its regulations "to minimize costs." Out-of-state offsets should, and the use of other credits from linked systems may, help minimize the costs of GHG regulation to California. If, however, ARB concludes that it would be desirable to have legislation more explicitly authorizing out-of-state offsets and linkages, we would support ARB in seeking such additional legislation.

7.6.1.3. Offsets and Co-Benefits

CEERT takes the position that an offset can only be accepted if it complies with the provisions of Sections 38562(b)[51] and 38570(b).[52]

However, AB 32 does not require that each and every offset have the characteristics described in those sections. Section 38562(b) describes things that ARB should do in "adopting regulations" "to the extent feasible." It does not

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[51] Section 38562(b) states, in part: "In adopting regulations pursuant to this section and Part 5 (commencing with Section 38570), to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

"(1) Design the regulations . . . in a manner that is equitable, seeks to minimize costs and maximize the total benefits to California, ...

"(2) Ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities.

. . .

"(4) Ensure that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions.

. . .

"(6) Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health.

"(7) Minimize the administrative burden of implementing and complying with these regulations.

"(8) Minimize leakage."

[52] Section 38570(b) states: "(b) Prior to the inclusion of any market-based compliance mechanism in the regulations, to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

"(1) Consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution.

"(2) Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants.

"(3) Maximize additional environmental and economic benefits for California, as appropriate."

require each and every project carried out by private parties under those regulations to have the described effects.[53] Similarly, Section 38570(b) only requires ARB, prior to the inclusion of any market-based compliance mechanism (such as offsets) in the regulations, *"to the extent feasible"* to (1) "consider" certain factors, including "localized impacts in communities that are already adversely impacted by air pollution," (2) "prevent any increase in the emissions of toxic air contaminants or criteria air pollutants," and (3) "[m]aximize additional environmental and economic benefits for California, *as appropriate*." (Emphasis added.) Furthermore, none of the parties commenting on the issue of offsets and co-benefits suggest that offsets would result in "any increase in the emissions of toxic air contaminants or criteria air pollutants" and we see no reason why the availability or use of offsets would produce that result.

NRDC/UCS apparently recognize that the factors set out in these two sections apply to ARB's regulations, and not to individual projects. Nevertheless, they express concern that "[i]t is not certain that offsets will achieve the . . . co-benefits for Californians as required by AB 32." (NRDC/UCS Comments at p. 26.) However, as pointed out above, these two sections of AB 32 require ARB to do certain things "to the extent feasible" and require ARB to balance a number of potentially conflicting goals, including minimizing costs (Section 38562(b)(1).) As we point out above, using offsets is one way to minimize costs. NRDC/UCS describe several hypothetical situations where they

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[53] Indeed, one of the goals stated in Section 38562(b) that CEERT fails to cite is minimizing "the administrative burden of . . . complying with" the regulations. An offset program that required a showing from each offset project on each of the points described in Sections 38562(b) and 38570(b) would greatly increase the administrative burden of complying with the regulation.

believe that allowing certain offsets would be a cause for concern.[54] However, NRDC/UCS have not shown that the concerns they identify would apply to the offset program as a whole.

7.6.2. Treaty and Compact Clauses

The Compact Clause of the U.S. Constitution provides that "[n]o State shall, without the Consent of Congress, . . . enter into any Agreement or Compact with another State . . . ."[55] The Treaty Clause of the U.S. Constitution grants the President the power to make treaties with the advice and consent of the Senate and also provides that "[n]o State shall enter into any treaty, alliance, or confederation . . . ."[56]

While some parties suggest that linkage could raise issues under the Compact and Treaty Clauses, no party argues that linkage would violate either of those clauses, and a number of parties conclude that a violation of those clauses is unlikely. Indeed, no party cites, and we are not aware of, any case holding that an agreement between a state and other states or provinces violated either the Compact or Treaty Clauses.[57]

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[54] NRDC/UCS argue that Section 38562(b)(8) means that the regulations should "prevent leakage of co-benefits outside of the state." (NRDC/UCS Comments, p. 28.) However, Section 38562(b)(8) refers to minimizing "leakage" and Section 38505(j) defines "leakage" as a "reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state." The concern of NRDC/UCS, however, is not with an *increase* in GHGs outside of California, but rather with a *reduction* in GHGs outside California. (See NRDC/UCS Comments, p. 28.)

[55] U.S. Const. art. I, § 10, cl. 3.

[56] U.S. Const. art. II, § 2, cl. 2; *id.* art. I, § 10, cl. 1.

[57] SDG&E/SoCalGas point out that no court has ever invalidated an interstate agreement for lack of consent under the Compact Clause, citing *Note: The Compact Clause and the Regional Greenhouse Gas Initiative*, 120 HARV. L. REV. 1958, 1960 (2007).

Nevertheless, case law (e.g., *United States Steel Corp. v. Multistate Tax Commission*, 434 U.S. 452 (1978)) does suggest that following certain principles in drafting linkage provisions will help avoid potential problems.[58] This issue is discussed in *Note: The Compact Clause and the Regional Greenhouse Gas Initiative*, 120 HARV. L. REV. 1958 (2007).

8. Comments on Proposed Decision

The proposed decision of the assigned Commissioner in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Public Utilities Commission's Rules of Practice and Procedure. Comments were filed no later than October 2, 2008 and reply comments were filed no later than October 7, 2008, except that DRA was allowed to late-file its reply comments on October 10, 2008. We have made corrections and clarifications in the proposed decision in response to comments, as well as substantive changes on selected issues, as we describe in today's decision.

In comments, several parties ask that we modify the proposed decision's recommendations to ARB to address implementation details of particular concern to them. We have made revisions to address certain implementation issues. Other implementation details, however, require further analysis. For convenience, we provide here a list of issues, certainly not exhaustive, that we have identified as requiring additional consideration as we work with ARB on the design and implementation of regulations related to AB 32:

- Market and regulatory barriers for CHP (discussed in Section 4.1.3.2 above);

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[58] DRA discusses some of the lessons that may be learned from this case in its Comments.

- Electrification in other sectors and potential impacts on allowance allocations to the electricity sector (Section 4.3.2.1 above);
- Natural gas sector contributions to GHG reductions and potential impacts of increased use of natural gas as a transportation fuel (Section 4.3.2.2);
- Weighting factors to be used for fuel-differentiated output based allowance allocations to deliverers (Section 5.4.2.4), including bottoming-cycle CHP (Section 6.4.2);
- How to update deliverer-specific output-based proportions used in the distribution process, and whether a small number of allowances should be set aside for new deliverers (Section 5.4.2.4);
- How to allocate allowances to new retail providers, and how to calculate and update sales-based proportions used for allocations to retail providers (Section 5.4.2.4);
- The appropriate trajectory for the transition from historical emissions-based to sales-based allowance allocations for retail providers (Section 5.4.2.4);
- Whether and how allowances should be distributed for verified energy efficiency (Section 5.4.3.1); and
- Whether and how allowances should be set aside for the voluntary renewable electricity market (Section 5.4.3.2).

One other issue raised in comments on the proposed decision deserves mention here. SCPPA asks that, in the allowance auctioning process, deliverers that are also retail providers be allowed to pay only the net difference between the cost of allowances they purchase and the auction revenues that are to be distributed to them as retail providers. We do not resolve this issue today, but believe it should be added to the list of issues for future consideration.

9. Assignment of Proceedings

For the Public Utilities Commission, President Michael R. Peevey is the assigned Commissioner and Charlotte F. TerKeurst and Jonathan Lakritz are the assigned Administrative Law Judges in Phase 2 of this proceeding.

For the Energy Commission, Chairman Jackalyne Pfannenstiel and Commissioner Jeffrey D. Byron were assigned as members of the Energy Commission's AB 32 Implementation Committee.

Findings of Fact

1. Energy efficiency is the cheapest and most effective resource for reducing GHG emissions in the electricity and natural gas sectors.

2. Many non-price market barriers to energy efficiency investment exist and will continue to exist even if a GHG emissions allowance cap-and-trade program is implemented.

3. As the cost of GHG mitigation becomes reflected in the cost of energy, more energy efficiency opportunities should become cost-effective. However, as more "low-hanging fruit" energy efficiency is achieved, incremental energy efficiency options may become more expensive.

4. It is reasonable for the State of California to require comparable investment in energy efficiency by all retail providers in California, including both investor-owned and publicly-owned utilities.

5. Achieving the goal of all cost-effective energy efficiency will require a continuation of existing direct regulatory/mandatory requirements, expansions of existing requirements and development of new ones where appropriate, and implementation of other innovative approaches such as market-based strategies.

6. It is reasonable for the State of California to set a goal of attainment of all cost-effective energy efficiency investment.

7. Renewable mandates play an important role in achieving aggressive renewable energy penetration, since they provide a long-term signal that can lead to market transformation of new renewable technologies and potential cost reductions.

8. E3 estimates that GHG emissions reductions obtained through achievement of 33% electricity from renewables may have an average incremental cost of $133 per ton, compared to the current 20% RPS mandate.

9. Renewable energy provides environmental co-benefits, including reducing other non-GHG pollutants, when sited in California.

10. Significant implementation barriers exist to the continued deployment of renewable energy in California.

11. Increased renewable energy penetration would increase fuel diversity.

12. California's longer term 2050 GHG reduction goals will require significantly reducing the GHG footprint of the electricity sector.

13. Obtaining 33% of the electricity delivered to customers from renewable resources by 2020 would be an important step in achieving this transformation.

14. It is reasonable for the State of California to set as requirements that by 2020 at least 33% of California's electricity needs be met by renewable resources, and that by 2020 each retail provider obtain at least 33% of the electricity delivered to its customers from renewable resources.

15. E3's approach and analysis to estimating costs from reducing GHG emissions are reasonable for the purpose of informing our recommendations to ARB.

16. E3 estimates that the Accelerated Policy Case would result in GHG emissions totaling 79 MMT CO2e for the electricity sector in 2020.

17. We did not study the cost and rate impacts on consumers of increasing energy efficiency goals, renewable energy mandates, or levels of CHP beyond

those in E3's Accelerated Policy Case. Prior to increasing these policies/mandates, the costs of additional reductions should be compared against the costs of mitigating GHG emissions across the California economy.

18. Linkage with a regional emissions trading system that includes all jurisdictions in the Western electricity grid would likely result in coal-fired generators operating less, would significantly mitigate opportunities for deliverers to mask the carbon intensity of electricity through "contract shuffling," and may result in low-carbon generation displacing either coal or natural gas-fired generation depending on time and location.

19. The Western Climate Initiative has issued draft design principles that target an opening date of January 1, 2012 for a linked regional cap-and-trade program.

20. Linking with other state cap-and-trade programs through the Western Climate Initiative would remove or mitigate some of the challenges of a California-only approach.

21. The modeling effort in this proceeding did not include effects of Western Climate Initiative or national approaches to controlling GHG emissions.

22. The level of responsibility or "burden" under AB 32 should be proportional and fair to consumers in all sectors of the economy.

23. ARB's Draft Scoping Plan would assign approximately 40% of the economy-wide responsibility for mandatory emissions to the electricity sector, even though electricity represents only 25% of the statewide emissions. This requirement would result in electricity sector emissions in 2020 roughly equal to the level that E3 estimates under the Accelerated Policy Case.

24. Under a cap-and-trade program, the responsibility for reducing emissions can be separated from the recovery of the cost of the emission reductions.

25. If ARB implements a multi-sector cap-and-trade program in California, it is reasonable to allocate allowances proportionally among the sectors in the cap-and-trade program, based on relative emissions during an historical baseline period.

26. It is reasonable that the trajectory of a multi-sector cap and the required annual reductions generally be a straight-line reduction between 2012 and 2020 for all sectors in the California cap-and-trade program, to ensure steady progress toward the 2020 goals. However, development through the Western Climate Initiative of regional emission reduction programs, which may include transportation and other sectors, may affect the schedule for implementing emission reductions.

27. A centralized auction of allowances undertaken by ARB or its agent would provide market liquidity, ensure that all deliverers have equal access to allowances, and reduce or avoid the need for a set-aside or other administrative accommodation for new entrants.

28. There is an expectation that if allowances are auctioned GHG compliance costs would be internalized in wholesale electricity prices, sending more accurate price signals that would encourage participants in the electricity sector to reduce emissions.

29. Auctioning allowances would result in entities with compliance obligations bearing the full financial responsibility for emissions associated with electricity that they deliver to the California grid.

30. Auctioning would preclude windfall profits from allowance rents to independent deliverers.

31. Distributing some free allowances to deliverers would reduce short-term impacts on generating resources, and would help generators adapt to the new regulatory environment.

32. A transition to auctioning would help protect ratepayers if problems arise as ARB implements AB 32 and experience is gained with the auctioning process.

33. A transition to 100% auctioning by 2016 would ensure that any allowance rents would be short-term and would give existing high-emitting resources time to adjust their generation investments.

34. It is reasonable to introduce auctioning in a phased approach, with 100% auctioning by 2016, so that California can reap initial benefits from auctioning and, at the same time, provide some protection and stability while the cap-and-trade market develops and matures.

35. A primary consideration in the early years of a cap-and-trade program should be to ensure that economic harm is mitigated to the range of market participants in the electricity sector, including customers, retail providers, and deliverers.

36. A fuel-differentiated output-based allocation approach with distributions limited to deliverers of electricity from emitting generation resources (including unspecified sources) would provide all deliverers with allowances roughly in proportion to the amount they need and would reduce the potential for allowance rents.

37. A fuel-differentiated output-based allocation approach with distributions limited to deliverers of electricity from emitting generation resources would avoid undue economic harm to California electricity consumers who are currently locked into a certain degree of dependence on coal.

38. In a fuel-differentiated output-based allocation approach, it is reasonable that a higher weighting factor be applied for all coal generation delivered to the California grid.

39. If 100% auctioning is not implemented by 2016, an important longer-term goal of deliverer distributions should be to provide strong incentives for GHG reductions.

40. It is reasonable, if 100% auctioning is not implemented for the electricity sector by 2016, that allowance distributions to deliverers transition toward an output-based approach that weights all types of generation equally, to be reached by 2020 if 100% auctioning is not achieved by that time.

41. A centralized auction undertaken by ARB or its agent, in which retail providers rather than the State own most or all of the electricity sector allowances at the time they are auctioned would simplify the auctioning and revenue distribution process, in that auction revenues would pass directly to the retail providers.

42. A centralized auction undertaken by ARB or its agent in which retail providers are required to sell any allowances they receive would remove anti-competitive concerns regarding the distribution of allowances to retail providers.

43. It is reasonable to require that retail providers sell any allowances they receive in a centralized auction undertaken by ARB or its agent. This finding does not apply to allowances that a vertically-integrated entity that is both a retail provider and a deliverer may receive based on its deliveries to the grid.

44. It is reasonable to require that each retail provider receive all auction revenues from the sale of its allowances through the centralized auction.

45. Allocating allowances to retail providers based on historical emissions in their electricity portfolios would accommodate carbon-intensive retail providers that may face relatively high rate impacts due to compliance costs.

46. A long-term priority for allocating allowances is to provide strong incentives for increased reliance on low- and non-emitting resources and to

provide consistent signals to all retail providers regarding the value of low-emitting portfolios.

47. It is reasonable to transition allocation of allowances to retail providers from an historical emissions basis to a sales basis by 2020 because a sales-based allocation would provide a long-term incentive to reduce reliance on high-emitting resources.

48. To meet the goals of AB 32, California is preparing to implement ambitious energy efficiency and renewable energy mandates.

49. Meeting the targets for the electricity sector outlined in ARB's Draft Scoping Plan will require significant additional expenditures on energy efficiency measures and the development of new renewable resources.

50. It is reasonable to require that all auction revenues be used for purposes related to AB 32 and that all auction revenues from allowances allocated to the electricity sector be used to finance investments in energy efficiency and renewable energy or for bill relief, especially for low income customers.

51. Electricity delivered to the California grid by CHP facilities is indistinguishable from electricity delivered from non-CHP sources.

52. With respect to GHG emissions, all electricity generated by a CHP facility is identical whether the electricity is delivered to the grid or consumed on-site.

53. It is reasonable to include the emissions associated with all electricity consumed in California and generated by CHP facilities in excess of a minimum size threshold, whether the electricity is used on-site or delivered to the grid, in a multi-sector cap-and-trade system.

54. It is reasonable to provide comparable GHG regulatory treatment for all CHP facilities that exceed the minimum size threshold, regardless of whether they deliver electricity to the grid or solely serve on-site load, and regardless of the metering configuration used.

55. It is reasonable to use the same minimum size threshold used for other deliverers to determine which CHP facilities should be included in a multi-sector cap-and-trade program.

56. It is not necessary to attribute GHG emissions from CHP facilities to a unique CHP sector if the GHG emissions are included in a multi-sector cap-and-trade program.

57. It is reasonable to treat entities that deliver CHP-generated electricity to the grid like other deliverers for GHG regulatory purposes, and to treat CHP operators comparable to deliverers for the portion of CHP-generated electricity that is consumed on-site.

58. It is reasonable to allocate allowances to entities that deliver CHP-generated electricity to the grid, and to CHP operators for CHP-generated electricity that is consumed on-site using the fuel-differentiated output basis, as described in this decision.

59. To the extent that CHP facilities provide electricity that is consumed on-site, distributing allowances to CHP facility operators on the same basis as retail providers would provide equitable treatment for CHP facilities.

60. Linking California's cap-and-trade program with other trading systems would add liquidity and efficiency to California's trading market.

61. Bilateral linkage would allow California to ensure that any allowances accepted by California entities from other systems are of comparable quality to California allowances.

62. It is reasonable for California to pursue bilateral linkage with other local, regional, national, and international GHG cap-and-trade systems that have comparable stringency, monitoring, compliance, and enforcement provisions.

63. Unique characteristics of the electricity sector necessitate that the cap-and-trade market include a reasonable range of flexible compliance options in order

to provide needed flexibility to the sector while maintaining the environmental integrity of the emissions cap.

64. Price triggers and safety valves could very likely distort or defeat the cap-and-trade market by creating uncertainty that investments in emissions reduction technologies will achieve returns commensurate with the level of reductions needed to meet the State's emissions reduction goals.

65. Declining allowance prices over time are likely to indicate that the market is working to drive sufficient investment toward the required emissions reductions.

Conclusions of Law

1. The administrative allocation of allowances that we are proposing is facially neutral, as between interstate and intrastate commerce, and does not have a discriminatory purpose or effect. The allowances allocated to deliverers would be distributed based on fuel-differentiated output, whether the generation of the electricity occurs in California or elsewhere.

2. The auctioning of allowances by ARB or its agent that we are proposing is facially neutral, as between interstate and intrastate commerce, and does not have a discriminatory purpose or effect.

3. Under Pike v. Bruce Church, Inc. (1970) 397 U.S. 137, 142, a state enactment "will be upheld unless the burden imposed on [interstate] commerce is clearly excessive in relation to the putative local benefits."

4. The use of an allocation based on fuel-differentiated output-based criterion would not violate the dormant Commerce Clause.

5. The centralized auctioning of allowances by ARB or its agent would not violate the dormant Commerce Clause.

6. The distribution of allowances to retail providers for subsequent auctioning, transitioning over time from being based initially on historical emissions in the retail providers' portfolios to being based on sales by 2020, would not violate the dormant Commerce Clause.

7. Under the California Constitution, Article XIII A, Section 3 a tax can only be enacted by not less than a two-thirds vote of the Legislature.

8. A regulatory fee does not require a Legislative vote of not less than two-thirds because it is enacted under a state's traditional police power, not its taxing authority.

9. Under *Sinclair Paint Co. v. State Bd. of Equal.* (1997 15 Cal.4th 866, 875-876) regulatory fees imposed to pay for the expenses of a regulatory program or to defray the actual or anticipated adverse effects of the payer's action are not taxes imposed for revenue purposes, provided the fees "bear a reasonable relationship to those adverse effects." *Sinclair Paint Co. v. State Bd. of Equal.*, (1997) 15 Cal. 4th 866, 870.

10. Our recommendation that any revenue generated from the auction of allowances be used to further the purposes and goals of AB 32, and not deposited in the State's general fund for non-AB 32 uses, does not violate Article XIII A, Section 3 of the California Constitution.

11. Our recommendation that revenue generated from the auction of allowances be reasonable in relationship to the adverse effects caused by the corresponding emission of GHGs, does not violate Article XIII A, Section 3 of the California Constitution.

12. The auction of allowances that we are recommending does not violate Article XIII, Section 19 or Article XVI, Section 6 of the State Constitution.

13. Using auction revenues to provide bill relief to customers generally, or to low income customers who spend a larger proportion of their incomes on utility

services, furthers the goals of AB 32, and is therefore a permissible use of auction revenues.

14. An historical emissions-based distribution of allowances to retail providers can be designed to recognize voluntary early actions these retail providers have taken to reduce emissions, consistent with Section 38562(b)(3). Section 38580(a) requires ARB to monitor compliance with, and enforce, the regulations it issues, but does not prohibit the use of out-of-state offsets or credits.

15. Section 38564 encourages linkage with the GHG-reduction programs of other states and nations.

16. AB 32 permits linkage to other GHG-reduction programs and the use offsets from outside of California.

17. Section 38562(b) describes things that ARB should do in "adopting regulations" "to the extent feasible." It does not require each and every project carried out by private parties under those regulations to have the described effects.

18. Section 38570(b) requires ARB to do certain things "to the extent feasible" prior to the inclusion of any market-based compliance mechanism (such as offsets) in the AB 32 regulations.

19. Sections 38562(b) and 38570(b) require ARB to balance a number of potentially conflicting goals, including providing equity, minimizing cost, maximizing total benefits to California, encouraging early action, not impacting low-income communities disproportionately, complementing efforts to achieve federal and state ambient air quality standards and reduce toxic air contaminant emissions, considering cost-effectiveness and overall societal benefits, minimizing administrative burdens and leakage, minimizing leakage,

considering emission impacts, preventing increases in other types of emissions, and maximizing additional environmental and economic benefits.

O R D E R

IT IS ORDERED that:

1. We recommend that the California Air Resources Board (ARB) set electricity and natural gas energy efficiency requirements in its Scoping Plan at the level of all cost-effective energy efficiency, with energy efficiency goals for investor-owned utilities set based on those adopted by the California Public Utilities Commission (Public Utilities Commission) in Decision (D.) 08-07-047, and as may be revised and updated by the Public Utilities Commission from time to time and with energy efficiency goals for publicly-owned utilities set at comparable levels, to be overseen by their governing boards.

2. We recommend that ARB work with the California Energy Commission (Energy Commission) and the Public Utilities Commission to develop approaches using a combination of direct regulatory/mandatory requirements and other potentially market-based strategies to achieve all cost-effective energy efficiency.

3. We recommend that ARB require comparable investment in energy efficiency from all retail providers in California, including both investor-owned and publicly-owned utilities, and assist in the implementation of the California Long-Term Energy Efficiency Strategic Plan to maximize energy efficiency savings opportunities Statewide.

4. We recommend that ARB rely on and adopt the Public Utilities Commission's analysis and conclusions in D.08-08-028 that Renewable Portfolio Standard-eligible generation with zero GHG emissions would not need GHG emissions allowances when delivered to the California grid, regardless of

whether Renewable Energy Credits have been unbundled from the electricity such that the electricity is delivered as null power.

5. We recommend that ARB adopt requirements that by 2020 at least 33% of California's electricity needs be met by renewable resources, and that by 2020 each retail provider obtain at least 33% of the electricity delivered to its customers from renewable resources.

6. We recommend that ARB not require the electricity sector to reduce its emissions below the approximately 79 million metric tons of carbon dioxide equivalent estimated in the Accelerated Policy Case modeled by consultant Energy and Environmental Economics unless such further reductions are justified based on detailed analysis of the costs of GHG mitigation in other sectors.

7. We recommend that ARB undertake the emission allowance allocation in steps for the electricity sector, determining first the total number of allowances to create for each year or other appropriate time period, for all of the sectors included in the California cap-and-trade program, and then the number of allowances to allocate to the electricity sector based on its proportion of total historical emissions in the sectors included in the cap-and-trade program (including emissions attributed to electricity imports that are included in the cap-and-trade program) during the chosen baseline year(s).

8. We recommend that the trajectory of the multi-sector emissions cap and the required annual reductions be generally a straight-line reduction between 2012 and 2020 for all sectors in the California cap-and-trade program, including electricity, although development of regional emission reduction programs may affect the schedule for implementing emission reductions.

9. We recommend that, for 2012, ARB distribute 20% of the allowances allocated to the electricity sector to retail providers, with a requirement that they

sell the allowances through a centralized auction undertaken by ARB or its agent, and distribute 80% of the allowances without cost to electricity deliverers.

10. We recommend that ARB increase the portion of allowances allocated to the electricity sector that are distributed to retail providers and sold at auction by 20% each year, so that in 2016 and each year thereafter all of the electricity sector allowances are auctioned through a centralized auction undertaken by ARB or its agent.

11. We recommend that for the portion of allowances distributed to deliverers, ARB distribute the allowances using a fuel-differentiated output-based approach with distributions limited to deliverers of electricity from emitting generation resources (including electricity from unspecified sources, and regardless of whether the electricity is generated inside or outside of California), as described in this decision.

12. We recommend that, if ARB either adopts less than 100% auctioning as the ultimate goal for electricity sector allowances or phases in 100% auctioning later than 2016, ARB phase out the weighting factors used to determine allowance distributions to deliverers starting in 2016, so that the distribution methodology would transition to a pure output-based approach by 2020.

13. We recommend that, for electricity sector allowances that will be auctioned, ARB distribute all or almost all allowances to retail providers on behalf of consumers, with the requirement that each retail provider sell the allowances in a centralized auction undertaken by ARB or its agent and receive all resulting revenues. The recommendation that retail providers be required to sell their distributed allowances does not apply to allowances that a vertically-integrated entity that is both a retail provider and a deliverer may receive based on its deliveries to the grid.

14. We recommend that ARB initially distribute electricity sector allowances to retail providers (which will be required to sell them through the centralized auction) in proportion to the historical emissions of the retail providers' portfolios, transitioning to a sales basis by 2020.

15. We recommend that ARB require that all allowance auction revenues be used for purposes related to Assembly Bill (AB) 32, and that ARB require all auction revenues from allowances allocated to the electricity sector be used to finance investments in energy efficiency and renewable energy or for bill relief, especially for low income customers.

16. We recommend that ARB allow the Public Utilities Commission for load serving entities and the governing boards for publicly-owned utilities to determine the appropriate use of retail providers' auction revenues consistent with the purposes of AB 32 and the restrictions recommended in Ordering Paragraph 15.

17. We recommend that ARB require each publicly-owned utility to demonstrate annually to the Energy Commission that its use of auction revenues during the prior year was consistent with the purposes of AB 32 and the restrictions recommended in Ordering Paragraph 15.

18. We recommend that ARB, in consultation with the Public Utilities Commission and the Energy Commission, condition free distribution of allowances to each retail provider on a demonstration of adequate progress in complying with energy efficiency and renewable energy procurement targets established for the retail provider.

19. We recommend that ARB provide comparable GHG regulatory treatment for all combined heat and power (CHP) facilities that exceed a minimum size threshold, regardless of whether they deliver electricity to the grid or solely serve on-site load, and regardless of the metering configuration used.

20. We recommend that, for CHP facilities that exceed the minimum size threshold that ARB uses for other deliverers, ARB include the emissions associated with CHP-generated electricity consumed in California in the electricity sector in any multi-sector GHG emissions cap-and-trade program.

21. We recommend that ARB treat entities that deliver CHP-generated electricity to the grid just like other deliverers for GHG regulatory purposes, and that ARB treat CHP operators comparable to deliverers for purposes of regulating GHG emissions associated with CHP-generated electricity used on-site, as described in this decision. Recognizing that they may be the same entity, the deliverer for the CHP electricity delivered to the grid and the CHP operator for CHP electricity used on-site should be responsible for surrendering allowances for the portion of CHP-generated electricity delivered to the grid and the portion used on-site, respectively. To the extent that allowances are distributed for free to deliverers, the deliverer for CHP delivered to the grid and the CHP operator for CHP electricity used on-site should receive allowances on the same basis as deliverers of electricity from other sources.

22. We recommend that ARB treat CHP operators comparable to retail providers for the portion of CHP-generated electricity that is used on-site. To the extent that allowances are distributed to retail providers, the CHP operator should receive allowances on the same basis as retail providers and should be required to sell the received allowances through a centralized auction undertaken by ARB or its agent and use the proceeds for purposes consistent with AB 32. The recommendation that CHP operators be required to sell their distributed allowances through the centralized auction does not apply to allowances that they may receive pursuant to Ordering Paragraph 21.

23. We recommend that, if ARB adopts a cap-and-trade program, ARB not pursue a California-only program, but rather pursue bilateral linkage with other

states in the Western Climate Initiative to help create a regional cap-and-trade market, and pursue bilateral linkage with other local, regional, national, and international GHG cap-and-trade systems that have comparable stringency, monitoring, compliance, and enforcement provisions.

24. We recommend that ARB, in developing a cap-and-trade program, avoid creating any price triggers or safety valves.

25. All issues in the Scoping Memos have been addressed and this proceeding is resolved for the purpose of compliance with Pub. Util. Code § 1701.5. However, the proceeding remains open to address pending petitions for modification and intervenor compensation requests.

This order is effective today.

Dated October 16, 2008, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

We will file a concurrence.

/s/ RACHELLE B. CHONG
/s/ JOHN A. BOHN
/s/ TIMOTHY ALAN SIMON
Commissioners

I reserve the right to file concurrence.

/s/ DIAN M. GRUENEICH
Commissioner

Concurrence of Commissioner Rachelle Chong
Opinion on Greenhouse Gas Regulatory Strategies
R.06-04-009
October 16, 2008

I support the general thrust of these recommendations to the California Air Resources Board (CARB), but I write separately to express some views on parts of this recommendation.

First, I particularly support the focus on including the electricity sector in a cap-and-trade system. I want the record to reflect my strong belief that California needs a market-based approach to unleash innovative solutions to the climate challenge. I have been very encouraged by the inventive clean green technologies that are coming out of Silicon Valley. In fact, Silicon Valley is fast becoming "Clean Green Valley." I predict we will see even more green investments once a cap-and-trade system is put into place.

Nor do I think California should "go it alone" with its own unique cap and trade system. It is imperative that California should join with other Western states in a cap-and-trade system serving all our markets through the Western Climate Initiative. Further, we should assume we should create linkages with other parts of the country. After all, climate change is a global problem, demanding global solutions.

Our decision today recommends gradually moving to a full auction of emissions allowances in 2016. During the transition period, some allowances will be given away for free to deliverers. While a transition period may be reasonable in this situation, I would like to emphasize my philosophical preference for auctions. Based on my experience overseeing spectrum auctions as a federal regulator, I know auctions can work. I strongly disagree with some parties' characterizations of auctions as "complex" and "difficult."

While I was a Commissioner at the Federal Communications Commission (FCC), the FCC conducted the first ever auctions of wireless radio spectrum for services like advanced wireless, wireless cable, and direct broadcast satellite. During my FCC tenure, from 1994 to 1997, the FCC conducted 16 auctions that brought in $23 billion for the federal government. To date, the FCC has conducted 82 auctions, bringing the total auction revenues to $78 billion. And the U.S. has not been alone. The governments of Canada, Sweden, Germany, the UK, Austria, and the Netherlands, among others, have auctioned off wireless radio spectrum.

The experience of the FCC shows that auctions are not difficult or complex. In fact, auctions have proven to be an effective way for government to get radio spectrum into the hands of the businesses that value them the most, while extracting the highest value for the American public. I believe that auctions of greenhouse gas allowances can be just as smooth and successful.

In recommending auctions, we need to carefully consider how the revenues should be spent. In the case of the FCC spectrum auctions, the auction revenues went to the United States Treasury because the American public owns the airwaves under federal law. In the case of Assembly Bill 32, similarly, I believe it is important that the revenues are returned to Californians who are energy consumers. Accordingly, I support the recommendation that auction revenues go toward offsetting the costs of energy efficiency and renewable energy. Otherwise, these programs could raise costs to our energy consumers. Beyond that, any extra revenues should be returned directly to consumers, particularly low income consumers.

This Commission has promoted advanced metering and new dynamic pricing rates. Through these initiatives, we expect to engage energy consumers with more information about their energy use, and to encourage them to reduce their environmental impact and also save money. We also should make sure that consumers understand that using energy generates expensive greenhouse gas emissions, and that causes climate change. Therefore, I support the recommendation that auction revenues be returned to consumers in a way that does not hide the cost of greenhouse gas emissions. For example, lump sum payments or dividends would be good ways to provide bill relief.

There are several areas where I would have preferred a somewhat different approach:

First, the decision recommends allocating some emissions allowances for free from 2012 to 2015 based on what is called a fuel-differentiated output-based approach. I have some concerns with this approach. First, it could distort the market price for electricity. Second, during this time period, it could encourage coal-fired generation, which in turn increases greenhouse gas emissions. I believe a historical emissions-based approach would be a better method, because it would not have these negative impacts.

Second, I also have some concerns with the output-based approach that is recommended for allocating auction revenues to utilities. This approach could discourage utilities from promoting energy efficiency and distributed generation. I do not think this problem can be easily fixed by adding back in energy efficiency savings, as suggested by some parties. I am pleased that the final language in the decision mitigates my concern by recommending that a utility should be required to demonstrate progress toward energy efficiency and renewable energy goals before receiving auction revenues. I encourage CARB to take a look at other approaches like historical output or number of customers.

Third, this decision generally does not address the natural gas sector. However, I do want to emphasize the importance of bringing natural gas into the cap-and-trade framework quickly. If CARB puts some energy-related sectors in the cap-and-trade framework and leaves others out, we could have problems down the road. For example, if natural gas vehicles become more popular, greenhouse gas emissions could shift from gasoline to natural gas. Uneven regulation could influence the decisions of consumers in ways that increase greenhouse gas emissions and raise costs. I am encouraged that the CARB's Proposed Scoping Plan recommends including natural gas in the cap-and-trade system.

Finally, I am very pleased that the California Public Utilities Commission and our sister agency, the California Energy Commission, were able to agree on these recommendations. To speak as one voice makes our recommendations more effective.

Dated October 17, 2008, at San Francisco, California.

/s/ RACHELLE B. CHONG
RACHELLE B. CHONG
Commissioner

Concurrence of Commissioner John Bohn

This decision is a major step forward in creating a statewide program for limiting and ultimately reducing greenhouse gas (GHG) emissions. With this decision we are making the transition from discussing and debating policies to making a commitment to a new way of doing business and a commitment to pay the costs of reducing greenhouse gas emissions in California. Let me be clear, the efforts to reduce GHG emissions contained in this decision will significantly increase costs for generators, for retail electric service providers, and ultimately for the consumers of electricity in California.

I do not take the imposition of billions of dollars of costs onto ratepayers lightly. However, the actions we take today are necessary. We must act because our state has identified greenhouse gas emissions as a major threat, and the legislative requirements of the Global Warming Solutions Act of 2006, Assembly Bill (AB) 32 are clear. Under AB 32, we are required to reduce GHG emissions to their 1990 level by 2020, with further reductions by 2050. Dramatic action is needed to meet these goals, and this decision is a critical step in meeting AB 32 goals.

I am pleased that in this time of financial uncertainty and distrust of market mechanisms, we have approved a market-based cap and trade program as an integral means of achieving GHG reductions. Competitive markets provide an important discipline to the process. In addition, as regulators we must recognize that no one, including us, knows everything about how best to do things. The cap and trade mechanism will promote innovative approaches and technologies to address the global warming crisis, and will allow us to move beyond the status quo and the standards that we have relied upon to date.

The market-based system we recommend in this decision is and will remain controversial. There is no simple correct answer on how to assign and allocate costs of compliance. There are many competing interests, all with reasonable, but differing, points of view of the measures we adopt. This decision reflects extensive consideration of the various interests put before us and a well thought out compromise of the issues. We have presented a plan that should be both equitable to the various interests and effective in promoting decreases in GHG emissions.

However, we must recognize that this process is far from over, and that considerable political pressures will come to bear to modify the structure we adopt today. We should expect that compromises will be proposed as this process moves forward, and we must remain vigilant to ensure that it retains the balance of equity and effectiveness that we are striving to achieve.

In particular, I am concerned that the large amounts of money that will be generated by auctioning of emission allowances could be tempting for government officials, who may wish to dip into these funds, particularly at this time of budgetary shortfalls. Given the high costs already being imposed on consumers for programs to directly reduce GHG emissions, from solar initiatives to increased energy efficiency efforts, and to clean coal research, it is of the utmost importance that the auction proceeds be kept within the electric sector to offset some of these costs. Otherwise, the combination of these programmatic costs and compliance with the GHG cap and trade costs may result in onerous electric rates that could plague California for years to come.

/s/ JOHN A. BOHN
John A. Bohn
Commissioner

San Francisco, CA
October 16, 2008

Joint Concurrence of Commissioners Simon and Grueneich on the Proposed Decision on Greenhouse Gas Regulatory Strategies

With the passage of Assembly Bill 32, California set the stage for its own transition to a sustainable clean energy future, has helped to put climate change on the national agenda, and has spurred action across a wide range of economic sectors and actors. We are proud to be on the frontlines with our State's proactive leadership on this issue. After careful evaluation of the Proposed Decision in this docket on Greenhouse Gas Regulatory Strategies, we chose to support the joint efforts by this Commission, the California Energy Commission, the California Air Resources Board (ARB), and parties with a "yes" vote. While this Decision marks the culmination of substantial effort and analysis, and we support many of its findings and conclusions, we file this concurrence to highlight a few aspects of the decision which merit particular attention and, in some cases, further analysis.

While the Decision recommends a combination of increased program mandates and a market-based cap-and-trade system for reducing emissions, it states clearly that energy efficiency shall be "the cornerstone" of California's strategy for achieving greenhouse gas reductions within the electricity and natural gas sectors. We wholeheartedly endorse this approach. Addressing climate change will come with a considerable price tag for our consumers. The decision is therefore a delicate balancing act as it walks a tightrope of difficult policy tradeoffs under aggressive carbon constraints and currently harsh economic realities. As we work broadly to mitigate greenhouse gas emissions associated with energy use in our State, we must seek to protect our environment in the most expeditious and cost-effective manner possible. No other emission reduction measure is so readily available as energy efficiency, both in terms of cost and the immediacy with which it can be employed.

In step with this finding, both this decision and the ARB's Proposed Scoping Plan count on dramatic reductions in energy use in order to achieve their emission reduction targets -- in many cases far beyond what our most successful efforts have delivered to date. These reductions are possible, but they will not fall out of the sky. Achieving them will require concerted effort on our part to ensure our energy efficiency policy framework is as robust as possible -- encouraging the achievement of stretch goals and delivering real savings. It will also require that we forge new strategies and partnerships to push the frontiers of action on energy efficiency statewide, many of which are outlined in the California Long Term Energy Efficiency Strategic Plan, approved by our Commission just two meetings ago. The implementation of this Plan should be the cornerstone of our approach to meeting AB 32 objectives for the electricity and natural gas sectors, in order to ensure a low-cost, high-impact path to a low-carbon future.

In addition, we have some concerns about the exposure of ratepayers to risk in a potential cap-and-trade system, if one is ultimately adopted by ARB. While we are hopeful that providing a market incentive to realize emission reduction opportunities will benefit the program as a whole, California's experiences with market failure in the energy sector give us pause as we recommend a market-driven regulatory system that has the potential to cost our ratepayers billions of dollars. Here we underscore three critical needs with regard to the design of the market mechanism.

First, although we hope for a robust market, we are concerned about the potential for gaming and other risk factors which could undermine environmental outcomes and emissions price stability. Particularly given the economic crisis we have been experiencing nationally, and now globally, it is essential that we take a more cautious approach at the outset to ensure ratepayer protection in California's nascent regulatory regime. We should endorse the implementation of adequate cost containment mechanisms to minimize volatility in an emissions market. In particular, the ARB should give serious consideration to the implementation, at least initially, of a reasonable price cap on emissions allowances to prevent runaway auction prices. Any such regulatory safeguards would of course have to be implemented in a balanced manner that does not compromise or defeat the purpose of a cap-and-trade system.

Second, we want to reiterate the importance of regional collaboration with regard to our recommended cap-and-trade market. As the joint Commissions' own analysis has shown, a California-only cap-and-trade scenario would run a higher risk of gaming than a more robust regional market. We strongly urge the ARB to work toward the concurrent and coordinated deployment of a regional cap-and-trade system with consistent rules between Western States, as recommended by the Decision. This point is critical to ensuring a robust and functioning market.

Third, we have some concerns about the impact of our recommended cap-and-trade system on consumers across the state, particularly for the disproportionately large number of low-income consumers in the service territories of some of our Publicly Owned Utilities (POUs). We recognize that the California Energy Commission and the ARB have jurisdiction over California's POUs. We also believe that the burden of emissions reductions must be shared by all Load Serving Entities (LSEs) and ratepayers. However, we have to be particularly vigilant of the potential for unintended financial consequences in this very difficult economy. The Decision attempts to moderate impacts on Southern California municipal utilities' customers through a gradual move toward a 100% auction and a transition to a sales-based allocation approach in 2020. However, there will still be winners and losers under this scenario and we encourage particular attention be paid to impacts on low-income populations throughout the implementation process.

Similarly, although it will ultimately be ARB's decision as to how to parse out the overall responsibility for emissions reductions across sectors, we must continue our dialogue with the CEC and the ARB to ensure that a disproportionate share of the State's emissions reduction responsibility is not placed on the electricity sector.

The key drivers behind our greenhouse gas policy should be cost and equity. We must continue to work with ARB to determine the most cost-effective and equitable mix of policy mandates and market-based emissions reductions rather than picking arbitrary targets for both. Mandating a disproportionate share of the responsibility to reduce total emissions could result in unnecessarily higher costs for electricity consumers. Moreover, if we are going to adopt a multi-sector cap-and-trade system, then we should allow it to function as intended: to find innovative emissions reductions across all sectors at marginal cost. Politics and the traditional ease of regulation of the electricity sector should not compromise the most cost-effective path to meeting AB 32 objectives.

Finally, producing our electricity responsibly and using it more intelligently will require a fundamental shift in human capital. We will not achieve the goals outlined in this recommendation if we fail to develop a workforce capable of turning our policies into realities. This is an opportunity to call upon California's best qualities and once again, demonstrate that our state is capable of reinventing itself through innovations in technology, policies, and practices.

We should urge the ARB to use emissions allowance auction revenue not only for investment in emissions reducing policies and customer rebates, but also to help fund statewide Workforce Development. Green collar job development must move from the periphery to the forefront with real metrics and targets. This has been identified as a priority aspect in the implementation of the California Long term Energy Efficiency Strategic Plan. There is no language in this Proposed Decision that addresses the need to cultivate economic stimulus in the form of green jobs. New career tracks and job classifications will clearly be a requirement to meet our energy efficiency, RPS, and AB 32 objectives.

In closing, we hope and expect this Commission will represent these matters in its continued discussions with ARB during the implementation of the recommendations in this Decision.

/s/ TIMOTHY ALAN SIMON
Timothy Alan Simon
Commissioner

/s/ DIAN M. GRUENEICH
Dian M. Grueneich
Commissioner

San Francisco, California
October 16th, 2008