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)
AB 32 Implementation	California Energy Commission Docket 07-OIIP-01

COMMENTS OF TURN ON ALLOWANCE ALLOCATION AND OTHER AB 32 IMPLEMENTATION ISSUES

TURN
affordable utilities
livable communities

Marcel Hawiger, Staff Attorney

THE UTILITY REFORM NETWORK
711 Van Ness Avenue, Suite 350
San Francisco, CA 94102
Phone: (415) 929-8876 ex. 311
Fax: (415) 929-1132
Email: marcel@turn.org

June 2, 2008

TABLE OF CONTENTS

I. Summary 2
II. GENERAL ISSUES 5
A. The California Air Resources Board Should Not Authorize Trading of Emissions Allowances 5
B. The Emissions Reduction Benefits of a Capped System Can Be Obtained without Authorizing the Secondary Trading of Allowances 8
III. Allowance Allocation and Reduction from Market Mechanisms 9
A. TURN's Proposal Calls for 100% Auction followed by an Allocation of Resulting Revenues to Load Serving Entities 9
1. 100% Auction Is the Most Equitable Method of Allowance Allocation, Especially in a Restructured Electric Sector 9
2. The Mechanics of an Auction without Trading 13
3. Allocation of allowances or revenues among LSE's 14
B. Response to Staff Paper 16
C. Legal Issues 16
D. Use of revenues 16
1. Auction revenues should first be used to assist low-income customers to ameliorate the increase in wholesale electric prices that exceed the pure cost of allowances 16
2. Use of revenues for energy efficiency and renewable energy 18
E. Reduction from Market Price for Allowances 19
IV. Flexible Compliance 20
V. Treatment of CHP 21
VI. Non-market-based emission reduction measures and emission caps 21
A. Electricity emission reduction measures 21
B. Natural gas emission reduction measures 30
C. Annual emission caps for the electricity and natural gas sectors 30
D. Legal issues 30
VII. Modeling Issues 30

COMMENTS OF TURN ON ALLOWANCE ALLOCATION AND OTHER AB 32 IMPLEMENTATION ISSUES

In four separate Rulings issued on April 16, May 1, May 6 and May 13[1] by Administrative Law Judges TerKeurst and Lakritz, the California Public Utilities Commission (Commission) requested that parties provide comments concerning the allocation of emissions allowances in a cap-and-trade system, the use of flexible compliance mechanisms in a cap-and-trade system, the treatment of combined heat and power (CHP) emissions, the use of programmatic measures to reduce emissions, the use of the model developed by Energy and Environmental Economics, Inc. (E3), and various other issues related to the reduction of greenhouse gas emissions in the electric sector. The deadline for filing comments was extended until June 2, 2008 by an ALJ Ruling dated May 20, 2008.

In the following comments TURN focuses on the issues of allowance allocation, use of auction revenues and the role of mandates versus market mechanisms in promoting emissions reductions goals. Due to limited resources, TURN answers only some of the numerous questions posed in the Rulings.

TURN generally uses the outline suggested in the May 13, 2008 Ruling. The April 16, 2008 Ruling asked several specific questions concerning the use of potential auction revenues, and the recommended outline lumped all of these questions together into Section III.B concerning "other allowance recommendations." Due to the critical

[1] The 5/13/08 Ruling included 24 attachments of various documents provided in workshops in April and May 2008. Any citation to "Attachment #" in these comments refers to one of these attachments to the May 30th ALJ Ruling. TURN thanks the ALJs and staff for their work in consolidating these documents to assist the parties.

importance of this issue to utility ratepayers, TURN added Section III.D to the outline concerning the use of auction revenues.

I. Summary

The landmark California Global Warming Solutions Act of 2006 (AB 32) mandates statewide reductions in greenhouse gas (GHG) emissions to 1990 levels by 2020. This ambitious goal to reverse the disastrous and life-threatening impacts of fossil fuel combustion, the use of fossil fuels in industrial processes and the impact of certain agricultural practices, will require a forecast reduction of about 173 million metric tons of carbon dioxide equivalent emissions (173 MMt CO2e) by 2020 in order to achieve an emissions target of 427 MMt CO2e.

In our previous comments submitted in November 2007, TURN emphasized the need to maximize emissions reductions by expanding the reach of mandates for energy efficiency and renewable energy that currently apply only to the investor-owned utilities (IOUs). While legislation requires certain measures to be achieved by other load-serving entities (LSEs), those municipal-owned utilities (munis) and electric service providers (ESPs) are not subject to the same stringent requirements to procure certain amounts of energy efficiency and renewable power. TURN recommended that California await federal legislation before promoting a cap-and-trade program, since leakage and contract shuffling would negate most of the benefits of a market mechanism.

In Decision 08-03-018 the Public Utilities Commission (Commission) did recommend that the California Air Resources Board (CARB) impose mandatory requirements for energy efficiency and renewable power on all LSEs. Nevertheless, the Commission also recommended that the California Air Resources Board institute a cap-and-trade market system that allows for the trading of GHG allowances by all entities in various industry sectors (for example, industrial process, transportation, electric generation).

One of the key conclusions from the actual emissions data and forecast modeling results is that the electricity sector is not the cause of future increases in emissions. Due to California's aggressive building and appliance standards and the use of cleaner-burning natural gas to meet load growth during the past ten years, emissions from the electricity sector have remained relatively flat since 1990 at between 100 and 120 MMt per year.[2] The E3 modeling results show that in the reference case, which assumes that renewable energy meets 20% of the load and energy efficiency gains continue at current levels,[3] emissions will remain relatively unchanged by 2020 at 108.2 MMt. Significant emissions reductions of about 30 MMt in the electric sector can be achieved by increasing renewable energy purchases to 33% and increasing energy efficiency savings to the "high-EE" goals.

One conclusion from these data is that in a "cap-and-trade" system the electricity sector may have excess allowances for sale to the transportation sector. Any use of "tradable allowances" will increase electricity prices since generators will include the opportunity cost of a tradable allowance in their energy prices. The structure of the wholesale electric market in a trading regime guarantees windfall profits to any generator whose unit is cleaner than the unit setting the marginal clearing price. If unregulated

---

[2] Attachment 23, p. 38. Annual variations in emissions are to be expected due to climate-related load changes and availability of hydroelectric power.

[3] Attachment 18, p. 19, explains the EE assumptions for different cases. Attachment 23, p. 13, explains the assumptions regarding EE and RPS for the reference case and the 33%RPS/high EE case.

merchant generators can also profit by selling excess allowances due to reductions in electric sector emissions, California's electric ratepayers will be unfairly saddled with paying for higher electric prices, the costs of emissions reductions and profit-taking by unregulated generators. This is the worst of all possible outcomes for people who must pay utility bills for heating, cooling and other basic necessities.

It is for this reason that TURN continues to oppose including the electric sector in a multi-sector cap-and-trade regime. However, TURN can support the use of a capped system with declining caps ***as long as all allowances are auctioned and the proceeds are used to benefit lower-income customers and to offset the costs of emissions reductions in the electric sector.*** Using the auction revenues to benefit utility ratepayers in the electric sector is an essential component of any equitable emission reduction strategy.

There is no need for secondary market trading of emissions allowances, as long as allowance prices are capped at a reasonable level and the revenues from allowance sales are used within the electric sector. The environmental goals of AB 32 can be achieved more equitably with a "cap and auction" program that does not include a "trade" component.

TURN recommends that the state auction 100% of the greenhouse gas (GHG) allowances available for the electric sector each year. TURN further recommends that the state allocate *all of the resulting revenues* – from all generation owners and first sellers of electricity – to the various load serving entities (LSEs), including investor-owned utilities, municipal utilities and energy service providers (ESPs). The LSEs should be required to use these monies first to fund programs that benefit low-income customers, in recognition of the higher electric prices which will be caused by GHG allowances and of the disproportionate impact of global warming on lower-income ratepayers. The remaining revenues should be used to subsidize cost-effective energy efficiency programs and renewable energy procurement.

TURN suggests that it is premature to mandate specific levels of energy efficiency and renewable power procurement. Rather, it makes sense first to adopt rules that apply *existing standards* on all relevant load serving entities. The effect of a declining cap with no trading will force all entities to take appropriate control measures or pay for allowances, with resulting revenues funding public programs and emissions reductions. The CARB and the legislature should authorize the CPUC to adopt more stringent mandatory measures at a later date if existing mandates and market incentives prove insufficient.

II. GENERAL ISSUES

A. The California Air Resources Board Should Not Authorize Trading of Emissions Allowances

TURN recognizes that the Commission in D.08-03-018 declined to recommend "a cap-only system for the electricity sector" in favor of a multi-sector cap-and-trade system.[4] The Commission concluded that the efficiency benefits of trading warranted such a recommendation despite the fact that it foresaw a large portion of emissions reductions coming from mandated investments in energy efficiency and renewable energy.

The Commission concluded that an auction of allowances has many benefits and that some portion of allowances available to the electricity sector should be auctioned.

[4] See, especially, D.08-03-018, *mimeo.* p. 36-37.

Furthermore, the Commission concluded that "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."[5] Nevertheless, the Commission concluded that parties should be given additional opportunity to comment on the various issues related to allowance allocation and use of potential auction revenues "in the context of a deliverer point of regulation."[6]

While TURN in these comments provides recommendations on the allocation of allowances or allowance revenue rights (ARRs) in the context of a first deliverer (or first seller) regulatory framework,[7] our comments do not imply support for a cap-and-trade system. Rather, we provide these suggestions as a recommendation for auctioning allowances to ensure compliance with a *cap* on emissions in the electric sector. Such an auction, and subsequent allocation of revenues, can occur without any subsequent secondary market trading of allowances.

There are several reasons for prohibiting, or at least delaying, secondary market trading of emissions allowances. The primary concern is the potential for harm to lower-income communities of color that are already disproportionately impacted by toxic emissions. While GHG emissions by themselves do not cause local harm, GHG emissions from stationary power plants are always accompanied by toxic co-pollutants.

---

[5] D.08-03-018, *mimeo.* at 97.
[6] *Id.* at p. 99.
[7] The Market Advisory Committee report and various Commission reports and presentation explain how allocating allowances is economically equivalent to auctioning allowances and allocating the resulting revenues, or allowance revenue rights. See, especially, Attachments 15, 24.

In the case of GHG allowances with a declining cap, trading could result in reductions of emissions in areas outside of the impacted communities without any beneficial reduction in those communities.

While both the MAC Report and Decision 08-03-018 give lip service to environmental justice concerns, neither of these documents provides any concrete recommendations for regulatory or market mechanisms to limit a disproportionate impact on local communities. TURN is aware of data that indicate that trading and offset mechanisms in the RECLAIM market have caused potential increases in local emissions of criteria pollutants and toxic emissions.[8] A declining cap for GHG emissions would most likely result in generator-specific reductions in co-pollutants. Allowing secondary trading may mean that communities that are already disproportionately impacted by emission will not see their fair share of pollution reduction.

The second concern is that any market trading mechanism is subject to potential abuse by speculators. TURN is not aware of any analysis or recommendations from the CPUC that would address the potential for speculation or market power exercised by entities that purchase allowances without any compliance obligation. TURN notes that the experience of more limited trading mechanisms for SOx and NOx emissions do not necessarily translate to the carbon emissions market. The global nature a multi-sector carbon market invites much broader participation. The trading opportunities can easily be seen by reading any of the numerous brochures targeting the nascent “carbon market”

---

[8] See, for example, Lejano, Raul and Hirosi, Rei, 2005. “Testing the assumptions behind emissions trading in non-market goods: the RECLAIM program in Southern California.” Available electronically from University of California, Irvine; Drury, R.T. et al., Spring 1999, “Pollution Trading And Environmental Injustice: Los Angeles’ Failed Experiment In Air Quality Policy,” Duke Environmental Law and Policy Forum, v. 9:231.

industry, with promises of billion-dollar trading opportunities. These opportunities are generated both by secondary trading and by the use of offset mechanisms as a cheaper compliance tool.

B. The Emissions Reduction Benefits of a Capped System Can Be Obtained without Authorizing the Secondary Trading of Allowances

Much of the debate has focused on the distinction between a carbon fee and a cap-and-trade system. While many economists suggest that a carbon fee (or tax) is preferable as the most efficient mechanism of internalizing the costs of GHG emissions, there are many who champion a cap-and-trade system as more politically palatable and capable of achieving specific reduction goals.

A carbon fee or tax does not provide certainty of achieving any particular level of emissions reductions, but does provide price certainty.[9] The degree of reductions will depend on the level of the administratively-set fee and the marginal costs of emissions reduction. In contrast, a capped system with declining caps and sufficient penalty levels provides greater certainty of meeting particular emissions reduction goals, but the cost of carbon permits is unknown.

As noted in D.08-03-018, however, it is possible to have a capped system with no trading. Such a system can combine elements of both the carbon fee and the cap-and-trade mechanism.

Without trading, only entities that must comply with emissions restrictions would purchase allowances, and they would purchase only the amount necessary for their expected compliance for a given year. If the entity is able to reduce emissions, they

---

[9] For a concise summary of the differences, see, Friedman, Lee S., "Price as a Regulatory Instrument for Climate Change," Presentation to the CARB, May 28, 2008.

cannot capture any of the opportunity cost of the allowances through trading; and if an entity emits more emissions than covered by their allowances, they would have to pay the applicable penalty as opposed to purchasing allowances.

Any entity that reduces emissions would need to purchase fewer allowances for the following year. Moreover, an entity has to reduce emissions due to the declining annual cap. Thus, an entity always has an incentive to reduce emissions as long as the reduction costs less than the penalty;[10] and an entity has an incentive to reduce emissions even more if the cost of reduction is less than the allowance price.

The proponents of secondary trading make no claim that trading increases emissions reductions. Rather, they assert that total societal costs would be reduced if an entity with higher marginal reduction costs can purchase allowances from an entity with lower marginal reduction costs.

III. Allowance Allocation and Reduction from Market Mechanisms

A. TURN's Proposal Calls for 100% Auction followed by an Allocation of Resulting Revenues to Load Serving Entities

1. 100% Auction Is the Most Equitable Method of Allowance Allocation, Especially in a Restructured Electric Sector

There is almost universal agreement that an auction is the only method to fairly allocate allowances in a capped system. As explained succinctly in the White Paper written by the National Commission on Energy Policy,[11] in a capped system allowances will by definition have value. Allocating allowances for free is thus tantamount to giving

[10] The impact of penalties on compliance is similar under a fee or cap-and-trade system.

[11] This White Paper was included as Appendix A to the Joint Staff Paper on Options for Allocation of Greenhouse Gas Allowances in the Electricity Sector. The updated version included as Attachment 24 did not include the Appendices.

away money. The NCEP paper explains how entities that require allowances for compliance will capture the opportunity cost of allowances by passing through the increased cost of the allowances through to consumers. The data from the EU Emissions Trading System fully support the theoretical analysis.

The NCEP white paper cogently explains how allowance allocation decisions result in providing value to different groups – compliance entities, consumers, workers, affected communities – that bear some of the burdens of the costs of complying with the changes necessary to actual produce GHG emissions reductions. [12] The rationale for administrative (i.e. free) allocation is to reduce the burden on the compliance entities. However, even if one accepts that compliance entities deserve some relief, the literature indicates that providing much less than 50% of the allowances for free to obligated entities will mitigate most of the compliance costs.[13]

TURN appreciates the concern of certain munis that an auction will disproportionately impact the LSEs with sunk costs in coal-fired generation and perhaps cause them to spend money on allowances rather than emission reductions. Theoretically, this concern can be fully addressed by allocating allowance revenue rights (the revenues collected from the auction) by a combination of historical emissions and actual electric output.

---

[12] Various Commission presentations likewise summarize the distributional impacts of different allocation methodologies. See, especially, Attachments 15 and 16.

[13] The NCEP modeling indicates that obligated entities in the electric sector (fuel providers and generators) require less than 10% of the allowances to cover compliance costs due to their ability to pass those costs through to customers. The MAC Report references a study indicating that in the EU ETS system the impact on generators would have been covered by an allowance of 35% of the allowances initially allocated to the sector. MAC Report, June 30, 2007, p. 105.

Nevertheless, some entities may wary of relying on ARR allocation.[14] For this reason, TURN could support a limited allocation based on emissions declining in later years, as proposed by Joint Staff in their preferred auction proposal. However, rather than starting with an auction of 75% of the allowances, the first year auction (2012) should be for a minimum of 80% of the allowances, increasing by 5% each year to reach 100% by year five (2016).

The opportunity cost of allowances is creating primarily by the potential for trading in a "cap-and-trade" system. Nevertheless, an auction of all allowances is still the equitable and environmentally preferable method of allowance allocation even if no secondary market trading is allowed.

As explained in the NCEP White Paper, the "burden" of GHG allowance costs does not necessarily fall on the entities which must purchase allowance but depends primarily on the degree to which those costs can be passed on to downstream consumers.[15] In particular, competition from unregulated entities (for example, international suppliers), the availability of less costly substitutes and the price elasticity of demand impact most strongly the degree to which a particular industry sector can pass costs downstream. The structure of the electric sector allows generators to pass through most of the allowance costs to consumers through higher electric prices.

---

[14] As noted in the NCEP white paper, receiving free allowances provides greater certainty than reimbursement from the government.

[15] NCEP White Paper, p. 17.

There should be no foreign competition under a first seller system that requires imported electricity to surrender allowances.[16] The elasticity of demand for electricity is fairly low, and there are no cheaper substitutes. Only at certain breakpoints in allowance prices is there a major change in the relative profitability of different production technologies (gas becomes profitable compared to coal at about $60/ton and renewables become profitable compared to gas at about $90).

Moreover, the structure of the wholesale market means not only that generators can pass through the costs of allowances, but also that those generators whose emissions are cleaner than the marginal unit (who thus need fewer allowances) will reap "windfall profits" due to the payment of the market clearing price to all generators. Generators with less than average emissions (nuclear, hydro and renewable generation with no need for allowances) will reap the benefit of the higher market price for electricity. The result is a transfer of money from LSE customers to all generators. The E3 modeling shows that at an allowance price of $30/ton the cleaner generators will reap an annual windfall profit of $700 million.[17]

The situation would be entirely different in a vertically regulated market. If utilities owned all generation and all auction revenues were returned to utilities for the benefit of their customers, then there would be no net impact on any utility from purchasing allowances for their own generation. Indeed, this is the primary reason why

---

[16] This does not at all minimize the potential for leakage and contract shuffling, which does make the entire California-only regulation of GHG from the electric sector highly problematic.

[17] Attachment 23, E3 Electricity and Natural Gas GHG Modeling, May 13, 2008, p. 25.

free allocation of SOx allowances in the Acid Rain program did not lead to excessive ratepayer impacts.

However, in a restructured market only merchant generators can retain the windfalls created by increased market clearing prices, and thus the relative impact of GHG allowances on utilities will depend partly on the amount of their retained generation.[18]

2. The Mechanics of an Auction without Trading

TURN proposes an auction of all allowances without the potential for trading. This means that only obligated entities would purchase allowances, and each purchased allowance would have a vintage date and the name of the purchasing entity. An entity could use only allowances with their name and the appropriate vintage date for compliance. There is no need for any prohibitions or penalties against trading, since named allowances could not have any value to any other entity.

In essence, such a system is similar to an administrative carbon fee. However, the price of an allowance for each auction (either annual or more frequent) is determined by the market response from all buyers. Assuming a single clearing price auction, the price should approximate the highest marginal cost of reduction. Moreover, allowance prices will likely increase in successive auctions due to scarcity as the cap declines. The declining number of allowances ensures decreasing emissions, in contrast to a simple administrative fee with no cap.

[18] Attachment 20, E3 Electricity and Natural Gas GHG Modeling, May 6, 2008, p. 53.

Due to the very high potential marginal costs of reduction in the electric sector,[19] TURN can support such a measure *if and only if* the allowance price is capped and the resulting revenues are recycled back to utility ratepayers as discussed further in Section D.

TURN proposes a cap on allowance prices of $30/ton. As illustrated in Section III.E below, such a cap will generate approximately $3 billion per year, sufficient to fund low-income and energy efficiency programs.

As with any system, compliance must be ensured by an appropriate penalty structure. TURN does not at this time provide any specific recommendation concerning penalty levels. The RGGI system provides for a three-year true-up process and requires the payment of penalties in proportion to over-emissions at the price set by the auction price following the true-up period.

3. Allocation of allowances or revenues among LSE's

It is the ability of generators to pass through the costs of allowances in wholesale markets and the potential for "windfall profits" created by the restructured electric market that warrants that *all revenues from an auction be allocated to load serving entities on behalf of their customers*. It is the customers of the LSEs who will be paying the entire cost of higher electricity prices.[20] In other words, it is likely the end-use electric customers will shoulder most, if not all, of the burden of GHG regulation of electric

---

[19] For example, given the modeling supply curves E3 estimated that renewable power would become competitive with natural gas at a carbon price of $90/ton, and a carbon price of $150/ton would be necessary to induce investment in renewable energy beyond the RPS. Attachment 18, p. 62-63.

[20] The IOUs can pass all their fuel and purchased power costs through to customers. TURN assumes that munis will likewise pass through costs to their customers. TURN cannot evaluate the extent to which ESPs can pass all costs through to customers.

generators.[21] This situation warrants transferring the revenues collected from merchant generators to the load serving entities.

Much of the debate to date has focused on whether allowances or allowance revenues should be allocated in proportion to emissions or output. This debate pits those utilities with relatively cleaner generation (PG&E, northern California munis) against those with coal contracts (LADWP). The Joint Staff Report does an exceptional job in describing the tradeoffs between these methods. The 'emissions' allocation approach promotes equity and fairness between different utilities. The sales approach promotes environmental integrity and GHG reduction.

TURN represents primarily the interests of the customers of regulated investor-owned utilities by advocating at the regulatory agency – the California Public Utilities Commission. We also promote policies at the legislative level that do impact customers of the municipal utilities, but we do not purport to represent those customers.

While the "output" based approach best serves the interests of the regulated IOUs, TURN strongly concurs with the practical recommendations in the Joint Staff Report that blend the two approaches and transition towards a full "output" based approach by 2020. An "output" based approach is most equitable and administratively straightforward in the long run.

As indicated above, TURN recommends auctioning at least 80% of the allowances and transitioning to a 100% auction. TURN does not recommend a particular

[21] The situation in the restructured market is probably closest to the modeling work described in the NCEP White Paper, which found that less than 10% of the net burden of GHG emissions costs fell on fuel producers and electric generators. NCEP White Paper, p. 21, Figure 5.

revenue allocation method at this time, though TURN suggests that parties should closely examine the "preferred emissions-based approach" in the Joint Agency Staff Paper, which recommends allocating the auction revenues based on a 50/50 split between emissions and output, and moving towards an allocation based 100% on output by 2017. The impact of this proposal is modeled as Scenario 5 in the E3 May 6th presentation.[22]

B. Response to Staff Paper

C. Legal Issues

D. Use of revenues

1. Auction revenues should first be used to assist low-income customers to ameliorate the increase in wholesale electric prices that exceed the pure cost of allowances

Question 12 of the April 16 Ruling asks about the potential uses of auction revenues to maintain affordable rates:

> If auction revenues are used to maintain affordable rates, should the revenues be used to lower retail providers' overall revenue requirements, returned to electricity consumers directly through a refund, used to provide targeted rate relief to low-income consumers, or used in some other manner? Describe your preferred option in detail. In addition to your recommendation, comment on the pros and cons of each method identified for maintaining reasonable rates.

TURN recommends that all revenues collected by an auction from the generators and 'first deliverers' of power into the state should be allocated to load serving entities for the benefit of utility ratepayers. In other words, the revenues from the auction of allowances to the electric sector should all be returned to electric ratepayers.

[22] Attachment 20, p. 70-72.

As explained previously, any increase in electric prices will be passed through to electric ratepayers. The increase in electric prices due to internalizing the price of CO2 fees or allowances will cause an increase in the subsidies provided by the California Alternative Rates for Energy (CARE) program, since larger bills will result in larger bill subsidies.[23]

In order to ameliorate the impact of higher electric prices, any auction revenues or carbon fees should be used first and foremost to fund programs for low-income customers, such as the California Alternative Rates for Energy (CARE) program and the Low Income Energy Efficiency program. Remaining funds should be used to supplement other energy efficiency investments if they can be used cost-effectively.

CARE costs are presently almost $900 million per year for the four large energy IOUs. Assuming a carbon auction price of $10/ton, annual revenues from an auction should generate more than one billion dollars from the electricity sector alone.[24] TURN thus recommends that this money be used to fund at least 50% of all CARE costs, and potentially low-income programs costs for the POUs. Such funding would respond to increased need for low-income subsidies to address higher electric prices.

Current LIEE costs are approximately $160 million annually for the four large energy IOUs. TURN recommends that auction revenues be used to fund 100% of LIEE costs.

---

[23] TURN presents this analysis in the context of auction revenues. TURN's recommendations would be similar if the state adopts a carbon fee, since there would still be the potential for windfall profits for cleaner generators due to an increase in the market clearing price of electricity. However, both in the case of fees and auctions without secondary trading, generators would not include the "opportunity cost" of allowances in their bids.

[24] Very approximately: 100 MMtCO2*$10/tCO2=$1 Billion.

2. Use of revenues for energy efficiency and renewable energy

Question 11 of the April 16th Ruling asks:

> If auction revenues are used to augment investments in energy efficiency and renewable power, how much of the auction proceeds should be dedicated to this purpose?

The auction revenues should be used to either replace or supplant the current ratepayer funding for energy efficiency. Of the over $700 million spent annually on energy efficiency, about $250 million is collected via the public goods charge and the remainder is embedded in utility rates.

TURN suggests that rather than first asking "how much money" to spend on energy efficiency and renewable power, the appropriate approach is to evaluate the supply curve for energy efficiency and the areas of greatest market failure, and then target the funds remaining from auction revenues to support those programs.

The E3 model provided "energy efficiency sensitivity" results which showed that both the incremental emissions benefits and incremental total costs of energy efficiency become negligible once one achieves the "low EE goals" scenario.[25] On the other hand, utility program costs increase significantly from the "low EE goals" scenario ($887 million/yr) to the "high EE goals" scenario ($2.1 billion/yr).[26] Whether it makes any economic sense to achieve the high-EE goals depends largely on the validity of the model assumptions concerning the avoided costs due to energy efficiency savings. TURN

---

[25] Attachment 20, p. 47.
[26]

recommends taking a cautious approach prior to spending another billion plus per year to achieve minimal emissions reductions.

E. Reduction from Market Price for Allowances

The Commission has recommended a multi-sector "cap and trade" system, which would allow for the trading of emission allowances among various market participants. This model is based on the underlying economic theory that a 'trading' system will minimize overall societal costs.

In the electric sector emissions reductions will be achieved primarily through expanding the procurement of renewable power, lowering demand through conservation and energy efficiency, and ultimately replacing imported coal with cleaner generation. The modeling results show that there are only a few options that will significantly reduce carbon emissions by 2020. New renewable generation would not be induced unless carbon prices rise above $150/MWh. The only reasons for promoting a 'trading' system is because either 1) very high carbon prices above $50/MWh could cause natural gas to displace coal, and/or 2) high carbon prices might cause unknown technological change that will reduce carbon emissions.

Such high carbon prices are unnecessary to foster emissions reductions and will simply harm ratepayers.

As noted above, a carbon price of $10/ton would raise over one billion dollars annually statewide. Higher prices would result in proportionately higher revenues. In comparison, the following table shows annual expenditures by the four energy IOUs on low-income programs, energy efficiency and renewable power.

Program Area	Approximate Annual Spending by the four energy IOUs
Energy Efficiency	$700 million
CARE subsidy[27]	$973 million
Low Income Energy Efficiency	$155 million
CSI	$210 million
Subtotal (excluding RPS)	**$2,038 million**
Renewable energy procurement if meet 20% RPS goal[28]	$1,525 million
Total	**$3,563 million**

Because carbon costs result in very large cost increases that may be magnified in the wholesale power market, TURN recommends that the price of carbon allowances be capped at $30/ton. Such a price would raise over three billion dollars, an amount that is probably sufficient to fund all low-income and energy efficiency programs for both the IOUs and POUs statewide.

IV. Flexible Compliance

TURN provides only limited recommendations concerning flexible compliance mechanisms. While our proposal is for no secondary trading of allowances, these

[27] TURN provides the authorized budget for 2007 for CARE. See, D.07-06-004, Appendix, p. 4. Only two of the utilities file their monthly CARE reports electronically so as to provide actual expenditure data on the CPUC website for R.07-01-042. TURN understands that actual expenditures on CARE in 2007 were approximately 90% of the budget for SDG&E and PG&E.

[28] The incremental cost of renewable energy procurement is very approximately calculated as the difference between the market price referent (approximately $100/MWh) and the average generation cost (approximately $60/MWh), assuming renewable power meets 20% of load of the three electric IOUs (Attachment 6, p. 2): (0.20*190,673GWh)*($100/MWh-$60/MWh)=$2.24 billion. This cost is less than what would be calculated using the $60/MWh cost difference "between market price and least cost renewable" assumed by E3. Attachment 18, p. 63.

recommendations would be similar even in a cap-and-trade system with secondary trading:

- The use of offsets should be extremely limited. Only projects within the state should qualify, and should demonstrate that they provide incremental and verifiable emissions reductions. Any cross-sector offsets should be screened for environmental justice impacts. While methane capture in the agricultural sector would seem a prime candidate for offsets, TURN notes that methane capture for injection into the natural gas distribution system can already qualify for compliance under the RPS mechanism.
- Limited banking for three years should be allowed to promote early reductions and to allow for annual variations.
- The penalty price must be set at a level sufficient to promote compliance. The RGGI system provides for penalty prices that are connected to annual allowance auction prices. This approach makes sense in the context of an auction.

V. Treatment of CHP

VI. Non-market-based emission reduction measures and emission caps

A. Electricity emission reduction measures

In its 5/13/08 Ruling the Commission asked parties to respond to the following questions:

1. What direct programmatic or regulatory emission reduction measures, in addition to current mandates in the areas of energy efficiency and renewables, should be included for the electricity

and natural gas sectors in ARB's Assembly Bill (AB) 32 scoping plan?

2. Are there additional regulations that ARB should promulgate in the context of implementing AB 32, that would assist or augment existing programs and policies for emission reduction measures in the electricity and natural gas sectors?
3. For any non-market-based emission reduction measures for electricity discussed in your opening comments, are there any overlap or compatibility issues with the potential electricity sector participation in a cap-and-trade program? Explain.

…

5. What percentage of emission reductions in the electricity sector should come from programmatic or regulatory measures, and what percentage should be derived from market-based measures or mechanisms? What criteria should be used to determine the portion from each approach? By what approach and in what timeframe should this question be resolved?

TURN offers limited observations based on the presentations on the record as well as some additional runs of the E3 model that analyzed the differential impacts of specific programmatic elements. TURN cautions that our initial modeling results have not been verified. TURN first discusses the impacts of specific programs (energy efficiency, renewable energy procurement, CSI, demand response) and the effect of existing coal contracts, and then offers more general observations concerning applicability of statewide mandates, the role of expanded mandates and the role of the state in technology acquisition.

Due to California's consistent focus on power efficiency, the use of increasingly efficient combined cycle natural gas plants and increasing use of renewable power, emissions from the electricity sector have remained relatively flat since 1990 at between

100 and 120 MMt per year.[29] The E3 modeling results show emissions increasing to approximately 130 MMt in 2020 under an assumption that all load growth is met with new natural gas generation.[30] In the reference case, which assumes that renewable energy meets 20% of the load and energy efficiency gains continue at current levels,[31] emissions remain relatively unchanged by 2020 at 108.2 MMt. In contrast, increasing RPS purchases to 33% and increasing energy efficiency gains to the "high-EE" goals reduces electric sector emissions to 78.6 MMt. These results are summarized in the graph at page 15 of attachment 23.

Impact of RPS Requirements

The reference case includes meeting the existing 20% requirement under the renewable portfiolio standard (RPS) and a Business as Usual energy efficiency gains, with resulting 2020 emission of 108.2 MMt. Modeling results indicate that going from the reference case to the 33% RPS/High goals EE case results in emissions of 78.6 MMt, a reduction of 29.6 MMt compared to the reference case. The unit emissions reductions costs from renewable energy increase from $79/ton to $133/ton in going from 20% to 33%.[32]

TURN ran a scenario with a 33% RPS but reference case EE savings, resulting in 2020 emissions of 88.9 MMt, a reduction of 19.3 MMt. It thus appears that about two-thirds of the emissions reductions in the aggressive modeling scenario results from

---

[29] Attachment 23, p. 38. Annual variations in emissions are to be expected due to climate-related load changes and availability of hydroelectric power.

[30] Attachment 23, pp. 15 and 38.

[31] Attachment 18, p. 19, explains the EE assumptions for different cases. Attachment 23, p. 13, explains the assumptions regarding EE and RPS for the reference case and the 33%RPS/high EE case.

[32] Attachment 20, p. 16.

increased renewable procurement and about one-third results from increased energy efficiency. The unit reduction costs for energy efficiency increase from $-98/ton to $63/ton, while the unit reduction costs for renewables increase from $79/ton to $133/ton. These results indicate a steeper increase in the supply curve for energy efficiency than for renewables, though energy efficiency remains the lowest cost form of achieving carbon emissions reductions.

Impact of Energy Efficiency Programs

The E3 modeling shows that under the assumed supply curve, energy efficiency provides the largest amount of emissions reductions at the lowest cost.[33] The costs to society, however, including individual customer costs, are higher.

The E3 model indicates that most of the emissions reductions gains are achieved by going from the no EE case to the "low EE" case, resulting in a reduction of 12.1 MMt, as summarized in the Table below.[34]

	BAU Reference	Low EE	Mid EE	High EE
Total utility program costs including admin.	$605 million/yr	$887 million/yr	$1.5 billion/yr	$2.1 billion/yr
Utility Program Energy Savings (2008-2020) (GWh)	16,450	14,056	21,638	21,738
T24 and fed standards, BBEES, AB1109 Energy Savings (2008-2020) (GWh)		13,801	11,733	15,240
Incremental Energy Savings (2008-2020)	16,450 GWh	27,857 GWh	33,371 GWh	36,978 GWh
Emissions (MMt CO2e)	108.2	102.5	100.4	99.5

[33] See, for example, supply curve in Attachment 18, p. 62.
[34] Table compiled from data in Attachment 20, p. 47 and Attachment 23, p. 17.

Going from the low-EE to the high-EE case results in an additional reduction of 3 MMt,[35] while utility annual program costs increase from $887 million to $2.1 billion. This impact simply reflects the fact that most of the energy incremental energy savings are achieved with the low-EE goals scenario. [36] The low-EE scenario includes gains from changes in building standards (Title 24) and the Big Bold Energy Efficiency Savings Goals. Going from the low-EE to the high-EE scenarios results in smaller incremental energy savings at much higher incremental costs in utility program spending. This is because even at utility rebates equal to the full incremental measure cost (IMC) of the EE measure, consumers by and large can still not afford to upgrade to the higher efficiency equipment and appliances.[37] California must break out of the long-standing utility-rebate program design and embrace various forms of EE financing.[38]

For this reason, TURN urges the CARB to work closely (1) with the CEC to maximize the gains from new building and appliance standards, which impact new construction and thus have a long-lasting impact on energy use, and (2) with the CPUC to

---

[35] 5/13/08 Ruling, Attachment 18, p. 19.

[36] The low- mid- and high-case forecasts of EE assume differing levels of utility rebated EE measure costs ranging from partial (low case) to full (high) case incremental measure cost (IMC).

[37] This would akin to CARB offering California consumers a rebate of say 30 percent of the cost of a new Toyota Prius, if the consumer could pay the 70% cost balance upfront in full.

[38] Consumers should be able to purchase EE over time through their utility bills (or other financing mechanisms), just as consumers now pay for capital intensive investments in generation, transmission, and distribution infrastructure, as well as operation and maintenance utility costs, over time via monthly utility bills. See D.07-10-032 dated October 12, 2007, page 91.

achieve EE financing. It is imperative to take advantage of cost-effective energy efficiency savings in order to achieve emissions reductions.

However, TURN strongly urges against simply increasing utility program spending on existing programs. Long-lasting energy efficiency savings may be better achieved by focusing on home retrofit services (weatherization, HVAC replacement and maintenance), requiring certain structural upgrades during sales transactions, providing on-bill financing for high-efficiency (not high size!) appliances, and other such measures.

Given the relative gains and costs between the low-EE case and the high-EE case, TURN does not support a mandate to achieve 100% of economic potential for energy efficiency savings, as modeled in the high-EE scenario.

TURN also notes that GHG emissions in the E3 model are extremely sensitive to forecasts in load growth rates. Significant reductions could be expected if there is a concerted public education campaign to promote conservation. Short term conservation impacts due to behavioral change were readily apparent during the deregulation crisis of 2000-2001, when the threats of rolling blackouts and the economic manipulations of merchant generators were nightly news.

Impact of Rooftop Solar PV (CSI)

The rooftop photovoltaic program yields a minimal emissions reduction of 1.7 MMt even in the aggressive scenario that includes 3,000 MW of installed capacity.

Utility unit costs of reduction are negative, apparently reflecting avoided procurement costs,[39] but total unit emissions costs are extremely high due to high consumer costs.[40]

Impact of Demand Response

The reference case includes a 5% reduction in peak demand due to demand response programs. A change in demand response to 0% or 10% results in zero change in CO2 emissions, because the model assumes demand response does not cause any decrease in net annual energy use. The 0% DR case results in a cost increase of $197 million compared to the reference case due to the purchase of more on-peak power.

These results are not surprising, even if they only approximate actual behavioral responses to higher on-peak prices. They should, however, dispel the myth that demand response programs and advanced metering technologies are actual carbon-reduction strategies.

Early Termination of Coal Contracts

It is striking that approximately five coal plants in Utah, Arizona, New Mexico and Oregon supply very high carbon electricity to California. The biggest ones have contracts that terminate in 2019 or later. It is clear that the termination of these contracts has a large impact on GHG emissions.[41] TURN did not have time to model the impacts on emissions of earlier termination of these contracts. Obviously, one possible solution

---

[39] TURN has not analyzed the CSI spreadsheet, but finds the negative utility costs (comprising incentives minus avoided procurement costs) somewhat counterintuitive, since any avoided procurement should be offset by reduced load.

[40] Attachment 20, p. 16.

[41] For example, there is a large drop in the emissions intensity of LADWP in 2019, after the expiration of imports from the Navajo Generating Station.

would be to terminate these contracts and pay damages. Such penalties, however, would likely be large (possibly the entire cost of the purchased power).

According to the E3 model coal-fired power becomes uneconomical compared to natural gas at a carbon price of about $60/ton and the assumed gas price of $7.85. Higher gas prices would require higher carbon prices to make gas more economic than coal.

However, if these contracts are terminated it is likely that other buyers would purchase the output and there would be no regional reductions in GHG emissions. The continuation of these coal plants illustrates the dilemma posed by a California-only reduction plan, as well as the paramount importance on a national level of preventing the construction of new conventional coal plants. Academic studies as well as the E3 modeling all conclude that "contract shuffling" and "leakage" will negate any benefits of reduced emissions from imported coal in a California-only cap-and-trade system. It is for this reason that TURN continues to oppose adopting any kind of cap-and-trade mechanism that includes the electric sector. California's ratepayers would be better served by continuing to promote existing energy efficiency and renewable policies and extending them to other entities to motivate future termination of coal contracts. Only a regional or national system will ensure that those out-of-state coal plants cease emitting carbon into the atmosphere.

<u>Applicability of Mandates to POUs and ESPs</u>

TURN agrees that mandates to achieve specific reductions through energy efficiency program spending and to meet a certain a certain percentage of sales with renewable energy purchases should apply to all load serving entities. The IOUs serve approximately 70% of all California consumption, though apparently they contribute approximately 81% of energy savings.[42] It is important to ensure that the munis and ESPs that serve 30% of the load contribute their fair share. The municipal utilities have adopted energy efficiency savings targets, but have no firm mandates. There are no mandates that apply to ESPs.

The ESPs' business models are inconsistent with requirements for long-term efficiency funding or renewable contracting. Customers of the ESPs do contribute to the portion of energy efficiency spending that is funded by the public goods charge, but they do not contribute to the more than 50% that is funded through procurement rates. TURN recommends that the ESPs be required to contribute additional funds for energy efficiency. To the extent the ESPs are unable or unwilling to meet existing RPS standards, the CPUC should impose penalties. The CARB should consider establishing a procurement entity that would collect penalties and/or payments from the ESPs to use for renewable energy contracting.

<u>Additional Mandates for RPS or EE</u>

TURN supports the existing 20% RPS mandate and the requirements to achieve economical and cost-effective energy efficiency savings. TURN does not believe that the CARB or legislature should at this time impose new mandates. It is not clear what the most cost-effective mix of resource options – energy efficiency, renewables, replacing coal with natural gas – to achieve the AB 32 goals will be. Setting mandatory requirements for particular technology purchases invites supplier market power. TURN does not oppose removing the existing restriction under §399.15(b)(1) that prohibits the CPUC from requiring more than 20% renewable purchases.

---

[42] 5/13/08 Ruling, Attachment 6, p. 2-3.

State Role in Technology Manufacture or Acquisition

TURN proposes that an alternative path to increasing renewable technology penetration is available to California that will better promote economic development goals at a lower cost. The primary source of large-scale renewable power is forecast to come from wind farms. The technology is well-developed. However, wind costs have recently increased, at least in part due to demand for wind turbines and lack of manufacturing capacity. One company – General Electric – supplies 50% of all turbines installed in the United States.

Even with the aggressive RPS mandate in California it has been difficult to build new wind construction. Obviously, much of the problem stems from continuing issues regarding transmission access to the Techachapi wind resource area and other potential wind spots. However, to the extent that turbine costs will be a continuing factor, the state should consider using some of the auction revenues to partner with turbine suppliers to build dedicated manufacturing facilities in California.

B. Natural gas emission reduction measures

C. Annual emission caps for the electricity and natural gas sectors

D. Legal issues

VII. Modeling Issues

TURN offers limited observations based on our initial review of the E3 model and its assumptions and inputs:

- The natural gas price of $7.85 in 2020 may be low. However, it is not clear that a higher price in any reasonable range will make renewable power more economic compared to natural gas. It will definitely increase consumer costs.

- Likewise, the estimates for capital construction costs may be too low and do not take into account recent cost increases.
- The reference case increase in utility rates of 13% is caused by hard-wired increases in utility non-generation rates of 2% above inflation. This is a self-fulfilling prophecy that is largely in control of the utilities and this Commission.
- The percentage of summer sales should be projected to increase if current trends of inland population growth continue.
- The EE savings reflect the relative lack of focus on air conditioner efficiency, since only 10% of EE savings are during summer heavy load hours. Greater focus on air conditioner efficiency and HVAC installation is required.

TURN appreciates this opportunity to comment on various issues and may provide additional input in reply comments.

June 2, 2008

Respectfully submitted,

By: ________/S/__________________
Marcel Hawiger, Staff Attorney

THE UTILITY REFORM NETWORK
711 Van Ness Avenue, Suite 350
San Francisco, CA 94102
Phone: (415) 929-8876, ex. 311
Fax: (415) 929-1132
Email: marcel@turn.org