**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<br>(Filed April 13, 2006) |

**California Energy Commission Docket #07-OIIP-01**

# COMMENTS OF THE NATURAL RESOURCES DEFENSE COUNCIL (NRDC) AND THE UNION OF CONCERNED SCIENTISTS (UCS) ON ALLOWANCE ALLOCATION, FLEXIBLE COMPLIANCE, CHP, EMISSION REDUCTION MEASURES, AND MODELING ISSUES

June 2, 2008

Kristin Grenfell, Audrey Chang, and Peter Miller
Natural Resources Defense Council
111 Sutter St., 20th Floor
San Francisco, CA 94104
415-875-6100
KGrenfell@nrdc.org
AChang@nrdc.org

Cliff Chen and Chris Busch
Union of Concerned Scientists
2397 Shattuck Ave., Ste.203
Berkeley, CA 94704
510-843-1872
CChen@ucsusa.org

## TABLE OF CONTENTS


**I. INTRODUCTION** .......... **1**

**II. SUMMARY** .......... **2**

**III. ALLOWANCE ALLOCATION** .......... **3**

A. NRDC/UCS GENERAL VIEWS ON ALLOWANCE DISTRIBUTION .......... 3
*1. Allowances should NOT be allocated for free to deliverers.* .......... *4*
*2. Allowances should NOT be grandfathered.* .......... *4*
*3. Allowances SHOULD be auctioned.* .......... *5*
*4. Auction revenues should be used in the public interest and to further the goals of AB 32.* .......... *5*
B. SUMMARY OF NRDC/UCS RECOMMENDATION FOR ALLOWANCE DISTRIBUTION .......... 6
C. DISCUSSION OF ALLOWANCE DISTRIBUTION RECOMMENDATION AND MODELING OF ALLOCATION SCENARIOS .......... 7
*1. Caveats to Use of E3 Model for Evaluating Allocation Scenarios* .......... *7*
*2. Auctioning with Revenue Recycling Results in Overall Lower Costs to Customers Compared to Free Allocation to Deliverers* .......... *11*
*3. "Use it or Lose It" Revenue Recycling* .......... *12*
*4. Method of Revenue Recycling to Retail Providers* .......... *13*
D. RESPONSE TO CRITERIA USED IN STAFF PAPER TO EVALUATE ALLOWANCE ALLOCATION OPTIONS. 18
*1. The Commissions should carefully select criteria for evaluating allocation options and should not use the criteria suggested by the Staff Report.* .......... *18*
*2. The Commissions should use the criteria below when evaluating allowance allocation options. 19*
E. LEGAL ISSUES .......... 20

**IV. FLEXIBLE COMPLIANCE MECHANISMS** .......... **21**

A. TRADING .......... 21
B. PRICE TRIGGERS AND OTHER SAFETY VALVES .......... 21
*1. No Safety Valve or Price Cap* .......... *21*
*2. Independent Oversight Board* .......... *22*
*3. Linkage* .......... *22*
*4. Compliance Periods* .......... *22*
C. BANKING AND BORROWING .......... 22
*1. Banking Should Be Allowed, with Appropriate Limits* .......... *22*
*2. No Borrowing from Future Compliance Periods* .......... *23*
D. PENALTIES AND ALTERNATIVE COMPLIANCE PAYMENTS .......... 23
E. OFFSETS .......... 24
*1. Should California allow offsets for AB 32 compliance purposes?* .......... *24*
*2. If offsets are allowed for compliance purposes, what types of offsets should be allowed? Should California establish geographic limits or preference on the location of offsets? If so, what should be the nature of those limits or preferences?* .......... *27*
*3. Should voluntary GHG emission reduction projects, i.e., projects that are not developed to comply with governmental mandates, be permitted as offsets if they are within sectors in California that are not within the cap and trade program? In particular, should voluntary GHG emission reduction projects within the natural gas sector in California be permitted as offsets, if the natural gas sector is not yet in the cap and trade program?* .......... *28*
*4. If offsets are allowed for compliance purposes, should there be limits to the quantity of offsets for compliance purposes? If so, how should the limit be determined?* .......... *29*

**V. TREATMENT OF CHP** .......... **30**

A. RECOMMENDATIONS .......... 30

**VI. EMISSION REDUCTION MEASURES (OTHER THAN CHP) AND EMISSION CAPS** .......... **31**

A. ELECTRICITY EMISSION REDUCTION MEASURES ........ 31
*1. 33% Renewable Portfolio Standard ........ 31*
*2. Embedded energy savings from water conservation ........ 33*
*3. Time-of-sale energy efficiency requirements ........ 33*
*4. Appliance Feebates ........ 33*
*5. What percentage of emission reductions in the electricity sector should come from programmatic or regulatory measures? ........ 34*
B. NATURAL GAS EMISSION REDUCTION MEASURES ........ 35
*1. Solar Hot Water ........ 35*
*2. Biomethane ........ 36*
*3. Time-of-sale energy efficiency requirements ........ 37*
*4. Appliance Feebates ........ 37*
C. ANNUAL EMISSION CAPS FOR THE ELECTRICITY AND NATURAL GAS SECTORS ........ 38
*1. What recommendations should the Commissions make to ARB regarding annual GHG emissions caps for the electricity and natural gas sectors? ........ 38*

**VII. MODELING ISSUES ........ 39**

A. PERFORMANCE, USEFULNESS, AND VALIDITY OF INPUT ASSUMPTIONS IN E3 MODEL ........ 39
*1. The model provides useful but incomplete information to form the basis of AB 32 policy decisions ........ 40*
*2. The model paints an unrealistically static picture of renewable technology development. ........ 42*
*3. The model fails to account for the natural gas price suppression effect of increased levels of renewable energy and energy efficiency. ........ 46*
*4. The model does not reflect the risks to consumers of different scenarios. ........ 47*
*5. Transmission costs should be shared between generators and load ........ 47*
*6. Combined-cycle gas turbine capital cost assumptions should be increased. ........ 48*
*7. The reference case should include achievement of the California Solar Initiative goal ........ 49*
B. ALTERNATE MODELING SCENARIO ........ 50

**VIII. CONCLUSION ........ 52**

## TABLE OF ATTACHMENTS

A. E3 Calculator Results for ARR Scenarios

B. NRDC/UC Alternate Modeling Scenarios Documentation (revised reference case and revised aggressive case)

C. May 20, 2008 Coalition Letter to Commissioners Regarding Allowance Distribution

D. May 9, 2008 Coalition Position Paper Regarding Cap and Auction

**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) |

**California Energy Commission Docket #07-OIIP-01**

**COMMENTS OF THE NATURAL RESOURCES DEFENSE COUNCIL (NRDC) AND THE UNION OF CONCERNED SCIENTISTS (UCS) ON ALLOWANCE ALLOCATION, FLEXIBLE COMPLIANCE, CHP, EMISSION REDUCTION MEASURES, AND MODELING ISSUES**

# I. INTRODUCTION

The Natural Resources Defense Council (NRDC) and Union of Concerned Scientists (UCS) respectfully submit these comments on allowance allocation, flexible compliance mechanisms, CHP, emission reduction measures, and modeling issues, in accordance with the "Administrative Law Judges' Modifying Schedule and Correcting Suggested Outline for Comments and Reply Comments" (ALJ Ruling), dated May 20, 2008, and in accordance with Rules 1.9 and 1.10 of the California Public Utilities Commission's (CPUC) Rules of Practice and Procedure. NRDC/UCS also concurrently submit these comments to the California Energy Commission (CEC) in Docket #07-OIIP-01, the CEC's sister proceeding to this CPUC proceeding. As requested by California Air Resources Board (CARB) staff, we are also sending a copy to them at ccplan@arb.ca.gov.

NRDC is a non-profit membership organization with a long-standing interest in minimizing the societal costs of the reliable energy services that a healthy California economy needs. In this proceeding, NRDC represents its more than 124,000 California members' interest in receiving affordable energy services and reducing the environmental impact of California's energy consumption.

UCS is a leading science-based non-profit working for a healthy environment and a safer world. Its Clean Energy Program examines the benefits and costs of the country's energy use and promotes energy solutions that are sustainable both environmentally and economically.

## II. SUMMARY

NRDC and UCS appreciate the opportunity to submit these comments to aid the Commissions' recommendations to the California Air Resources Board (CARB) on a comprehensive approach for reducing greenhouse gas (GHG) emissions in the electricity and natural gas sectors. In summary:

- We strongly oppose any free allocation of allowances to first deliverers and any grandfathering of allowances. Instead, we support using the value of allowances for the public good and to further the goals of AB 32.
- Our preferred allowance distribution approach is a full auction of allowances and recycling of most auction revenues to retail providers through a "use it or lose it" approach for investments in GHG emissions reductions. We remain open to the possibility of free allocation of allowances to customers, through their retail providers, in a manner that would aid consumers and further the state's energy efficiency and pollution reduction goals.
- We urge the Commissions to carefully consider and publicly select criteria for evaluating allowance distribution options, and to choose an option based on those criteria.
- Trading is an important flexible compliance mechanism as long as the entire program is carefully and properly designed. The Commissions should recommend that CARB not adopt safety valves or offsets that could undermine the state's emissions reduction efforts and instead recommend multi-year compliance periods and allowance banking to provide flexibility. Adequate and meaningful penalties for non-compliance are essential for enforcement.
- The Commissions should advise CARB to exercise an abundance of caution when contemplating an offsets program for compliance purposes. Offsets do not offer any additional environmental benefits, but they do present several substantial risks. *If* offsets are allowed as part of a cap and trade program, the cap must be set tightly to ensure that meaningful reductions occur in capped sectors, and the offsets must be real, additional, verifiable, permanent, and enforceable.

- In order to ensure the proper incentives to encourage large clean CHP, the Commissions should recommend that CARB include the electricity, natural gas, and industrial sectors in a cap and trade program.
- The Commissions should consider all promising emission reduction measures (ERMs), along with various policy mechanisms to encourage them, in both the electricity and natural gas sectors. A majority of emission reductions in the electricity sector and natural gas sectors should come from programmatic and regulatory measures, including expansion of existing policies as well as new ones. In particular, the Commissions should urge CARB to consider the many ERMs for the natural gas sector that have been presented by parties throughout this proceeding.
- We urge the Commissions to acknowledge and stress the limitations of the E3 model, as we have concerns about some of the model's assumptions that cast some degree of doubt on the overall reliability of the model's cost estimates.
- Careful attention must be paid to how to best present the E3 model's output metrics and summary of results in order to answer the key questions policymakers will need to consider in order to develop a comprehensive and effective strategy to reduce GHG emissions from the energy sectors.

# III. ALLOWANCE ALLOCATION

## A. NRDC/UCS GENERAL VIEWS ON ALLOWANCE DISTRIBUTION

The method of distributing[1] allowances in a cap-and-trade program has great significance for the overall effectiveness, fairness, and cost-effectiveness of the program. Allowances should be distributed in a manner that benefits the public and accomplishes the environmental and economic goals of AB 32. Our preferred approach for doing this is to auction allowances and to direct most of the revenue through retail providers to cost-effective energy efficiency and other investments to reduce GHG emissions that will benefit customers through what we have called a "use it or lose it" approach to auction revenue distribution (for further details, see section III(B) below on our recommendations for allowance distribution).

In addition, several other environmental and public health groups in California share many of our concerns and principles about allowance distribution below. We have

[1] We prefer the term "distribution" which is a broader term including many types of allowance distribution, whereas "allocation" is often associated with one particular form of allowance distribution: free allocation.

attached a letter regarding allowance allocation that we submitted with other groups to the CPUC and CEC Commissioners (Attachment C) and also a coalition position paper stating ours and other groups' views on cap and auction programs, including allowance allocation (Attachment D).

***1. Allowances should NOT be allocated for free to deliverers.***

We oppose giving any allowances away for free to deliverers. Free allocation to deliverers will result in windfall profits to at least some deliverers at the expense of California consumers. If deliverers are not regulated or publicly-owned utilities and are not facing intense competition from deliverers outside the scope of the cap and trade program, then they will be in a position to pass costs (or opportunity costs) through to customers no matter how they acquire the allowances. If these deliverers receive allowances for free, they will pass the costs on and keep the value of the allowance as a windfall profit.

Allowances provide permission to use the public atmosphere, and there is no convincing rationale in the electricity sector for giving away a public asset for free to private companies that can simply pass along the cost to consumers. We are extremely concerned that five of the six preliminary allocation options presented in the Staff Paper, and ***all three*** of the staff-preferred options, suggest allocating some or all allowances for free to deliverers. Though it is not our preferred option, we remain open to the possibility of free allocation to ***customers***, through their retail provider, in a manner that would aid consumers and further the state's energy efficiency and pollution reduction goals. We strongly oppose any free allocation to ***deliverers***.

***2. Allowances should NOT be grandfathered.***

Allowances should not be grandfathered (i.e.: given away for free based on historical emissions). Grandfathering allowances rewards pollution, penalizes early action, and can also result in windfall profits at the expense of consumers if given to deliverers who are able to pass the costs through and keep the value of the allowance. We are very concerned that three of the six allocation options presented in the Staff Paper, including two of the three staff-preferred options, suggest grandfathering some or all allowances. Grandfathering does not further the goals of AB 32 and it sets a very bad precedent for California with respect to distribution of allowance value in a future national global warming reduction scheme. California is much more efficient in its use of energy than the national average and has been taking steps to reduce its GHG emissions for many years. If a federal program rewards historical polluters through grandfathering, California and its clean utilities and efficient consumers will be losers. California should not grandfather any of its allowances.

### 3. *Allowances SHOULD be auctioned.*

We believe that auctions are the fairest, simplest way of distributing allowances.[2] Auctioning avoids unfair windfall profits, and encourages innovation and rewards early action.[3] In addition, auctions will benefit consumers and further AB 32's goals if the revenues are used for the public good. An important way that auction revenues from the utility sectors should be used for the public good is to recycle the revenue back to benefit utility customers through specified investments by their retail provider (see our recommendations in Section III(B) below).

### 4. *Auction revenues should be used in the public interest and to further the goals of AB 32.*

The majority of auction revenue from the utility sectors should be returned to benefit consumers through specified types of investments by their retail providers. We've called this a "use it or lose it" approach because retail providers would have to use the revenue for the specified investments within a specified time or forfeit its use. Some revenue not recycled to retail providers could be invested through statewide programs that would also benefit consumers throughout the state. All investments should benefit consumers and also help the state meet the other environmental and economic goals specified in the statute. The uses for auction revenue should include:

- Investments in technologies to reduce GHG emissions, including energy efficiency and renewable energy;
- Research, development, and demonstration (RD&D) and deployment of new technologies to reduce GHG emissions;

---

[2] Many RGGI states have already recognized the benefits of auctioning and are starting out with an auction of 100% of their allowances. The first RGGI auction will be held in September of this year. *RGGI Press Release* (March 17, 2008), available at http://www.rggi.org/docs/20080317news_release.pdf.

[3] For more detail on the benefits of auctions, see *NRDC/UCS Comments on the Proposed "Interim Opinion on Greenhouse Gas Regulatory Strategies,"* submitted February 28, 2008, pp.9-10.

- Reduce costs to consumers, particularly low-income consumers, for example by supplementing funding for existing low-income energy efficiency and bill assistance programs;
- Support for air and toxic pollution reduction efforts, especially in communities historically burdened by air and toxic pollution;
- Support for green collar job development and training; and
- Providing economic opportunities for low-income and disadvantaged communities.

In summary, we strongly urge the Commissions to recommend that if CARB decides to adopt a cap-and-trade program, it should auction allowances and invest the revenue in a manner that benefits consumers and furthers the goals of AB 32.

## B. Summary of NRDC/UCS Recommendation for Allowance Distribution

Our preferred approach for allocating allowance value is to auction 100% of allowances and to use the revenue to benefit consumers. We recommend distributing most of the auction revenue to retail providers through a "use it or lose it" approach in which retail providers must invest the revenue in energy efficiency and other specified GHG emission reduction measures or else forfeit its use. We strongly oppose any free allocation to deliverers. We believe that our preferred approach is a workable solution that avoids windfall profits to businesses, ensures fair treatment for "early actors" that have proactively reduced their emissions already, motivates emitters to reduce their emissions, and minimizes costs to customers.

Though not our preferred approach, we remain open to the possibility of free allocation of allowances to customers, through their retail providers, in a manner that would aid consumers and further the state's energy efficiency and pollution reduction goals. We believe this could also be a workable solution.

We recommend that most of the auction revenue be recycled to retail providers, who must "use it or lose it," subject to oversight and verification that the investments meet appropriate criteria. Within an appropriate time period, retail providers ***must*** invest these funds in specified ways that benefit their customers and result in long-term investments to reduce their GHG emissions. Acceptable investments include energy efficiency and RD&D for new technologies, and are described in Section III(B)(4) above. It is also important that auction revenue distributed via "use it or lose it" or invested by another mechanism be dispersed expeditiously. All else equal, a minimum lag between collection and distribution of auction revenue is preferable.

The method for auction revenue recycling to retail providers should ultimately reach 100% sales-based distribution (adjusted for verified energy efficiency savings) in 2020 or earlier in order to provide the proper long-term incentive to reduce emissions, but we believe there are many workable approaches over time for the basis of auction revenue recycling to retail providers and do not have a single preferred approach.

As explained below in section III(E), no auction revenue could be diverted into the General Fund. All auction revenues must be used to further the goals of AB 32.

## C. DISCUSSION OF NRDC/UCS RECOMMENDATION FOR ALLOWANCE DISTRIBUTION AND MODELING OF ALLOCATION SCENARIOS

### *1. Caveats to Use of E3 Model for Evaluating Allocation Scenarios*

The results produced by the E3 model are greatly dependent on the assumptions that are used, so we caution the Commissions and all parties against relying too heavily on specific results. The E3 model is helpful in producing directional and comparative results between scenarios, but should not be heavily relied upon when analyzing specific cost implications of allocation scenarios. In particular, we wish to draw attention to two aspects of modeling allocation scenarios that greatly impact the results produced by the E3 model: emission reduction assumptions and natural gas prices.

#### (a) Emission reductions assumptions:

In evaluating different allocation scenarios, it is important to recognize that the E3 GHG calculator allows the user to specify a carbon market completely apart from the level of emissions reductions. In particular, the GHG calculator allows the user to specify the establishment of a regulatory carbon market without achieving any emissions reductions in the sector. For example, scenarios 2 through 7 presented by E3 comparing different market options all have the same level of emissions in 2020 as in the reference case, meaning that E3 is modeling a market but assuming no reductions beyond current policies.

These scenarios may provide interesting information about current policies, but since there is little value in implementing a carbon market unless it is used to reduce emissions (we must not only achieve our reduction goal in 2020, but also ensure we are on the right path toward the ultimate emissions reductions needed by 2050), it is essential that different regulatory options be compared under a scenario in which there are significant reductions in emissions. More generally, it would be advantageous to evaluate all allocation proposals under a single, consistent emission reductions scenario in order to provide fully comparable results.

We evaluated all of the allocation scenarios with the new resource additions and emissions reductions achieved under E3's 33% RPS/High EE goals scenario (although we do not modify modeling input assumptions for this purpose, we suggest changes to various assumptions below in the modeling section of these comments). The 33% RPS/High EE goals scenario provides a reasonable basis for an appropriate emissions target because it provides a challenging but plausible level of GHG reductions.

In evaluating the allocation proposals submitted in comments, we urge the staff and parties to consider the different level of emissions reductions associated with each proposal and, at a minimum, to evaluate the impact of each proposal in a scenario that includes significant emissions reductions. Evaluation of proposals under the unlikely assumption that emissions are not significantly reduced from reference case levels may provide an inaccurate and irrelevant indication of the relative impacts of each allocation proposal.

**(b) Natural gas prices**

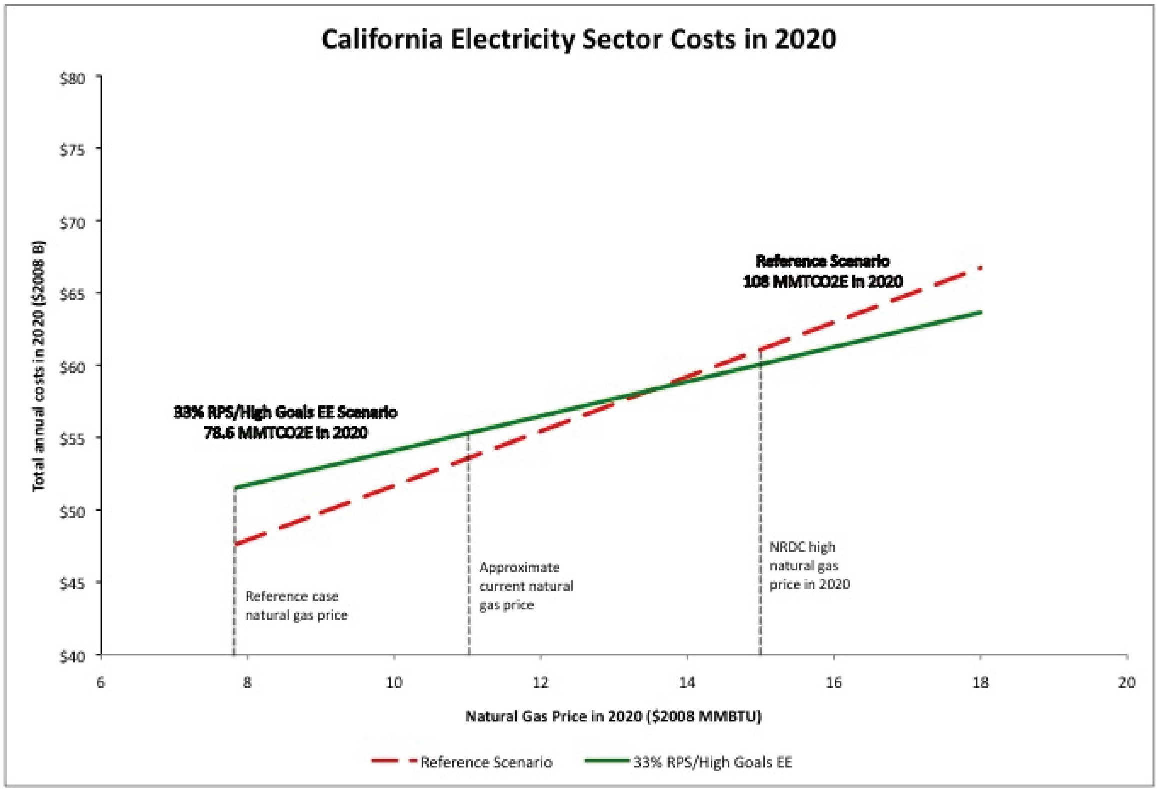
Natural gas prices are a key variable that significantly affects the relative costs and benefits of different allocation options. The assumption in the E3 Reference scenario is that natural gas prices will stay at $7.85/MMBTU (2008$) from 2008 through 2020. In contrast, natural gas prices increased by approximately 12% per year (in nominal dollars) between 2003 to 2007,[4] and are currently trading at around $11.00/MMBTU.[5] Given high current prices and the fact that natural gas price forecasts in recent years have consistently underestimated future prices, the assumption that natural gas prices will be only $7.85/MMBTU in 2020 is highly conservative. As we discuss further below, it is

[4] Estimated nominal rate based on an increase from $4/MMBTU in 2003 to $8/MMBTU in 2007.
[5] California Energy Commission , *Weekly Natural Gas Price Report*, available at http://www.energy.ca.gov/naturalgas/update.html (last visited May 29, 2008).

essential that the model account for the possibility of a continued rise in natural gas prices.

The need to consider a range of natural gas price scenarios can easily be seen from Figure 1, which provides a graph of the total cost in 2020 of the Reference scenario of current policies and the 33% RPS/High-Goals EE scenario under a range of natural gas prices. Using E3's own assumptions, including the default natural gas price assumption of $7.85/MMBTU, the latter scenario increases total costs by approximately $4 billion/year. However, 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. The average cost of emissions reductions can be calculated by dividing the incremental total cost by the 29.6 MMT $CO_2$e/yr reduction that would be achieved under the 33% RPS/High-Goals EE scenario. The average cost ranges from $132/MT at a gas price of $7.85/MMBTU to less than $2/MT at a gas price of $13.50/MMBTU. At gas prices above $14/MMBTU the cost of carbon is negative. Again, these 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.

**Figure 1**




The sensitivity of the E3 model cost results to natural gas prices has important implications for the evaluation of regulatory policy in the current proceeding. It demonstrates the importance of comparing different policies under a range of gas prices since the total cost, the marginal cost, and the cost differential can vary dramatically in response to a range of plausible gas prices. We analyzed all of our scenarios at the reference scenario gas price and with a gas price forecast of $15/MMBtu in 2020, which assumes an increase of approximately 2%/year from today's gas price of $11/MMBtu and can be used as a reasonable upper bound for natural gas prices in 2020. This assumption of 2%/year rise in gas prices is very plausible, especially considering the 12%/year (nominal) increase that we have seen over the past four years.[6] We recommend that other parties and staff adopt a similar sensitivity analysis to ensure that their conclusions are robust under different natural gas price scenarios.

[6] See footnote 4.

### 2. *Auctioning with Revenue Recycling Results in Overall Lower Costs to Customers Compared to Free Allocation to Deliverers*

Many southern California utilities have expressed concern that auctioning would result in high costs to their customers and are understandably concerned about auctioning if the revenues generated are not returned to their service territories to make investments to reduce emissions. We share these concerns, and support the Commission's joint recommendation in March 2008 that "the majority of the proceeds from the auctioning of allowances for the electricity sector [be] used in ways that benefit electricity consumers in California."[7] To address their concerns, some of these utilities have asked for a "cap" based on their emissions, which would essentially give these utilities a lot of allowances to emit for free; i.e., grandfathering of allowances. We are concerned that this approach would reward high emitters and ask them to do relatively less to reduce emissions than others that have already made such investments. We are also concerned that it could also result in windfall profits if applied to privately owned entities. Rather than grandfathering emissions allowances, we believe there are ways to design the program to successfully reduce emissions and to address these concerns, by directing auction revenues into emission reduction investments in the utilities' service territories.

Our work with the E3 model generally shows that freely allocating allowances to deliverers results in higher overall costs than auctioning allowances with auction revenue recycling. We evaluated a range of different allocation scenarios using the E3 model to compare the cost of administratively allocating allowances with the cost of auctioning allowances and recycling the revenues to retail providers, which is our preferred approach. We found that in the E3 model, freely allocating allowances results in total costs to consumers that are \$900 million/year to \$1.5 billion/year *higher* in 2020 than the cost of auctioning allowances with revenue recycling, depending primarily on whether allowances were allocated on the basis of emissions or output.[8] The significantly increased cost to consumers, largely due to our concern described above about windfall profits to private companies (not associated with activities that reduce emissions), provides strong justification for rejecting free allocation of allowances to deliverers.

---

[7] Cal. Pub. Util. Com., R. 06-04-009, D. 08-03-018, March 13, 2008, p.136.

[8] Assuming 33% RPS/High Goals EE resources with E3's assumption of market clearing price of \$30/tonne $CO_2$, comparing allocation by output or emissions, all GWh or only fossil fuel GWh to a range of ARR scenarios from 100% sales to 100% emissions.

In particular, if auction revenues are recycled toward investments in energy efficiency and renewables, these investments will help to reduce GHG emissions over time. Especially in the case of energy efficiency, these investments will also reduce overall net costs to customers, thus providing a durable benefit which is preferable to the temporary benefit derived from a single cash payment to consumers. It is important to note that E3 results show that auctioning *without* revenue recycling (i.e., assuming that the revenues are used for unrelated purposes outside of the electricity sector) results in high costs for customers of all retail providers. Thus, it is imperative that auctioning in the electricity sector employ revenue recycling to the retail providers on behalf of their customers.

### ***3. "Use it or Lose It" Revenue Recycling Reduces Costs for Consumers***

Our proposal is distinct from the auction revenue recycling as modeled in the E3 calculator (which models recycled revenue as simple rate reductions) in that our proposed system implements a "use it or lose it" approach to revenue recycling. Under such a system, revenues that are recycled back to retail providers ***must*** be invested in the retail providers' service territories in specified ways that benefit their customers and result in long-term investments to reduce their GHG emissions (e.g., energy efficiency, renewable energy, etc.). These investments would be subject to oversight and verification that the investments meet appropriate criteria. If a retail provider fails to use the revenues recycled to it in appropriate ways and within a specified time limit, the revenues are forfeited to the state.

In the case of retail providers who are also "first deliverers," these funds could simply be retained by the utility in a special account and would not need to be paid to the state and subsequently returned to them, thus addressing the concern that funds paid to the state in an auction may be diverted to purposes not related to furthering the goals of AB 32. Given California's historical success at implementing energy efficiency programs with benefits that exceed costs, and the substantial supply of cost-effective energy efficiency measures that still exists and will continue to grow with increasing energy and commodity costs and technological advances, our preferred "use it or lose it" approach is particularly advantageous for reducing overall cost to consumers.

### *4. Method of Revenue Recycling to Retail Providers*

The method in which auction revenue is distributed (or "recycled") to retail providers on behalf of their customers can be done in several ways: on the basis of emissions, sales (or output), or number of customers. NRDC/UCS suggested a per-customer allocation methodology for consideration in our October 31, 2007 comments, consistent with the principle that allowances (and their value) represent a public asset that belongs to all of us, and we are each entitled to equal use of the public asset.[9] While we continue to believe this concept has merit, as this was not an option that was considered by the staff paper on allocation nor modeled by E3, we have not considered it further in our analysis of allocation methods using the E3 model.

We evaluated a range of scenarios that were based on 100% auctioning of allowances with auction revenue recycling (ARR) to retail providers. These scenarios differed in the basis for recycling revenue over time, from 100% emissions to 100% output, with a range of intermediate alternatives. As described above, we also evaluated each scenario under two different gas price forecasts (low and high).

In general, while we found differences in the relative impact of our scenarios to retail providers, these differences were quite small relative to the projected cost increase in the business as usual scenario and to the additional increase from even a relatively small increase in the price of natural gas. Under business-as-usual current policies, total costs statewide are projected to rise 31% by 2020. Under a high natural gas price scenario in which natural gas prices increase to $15/MMBtu in 2020, total electricity costs in California will rise by 67%, and each retail provider will face cost increases of at least 60% by 2020 assuming business-as-usual policies.

In contrast, the difference in total cost impact of different revenue recycling scenarios is an order of magnitude smaller, generally a couple of percentage points. For example, Figure 2 shows the differences in cost impacts in 2020 from 2008 between revenue recycling on the basis of two scenarios, 100% emissions and 100% output, for LADWP, which is a relatively carbon-intensive retail provider and the retail provider that generally has the largest differences in impact across ARR scenarios. The difference between the two ARR scenarios is approximately 6% of total costs (which is very small

[9] *Opening Comments of NRDC/UCS on Allowance Allocation Issues*, submitted October 31, 2007, pp. 13-14, 22.

compared to business-as-usual cost increases of 31 to 67% under current policies in the reference case). For comparison, Figure 3 shows the differences in total costs for PG&E, a relatively low-carbon retail provider, for the same two scenarios. For PG&E, the difference between the two ARR scenarios is only 1.5% of total costs, which is also very small compared to business-as-usual total cost increases of 31% to 64% under current policies. Other retail providers and intermediate ARR scenarios (e.g., 50% emissions/50% sales) generally show much smaller impacts across ARR scenarios.

**Figure 2**

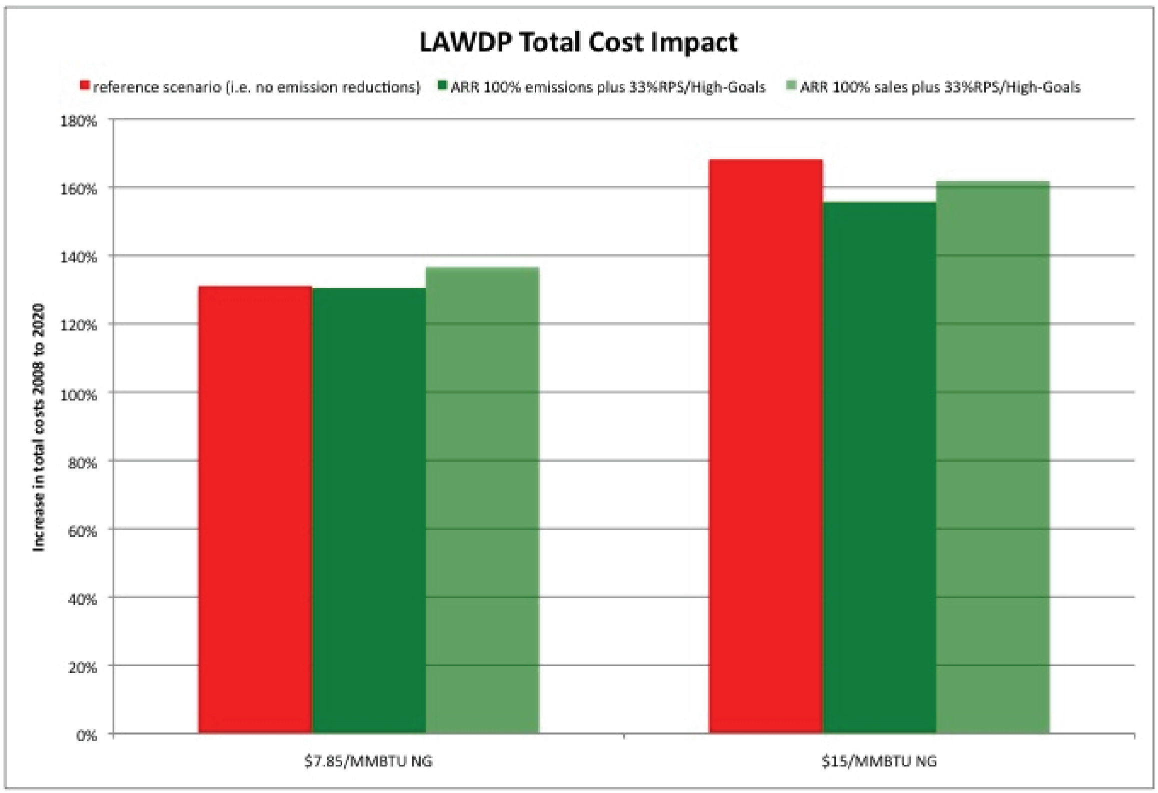
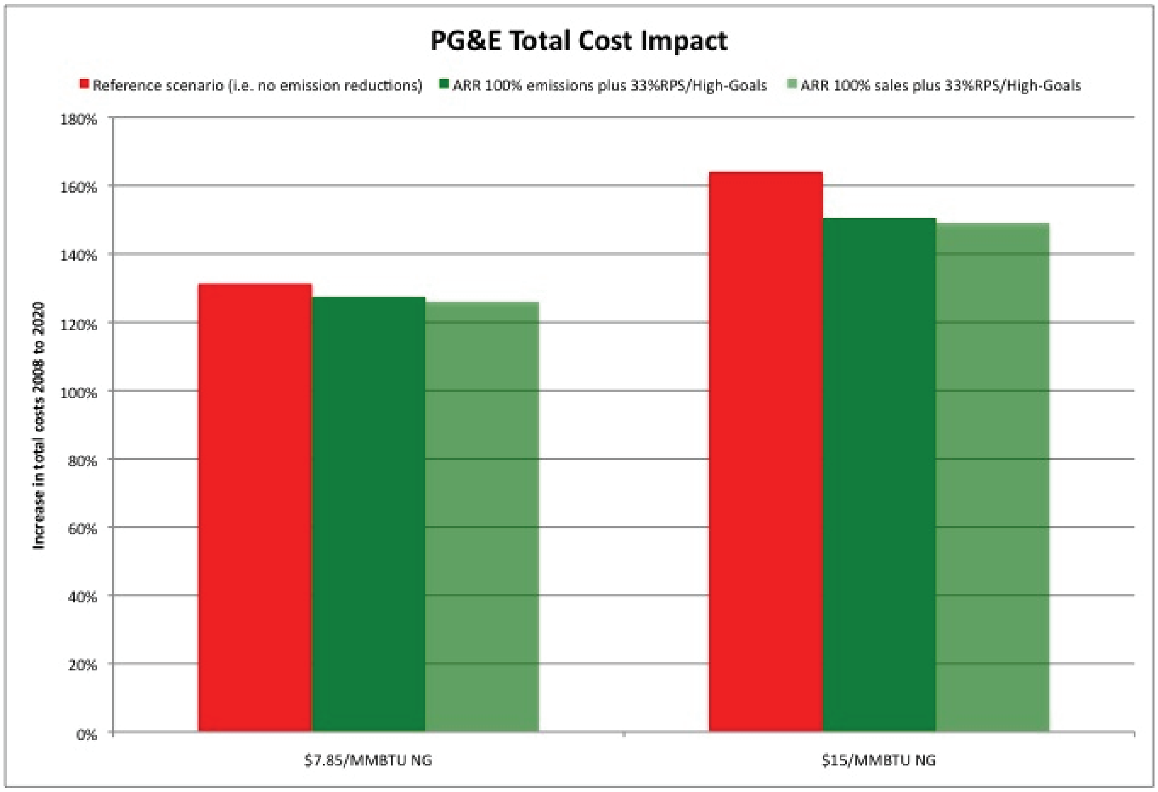


**Figure 3**




Thus, since our runs of the E3 model for various auction revenue recycling (ARR) scenarios result in relatively small differences in cost impacts across the various retail providers, we felt the more important factor to examine is the incentives or disincentives for emission reductions that are created through different auction revenue distribution methods.

In order to provide the proper long-term incentives for retail providers to reduce the overall emissions associated with serving their customers, distribution of auction revenues should ultimately be completely separated from emissions; i.e., by 2020 or earlier, auction revenues should be recycled to retail providers purely on the basis of retail providers' sales. As we and many other parties have commented in the past, we stress that in order to truly provide proper incentives for emissions reductions and adherence to the state's loading order, distribution of revenues on a sales basis must use sales that are adjusted for verified energy efficiency savings (although the E3 model did not model this adjustment).

However, the most carbon-intensive retail providers in the state (such as the southern California publicly-owned utilities) will need to make a lot of investments in order to clean up their systems.  Distribution of auction revenues based on emissions in a "use it or lose it" approach results in the same distributional impact as grandfathering, but avoids the downside of grandfathering because it essentially requires the biggest polluters to invest the most to clean themselves up.

The question that then remains is how to transition the method of revenue recycling from the start of the program in 2012 to 100% sales-based (adjusted for verified energy efficiency savings) distribution in 2020 or earlier.  This is the key determinant of the distributional impact among retail providers' territories.  As shown in Figures 2 and 3 above, the basis of ARR has different impacts on retail providers depending on whether they are relatively clean or dirty.  Emissions-based ARR will tend to reward the dirtier utilities while penalizing the cleaner utilities, whereas sales-based ARR will have the opposite effect.  We urge the Commissions to focus on the core equity impacts for all entities involved, since arguments about equity and fairness can be made about any allowance distribution system.

***We believe there are many workable approaches, and do not have a single preferred approach;*** as we discussed above, the most important issue from our perspective is that the auction revenues be recycled to benefit consumers and to make investments to reduce GHG emissions.  Although we do not have a single preferred approach for the method of ARR to retail providers, to illustrate the general approach and explore variations, we modeled four different 100% auction ARR scenarios that ended with 100% sales-based distribution in 2020, the results for which are provided in as attachments:

- 100% sales-based ARR throughout 2012-2020 period ("NRDC/UCS 3c");
- 100% emissions-based ARR in 2012 with straight-line transition to 100% sales-based ARR in 2020 ("NRDC/UCS 3e");
- 50% emissions-based/50% sales-based ARR in 2012 with straight-line transition to 100% sales-based ARR in 2020 ("NRDC/UCS 3g"); and

- 23% emissions-based/77% sales-based ARR in 2012 with straight-line transition to 100% sales-based ARR in 2020 ("NRDC/UCS 3i").[10]

The ARR scenario that starts at 100% sales-based ARR in 2012 would reward the relatively cleaner retail providers, whereas the scenario that starts at 100% emissions-based ARR in 2012 would reward the more carbon-intensive retail providers. The last two scenarios with a mix of emissions- and sales-based ARR in 2012 would provide some accommodation for those carbon-intensive retail providers that need to reduce their emissions the most, but also rewards and would not penalize those utilities that took early actions prior to the start of the program in 2012. Again, NRDC/UCS do not have a single preferred approach for the ARR method, except that we recommend that the ARR basis should transition to 100% sales-based (adjusted for verified energy efficiency savings) distribution in 2020 or earlier.

To summarize the assumptions we used when modeling these various ARR scenarios, the various ARR scenarios we present for discussion are based on using the following assumptions in the E3 GHG calculator:

- Resource additions from E3 33% RPS/High Goals EE scenario
- No other changes to defaults in E3 model, including:[11]
    - E3 assumption of constant market clearing price of \$30/tonne $CO_2$
- Constant natural gas price of \$7.85 (2008\$) /MMBTU

As directed by the ALJ rulings, scenario summary sheets for each of these scenarios are included as Attachment A.

[10] This last scenario represents a straight-line transition from 100% emissions-based ARR in 1990 to 100% sales-based ARR in 2020. As we pointed out in our November 14, 2007 reply comments on allocation, since the electric industry has been on notice since 1990 about the threat of global warming and the risk of forthcoming GHG regulations, and major utilities including LADWP and SCE made voluntary pledges to reduce their emissions at that time, a long transition period has already been underway. (See *NRDC/UCS/GPI Reply Comments on Allowance Allocation Issues*, submitted November 14, 2007, pp. 5-6.) Thus, one option for determining the transition path from 2012 to 2020 would be based on the transition period from 1990 to 2020. Assuming a straight-line transition from 100% emissions-based auction revenue recycling in 1990 to 100% sales-based revenue recycling in 2020, the 2012 revenue recycling split would be 23% emissions-based and 77% sales-based, transitioning to 100% sales-based in 2020.

[11] Though no changes were made to the other assumptions in the model for these ARR scenario runs, this does not necessarily imply our endorsement of these assumptions; rather, minimal changes were purposely made to the allocation scenarios to facilitate comparison of scenarios.

## D. RESPONSE TO CRITERIA USED IN STAFF PAPER TO EVALUATE ALLOWANCE ALLOCATION OPTIONS

### *1. The Commissions should carefully select criteria for evaluating allocation options and should not use the criteria suggested by the Staff Report.*

The Staff Report identified four criteria by which to judge different allocation options: consumer cost, transfers among retail providers, administrative simplicity, and new entrants.[12] Staff rejected other possible criteria as not being relevant to choice of allocation option.[13] The staff paper purported to choose these criteria "based on the Interim Opinion's direction."[14] However, the criteria used do not accurately represent the guidance from the Interim Opinion, and are not the most important criteria.

The Commissions' recommendations in the Interim Opinion explicitly stated criteria for choosing a *point of regulation* for the electricity sector,[15] but it did not lay out criteria for *allocation* because it was not yet addressing allocation issues. The Commissions, did, however, state that their "intent in developing additional allocation policy recommendations is to ensure that GHG emissions reductions are accomplished equitably and effectively, at the lowest cost to consumers."[16] It then went on to state: "As a starting principle, it is important that any policy for distribution of allowances provide that revenues from the sale of allowances be used primarily to benefit consumers in the energy sectors directly."[17] The Interim Opinion also recommended that "some portion of the emission allowances available to the electricity sector should be auctioned" and that 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

---

[12] *Joint California Public Utilities Commission and California Energy Commission Staff Paper on Options for Allocation of GHG Allowances in the Electricity Sector: R.06-04-009 and D.07-OIIP-01* (April 16, 2008), p.3

[13] *Id*. at 10.

[14] *Id*. at 1.

[15] These criteria were: 1) Environmental integrity (i.e., ability to produce real GHG emissions reductions); 2) Compatibility with/expandability to potential regional and/or national GHG emissions cap-and-trade markets; 3) Accuracy and ease of reporting, tracking, and verifying GHG emissions reductions; 4) Compatibility with ongoing reforms in wholesale and retail energy markets; and 5) Legal issues. After evaluating the point of regulation. *Interim Opinion on Greenhouse Gas Regulatory Strategies*, D.08-03-018 (March 13, 2008), pp.6-7, available at http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/80150.pdf

[16] *Id*. at 8.

[17] *Id*.

electricity consumers in California, such as to augment investments in energy efficiency and renewable energy or to provide customer bill relief."[18]

The Commissions have not yet adopted criteria for choosing an allocation method for the electricity sector. The criteria the Commissions choose will be instrumental in evaluating the various allocation options, so it is critical that the Commissions choose good criteria. The Commissions have given a good starting point by stating that allowances should be allocated in a way that benefits electricity consumers and augments investments in energy efficiency and renewable energy. The criteria chosen by staff did not reflect the important principles the Commissions mentioned in the Interim Opinion. The Commissions should start from the principles stated in the Interim Opinion and develop clear, appropriate criteria by which to judge allocation options.

### *2. The Commissions should use the criteria below when evaluating allowance allocation options.*

Because the Commissions have not yet chosen criteria for evaluating allocation options, we suggest the following. Allowances are valuable permits to pollute the public atmosphere, and their value should be distributed in the public interest and to further the goals of AB 32. AB 32 requires that the distribution of allowances must: (all references below are to sections of the Health and Safety Code)

- Be equitable; (38562(b)(1))
- Reduce the cost of the program to consumers, especially in low-income communities; (38562(b)(2))
- Encourage early action; (38562(b)(1))
- Promote investment in technologies to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions; (38562(a))
- Contribute to the state's efforts to improve air quality and reduce toxic air contaminant emissions; (38501(h), 38562(b)(4) and 38570 (b)(2))
- Promote investment in innovative and pioneering technologies; (38501(e))
- Minimize costs and maximize the total benefits to California; (38562(b)(1))
- Help improve and modernize California's energy infrastructure and maintain electric system reliability; (38501(h))
- Maximize additional environmental and economic co-benefits for California; (38501(h) and 38570 (b)(3))
- Direct investment toward the most disadvantaged communities in California and provide an opportunity for small businesses, schools, affordable housing

[18] *Id*. at 9.

associations, and other community institutions to participate in and benefit from statewide efforts to reduce greenhouse gas emissions. (38565)

NRDC/UCS do not believe that the four staff criteria accurately encompass the requirements of AB 32. Instead, we urge the Commissions to use the following four criteria when evaluating allowance allocation options:

- Benefit consumers. This criterion includes:
    - Avoid windfall profits (i.e. profits unrelated to actions to reduce GHG emissions) to private entities at the expense of consumers;
    - Minimize costs and maximize total benefits to consumers;
    - Invest in disadvantaged communities;
    - Invest in technologies and infrastructure that will benefit consumers in the long-term;
- Encourage early action, including both early action to reduce emissions going forward, and recognizing past early actions;
- Be equitable;
- Be administratively simple.

In evaluating allocations options involving an auction, the assumptions about use of auction revenue are critical to how that option will perform under the above criteria. Any auction option should be evaluated using the assumption that a majority of the auction revenue will be recycled for the benefit of electricity consumers as directed by D.08-03-018.[19]

## E. LEGAL ISSUES

The Staff Report suggests that the "pure" auction option would mean none of the auction revenue would be returned to the electricity sector. Not only is this inconsistent with the Commissions' joint recommendations in D.08-03-018, as discussed above, but it could also raise concerns about the levying of a tax, which is not authorized by AB 32 and would require approval by a two-thirds vote of the Legislature. If auction funds are directed to the General Fund to be used for any purpose, then they would be considered a tax.[20] In order to avoid being considered a tax, revenue from fees must be used for

[19] *Id*.

[20] *United Business Com.* v. *City of San Diego* (1979) 91 Cal.App.3d 156, 165 (a fee may be imposed under the police power "for the purpose of regulation, not revenue." However, "where it is exacted solely for revenue purposes . . . it is a tax."); *Terminal Plaza Corp. v. City and County of San Francisco* (1986) 177 Cal.App.3d 892, 906 ("fees not exceeding the reasonable cost of providing the service or regulatory activity for which the fee is charged and which are not levied for general revenue purposes, have been considered outside the realm of 'special taxes'")

purposes that are reasonably related to the purposes of the statute.[21] In this case, auction revenues must be used to further the goals of AB 32. The safest course would be to use all auction revenue to further the goals of AB 32, and, if there is a multi-sector cap and trade program, to use a majority of the auction revenues from the electricity sector to benefit electricity consumers and to spur changes in the electricity sector that further the goals of AB 32.[22]

# IV. FLEXIBLE COMPLIANCE MECHANISMS

## A. TRADING

Trading in a cap and trade program is itself a flexible compliance mechanism. By allowing entities to trade allowances, investment can flow to lower cost emission reduction measures as long as other provisions of AB 32 are followed. If a particular entity is able to lower their emissions more easily than other entities, then cap and trade will allow more of the lower cost reductions to occur. By lowering the cost of reducing emissions, a cap and trade program can allow the state to get "more for its money" by lowering emissions further than regulatory programs alone and can allow capped entities the flexibility to lower their own emissions or find another entity with a lower cost of reduction. Given the tight cap for which we advocate, all capped entities will need to reduce their emissions over time.

## B. PRICE TRIGGERS AND OTHER SAFETY VALVES

### *1. No Safety Valve or Price Cap*

AB 32 already has an emergency mechanism built into Health and Safety Code section 38599(a). Creating a safety valve or price cap in the design of the cap-and-trade system ***in addition to*** the emergency mechanism in the statute is unnecessary and would lead to unacceptable consequences; it would allow the cap to be broken and emissions to increase, undermining the purpose of the law. Instead, other design elements discussed below should be used to constrain costs and limit market volatility.

[21] *Sinclair Paint Co. v. State Bd. of Equalization* (1997) 15 Cal.4th 866, 881 (citing *San Diego Gas & Electric v. San Diego County Air Pollution Control District* (1988) 203 Cal.App.3d 1132, 1146).
[22] See Health and Safety Code § 38501 (stating that it is the intent of the Legislature that AB 32 be implemented in a way that "improves and modernizes California's energy infrastructure")

### *2. Independent Oversight Board*[23]

NRDC supports the creation of an independent market oversight body, such as the California Carbon Trust proposed in the Final Report from the Economic and Technological Advancement Advisory Committee (ETAAC).[24] The California Carbon Trust could act as a market maker and market stabilizer, and could also direct auction funds to ensure that they are used in a way that furthers the public good for all Californians and achieves AB 32's goals. Basic market rules and specific rules for when the board would intervene in the market would have to be developed in advance. An independent market oversight board would reduce the need for other cost-containment mechanisms such as borrowing

### *3. Linkage*

Any system that has a comparably stringent cap and trade program (including a tight cap, comparable verification and reporting requirements, limits on offsets, strong enforcement, etc.) should be considered for linkage with a potential California cap-and-trade system.

### *4. Compliance Periods*

We believe that the CPUC/CEC should recommend that CARB implement a three year compliance period in order to allow capped entities time to make the investment decisions necessary to meet their obligations.

## C. BANKING AND BORROWING

### *1. Banking Should Be Allowed, with Appropriate Limits*

Allowing covered entities to bank extra allowances (i.e., to hold them for use in a future compliance period) can encourage actions to reduce GHG emissions sooner rather than later. Allowing banking would provide an important means to encourage significant capital-intensive investments, because such investments may result in significant reductions that the capped entity will want to use for compliance during more than one compliance period. Some constraints on banking, such as limits on the number of

[23] Please note that this section, V(B)(2) is only put forward by NRDC; UCS is not ready to comment on this issue at this time, although all other sections of these comments are submitted jointly.

[24] *Recommendations of the Economic Advancement Advisory Committee, FINAL REPORT: Technologies and Policies to Consider for Reducing Greenhouse Gas Emissions in California* (February 11, 2008), pp. 2-3 – 2-9, available at http://www.arb.ca.gov/cc/etaac/ETAACFinalReport2-11-08.pdf .

allowances an entity may bank and limits on the number of compliance periods an entity may wait to surrender allowances, may be appropriate to prevent hoarding and market distortions from allowances being kept out of circulation for too long.

### *2. No Borrowing from Future Compliance Periods*

Allowing covered entities to borrow allowances from future compliance periods would likely discourage actions to reduce emissions in earlier years, and thus we do not support borrowing allowances from future compliance periods.[25] We acknowledge that some sectors will need flexibility to respond to the variations in emissions that occur due to factors out of their control. In particular, the electricity sector's year-to-year emissions can vary significantly due to weather conditions and the availability of hydroelectric power. A multi-year compliance period as we recommend can provide this necessary flexibility.

***If*** borrowing is allowed, it should be limited. Limitations should include the percentage of an entity's allowances allowed to be borrowed, how often a single entity may borrow over the life of the program, and how many compliance periods ahead the may borrow from. Borrowed allowances should also be paid back with interest, just like borrowed money must be paid back with interest.

## D. PENALTIES AND ALTERNATIVE COMPLIANCE PAYMENTS

There should be strong enforcement of entities that fail to meet their compliance obligations, i.e., entities whose emissions exceed their surrendered allowances at the end of each compliance period. Enforcement provisions against non-complying entities should include penalties, a requirement to retire in the following compliance period a multiple of the allowances not surrendered, and all other legal remedies (including civil and criminal penalties) contained in AB 32.[26] The CPUC/CEC should recommend that CARB establish up-front a clear penalty and allowance retirement requirement for any non-compliance through excess emissions. These should be set at a level where no

[25] If borrowing were allowed, an entity would still have to surrender in total the same number of allowances to cover its total emissions over time, but it would be allowed to put off reductions until a later compliance period. For example, an entity could surrender 10 allowances in compliance period one, but emit 15 tons of $CO_2e$. It would then achieve reductions in period two so that it only emits 10 tons but it must surrender 15 allowances.

[26] See CALIFORNIA HEALTH AND SAFETY CODE §38580(b).

rational entity would choose to pay the penalty and submit to the allowance retirement requirements rather than comply. Penalty revenue should be used to further the goals of AB 32.

Alternative compliance payments should not be allowed because they could undermine the integrity of the cap by encouraging entities to pay rather than to reduce emissions. An alternative compliance payment is effectively the same as a price cap – the amount of the alternative compliance is the maximum amount that an entity will have to pay, so if the price of allowances goes above that, entities will choose the alternative compliance payment instead of purchasing more allowances or reducing emissions. We do not support a price cap for all the reasons discussed above.

## E. OFFSETS

### *1. Should California allow offsets for AB 32 compliance purposes?*

CPUC/CEC should advise CARB to exercise an abundance of caution when contemplating an offsets program for compliance purposes. Offsets do not achieve any additional global GHG emissions reductions over those that would be achieved directly via a cap and trade program. Since offsets by definition are GHG emissions reductions in uncapped sectors, they merely offer an alternative path for capped entities to demonstrate compliance in the cap and trade program while allowing GHG emissions to in fact rise within the capped sectors; overall emissions of the capped and uncapped sectors remains unchanged. Offsets do not offer any additional environmental benefits, but they do present several substantial risks, as we discuss further below. We urge the CPUC/CEC to recommend to CARB that other regulatory measures should be used to achieve reductions in uncapped sectors. ***If*** offsets are allowed as part of a cap and trade program, the cap ***must*** be set tightly to ensure that meaningful reductions occur in capped sectors, and the offsets ***must*** be real, additional, verifiable, permanent, and enforceable.

#### (a) Real, Additional, Verifiable, Permanent, and Enforceable

The primary risk from offsets is that they will not actually achieve the GHG reductions they claim to achieve. All stakeholders agree that offsets must be real, additional, verifiable, permanent, and enforceable, yet the fact remains that achieving these goals is fraught with difficulties. In many cases, if regulators could have substantial certainty about the GHG reductions from a type of project, then those projects should be covered by a regulatory or market-based program, not left unregulated and uncapped as offsets.

If we can achieve real, additional, permanent, verifiable and enforceable GHG emissions reductions and all of the co-benefits required by the law at a lower price, then we can all agree that that would be a wonderful result. However, the tricky part is making sure these offset reductions actually are real, additional, verifiable, permanent and enforceable, and are also providing the co-benefits required by the law. The question of whether ***these offset*** reductions are still cheap is the harder question. Experience with offsets under the Clean Development Mechanism (CDM) has shown that it is very difficult to guarantee that offsets projects actually achieve real, additional, verifiable, permanent and enforceable GHG reductions, much less achieve the environmental, health, economic, and other co-benefits required by AB 32.[27] Many proponents of offsets simply assume that reductions will be real, additional, verifiable, permanent and enforceable, and will also meet California's other goals (see below section on co-benefits), but do not provide rigorous analysis of the costs of evaluating, monitoring, and enforcing offset projects.[28] In effect, they conclude that offsets will be cheaper before actually accounting for all the associated costs of ensuring they achieve the GHG emissions reductions they claim.

To ensure offsets are real, additional, verifiable, permanent and enforceable requires significant administrative costs.  CARB would have to develop processes to verify emission reductions, including methodologies for different project types, an approval process for individual projects, and public comment procedures for every step.[29]

---

[27] See *U.N. Effort To Curtail Emissions In Turmoil*, Wall Street Journal page A1, April 12, 2008, available at http://online.wsj.com/article/SB120796372237309757.html

[28] CRA's presentation of Chevron-funded modeling at the April 4 workshop was an example of this conclusive thinking. This modeling "unequivocally" concluded that offsets would be cheaper than reductions under the cap and trade program, and then added as an afterthought that the offsets would have to meet California's strict requirements that they be real, additional, permanent and verifiable. See Chevron Presentation, slide 12, available at http://www.arb.ca.gov/cc/scopingplan/economicssp/meetings/040408/chevron_slides_for_arb_workshop_offsets_v4.pdf.

[29] The Market Advisory Committee's Report concluded that the costs of administering an offsets program could be greater than the costs of administering the entire cap and trade program.  California Market Advisory Committee, *Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California*, June 30, 2007, p.74, available at

Even with strong (and costly) administrative procedures, the CDM has had great difficulty guaranteeing real, additional, verifiable, permanent and enforceable reductions.

**(b) Co-Benefits**

Another critical risk is that offsets will not achieve the environmental, health, economic and other co-benefits that would be achieved directly by reductions from regulations, either through a cap and trade program or other policies. Any market-based or regulatory program under AB 32 must take into account "localized impacts," must not "disproportionately impact low-income communities," must not increase "emissions of toxic air contaminants or criteria air pollutants" nor interfere with "air quality standards" and efforts to reduce "toxic air contaminant emissions," and must maximize "additional environmental and economic benefits for California" and consider "overall societal benefits."[30] It is not certain that offsets will achieve these co-benefits for Californians as required by AB 32. For example, a facility which would concurrently reduce toxic pollutants with localized impacts when reducing GHG emissions could be allowed to instead purchase offsets in the form of a forestry project that would not reduce these co-pollutants. Or, an electricity generator could purchase offsets instead of switching out an older, polluting power plant and thus risk exposing its consumers to even higher costs under a future federal or international reduction scheme. These examples are cause for concern about allowing offsets.

**(c) Innovation**

Finally, offsets could undermine one of the most important goals of AB 32 – driving technological innovation and low-carbon infrastructure development in the state's key emitting sectors.[31] The Economic and Technology Advancement Advisory Committee (ETAAC), concluded that offsets could "reduce the pressure to be creative within a given sector and weaken price signals for would-be innovators."[32] If CARB adopts a broad, multi-sector cap and trade program in California, the capped sectors

---

http://www.climatechange.ca.gov/publications/market_advisory_committee/2007-06-29_MAC_FINAL_REPORT.PDF.

[30] CALIFORNIA HEALTH & SAFETY CODE §§ 38570(b); 38562(b)

[31] See CALIFORNIA HEALTH & SAFETY CODE § 38501(h).

[32] *Recommendations of the Economic and Technology Advancement Advisory Committee (ETAAC) FINAL REPORT: Technologies and Policies to Consider for Reducing Greenhouse Gas Emissions in California*, February 14, 2008, p.9-6, available at http://www.arb.ca.gov/cc/etaac/ETAACFinalReport2-11-08.pdf.

would be the largest sources of GHG emissions and co-pollutants, and the sectors in which we ***must*** achieve transformative change and innovation in order to meet our 2020 and especially our 2050 goals.[33] If California's capped entities are allowed to purchase offsets rather than making investments to reduce their GHG emissions, the incentive for innovation in capped sectors will be weakened. Furthermore, to the extent that offset projects take place outside of California, offset payments siphon investment from California and delay progress in putting the State on a path toward achieving our long term climate objectives.

For the crucial capped sectors, we need to focus on driving the technological and infrastructural changes in the near-term that will be absolutely necessary for meeting our long-term emissions reduction goals. Rather than offsets, other mechanisms, including other targeted policy instruments and voluntary offsets (such as PG&E's Climate Smart program that targets the forest sector), should be used to drive emission reductions and innovation in uncapped sectors.

2. ***If offsets are allowed for compliance purposes, what types of offsets should be allowed? Should California establish geographic limits or preference on the location of offsets? If so, what should be the nature of those limits or preferences?***

**(a) Protocols and Project Types**

If California allows offsets for compliance purposes, California should adopt strict protocols for specific offset project types, and approve and quantify offset projects according to those protocols. The California Climate Action Registry has already developed several sets of protocols that could be used for these purposes. Approval, verification, and monitoring of projects should be performed by a California-certified third-party verifier. Third-party verifiers should be assigned to projects by CARB, in order to avoid the possibility that offsets providers could "shop" for their own verifier, thus compromising the integrity of the verification system. There should also be a process to regularly and randomly check the quality of work done by third party verifiers. CARB should have enforcement authority over every offset provider.

[33] See CALIFORNIA HEALTH AND SAFETY CODE § 38501(h).

The costs of approval, as well as on-going costs of monitoring and verification, should be borne by the offsets provider.

**(b) Co-Benefits**

If offsets are allowed for compliance purposes, they must not only reduce GHG emissions but must contribute to AB 32's co-benefits goals, as described above. These statutory requirements mean that California's attempts to reduce GHG emissions under AB 32 should also result in reductions of co-pollutants, and other benefits to the health and safety of Californians.

If offsets do not provide these co-benefits for Californians because they are outside of California, then CARB must disallow or strictly limit those offsets in order to secure the overall integrity of the California program and to prevent leakage of co-benefits outside of the state.[34] One possible way to ensure that offsets do not undermine AB 32's co-benefits goals would be to only allow capped entities to purchase offsets that achieve similar co-benefits.

**(c) Real, Additional, Verifiable, Permanent, and Enforceable**

Finally, as discussed above, if offsets are allowed for compliance purposes, they must be real, additional, verifiable, permanent, and enforceable. If California does not have the ability to enforce its strict requirements on offsets projects outside the state, then those offsets could not be allowed for compliance purposes.

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

If voluntary emissions reductions projects are not real additional, verifiable, permanent, and enforceable, then they should NOT be allowed for compliance purposes within a mandatory cap and trade program. Voluntary projects may not actually achieve the reductions they claim to achieve. If offsets are allowed for compliance purposes, they must be real, additional, verifiable, permanent, and enforceable, and there is no guarantee

[34] See CALIFORNIA HEALTH & SAFETY CODE § 38562(b)(8

that voluntary projects will be any of those. *All* offsets, *if* allowed to be used for compliance purposes, must meet the same requirements.

In particular, unverified voluntary emission reductions in the natural gas sector should not be allowed as offsets within a mandatory cap and trade program. As we have stated in previous comments,[35] the natural gas sector should be ***included*** in a cap and trade program. There are significant emission reductions that can be achieved in the natural gas sector and that sector should be included in a cap and trade program and those potential reductions should be taken into account when CARB sets a strict cap. Allowing the natural gas sector to siphon money from the capped sectors for unverified voluntary reductions could undermine the integrity of the cap, reduce the flexibility of the market for real emission reductions, and would not provide additional emission reductions to help the state achieve the AB 32 limit. The natural gas sector should be included under the cap, and its reductions should be subject to the same requirements as other capped sectors.

4. ***If offsets are allowed for compliance purposes, should there be limits to the quantity of offsets for compliance purposes? If so, how should the limit be determined?***

If offsets are allowed, they should be limited to a small percentage, possibly 10% of the total GHG reductions to be achieved by the cap and trade program.[36] This will ensure that the integrity of the cap is maintained and that meaningful reductions occur in capped sectors, will promote innovation in key capped sectors of the economy, and will prevent leakage of co-benefits. Both the RGGI program and the EU ETS have conceptualized limits on offsets in terms of the amount of reductions these programs seek to achieve directly for the aforementioned reasons – ensuring significant reductions and technological progress in the capped sectors that are the primary target.

In addition, if offsets are allowed for compliance purposes, they should be discounted. All stakeholders agree that offsets must be real, additional, verifiable, permanent, and enforceable in order to be used for compliance. However, the reality is

[35] *NRDC/UCS/GPI Comments On Type and Point of Regulation Issues for the Natural Gas Sector*, submitted January 8, 2008, pp.3-6.

[36] The RGGI states only allow offsets to account for 3.3% of emissions. See RGGI Model Rule, p.63, available at http://www.rggi.org/docs/model_rule_corrected_1_5_07.pdf

that it will not be possible to guarantee this with 100% certainty. The value of the offset should be discounted to reflect this uncertainty.

# V. TREATMENT OF CHP

We applaud the staff's summary of CHP issues and compilation of questions in its Joint Report released May 1, 2008. We appreciate the staff's recognition that CHP presents difficult regulatory issues, but is a potentially very important source of GHG reductions.

## A. RECOMMENDATIONS

The Joint Staff Paper on CHP presents very important information about the sector, but we believe there are a few more data points that would be helpful to know in crafting a program for the sector. Regulation of the CHP sector should encourage facilities that are net GHG reducers and should not encourage facilities that are not.

In their previous comments, EPUC/CAC expressed the view that there is a possibility for a perverse incentive in which clean CHP facilities would be responsible for more emissions than their more polluting counterpart which operates a boiler on site without CHP and instead purchases electricity from a utility.[37] EPUC/CAC explained that this would be because the CHP facility would be responsible for all of its emissions, whereas the counterpart would only be responsible for GHG emissions from the on-site boiler, not the grid-purchased electricity. If this occurred as APUC/CAC envisioned, then CHP facilities, while lowering societal GHG emissions as a result of the increased efficiency of CHP, could be required to pay more for on-site GHG emissions. Parties at the May 2 workshop at CARB also raised the issue that not all CHP facilities are net GHG reducers, so a blanket policy supporting CHP facilities would not be wise.

We think that the best way to avoid any possible perverse incentive for net GHG reducers and to avoid unproductive incentives for CHP facilities that are not net GHG reducers is to include the electricity, natural gas, and industrial sectors under the cap and trade program. If all are included, then all will be paying the market price for emissions, and there will be no perverse incentive for being all in the system rather than half in and half out.

[37] *EPUC/CAC Comments Regarding Interim Opinion on Greenhouse Gas Regulatory Strategies*, submitted February 8, 2008, pp.2, 10-13.

Even if all three sectors are included, we understand that only 336 of the 940 CHP facilities in California would likely be included in a potential cap and trade program, because they would meet CARB's threshold reporting requirements for electricity generators of 1 MW capacity and 2,500 tonnes $CO_2e$ emissions per year.[38] Those 336 facilities would be properly incentivized because they would have to pay less for emissions than would their separate generator and boiler counterparts.

The other two-thirds of CHP facilities which are very small should not be included in the cap and trade program. These facilities should receive some sort of incentive if they can prove that they are net GHG, air, and toxic pollution reducers.

# VI. EMISSION REDUCTION MEASURES (OTHER THAN CHP) AND EMISSION CAPS

NRDC/UCS also commented in its January 4, 2008 modeling comments on additional emission reduction measures (ERMs) that should be considered in the electricity and natural gas sectors. Many of these ERMs include market-based flexibility mechanisms, so we do not think that "non-market based," as described in the ALJ Ruling, is an accurate descriptor of ERMs. Although we understand that the E3 team has made a decision not to model some of these ERMs, we urge the CPUC/CEC to include these additional policy measures in their recommendation to CARB to be included in the Scoping Plan. Emission reductions must be achieved through both continued expansion of existing regulatory programs, as well as adoption of additional policies.

## A. ELECTRICITY EMISSION REDUCTION MEASURES

### *1. 33% Renewable Portfolio Standard*

California should adopt a 33% Renewables Portfolio Standard ("RPS") as soon as possible. The 33% RPS is a state policy goal established in 2005 by Governor Schwarzenegger and included in the Energy Action Plan II. The passage of AB 32 underscores the need for policy measures that will provide substantial in-state GHG reductions while bringing significant co-benefits to the state. The E3 modeling results

[38] CARB's mandatory reporting threshold for electricity generators is 1 MW capacity and emission of 2,500 tonnes $CO_2e$ per year; for stationary sources it is 25,000 tonnes $CO_2e$ per year. CARB, *Proposed "Regulation for the Mandatory Reporting of Greenhouse Gas Emissions*," 15-day language, May 2008, Section 95101(b). There are 336 CHP facilities in California above 1 MW. See http://www.eea-inc.com/chpdata/States/CA.html.

indicate that a 33% RPS would reduce CO2 emissions in 2020 by an additional 12.8 MMT over the 20% RPS[39] – more than any other electricity sector emission reduction measure. At the same time, increasing the RPS to 33% by 2020 will enhance the economic development, fuel diversity, rate stability, and public health and air quality benefits that renewables provide to California.

In addition to these important benefits, a 33% RPS will put the state's electricity sector on the right path to achieving the much deeper GHG emission reductions that are required beyond the 2020 limit established by AB 32. A significant expansion of California's use of renewable energy is essential to the state's transition to a low-carbon, clean energy economy.

NRDC/UCS recognize the continued existence of significant barriers to renewable development in the state, and fully support the Commissions' efforts to address these barriers through the Renewable Energy Transmission Initiative, the IEPR, and other similarly important efforts. The challenges to getting more renewables built in California will not be resolved in a matter of months or even years. Overcoming these challenges will require extreme commitment from and extraordinary coordination among state agencies. A significantly higher RPS mandate is necessary to drive the inter-agency coordination and focus the efforts of government, utilities, and industry that are necessary to overcome the transmission, siting, and other market barriers to developing renewable energy in the state. As the 2007 IEPR notes, "meeting the 33 percent goal in 2020 *is* feasible (emphasis in original)" with significant infrastructure changes and changes to the structure of the RPS program.[40] These changes will not happen organically – they require a strengthened RPS policy that includes both a higher renewables mandate and statutory and regulatory reforms to enable more renewable energy in the state.

The Commissions should signal their commitment to achieving the state's renewable energy goals by recommending to CARB that a comprehensive 33% RPS policy, including key policy reforms, be adopted as an essential AB 32 electricity sector emission reduction measure in the Scoping Plan.

[39] E3 presentation: "Electricity and Natural Gas GHG Modeling: Revised Results and Sensitivities," updated on May 13, 2008. Slide 16.
[40] CEC 2007. *2007 Integrated Energy Policy Report,* p. 117.

### 2. *Embedded energy savings from water conservation*

There is significant potential to reduce GHG emissions by saving energy through increased water efficiency. NRDC estimates that increased water efficiency throughout the state could reduce the state's GHG emissions by up to 4.8 MMT $CO_2e$ from business-as-usual emissions in 2020,[41] with further savings from strategies like water recycling. We urge the Commissions and CARB to include increased water efficiency as an emission reduction measure to include in CARB's Scoping Plan.

### 3. *Time-of-sale energy efficiency requirements*

We strongly support the goal of attaining all cost-effective energy efficiency in California by 2020, as is modeled by E3. However, we also suggest that additional policy tools beyond what is already in place may also be needed to achieve all cost-effective energy efficiency. In particular, NRDC recommends that the CEC and CARB establish time-of-sale information disclosure requirements, followed by time-of-sale efficiency requirements, or alternatively the Legislature could authorize the CEC to implement such a requirement.[42] Such time-of-sale requirements, as supported by the CEC in its 2007 *Integrated Energy Policy Report*, can work in concert with the utilities' energy efficiency programs as well as the Title 24 standards for new buildings and Title 20 appliance standards.[43]

### 4. *Appliance Feebates*

An additional policy measure that we suggest be considered for inclusion in the Scoping Plan for the electricity and natural gas sectors is the use of "feebates" for appliances. Although utilities currently already offer rebates to customers for the purchase of appliances that use less energy, a feebate structure could help to encourage greater appliance efficiency, wherein a fee would be assessed for appliances that use more energy than a benchmark level of performance, and a rebate would be given for appliances that use less energy than the benchmark.

---

[41] See NRDC Scoping Plan recommendation submitted to CARB, "Urban Water Use Efficiency," October 1, 2007. Available at http://www.arb.ca.gov/cc/scopingplan/submittals/electricity/nrdc_water_efficiency_final.pdf.

[42] See NRDC Scoping Plan recommendation submitted to CARB, "Energy Efficiency Ratings and Standards for Buildings at Time-of-Sale," October 1, 2007. Available at .http://www.arb.ca.gov/cc/scopingplan/submittals/electricity/nrdc_time_of_sale_ee_final.pdf.

[43] California Energy Commission, *2007 Integrated Energy Policy Report*, Publication CEC-100-2007-008-CMF, p. 87.

**5. *What percentage of emission reductions in the electricity sector should come from programmatic or regulatory measures?***

Many regulatory measures include elements of market-based mechanisms,[44] so our response to this question will address what portion should come from programmatic or regulatory measures, and what portion should come from any cap and trade program. Based on the analysis in this proceeding, we recommend that a majority of emission reductions in the electricity sector and natural gas sectors should come from programmatic and regulatory measures, including expansion of existing measures as well as new measures. Less than half of the reductions in the electricity sector should come from a potential cap and trade program. We support the recent statements made by CARB that direct programmatic regulations should account for 60% of the overall emissions reductions required by AB 32, and this proportion could be even higher.

There is no abstract number that would determine the "right" portion from each approach. Instead, the determination should be based on an analysis of the strengths and weaknesses of each policy tool, the often multiple public policy objectives that can be achieved by each tool, and the best package of these policies to meet the multiple objectives of AB 32 and other state laws. For example, the strengths of regulations and performance standards (such as the efficiency standards and the RPS) include spurring technological innovation, overcoming non-price market barriers, and providing targeted co-benefits (such as air quality improvements and protection from natural gas price volatility). The strengths of fee and incentive programs (such as the efficiency programs and California Solar Initiative) include spurring technological innovation, overcoming non-price market barriers, and engaging decentralized decision-makers (e.g., millions of consumers). The strengths of a cap and trade program include providing certainty that emissions will not exceed a certain level, creating a price signal to integrate GHG emission considerations into everyday decision-making, and letting regulators focus on the environmental objective. Since each type of policy tool has different strengths and weaknesses, a multi-dimensional assessment beyond what simple economic modeling can provide is necessary.

---

[44] For example, energy efficiency programs provide incentives to encourage market participation, and the RPS sets a minimum requirement for renewable content in the retail providers' portfolios and the market competes to meet this requirement.

We urge the Commissions to recommend that CARB include in the scoping plan many programmatic and regulatory measures, including those described in these comments. For example, expanded efficiency programs and a 33% RPS are necessary to meet many statewide objectives (including reduced GHG emissions, improved air quality, and reduced exposure to natural gas price volatility), and these policy tools have the strengths described above that would not be captured by a cap and trade program.[45] The Commissions should determine the amount of emissions reductions achievable from these many programmatic and regulatory measures, and should recommend that they be included in the scoping plan. The cap and trade program should supplement these programmatic and regulatory measures, providing the remaining reductions necessary to achieve the sectors' responsibilities, providing a backstop to ensure the reductions from the programmatic and regulatory measures are achieved, and ensuring that emissions from the sectors do not exceed a total cap.

## B. NATURAL GAS EMISSION REDUCTION MEASURES

### *1. Solar Hot Water*

As we and many other parties have mentioned in previous comments,[46] solar hot water is an important way to reduce natural gas consumption and has the technical potential to save over one billion therms of natural gas in California every year,[47] or

---

[45] The CPUC and CEC have long understood that many cost-effective efficiency improvements remain untapped even at current prices, due to a large number of market barriers. The price signal from a cap and trade program will not overcome these many market barriers.

[46] See *NRDC/UCS Comments On the Proposed "Interim Opinion on Greenhouse Gas Regulatory Strategies," on Proposed Decision on GHG Regulatory Strategies*, submitted February 28, 2008, pp.4-5; *NRDC/UCS Comments on Modeling Related Issues*, submitted January 4, 2008, p.5; *Prehearing Hearing Conference Statement of NRDC, UCS and ED Comments on Preliminary Staff Recommendations for Treatment of Natural Gas Sector GHG Emissions*, submitted July 26, 2007, pp.6; Southern California Generation Coalition Reply Comments, submitted January 8, 2008, pp.7-8; Community Environmental Council Reply Comments, submitted January 8, 2008, pp.5-6; *California Solar Energy Industries Association and the Solar Rating and Certification Corporation Comments on Type and Point of Regulation Issues For the Natural Gas Sector*, submitted December 17, 2007, p. 3; *Community Environmental Council Comments on Natural Gas Sector Point of Regulation Issues*, submitted December 17, 2007, pp.5-7.

[47] National Renewable Energy Laboratory, *The Technical Potential of Solar Water Heating to Reduce Fossil Fuel Use and Greenhouse Gas Emissions in the United States*, March 2007, p.10; *See also* Environmental California Research & Policy Center, *Solar Water Heating: How California Can Reduce Its Dependence on Natural Gas*, April 2007, p.14, citing Fred Coito and Mike Rufo, KEMA-Xenergy Inc, for Pacific Gas & Electric Company, *California Statewide Residential Sector Energy Efficiency Potential Study*, April 2003 and Fred Coito and Mike Rufo, KEMA-Xenergy Inc, for Pacific Gas & Electric

approximately 5.3 $MMTCO_2e$ reductions.[48] This important strategy was not mentioned as a potential emission reduction measure during the May 2 workshop.

The scoping plan should include mechanisms for ensuring that the funding authorized by AB 1470 (The Solar Water Heating and Efficiency Act of 2007, Huffman) is fully utilized so that as many solar water heating units as possible are incentivized by the Act and the resultant emissions reductions are achieved. The scoping plan should go even further and provide that solar hot water is encouraged and promoted even beyond the funding provided for in AB 1470. These mechanisms could include:

- Timelines for implementation of AB 1470.
- Funding sources for incentive for solar hot water beyond those provided for in AB 1470, to achieve all cost-effective savings.

### *2. Biomethane*

As we have mentioned in previous comments,[49] biomethane is an important renewable alternative to natural gas with the potential to save 7.2 $MMTCO_2e$ of emissions by 2020 from dairies alone,[50] with further potential savings from wastewater treatment facilities. This important strategy was not mentioned as a potential emission reduction measure during the May 2 workshop.

The scoping plan should include mechanisms for promoting the use of biomethane to replace natural gas. These mechanisms could include:

- *Loading Order*. Adopting a "loading order" of resources for the natural gas sector to prioritize: first, *all* cost-effective natural gas efficiency and solar resources, and second, renewable fuels like biomethane.
- *Renewable Fuel Portfolio Standard*. A Renewable Fuel Portfolio Standard could function like the RPS in the electric sector, requiring the utilities to increase

---

Company, *California Statewide Commercial Sector Natural Gas Energy Efficiency Potential Study*, May 14, 2003.

[48] California Air Resources Board, *Updated Macroeconomic Analysis of Climate Strategies Presented in the March 2006 Climate Action Team Report: Final Report*, October 15, 2007, p.11, available at http://www.climatechange.ca.gov/events/2007-09-14_workshop/final_report/2007-10-15_MACROECONOMIC_ANALYSIS.PDF states that 1MMBtu = 53.06 kg CO2e (1,000 million therms * (100,000 MBtu / million therm) * (53.06 kg CO2 / MBtu) * (1 metric tons CO2 / 1,000 kg CO2) = 5,306,000 metric tons CO2)

[49] See *NRDC/UCS Comments on Proposed Decision on GHG Regulatory Strategies*, submitted February 28, 2008, p.4-5; *Prehearing Hearing Conference Statement of the Natural Resources Defense Council (NRDC), Union of Concerned Scientists (UCS) and Environmental Defense (ED) Comments on Preliminary Staff Recommendations for Treatment of Natural Gas Sector GHG Emissions*, submitted July 26, 2007, pp.6-7.

[50] See NRDC's scoping plan recommendation, available at http://www.arb.ca.gov/cc/scopingplan/submittals/agriculture/nrdc_biomethane_final.pdf.

procurement of biomethane every year to reach a certain percent of supply by 2020.

- *Enable and Encourage Long-Term Contracts*. While long-term contracts for supply are commonplace in the electric sector, they are much less common in the natural gas sector. Just as electric renewable resources need the certainty of long-term contracts to get financed, biomethane facilities need long-term contracts to be viable. Long-term fixed price contracts can provide significant benefits to customers by stabilizing rates.
- *Facilitating Interconnection.* Access to the utilities' natural gas pipelines will be essential to enable biomethane to become a part of the state's natural gas supply. A recent University of San Diego report recommends that the "CPUC should assess existing interconnection processes and costs to determine whether they are appropriate for introduction of biomethane into the natural gas transmission system" and to "consider subsidizing and standardizing interconnection costs among gas utilities in California." The CPUC recently issued a Proposed Decision dismissing, among other things, SDG&E and Southern California Gas companies proposal to create an "interconnection allowance" for biomethane[51] because the proposal was "duplicative of the existing scope for R.06-04-009 addressing greenhouse gases."[52] If the Commissions are not addressing such projects in other proceedings, they should properly address them in this proceeding.
- *Technology Transfer.* Several countries in Europe have significant experience with biomethane, and California should learn from their success. This effort should build on the 2006 Memorandum of Understanding between California and Sweden to cooperate on developing a biomethane industry.
- *RD&D.* The CEC should expand the Public Interest Energy Research program's focus on RD&D to advance biomethane. The PIER program's *Natural Gas Research Investment Plan* includes development of renewable energy technologies to replace the use of natural gas as a strategic objective, but the emphasis on this effort could be expanded and supplemented with a detailed plan to advance biomethane.

### *3. Time-of-sale energy efficiency requirements*

As discussed above with regard to electricity sector ERMs, we also recommend that time-of-sale efficiency requirements also be implemented for natural gas efficiency.

### *4. Appliance Feebates*

As discussed above, we suggest that "feebates" for appliances be used as an ERM in both the electricity and natural gas sectors.

---

[51] See *SDG&E Advice Letter 1760-G: Revisions to Rule 39 – Access to the SDG&E Pipeline* (March 26, 2008) available at http://www.sdge.com/tm2/pdf/1760-G.pdf.

[52] Proposed Decision of ALJ Long in A.07-08-031 (January 29, 2008) p.8 available at http://docs.cpuc.ca.gov/efile/PD/78187.pdf

## C. ANNUAL EMISSION CAPS FOR THE ELECTRICITY AND NATURAL GAS SECTORS

### 1. *What recommendations should the Commissions make to ARB regarding annual GHG emissions caps for the electricity and natural gas sectors?*

We believe that sufficient information is available for the Commissions to make a preliminary recommendation to CARB regarding the emissions cap for the electricity and natural gas sectors, if CARB decides to include them in a cap and trade program. To the extent that some information is uncertain, the Commissions should point these areas out and recommend that CARB conduct further study or modeling in these areas.

The Commissions should recommend that CARB adopt a tight cap for the electricity and natural gas sectors that reduces emissions *below* business as usual and the reductions that can be achieved by regulatory programs, and below today's emission levels. The cap should be set based on consideration of a variety of factors. A primary consideration should be the level of a cap that will achieve all likely cost-effective emission reductions. CARB will have to determine what is cost-effective by looking at the entire scoping plan as a whole and ensure that the state will meet its 2020 goal, and the Commissions can be most helpful to CARB by recommending the maximum amount of cost-effective reductions that can come from the electricity and natural gas sectors.

Another factor the Commissions should recommend CARB consider is what level of a cap would yield a proportional reduction for these sectors relative to other sectors to meet the statewide limit. The cap should also take into account what reductions CARB believes can be achieved in other sectors, and therefore what level of a cap would be necessary in the electricity and natural gas sectors to achieve the statewide limit.

Finally, the cap should be informed by the trajectory necessary to transform the sectors and get them on the path to the deep reductions in emissions the science indicates is necessary to curb global warming and to meet the Governor's goal of reducing statewide emissions 80% below 1990 levels by 2050. The Commissions can provide valuable information on all these factors to CARB, and CARB will need to consider what is equitable, cost-effective, and necessary in setting the level of any cap.

# VII. MODELING ISSUES

## A. PERFORMANCE, USEFULNESS, AND VALIDITY OF INPUT ASSUMPTIONS IN E3 MODEL

NRDC/UCS appreciate the Commission's efforts to model the impacts of AB 32 regulations on the electricity sector. We are especially grateful for E3's considerable efforts to produce a spreadsheet modeling tool that permits user changes to certain assumptions. The E3 model is a useful tool to estimate the cost impacts of different resource scenarios. That said, NRDC/UCS have several concerns with the E3 model, dating back to our comments on GHG-modeling issues on January 4, 2008, and reply comments filed on January 18, 2008. Some of the concerns we expressed in previous comments are repeated below. NRDC/UCS have also identified additional concerns with the model. Our primary concerns with the models are summarized as follows:

- The model provides useful but incomplete information to form the basis of AB 32 policy decisions.[53]
- We remain concerned that the costs of energy efficiency in the model are too high.[54]
- The model paints an unrealistically static picture of renewable technology development.
- The model fails to account for the natural gas price suppression effect of increased levels of clean energy.
- The model does not assess the risk to consumers of different scenarios.
- Transmission costs should be shared between generators and load.
- Combined-cycle gas turbine capital cost assumptions should be increased.
- The reference case should include achievement of the California Solar Initiative goal.
- The assumed capacity values for renewable generators discount the capacity contribution of renewable resources.

In combination, these concerns cast some degree of doubt on the overall reliability of the model's cost estimates. If the model is used to inform AB 32 policy decisions, its results must be judiciously presented and carefully interpreted. E3 itself cautions that the model "should not be used for resource planning decisions."[55]

[53] NRDC/UCS Comments on Modeling-Related Issues, filed January 4, 2008, p. 18-20.
[54] NRDC/UCS Comments on Modeling-Related Issues, filed January 4, 2008, p. 8-9.
[55] "Electricity and Natural Gas GHG Modeling: Revised Results and Sensitivities," E3, May 13, 2008, slide 27.

### 1. *The model provides useful but incomplete information to form the basis of AB 32 policy decisions.*

Policymakers have been asked to develop a comprehensive and effective strategy to reduce GHG emissions from the energy sectors. This strategy will likely include a variety of programs and policies and will need to be both reliable and cost-effective. The output metrics from E3 model can help inform the state's development of GHG emissions reduction strategies, but these metrics alone provide incomplete information to form the basis for policymaking decisions.

Pursuant to AB 32, CARB must adopt regulations "to achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions," and consider numerous factors, including "additional environmental and economic co-benefits for California" and reduc[ing] other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health." [56] The E3 model does not consider the co-benefits of AB 32 regulations, and policymakers should understand that these benefits are not included in the \$/tonne cost-effectiveness metric provided by the model. Furthermore, whenever the modeling results are presented to CARB or other decision-makers, it should be emphasized that the cost metrics of the model are highly sensitive to the choice of input assumptions – many of which are disputed in this proceeding. The \$/tonne cost-effectiveness metric is particularly sensitive to changes in input assumptions, as slight changes to both the numerator and denominator of the \$/tonne calculation can substantially alter the resulting quotient.

NRDC/UCS recommend that the model outputs include system-wide cost and benefit estimates under different emissions targets, emissions reductions at different costs, information on the costs and impacts of different policies, and an analysis of key risks and uncertainties. In particular, we recommend that, to the extent possible, the GHG modeling effort be expanded to provide the following information:

- All output metrics for reducing emissions of each sector: 1) back to each sector's 1990 levels; and 2) by 29% below 2020 business as usual levels.

[56] Health and Safety Code §§ 38501(h), 38562(b)(6)

- Total emission reductions in 2020 and all output metrics for a range of marginal and average emission reduction costs, e.g. $100 per ton, $150 per ton, $200 per ton, etc.
- Summary information should be broken out to provide results for the electric sector, natural gas sector, and combined energy sector.
- An analysis of the variability associated with natural gas prices and other key assumptions and uncertainties. This analysis should include, at a minimum, the impact of emission reductions policies on costs and rates at a range of potential natural gas prices.
- An analysis of key policies, beyond simple ERMs, that might be implemented including a 33% RPS and a regional efficiency initiative. This might include an analysis of the impact of different targets with and without these policies.

The output metrics and presentation of model results should be geared towards answering the key questions policymakers will need to consider, including the following for each scenario:

- What level of GHG emissions is reached in 2020? How does this compare to the sector's 1990 emissions, 2008 emissions, and 2020 BAU levels? What is the trajectory from 2012 to 2020?
- What is the total costs/savings of the investments relative to business as usual?
- What is the average total cost (bill) impact to the average customer in 2020? What is this average bill increase/decrease relative to business as usual?
- What will rates be in 2020? What is the rate increase/decrease relative to business as usual? What is the total and incremental *annual* rate increase/decrease necessary to get there?
- How does the level of portfolio risk compare to that of the business as usual scenario (e.g., how does the variability in customers' costs change if gas prices were one standard deviation above or below the estimated value)?

While some of this information is contained in the model's summary tables, it could be presented more clearly, along with additional contextual information. For example, the summary table currently provides the total GHG emissions for the scenario, BAU, and 2008 levels. We recommend that this be expanded to show GHG emissions for 1990 levels and 29% below BAU for comparison purposes, and to provide more detailed graphs that split out the electric and gas sector information. In addition, the summaries for the demand side activities should clearly show the cost savings that are coming from energy efficiency. Finally, all model outputs should be clearly labeled and defined to avoid confusion.[57]

***2. The model paints an unrealistically static picture of renewable technology development.***

NRDC/UCS are concerned that the reference and 33% RPS/High EE goals cases fail to capture expected renewable technology improvements and cost reductions over time. In both cases, the model assumes that solar thermal and PV costs are unchanged from 2008 to 2020. In contrast, most studies of renewable technology costs predict significant cost reductions for solar technologies, which are less mature than wind and geothermal technologies. Figure 1 presents a comparison of solar thermal cost assumptions from four sources: three sources from the U.S. Department of Energy ("U.S. DOE"), and a conference paper from the National Renewable Energy Laboratory ("NREL").[58]

[57] For example, the summary results in the v2b of the GHG calculator includes both total producer costs (as a dollar figure) and total system costs (relative to 2008 and the reference scenario in the bar chart) without clearly identifying the differences between the two estimates.

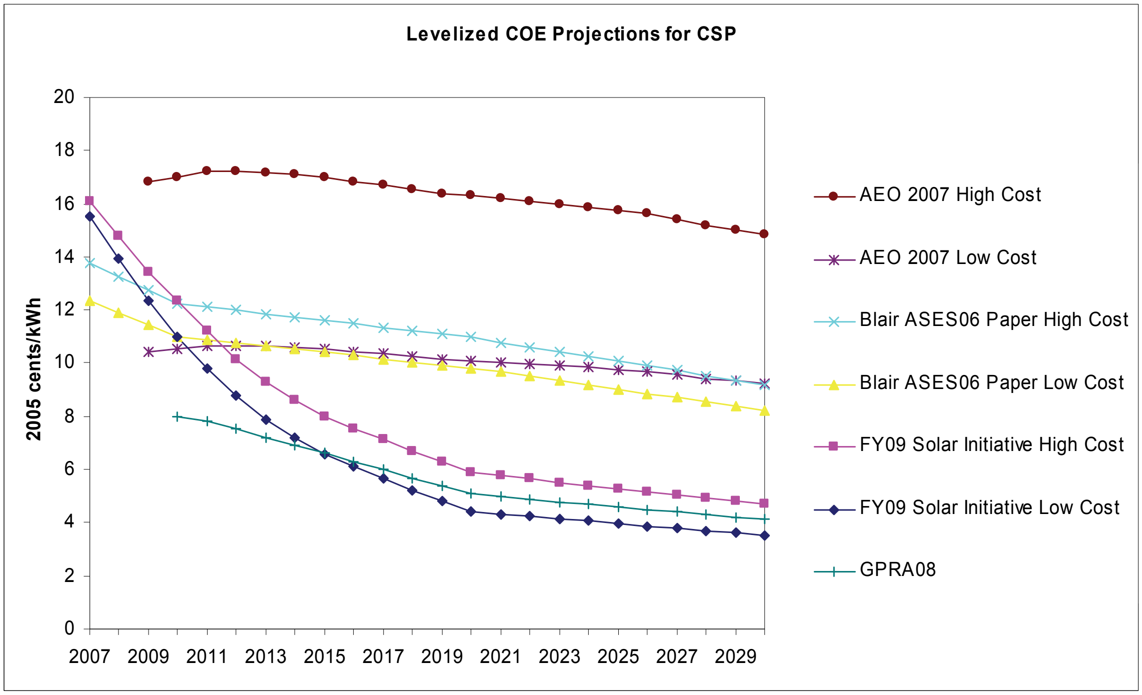
[58] U.S. DOE, *Concentrating Solar Power: FY09 Proposed Solar Initiative,* Budget Summit Meeting at the National Press Club, March 15, 2007

U.S. DOE, Government Performance Review Act FY08, *Appendix D: Solar Energy Technologies Program Inputs for FY08 Benefits Estimates.*

U.S. EIA 2007. *2007 Annual Energy Outlook*.

Blair, N. et al. National Renewable Energy Laboratory, "Concentrating Solar Deployment System (CSDS) – A New Model for Estimating U.S. Concentrating Solar Power Market Potential," paper prepared for the American Solar Energy Society 2006 conference.

**Figure 1. Comparison of Levelized Cost Projections for Concentrating Solar Power**




All of the projections, except for the two Annual Energy Outlook projections, predict significant cost reductions over time, ranging from 17% to 68% (in constant dollars) from 2008 to 2020. Given that the majority of U.S. government cost projections predict significant cost reductions, the E3 model should reflect some degree of future cost reduction for solar thermal technology.

Figures 2 and 3 present a comparison of the total installed costs of residential and commercial PV systems from two government sources: the 2007 Annual Energy Outlook and the Government Performance Review Act FY07 and FY08 EERE Program Benefits Analysis.[59] Both of these reports project substantial cost reductions over time, ranging from 16% to 67% from 2008 to 2020.

[59] U.S. EIA 2007. *2007Annual Energy Outlook 2007.*
U.S. DOE, Government Performance Review Act FY07. *Appendix D: Solar Energy Technologies Program Documentation.*

U.S. DOE, Government Performance Review Act FY08. *Appendix D: Solar Energy Technologies Program Inputs for FY08 Benefits Estimates.*

**Figure 2. Comparison of Installed Cost Projections for Residential PV Systems**

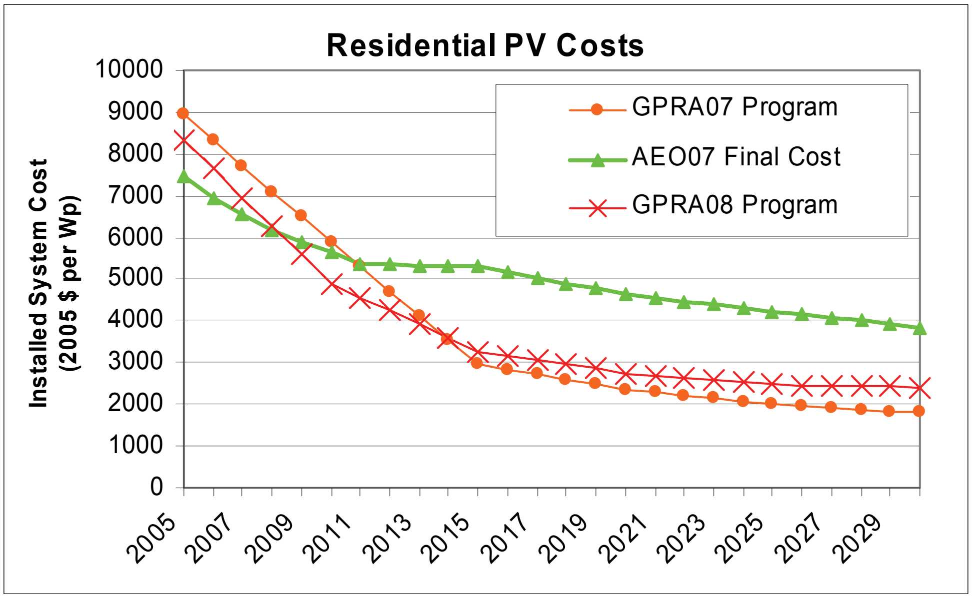
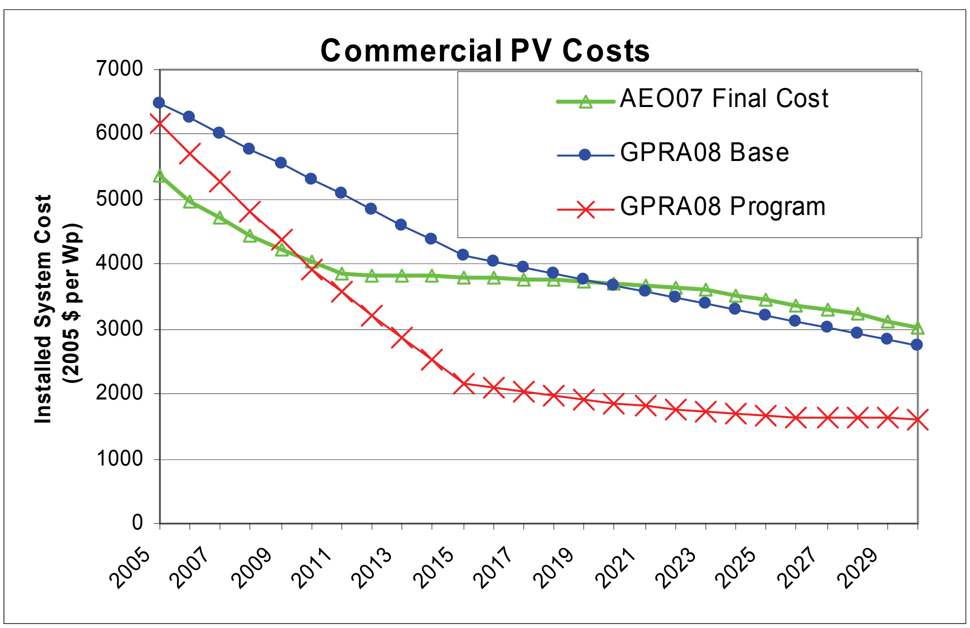



**Figure 3. Comparison of Installed Cost Projections for Commercial PV Systems**




As PV technology is brought to scale on a global basis, module costs will decline. Balance-of-system costs will also decrease with increased installations. Given California's commitment to providing long-term incentives through the California Solar Initiative ("CSI"), it is reasonable to expect that balance-of-system costs will significantly decline. The E3 model's assumption that costs remain the same between 2008 and 2020 is inconsistent with these expectations, and should be revised.

Furthermore, the E3 model should be revised to reflect expectations that wind capacity factors will increase over time. While E3 increased its capacity factor assumptions in response to January comments filed by NRDC/UCS and CEERT,[60] NRDC/UCS are concerned that the wind capacity factors assumed by the model are still extremely conservative. In particular, the E3 model's assumption that wind capacity factors remain constant from 2008 to 2020 contradicts government analyses that predict higher future wind capacity factors due to improvements in turbine technology.[61] Table 1 compares the E3 model's wind capacity factor assumptions with the capacity factor assumptions from a comprehensive report of wind energy potential released by the U.S. DOE in May 2008.[62]

**Table 1. Comparison of E3 and U.S. DOE Wind Capacity Factor Assumptions**

| | E3 average (2008 and 2020) | U.S. DOE (2010) | U.S. DOE (2020) |
|---|---|---|---|
| Class 3 | 29% | 35% | 38% |
| Class 4 | 34% | 39% | 42% |
| Class 5 | 37% | 43% | 45% |
| Class 6 | 40% | 46% | 48% |
| Class 7 | 44% | 50% | 52% |

E3's average capacity factor assumptions for both 2008 and 2020 are substantially lower than the U.S. DOE report's assumed capacity factors for 2010, and lower still compared to the U.S. DOE report's assumed capacity factors for 2020. These pessimistic assumptions should be revised to be consistent with more reasonable estimates of wind turbine performance over time.

[60] "Stage 1 GHG Calculator Changes," E3, February 29, 2008, p.14.
[61] The U.S. EIA Annual Energy Outlook 2007, U.S. DOE GPRA FY 08 report, and U.S. DOE Wind Vision analysis all project increased wind capacity factors in 2020.
[62] U.S. DOE 2008. *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply*, pp.181-182.

### *3. The model fails to account for the natural gas price suppression effect of increased levels of renewable energy and energy efficiency.*

In January comments filed on the GHG model, NRDC/UCS expressed concerns with the model's failure to account for the effect of increased levels of clean energy on reducing natural gas prices.[63] NRDC/UCS continue to maintain that this is a significant oversight of the model. The policies modeled in the 33% RPS/High EE goals scenario would reduce natural gas demand by approximately 20% relative to the reference scenario.[64] It is reasonable to expect that such a significant reduction in statewide natural gas demand would substantially reduce prices. By ignoring the natural gas price reduction effect, the E3 model could substantially overstate the cost of achieving high renewable energy and energy efficiency levels.

The 2007 CEC Integrated Energy Policy ("IEPR") Scenario Analysis Project used two different models to examine the effect of high levels of efficiency and renewables throughout the West on natural gas prices. The IEPR found that average wholesale natural gas prices in the WECC would decline by 15% using one model and by 2% in the other model.[65]

NRDC/UCS observe that decreasing the natural gas prices in the 33% RPS/High EE goals scenario in the model by 5% would result in a decrease in total utility costs in 2020 of approximately $550 million. A 10% decrease in natural gas prices would result in a decrease in total utility costs of over $1.1 billion in 2020. These potential price savings are too large to ignore. To reflect the likely effect of reduced natural gas demand on natural gas prices, NRDC/UCS' alternate modeling scenario assumes that gas prices are $0.50/MMBtu lower in the 33% RPS/High EE goals than in the reference case.[66] This represents a reduction to the assumed natural gas price of 6% - roughly in the middle of the 2% to 15% range of price reductions indicated by the IEPR.

---

[63] NRDC/UCS Comments on Modeling-Related Issues, filed January 4, 2008, p. 17.

[64] Estimate based on displaced natural gas electricity generation and savings from natural gas efficiency programs in the 33% RPS/High EE goals case.

[65] CEC 2007. *2007 Final Integrated Energy Policy Report*, p. 237.

[66] This assumption was not applied to develop the illustrative cost results in the previous section on allowance allocation.

***4. The model does not reflect the risks to consumers of different scenarios.***

NRDC/UCS are concerned that the E3 model does not account for the price risks associated with different resource scenarios and thus fails to provide sufficient information for making policy decisions. In previous comments on the Commissions' GHG modeling efforts, NRDC/UCS emphasized that California's heavy reliance on volatile natural gas prices carries significant and growing financial risks for customers – risks that are not reflected in the model.[67] With fossil fuel prices at or near all-time highs, it is imperative that the model include at least basic metrics to evaluate the risk to consumers of different levels of statewide fossil fuel demand. A portfolio with the lowest deterministically estimated cost may be much less preferable than a portfolio with higher projected cost but much lower levels of risk. This is particularly true in the policy and energy market context of California, where AB 32 regulations have the potential to substantially mitigate consumers' exposure to natural gas price risk.

As the 2007 IEPR stated:

> Today's environment calls for an electric resource planning process that includes the variety of options, risks, and uncertainties that utilities must consider in evaluating potential resource additions. Choosing a resource addition based on current lowest-cost projections is no longer adequate if the potential for dramatically higher prices is ignored.[68]

NRDC/UCS urge the Commissions to revise the E3 model to incorporate risk metrics such as cost variability, at least with respect to natural gas prices, which are typically the most important risk factor affecting overall portfolio risk. This would provide policymakers with better information to make AB 32 policy decisions.

***5. Transmission costs should be shared between generators and load***

The E3 model assumes that the costs of transmission investments to access renewable resources is fully borne by renewable generators. NRDC/UCS disputed this assumption in their January comments on GHG modeling-related issues,[69] and remain concerned that the model may be unfairly allocating all incremental transmission costs to renewable generators. Other studies of high levels of renewable energy penetration routinely assign roughly half of incremental renewable transmission costs to load. For

[67] NRDC/UCS Comments on Modeling-Related issues, filed January 4, 2008, p. 15.
[68] CEC 2007. *2007 Final Integrated Energy Policy Report,* p. 63.
[69] NRDC/UCS Comments on GHG Modeling-Related Issues, January 4, 2008, pp.14-15.

instance, the NREL WinDS model, which is frequently used to model the cost impacts of high wind energy scenarios, assumes that the cost of new transmission to access generation is shared equally by generators and by load:

> The WinDS model assumes that 50% of the cost of new transmission is borne by the generation technology for which the new transmission is being built (wind or conventional); the other half is borne by the ratepayers within a region (because of the reliability benefits to all users associated with new transmission). This 50–50 allocation, which is common in the industry, was recently adopted for the 15-state Midwest Independent Transmission System Operator (Midwest ISO) region. New wind transmission lines that carry power across the main interconnects are not cost-shared with other technology. In the WinDS model, this sharing of costs is implied by reducing the cost of new transmission associated with a particular capacity by 50%. This means that the relative costs of transmission and capacity capital are in line with the model's assumption. The remaining 50% of transmission costs are integrated into the final cost value outputs from the model, resulting in accurate total transmission costs.[70]

In the case of the E3 model, it is reasonable to expect that the significant transmission investments needed to achieve the 33% RPS would displace or defer transmission costs needed for load growth or reliability. Ignoring the benefits to load of new transmission investments, as the E3 model has done, is likely to overstate the cost of achieving the 33% RPS.

***6. Combined-cycle gas turbine capital cost assumptions should be increased.***

The model's capital cost assumption for new combined-cycle gas turbines ("CCGT") is based on capital cost inputs to the 2007 Market Price Referent ("MPR") in the RPS proceeding.[71] UCS has expressed concerns in the RPS proceeding that the capital cost assumptions underlying the MPR are unrealistically low and should be adjusted to reflect the recent escalation in material and construction costs.[72] These same concerns apply to the E3 model's treatment of CCGT capital costs. In particular, the

[70] U.S. DOE 2008. *20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply,* p. 178.
[71] E3 modeling documents, "New Combined Cycle Gas Turbine (CCGT) Generation Resource, Cost, and Performance Assumptions." November 2007, p. 2.
[72] Pre-Workshop Comments of the Union of Concerned Scientists on 2008 Market Price Referent for the Renewables Portfolio Standard Program, filed March 6. 2008 in R.06-02-012, pp.18-19.

CCGT capital cost input to the MPR model is based on two California CCGT plants that were primarily built in 2004 and 2005 – prior to the more recent dramatic increase in plant construction costs. 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 solar thermal and wind."[73] 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.

### 7. *The reference case should include achievement of the California Solar Initiative goal*

The E3 model's reference case assumes that only 847 MW of rooftop solar will be installed statewide by 2020 – far short of the California Solar Initiative goal of 3,000 MW by 2016. The reference case assumes that only 65 MW of rooftop PV will be installed in each year between 2012 and 2020.[74] Over the entire 2008-2020 period, this equates to a PV installation rate of only 46 MW per year – less than the 59 MW installed in 2006 and 81 MW installed in 2007.[75] According to the CPUC staff's most recent progress report on the CSI, PV system installations in 2008 should amount to at least 100 MW.[76] This IOU-specific figure does not include the installations resulting from the CEC New Solar Homes Partnership or from POU programs, which are expected to contribute over 1,000 MW to the statewide goal in 2016.

Given expected PV system cost reductions, PV installations should increase over time, consistent with the increasing amount of installations observed in the brief history of the CPUC-administered CSI program. The reference case should be revised to assume both PV system cost reductions over time and the full achievement of the 3,000 MW statewide CSI goal.

---

[73] "Data notes" in cell B112 of "Gen Cost" tab of E3 GHG Calculator v2b.
[74] 'CSI' tab of E3 GHG Calculator v2b.
[75] CPUC 2008. *California Solar Initiative: CPUC Staff Progress Report,* April 2008, p.5.
[76] Ibid p.6.

## B. ALTERNATE MODELING SCENARIO

NRDC/UCS developed an alternate modeling scenario, which included adjustments to model input assumptions to address some of the concerns described above. Because the architecture of the E3 model does not easily permit user changes to address all of our concerns, we developed an alternate modeling scenario with a limited set of changes to certain input assumptions. The NRDC/UCS alternate modeling scenario includes a revised reference case and a revised 33% RPS/High EE goals case. Both cases incorporate the following changes:

- Solar thermal capital costs are reduced by 25% in 2020.
- The class 4 wind capacity factor is increased from 37% to 43% (which similarly increases all of the other wind class capacity factors).[77]
- CSI installations are equal to 3,000 MW in 2020.
- The "Market Transformation" cell in the CSI tab is set to "yes."

In addition, the revised 33% RPS/High EE goals case incorporates the following changes:

- The natural gas price is reduced from \$7.85/MMBtu to \$7.35/MMBtu in the 33% RPS/High EE goals scenario.
- Renewable resources are changed in the following zones to achieve the 33% RPS at lower overall cost:
    - CA – Distributed: decreased from 900 MW to 500 MW
    - CFE: decreased from 1500 MW to 0
    - Geysers/Lake: decreased from 500 MW to 0
    - Imperial: increased from 4500 MW to 6000 MW
    - Riverside: increased from 0 to 1500 MW
    - San Diego: increased from 750 MW to 1500 MW

Table 2 summarizes the GHG emissions and cost impacts resulting from these limited changes to the model.

[77] 43% is the capacity factor assumed by the U.S. DOE 20% wind report for class 4 wind in 2010.

**Table 2. GHG Emissions and Cost Impacts of NRDC/UCS Alternate Modeling Scenario**

| | 2020 GHG emissions (MMTCO2e) | 2020 utility cost ($M) | Δ 2020 utility cost[a] ($M) | Δ 2020 consumer cost[a] ($M) | Δ 2020 total resource cost[a] ($M) |
|---|---|---|---|---|---|
| Reference case | 108.2 | $47,639 | — | — | — |
| Revised reference case | 106.5 | $47,296 | ($343) | $1,215 | $872 |
| Revised 33% RPS/High EE goals case | 77.6 | $44,983 | ($2,656) | $4,822 | $2,166 |

[a] Change in cost from reference case.

The total resource cost of the revised 33% RPS/High EE goals case is $1.3 billion greater than the total resource cost of the revised reference case. This translates to 2.7% of the 2020 reference case total revenue requirement. However, the revised 33% RPS/High EE goals case also results in 28.9 MMTCO2e fewer emissions than the revised reference case. This implies an average incremental cost (including consumer costs) of CO2 mitigation of $45/tonne – almost three times less than the $131/tonne figure estimated by E3 to achieve the 33% RPS/High EE goals case relative to the reference case.

NRDC/UCS' alternate modeling scenario does not attempt to change the allocation of transmission costs in the 33% RPS/High EE goals case. The alternate modeling scenario also does not attempt to increase the capital cost of CCGT plants, nor does it attempt to model the impact of lower total resource costs for energy efficiency. Changing these assumptions in the model would further minimize the estimated incremental cost of the 33% RPS/High EE goals case. Using higher natural gas prices than the model's conservatively low estimate of $7.85/MMBtu in 2020 would also reduce the relative cost impact of the 33% RPS/High EE goals case.

## VIII. CONCLUSION

We appreciate the Commissions and staffs' efforts on the staff papers and rulings on allocation, CHP, ERMs, and Modeling. We urge the Commissions to consider our recommendations described above.

Dated: June 2, 2008

Respectfully submitted,


Kristin Grenfell
Attorney
Natural Resources Defense Council
111 Sutter St., 20th Floor
San Francisco, CA 94104
415-875-6100
kgrenfell@nrdc.org

Audrey Chang
Director, California Climate Program
Natural Resources Defense Council
111 Sutter St., 20th Floor
San Francisco, CA 94104
415-875-6100
achang@nrdc.org

Cliff Chen
Senior Energy Analyst
Union of Concerned Scientists
2397 Shattuck Avenue, Suite 203
Berkeley, CA 94704
510-843-1872
cchen@ucsusa.org

Chris Busch
Economist
Union of Concerned Scientists
2397 Shattuck Avenue, Suite 203
Berkeley, CA 94704
510-843-1872
cbusch@ucsusa.org

**CERTIFICATE OF SERVICE**

I hereby certify that I have this day served a copy of the **"Comments of the Natural Resources Defense Council (NRDC) and the Union of Concerned Scientists (UCS) on Allowance Allocation, Flexible Compliance, CHP, Emission Reduction Measures, and Modeling Issues" in the matter of R.06-04-009** to all known parties of record in this proceeding by delivering a copy via email or by mailing a copy properly addressed with first class postage prepaid.

Executed on June 2, 2008 at San Francisco, California.

Shari Walker
Natural Resources Defense Council
111 Sutter St., 20th Floor
San Francisco, CA 94104
415-875-6100
Swalker@nrdc.org

## ATTACHMENT A:

## E3 CALCULATOR RESULTS FOR ARR SCENARIOS

NRDC/UCS modeled four different 100% auction ARR scenarios that ended with 100% sales-based distribution in 2020:

- 100% sales-based ARR throughout 2012-2020 period ("NRDC/UCS 3c");
- 100% emissions-based ARR in 2012 with straight-line transition to 100% sales-based ARR in 2020 ("NRDC/UCS 3e");
- 50% emissions-based/50% sales-based ARR in 2012 with straight-line transition to 100% sales-based ARR in 2020 ("NRDC/UCS 3g"); and
- 23% emissions-based/77% sales-based ARR in 2012 with straight-line transition to 100% sales-based ARR in 2020 ("NRDC/UCS 3i").[1]

NRDC/UCS do not have a single preferred approach for the basis of ARR, except that we recommend that the ARR basis should transition to 100% sales-based (adjusted for verified energy efficiency savings) distribution in 2020 or earlier. ***We believe there are many workable approaches, and do not have a single preferred approach;*** the most important issue from our perspective is that the auction revenues be recycled to benefit consumers and to make investments to reduce GHG emissions.

NRDC/UCS used the following assumptions in the E3 GHG calculator for each of these scenarios:

- Resource additions from E3 33% RPS/High Goals EE scenario
- No other changes to defaults in E3 model, including:[2]
    - E3 assumption of constant market clearing price of \$30/tonne $CO_2$
- Constant natural gas price of \$7.85 (2008\$) /MMBTU

[1] This last scenario represents a straight-line transition from 100% emissions-based ARR in 1990 to 100% sales-based ARR in 2020. As we pointed out in our November 14, 2007 reply comments on allocation, since the electric industry has been on notice since 1990 about the threat of global warming and the risk of forthcoming GHG regulations, and major utilities including LADWP and SCE made voluntary pledges to reduce their emissions at that time, a long transition period has already been underway. (See *NRDC/UCS/GPI Reply Comments on Allowance Allocation Issues*, submitted November 14, 2007, pp. 5-6.) Thus, one option for determining the transition path from 2012 to 2020 would be based on the transition period from 1990 to 2020. Assuming a straight-line transition from 100% emissions-based auction revenue recycling in 1990 to 100% sales-based revenue recycling in 2020, the 2012 revenue recycling split would be 23% emissions-based and 77% sales-based, transitioning to 100% sales-based in 2020.

[2] Though no changes were made to the other assumptions in the model for these ARR scenario runs, this does not necessarily imply our endorsement of these assumptions; rather, minimal changes were purposely made to the allocation scenarios to facilitate comparison of scenarios.

**USER DEFINED SCENARIO: KEY OUTPUTS, PG. 1** **Scenario Name:** NRDC 3c
**Party Name and Scenario Number:** NRDC/UCS 3c - ARR 100%sales, $7.85/MMBTU, $30/t, 33%RPS/High-Goals EE

**Greenhouse gas emissions summary information**

| MMT CO2e | California | Total Offsets | Non-CA WECC | Total |
|---|---|---|---|---|
| 2020 User Case | 78.6 | 0.0 | 327 | 405 |
| 2020 Reference Case | 108.2 | n/a | 327 | 435 |

**Summary of change in electricity sector average rates & costs**

| | |
|---|---|
| Change in 2020 rates relative to reference case ($/kWh) | $ 0.023 |
| % change in 2020 rates relative to reference case | 15.4% |
| % change in 2020 rates relative to 2008 | 30.5% |
| Change in 2020 utility cost relative to reference case ($M) | $ (632) |
| Change in 2020 utility cost relative to 2008 ($M) | $ 10,546 |

**USER DEFINED SCENARIO: KEY INPUTS**

**Loads**

| | |
|---|---|
| Change in annual growth rate from ref. case | 0.0% |

**Energy Efficiency**

| | | |
|---|---|---|
| Electricity energy efficiency (EE) scenario | 4 | 1= Reference case, 2=low goals case, 3=mid goals case, 4=high goals case |
| Natural gas energy efficiency scenario | 4 | 1= Reference case, 2=low goals case, 3=mid goals case, 4=high goals case |

| | |
|---|---|
| % change in EE achieved from selected scenario | 100% |

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

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

**Demand Response**

Demand Response

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

**Rooftop Photovoltaics**

| | |
|---|---|
| CA rooftop solar PV: 2020 nameplate installed MW | 3000 |

**Combined Heat and Power**

| | <5 MW | >5 MW |
|---|---|---|
| Combined Heat and Power (CHP) new capacity | 1574 | 2804 |

| | |
|---|---|
| CHP receives thermal credit | FALSE |
| Boiler efficiency | 0.8 |

Grid Connected CHP Characteristics

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

CHP Time of Use (TOU) shares, Operating Hours

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

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

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

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

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

**New Renewable Resources & New Non-Renewable Resources**

Renewable resources by transmission cluster

| | |
|---|---|
| Alberta | 0 |
| Arizona-Southern Nevada | 0 |
| Bay Delta | 0 |
| British Columbia | 0 |
| CA - Distributed | 900 |
| CFE | 1500 |
| Colorado | 0 |
| Geysers/Lake | 500 |
| Imperial | 4500 |
| Mono/Inyo | 0 |
| Montana | 0 |
| NE NV | 0 |
| New Mexico | 0 |
| Northeast CA | 0 |
| Northwest | 0 |
| Reno Area/Dixie Valley | 0 |
| Riverside | 0 |
| San Bernardino | 0 |
| San Diego | 750 |
| Santa Barbara | 0 |
| South Central Nevada | 0 |
| Tehachapi | 4394 |
| Utah-Southern Idaho | 0 |
| Wyoming | 0 |

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

Year to hit RPS Target: 9

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

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

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

| | Biogas | Biomass | Geothermal | Hydro - Small | Solar Therma | Wind | Not Used | Not Used |
|---|---|---|---|---|---|---|---|---|
| Heat Rate (BTU/kWh) | 11566 | 15509 | 0 | 0 | 0 | 0 | 0 | 0 |
| Capital Costs (WECC Average) 2008$/kW | 2554 | 3737 | 3011 | 2402 | 2696 | 1931 | 0 | 0 |
| Tax Credits in Use? (1=Yes, 0=No) | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 |
| Capacity Factor | 85% | 85% | 90% | 50% | 40% | 37% | 100% | 100% |
| On-Peak Capacity Contribution | 100% | 100% | 100% | 65% | 85% | 20% | 100% | 100% |

**USER DEFINED SCENARIO: KEY INPUTS, PG. 2** **Scenario Name:** NRDC 3c
**Party Name and Scenario Number:** NRDC/UCS 3c - ARR 100%sales, $7.85/MMBTU, $30/t, 33%RPS/High-Goals EE

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

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

**Fuel Prices**

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

**CO2 Market**

| **Price for Emissions Permits** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|---|---|---|---|
| Price for permits ($/tonne CO2e) | $ 30.00 | | | | | | | | $ 30.00 |
| **Administrative allocation** | | | | | | | | | |
| Percent of permits administratively allocated | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Percent of permits auctioned | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Basis of allocation** | | | | | | | | | |
| Energy Output (updated yearly) | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Historic 2008 emissions | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Basis of energy output allocation | 2 | 1 = Use all GWh for output-based allocations | | | | | | | |
| | | 2 = Exclude non-fossil GWh from output-based allocations | | | | | | | |
| % of CO2 cost reflected in MCP under output-based allocation | | 100% | | | | | | | |

| **Offsets Price ($/tonne CO2e)** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| California offsets | $ - | | | | | | | | $ - |
| Regional offsets | $ - | | | | | | | | $ - |
| International offsets | $ - | | | | | | | | $ - |
| **Maximum % of emissions requirement that can be met with offsets** | | | | | | | | | |
| California offsets | 0% | | | | | | | | 0% |
| Regional offsets | 0% | | | | | | | | 0% |
| International offsets | 0% | | | | | | | | 0% |

| **Auction Revenue Redistribution to LSEs** | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|
| Percent of auction revenue returned to LSEs | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Method for Returning Revenues** | | | | | | | | | |
| Return based on LSE Sales (updated yearly) | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Return based on 2008 emissions | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Scope of auction revenue return | 1 | 1 = Constant Auction Return (Default Assumption) | | | | | | | |
| | | 2 = Sector-Only Auction Return (Alternative Scenario) | | | | | | | |

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

**Deemed CO2 emissions intensity for imported electricity**

Unspecified imports emissions intensity

| | lbs/MWh |
|---|---|
| Northern | 1100 |
| Southern | 1100 |

Emissions intensity of previously unspecified imports, that become specified

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

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

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Northern | 0% | | | | | | | | 0% |
| Southern | 0% | | | | | | | | 0% |

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

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

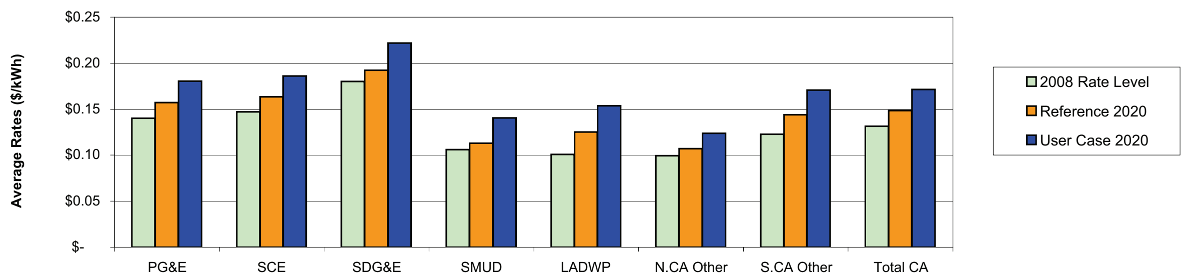
Contract expiration: 2
2 = Generator sells to the power pool after bilateral contract ends (reference case assumption)
1 = Assume renewal of contract ownership (alternative scenario)

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

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

**USER DEFINED SCENARIO: KEY OUTPUTS, PG. 3** **Scenario Name:** NRDC 3c
**Party Name and Scenario Number:** NRDC/UCS 3c - ARR 100%sales, $7.85/MMBTU, $30/t, 33%RPS/High-Goals EE

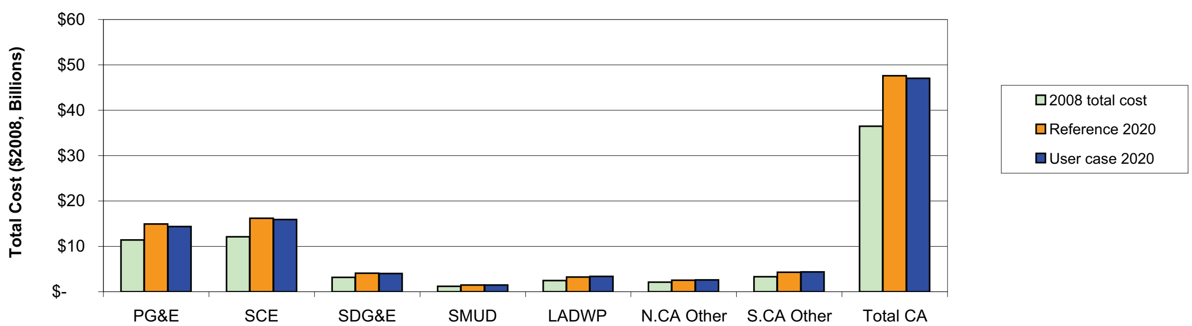
**Comparison of 2008 and 2020 Rates**




**Impact on Rates**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | Total CA |
|---|---|---|---|---|---|---|---|---|
| 2008 Rate Level | $ 0.14 | $ 0.15 | $ 0.18 | $ 0.11 | $ 0.10 | $ 0.10 | $ 0.12 | $ 0.13 |
| Reference 2020 | $ 0.16 | $ 0.16 | $ 0.19 | $ 0.11 | $ 0.13 | $ 0.11 | $ 0.14 | $ 0.15 |
| User Case 2020 | $ 0.18 | $ 0.19 | $ 0.22 | $ 0.14 | $ 0.15 | $ 0.12 | $ 0.17 | $ 0.17 |
| Change 2020 User to Reference | 14.8% | 13.7% | 15.3% | 24.5% | 23% | 15.5% | 18.5% | 15.4% |
| Change 2008 to 2020 User Case | 29% | 27% | 23% | 33% | 52% | 24% | 39% | 31% |

**Comparison of 2008 and 2020 Total Cost**




**Impact on Cost**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | Total CA |
|---|---|---|---|---|---|---|---|---|
| 2008 total cost | $ 11,374 | $ 12,108 | $ 3,141 | $ 1,184 | $ 2,492 | $ 2,138 | $ 3,285 | $ 36,462 |
| Reference 2020 | $ 14,936 | $ 16,231 | $ 4,068 | $ 1,485 | $ 3,266 | $ 2,563 | $ 4,266 | $ 47,639 |
| User case 2020 | $ 14,337 | $ 15,906 | $ 4,039 | $ 1,450 | $ 3,404 | $ 2,602 | $ 4,363 | $ 47,007 |
| Change 2020 User to Reference | -4.0% | -2.0% | -0.7% | -2.4% | 4.2% | 1.5% | 2.3% | -1.3% |
| Change 2008 to 2020 User Case | 26% | 31% | 29% | 22% | 37% | 22% | 33% | 29% |

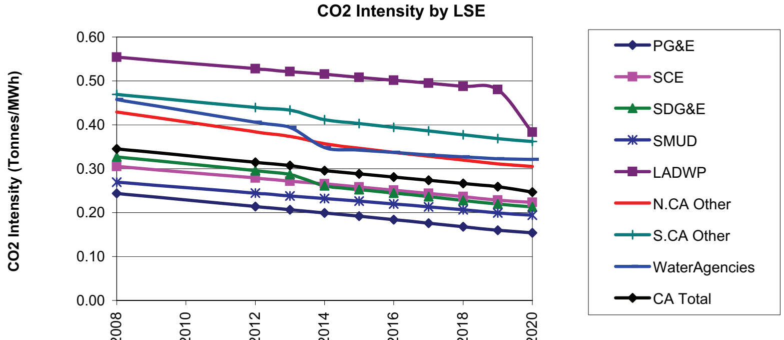
**2020 Producer Surplus ($M)**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | WaterAgenci | Total CA |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | $ 180.50 | $ 215.77 | $ 38.31 | $ 15.04 | $ 32.48 | $ 77.44 | $ 66.07 | $ 41.67 | $ 667.27 |

**Greenhouse Gas Emissions Intensity (tonnes CO2/MWh)**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | WaterAgenci | CA Total |
|---|---|---|---|---|---|---|---|---|---|
| 2008 | 0.24 | 0.31 | 0.33 | 0.27 | 0.55 | 0.43 | 0.47 | 0.46 | 0.34 |
| 2012 | 0.21 | 0.28 | 0.30 | 0.24 | 0.53 | 0.38 | 0.44 | 0.41 | 0.31 |
| 2013 | 0.21 | 0.27 | 0.29 | 0.24 | 0.52 | 0.37 | 0.43 | 0.39 | 0.31 |
| 2014 | 0.20 | 0.27 | 0.26 | 0.23 | 0.51 | 0.36 | 0.41 | 0.35 | 0.30 |
| 2015 | 0.19 | 0.26 | 0.25 | 0.23 | 0.51 | 0.35 | 0.40 | 0.34 | 0.29 |
| 2016 | 0.18 | 0.25 | 0.24 | 0.22 | 0.50 | 0.34 | 0.39 | 0.34 | 0.28 |
| 2017 | 0.18 | 0.24 | 0.24 | 0.21 | 0.49 | 0.33 | 0.39 | 0.33 | 0.27 |
| 2018 | 0.17 | 0.24 | 0.23 | 0.21 | 0.49 | 0.32 | 0.38 | 0.33 | 0.27 |
| 2019 | 0.16 | 0.23 | 0.22 | 0.20 | 0.48 | 0.31 | 0.37 | 0.32 | 0.26 |
| 2020 | 0.15 | 0.22 | 0.21 | 0.19 | 0.38 | 0.31 | 0.36 | 0.32 | 0.25 |

**CO2 Intensity by LSE**



## USER DEFINED SCENARIO: KEY OUTPUTS, PG. 1

**Scenario Name:** NRDC 3e
**Party Name and Scenario Number:** NRDC/UCS 3e - ARR 100%em to 100%sales, $7.85/MMBTU, $30/t, 33%RPS/High-

**Greenhouse gas emissions summary information**

| MMT CO2e | California | Total Offsets | Non-CA WECC | Total |
|---|---|---|---|---|
| 2020 User Case | 78.6 | 0.0 | 327 | 405 |
| 2020 Reference Case | 108.2 | n/a | 327 | 435 |

**Summary of change in electricity sector average rates & costs**

| | |
|---|---|
| Change in 2020 rates relative to reference case ($/kWh) | $ 0.023 |
| % change in 2020 rates relative to reference case | 15.4% |
| % change in 2020 rates relative to 2008 | 30.5% |
| Change in 2020 utility cost relative to reference case ($M) | $ (632) |
| Change in 2020 utility cost relative to 2008 ($M) | $ 10,546 |

## USER DEFINED SCENARIO: KEY INPUTS

### Loads

| | |
|---|---|
| Change in annual growth rate from ref. case | 0.0% |

### Energy Efficiency

| | | |
|---|---|---|
| Electricity energy efficiency (EE) scenario | 4 | 1= Reference case, 2=low goals case, 3=mid goals case, 4=high goals case |
| Natural gas energy efficiency scenario | 4 | 1= Reference case, 2=low goals case, 3=mid goals case, 4=high goals case |

| | |
|---|---|
| % change in EE achieved from selected scenario | 100% |

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

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

### Demand Response

Demand Response

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

### Rooftop Photovoltaics

| | |
|---|---|
| CA rooftop solar PV: 2020 nameplate installed MW | 3000 |

### Combined Heat and Power

| Combined Heat and Power (CHP) new capacity | <5 MW | >5 MW |
|---|---|---|
| | 1574 | 2804 |

| | |
|---|---|
| CHP receives thermal credit | FALSE |
| Boiler efficiency | 0.8 |

Grid Connected CHP Characteristics

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

CHP Time of Use (TOU) shares, Operating Hours

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

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

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

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

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

### New Renewable Resources & New Non-Renewable Resources

Renewable resources by transmission cluster

| | |
|---|---|
| Alberta | 0 |
| Arizona-Southern Nevada | 0 |
| Bay Delta | 0 |
| British Columbia | 0 |
| CA - Distributed | 900 |
| CFE | 1500 |
| Colorado | 0 |
| Geysers/Lake | 500 |
| Imperial | 4500 |
| Mono/Inyo | 0 |
| Montana | 0 |
| NE NV | 0 |
| New Mexico | 0 |
| Northeast CA | 0 |
| Northwest | 0 |
| Reno Area/Dixie Valley | 0 |
| Riverside | 0 |
| San Bernardino | 0 |
| San Diego | 750 |
| Santa Barbara | 0 |
| South Central Nevada | 0 |
| Tehachapi | 4394 |
| Utah-Southern Idaho | 0 |
| Wyoming | 0 |

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

Year to hit RPS Target: 9

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

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

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

| | Biogas | Biomass | Geothermal | Hydro - Small | Solar Therma | Wind | Not Used | Not Used |
|---|---|---|---|---|---|---|---|---|
| Heat Rate (BTU/kWh) | 11566 | 15509 | 0 | 0 | 0 | 0 | 0 | 0 |
| Capital Costs (WECC Average) 2008$/kW | 2554 | 3737 | 3011 | 2402 | 2696 | 1931 | 0 | 0 |
| Tax Credits in Use? (1=Yes, 0=No) | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 |
| Capacity Factor | 85% | 85% | 90% | 50% | 40% | 37% | 100% | 100% |
| On-Peak Capacity Contribution | 100% | 100% | 100% | 65% | 85% | 20% | 100% | 100% |

**USER DEFINED SCENARIO: KEY INPUTS, PG. 2** **Scenario Name:** NRDC 3e
**Party Name and Scenario Number:** NRDC/UCS 3e - ARR 100%em to 100%sales, $7.85/MMBTU, $30/t, 33%RPS/High-

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

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

**Fuel Prices**

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

**CO2 Market**

| **Price for Emissions Permits** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|---|---|---|---|
| Price for permits ($/tonne CO2e) | $ 30.00 | | | | | | | | $ 30.00 |
| **Administrative allocation** | | | | | | | | | |
| Percent of permits administratively allocated | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Percent of permits auctioned | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Basis of allocation** | | | | | | | | | |
| Energy Output (updated yearly) | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Historic 2008 emissions | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Basis of energy output allocation | 2 | 1 = Use all GWh for output-based allocations | | | | | | | |
| | | 2 = Exclude non-fossil GWh from output-based allocations | | | | | | | |
| % of CO2 cost reflected in MCP under output-based allocation | | 100% | | | | | | | |
| **Offsets Price ($/tonne CO2e)** | | | | | | | | | |
| California offsets | $ - | | | | | | | | $ - |
| Regional offsets | $ - | | | | | | | | $ - |
| International offsets | $ - | | | | | | | | $ - |
| **Maximum % of emissions requirement that can be met with offsets** | | | | | | | | | |
| California offsets | 0% | | | | | | | | 0% |
| Regional offsets | 0% | | | | | | | | 0% |
| International offsets | 0% | | | | | | | | 0% |

| **Auction Revenue Redistribution to LSEs** | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|
| Percent of auction revenue returned to LSEs | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Method for Returning Revenues** | | | | | | | | | |
| Return based on LSE Sales (updated yearly) | 0% | 13% | 25% | 38% | 50% | 63% | 75% | 88% | 100% |
| Return based on 2008 emissions | 100% | 88% | 75% | 63% | 50% | 38% | 25% | 13% | 0% |
| Scope of auction revenue return | 1 | 1 = Constant Auction Return (Default Assumption) | | | | | | | |
| | | 2 = Sector-Only Auction Return (Alternative Scenario) | | | | | | | |

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

**Deemed CO2 emissions intensity for imported electricity**

Unspecified imports emissions intensity

| | lbs/MWh |
|---|---|
| Northern | 1100 |
| Southern | 1100 |

Emissions intensity of previously unspecified imports, that become specified

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

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

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

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

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

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

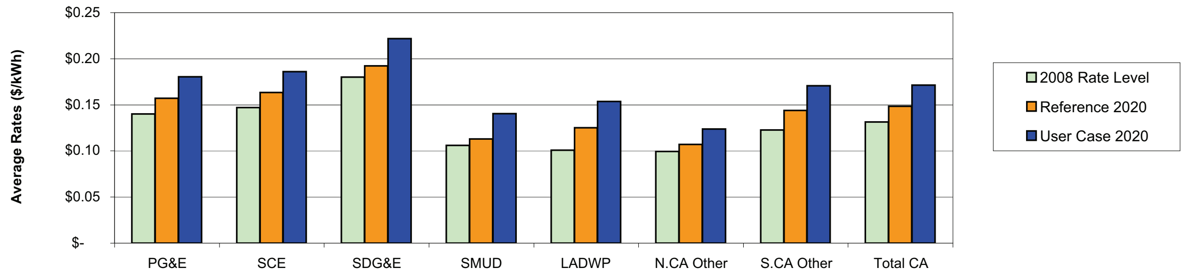
Expiration dates of major LSE contracts or ownership shares with coal generators

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

# NRDC/UCS 3e - 100% emissions-based ARR in 2012 with straight-line transition to 100% sales-based ARR in 2020

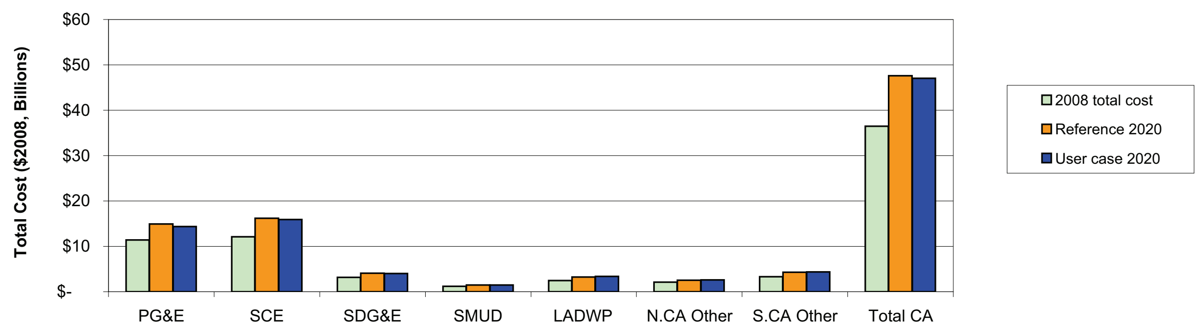


**USER DEFINED SCENARIO: KEY OUTPUTS, PG. 3**   **Scenario Name:** NRDC 3e
**Party Name and Scenario Number:** NRDC/UCS 3e - ARR 100%em to 100%sales, $7.85/MMBTU, $30/t, 33%RPS/High-




**Impact on Rates**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | Total CA |
|---|---|---|---|---|---|---|---|---|
| 2008 Rate Level | $ 0.14 | $ 0.15 | $ 0.18 | $ 0.11 | $ 0.10 | $ 0.10 | $ 0.12 | $ 0.13 |
| Reference 2020 | $ 0.16 | $ 0.16 | $ 0.19 | $ 0.11 | $ 0.13 | $ 0.11 | $ 0.14 | $ 0.15 |
| User Case 2020 | $ 0.18 | $ 0.19 | $ 0.22 | $ 0.14 | $ 0.15 | $ 0.12 | $ 0.17 | $ 0.17 |
| Change 2020 User to Reference | 14.8% | 13.7% | 15.3% | 24.5% | 23% | 15.5% | 18.5% | 15.4% |
| Change 2008 to 2020 User Case | 29% | 27% | 23% | 33% | 52% | 24% | 39% | 31% |




**Impact on Cost**

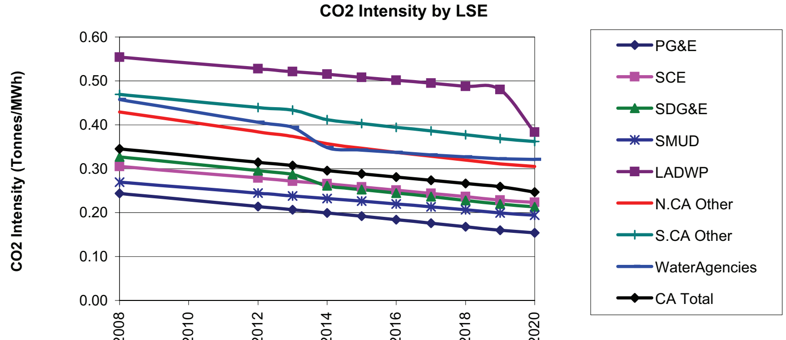
| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | Total CA |
|---|---|---|---|---|---|---|---|---|
| 2008 total cost | $ 11,374 | $ 12,108 | $ 3,141 | $ 1,184 | $ 2,492 | $ 2,138 | $ 3,285 | $ 36,462 |
| Reference 2020 | $ 14,936 | $ 16,231 | $ 4,068 | $ 1,485 | $ 3,266 | $ 2,563 | $ 4,266 | $ 47,639 |
| User case 2020 | $ 14,337 | $ 15,906 | $ 4,039 | $ 1,450 | $ 3,404 | $ 2,602 | $ 4,363 | $ 47,007 |
| Change 2020 User to Reference | -4.0% | -2.0% | -0.7% | -2.4% | 4.2% | 1.5% | 2.3% | -1.3% |
| Change 2008 to 2020 User Case | 26% | 31% | 29% | 22% | 37% | 22% | 33% | 29% |

**2020 Producer Surplus ($M)**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | WaterAgenci | Total CA |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | $ 180.50 | $ 215.77 | $ 38.31 | $ 15.04 | $ 32.48 | $ 77.44 | $ 66.07 | $ 41.67 | $ 667.27 |

**Greenhouse Gas Emissions Intensity (tonnes CO2/MWh)**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | WaterAgenci | CA Total |
|---|---|---|---|---|---|---|---|---|---|
| 2008 | 0.24 | 0.31 | 0.33 | 0.27 | 0.55 | 0.43 | 0.47 | 0.46 | 0.34 |
| 2012 | 0.21 | 0.28 | 0.30 | 0.24 | 0.53 | 0.38 | 0.44 | 0.41 | 0.31 |
| 2013 | 0.21 | 0.27 | 0.29 | 0.24 | 0.52 | 0.37 | 0.43 | 0.39 | 0.31 |
| 2014 | 0.20 | 0.27 | 0.26 | 0.23 | 0.51 | 0.36 | 0.41 | 0.35 | 0.30 |
| 2015 | 0.19 | 0.26 | 0.25 | 0.23 | 0.51 | 0.35 | 0.40 | 0.34 | 0.29 |
| 2016 | 0.18 | 0.25 | 0.24 | 0.22 | 0.50 | 0.34 | 0.39 | 0.34 | 0.28 |
| 2017 | 0.18 | 0.24 | 0.24 | 0.21 | 0.49 | 0.33 | 0.39 | 0.33 | 0.27 |
| 2018 | 0.17 | 0.24 | 0.23 | 0.21 | 0.49 | 0.32 | 0.38 | 0.33 | 0.27 |
| 2019 | 0.16 | 0.23 | 0.22 | 0.20 | 0.48 | 0.31 | 0.37 | 0.32 | 0.26 |
| 2020 | 0.15 | 0.22 | 0.21 | 0.19 | 0.38 | 0.31 | 0.36 | 0.32 | 0.25 |



**USER DEFINED SCENARIO: KEY OUTPUTS, PG. 1** Scenario Name: NRDC 3g

Party Name and Scenario Number: NRDC/UCS 3g - ARR 50%em/50%sa to 100%sales, $7.85/MMBTU, $30/t, 33%RPS

**Greenhouse gas emissions summary information**

| MMT CO2e | California | Total Offsets | Non-CA WECC | Total |
|---|---|---|---|---|
| 2020 User Case | 78.6 | 0.0 | 327 | 405 |
| 2020 Reference Case | 108.2 | n/a | 327 | 435 |

**Summary of change in electricity sector average rates & costs**

| | |
|---|---|
| Change in 2020 rates relative to reference case ($/kWh) | $ 0.023 |
| % change in 2020 rates relative to reference case | 15.4% |
| % change in 2020 rates relative to 2008 | 30.5% |
| Change in 2020 utility cost relative to reference case ($M) | $ (632) |
| Change in 2020 utility cost relative to 2008 ($M) | $ 10,546 |

**USER DEFINED SCENARIO: KEY INPUTS**

**Loads**

| | | |
|---|---|---|
| Change in annual growth rate from ref. case | 0.0% | |

**Energy Efficiency**

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

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

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

**Demand Response**

Demand Response

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

**Rooftop Photovoltaics**

| | |
|---|---|
| CA rooftop solar PV: 2020 nameplate installed MW | 3000 |

**Combined Heat and Power**

| | <5 MW | >5 MW |
|---|---|---|
| Combined Heat and Power (CHP) new capacity | 1574 | 2804 |

| | |
|---|---|
| CHP receives thermal credit | FALSE |
| Boiler efficiency | 0.8 |

Grid Connected CHP Characteristics

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

CHP Time of Use (TOU) shares, Operating Hours

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

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

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

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

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

**New Renewable Resources & New Non-Renewable Resources**

Renewable resources by transmission cluster

| | |
|---|---|
| Alberta | 0 |
| Arizona-Southern Nevada | 0 |
| Bay Delta | 0 |
| British Columbia | 0 |
| CA - Distributed | 900 |
| CFE | 1500 |
| Colorado | 0 |
| Geysers/Lake | 500 |
| Imperial | 4500 |
| Mono/Inyo | 0 |
| Montana | 0 |
| NE NV | 0 |
| New Mexico | 0 |
| Northeast CA | 0 |
| Northwest | 0 |
| Reno Area/Dixie Valley | 0 |
| Riverside | 0 |
| San Bernardino | 0 |
| San Diego | 750 |
| Santa Barbara | 0 |
| South Central Nevada | 0 |
| Tehachapi | 4394 |
| Utah-Southern Idaho | 0 |
| Wyoming | 0 |

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

Year to hit RPS Target: 9

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

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

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

| | Biogas | Biomass | Geothermal | Hydro - Small | Solar Therma | Wind | Not Used | Not Used |
|---|---|---|---|---|---|---|---|---|
| Heat Rate (BTU/kWh) | 11566 | 15509 | 0 | 0 | 0 | 0 | 0 | 0 |
| Capital Costs (WECC Average) 2008$/kW | 2554 | 3737 | 3011 | 2402 | 2696 | 1931 | 0 | 0 |
| Tax Credits in Use? (1=Yes, 0=No) | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 |
| Capacity Factor | 85% | 85% | 90% | 50% | 40% | 37% | 100% | 100% |
| On-Peak Capacity Contribution | 100% | 100% | 100% | 65% | 85% | 20% | 100% | 100% |

**USER DEFINED SCENARIO: KEY INPUTS, PG. 2** **Scenario Name:** NRDC 3g
**Party Name and Scenario Number:** NRDC/UCS 3g - ARR 50%em/50%sa to 100%sales, $7.85/MMBTU, $30/t, 33%RPS

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

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

**Fuel Prices**

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

**CO2 Market**

| **Price for Emissions Permits** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|---|---|---|---|
| Price for permits ($/tonne CO2e) | $ 30.00 | | | | | | | | $ 30.00 |
| **Administrative allocation** | | | | | | | | | |
| Percent of permits administratively allocated | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Percent of permits auctioned | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Basis of allocation** | | | | | | | | | |
| Energy Output (updated yearly) | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Historic 2008 emissions | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Basis of energy output allocation | 2 | 1 = Use all GWh for output-based allocations | | | | | | | |
| | | 2 = Exclude non-fossil GWh from output-based allocations | | | | | | | |
| % of CO2 cost reflected in MCP under output-based allocation | | 100% | | | | | | | |

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

| **Auction Revenue Redistribution to LSEs** | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|
| Percent of auction revenue returned to LSEs | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Method for Returning Revenues** | | | | | | | | | |
| Return based on LSE Sales (updated yearly) | 50% | 56% | 62% | 68% | 75% | 81% | 87% | 93% | 100% |
| Return based on 2008 emissions | 50% | 44% | 38% | 32% | 25% | 19% | 13% | 7% | 0% |
| Scope of auction revenue return | 1 | 1 = Constant Auction Return (Default Assumption) | | | | | | | |
| | | 2 = Sector-Only Auction Return (Alternative Scenario) | | | | | | | |

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

**Deemed CO2 emissions intensity for imported electricity**

Unspecified imports emissions intensity

| | lbs/MWh |
|---|---|
| Northern | 1100 |
| Southern | 1100 |

Emissions intensity of previously unspecified imports, that become specified

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

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

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

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

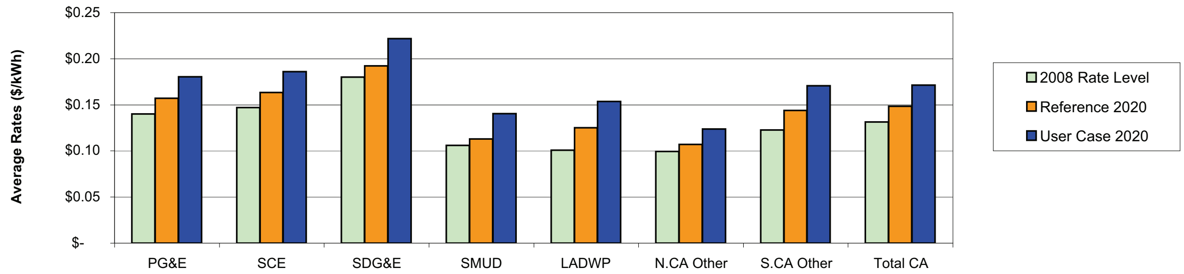
| | | |
|---|---|---|
| Existing contracts: | 2 | 2 = Continue to honor contracts, regardless of economics (reference case assumption) |
| | | 1 = Eliminate contracts if not economic, including price of emission permits (alternative scenario) |
| Contract expiration: | 2 | 2 = Generator sells to the power pool after bilateral contract ends (reference case assumption) |
| | | 1 = Assume renewal of contract ownership (alternative scenario) |

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

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

**USER DEFINED SCENARIO: KEY OUTPUTS, PG. 3** **Scenario Name:** NRDC 3g
**Party Name and Scenario Number:** NRDC/UCS 3g - ARR 50%em/50%sa to 100%sales, $7.85/MMBTU, $30/t, 33%RPS

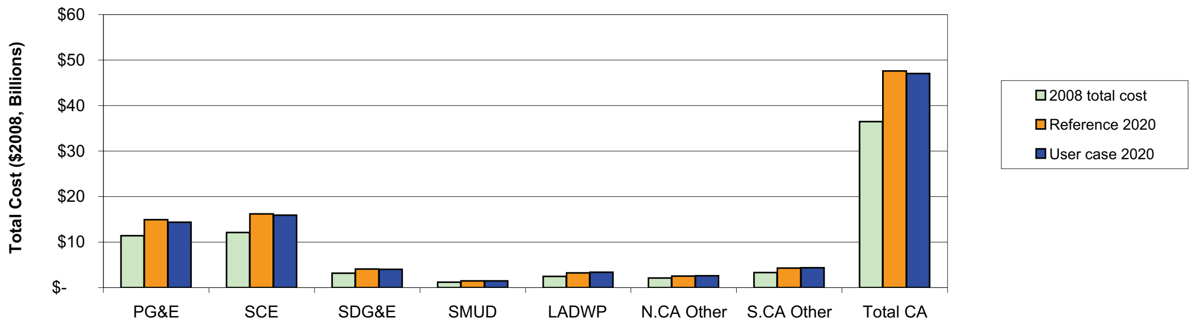
**Comparison of 2008 and 2020 Rates**




**Impact on Rates**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | Total CA |
|---|---|---|---|---|---|---|---|---|
| 2008 Rate Level | $ 0.14 | $ 0.15 | $ 0.18 | $ 0.11 | $ 0.10 | $ 0.10 | $ 0.12 | $ 0.13 |
| Reference 2020 | $ 0.16 | $ 0.16 | $ 0.19 | $ 0.11 | $ 0.13 | $ 0.11 | $ 0.14 | $ 0.15 |
| User Case 2020 | $ 0.18 | $ 0.19 | $ 0.22 | $ 0.14 | $ 0.15 | $ 0.12 | $ 0.17 | $ 0.17 |
| Change 2020 User to Reference | 14.8% | 13.7% | 15.3% | 24.5% | 23% | 15.5% | 18.5% | 15.4% |
| Change 2008 to 2020 User Case | 29% | 27% | 23% | 33% | 52% | 24% | 39% | 31% |

**Comparison of 2008 and 2020 Total Cost**




**Impact on Cost**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | Total CA |
|---|---|---|---|---|---|---|---|---|
| 2008 total cost | $ 11,374 | $ 12,108 | $ 3,141 | $ 1,184 | $ 2,492 | $ 2,138 | $ 3,285 | $ 36,462 |
| Reference 2020 | $ 14,936 | $ 16,231 | $ 4,068 | $ 1,485 | $ 3,266 | $ 2,563 | $ 4,266 | $ 47,639 |
| User case 2020 | $ 14,337 | $ 15,906 | $ 4,039 | $ 1,450 | $ 3,404 | $ 2,602 | $ 4,363 | $ 47,007 |
| Change 2020 User to Reference | -4.0% | -2.0% | -0.7% | -2.4% | 4.2% | 1.5% | 2.3% | -1.3% |
| Change 2008 to 2020 User Case | 26% | 31% | 29% | 22% | 37% | 22% | 33% | 29% |

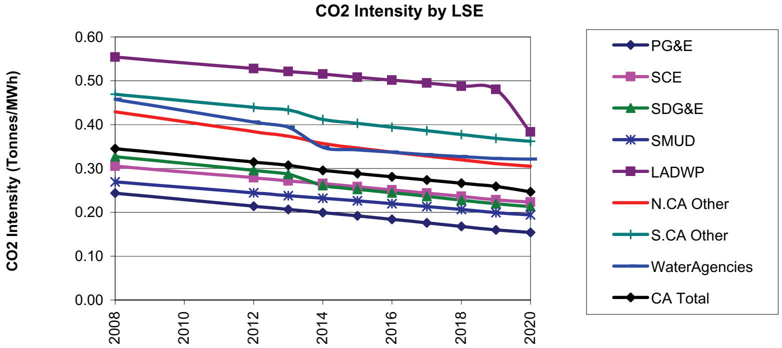
**2020 Producer Surplus ($M)**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | WaterAgenci | Total CA |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | $ 180.50 | $ 215.77 | $ 38.31 | $ 15.04 | $ 32.48 | $ 77.44 | $ 66.07 | $ 41.67 | $ 667.27 |

**Greenhouse Gas Emissions Intensity (tonnes CO2/MWh)**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | WaterAgenci | CA Total |
|---|---|---|---|---|---|---|---|---|---|
| 2008 | 0.24 | 0.31 | 0.33 | 0.27 | 0.55 | 0.43 | 0.47 | 0.46 | 0.34 |
| 2012 | 0.21 | 0.28 | 0.30 | 0.24 | 0.53 | 0.38 | 0.44 | 0.41 | 0.31 |
| 2013 | 0.21 | 0.27 | 0.29 | 0.24 | 0.52 | 0.37 | 0.43 | 0.39 | 0.31 |
| 2014 | 0.20 | 0.27 | 0.26 | 0.23 | 0.51 | 0.36 | 0.41 | 0.35 | 0.30 |
| 2015 | 0.19 | 0.26 | 0.25 | 0.23 | 0.51 | 0.35 | 0.40 | 0.34 | 0.29 |
| 2016 | 0.18 | 0.25 | 0.24 | 0.22 | 0.50 | 0.34 | 0.39 | 0.34 | 0.28 |
| 2017 | 0.18 | 0.24 | 0.24 | 0.21 | 0.49 | 0.33 | 0.39 | 0.33 | 0.27 |
| 2018 | 0.17 | 0.24 | 0.23 | 0.21 | 0.49 | 0.32 | 0.38 | 0.33 | 0.27 |
| 2019 | 0.16 | 0.23 | 0.22 | 0.20 | 0.48 | 0.31 | 0.37 | 0.32 | 0.26 |
| 2020 | 0.15 | 0.22 | 0.21 | 0.19 | 0.38 | 0.31 | 0.36 | 0.32 | 0.25 |

**CO2 Intensity by LSE**



# NRDC/UCS 3i - 23% emissions-based/77% sales-based ARR in 2012 with straight-line transition to 100% sales-based ARR in 2020



## USER DEFINED SCENARIO: KEY OUTPUTS, PG. 1

**Scenario Name:** NRDC 3i

**Party Name and Scenario Number:** NRDC/UCS 3i - ARR 23%em/77%sa to 100%sales, $7.85/MMBTU, $30/t, 33%RPS/

### Greenhouse gas emissions summary information

| MMT CO2e | California | Total Offsets | Non-CA WECC | Total |
|---|---|---|---|---|
| 2020 User Case | 78.6 | 0.0 | 327 | 405 |
| 2020 Reference Case | 108.2 | n/a | 327 | 435 |

### Summary of change in electricity sector average rates & costs

| | |
|---|---|
| Change in 2020 rates relative to reference case ($/kWh) | $ 0.023 |
| % change in 2020 rates relative to reference case | 15.4% |
| % change in 2020 rates relative to 2008 | 30.5% |
| Change in 2020 utility cost relative to reference case ($M) | $ (632) |
| Change in 2020 utility cost relative to 2008 ($M) | $ 10,546 |

## USER DEFINED SCENARIO: KEY INPUTS

### Loads

| | |
|---|---|
| Change in annual growth rate from ref. case | 0.0% |

### Energy Efficiency

| | | |
|---|---|---|
| Electricity energy efficiency (EE) scenario | 4 | 1= Reference case, 2=low goals case, 3=mid goals case, 4=high goals case |
| Natural gas energy efficiency scenario | 4 | 1= Reference case, 2=low goals case, 3=mid goals case, 4=high goals case |

| | |
|---|---|
| % change in EE achieved from selected scenario | 100% |

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

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

### Demand Response

Demand Response

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

### Rooftop Photovoltaics

| | |
|---|---|
| CA rooftop solar PV: 2020 nameplate installed MW | 3000 |

### Combined Heat and Power

| | <5 MW | >5 MW |
|---|---|---|
| Combined Heat and Power (CHP) new capacity | 1574 | 2804 |

| | |
|---|---|
| CHP receives thermal credit | FALSE |
| Boiler efficiency | 0.8 |

Grid Connected CHP Characteristics

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

CHP Time of Use (TOU) shares, Operating Hours

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

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

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

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

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

### New Renewable Resources & New Non-Renewable Resources

Renewable resources by transmission cluster

| | |
|---|---|
| Alberta | 0 |
| Arizona-Southern Nevada | 0 |
| Bay Delta | 0 |
| British Columbia | 0 |
| CA - Distributed | 900 |
| CFE | 1500 |
| Colorado | 0 |
| Geysers/Lake | 500 |
| Imperial | 4500 |
| Mono/Inyo | 0 |
| Montana | 0 |
| NE NV | 0 |
| New Mexico | 0 |
| Northeast CA | 0 |
| Northwest | 0 |
| Reno Area/Dixie Valley | 0 |
| Riverside | 0 |
| San Bernardino | 0 |
| San Diego | 750 |
| Santa Barbara | 0 |
| South Central Nevada | 0 |
| Tehachapi | 4394 |
| Utah-Southern Idaho | 0 |
| Wyoming | 0 |

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

Year to hit RPS Target: 9

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

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

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

| | Biogas | Biomass | Geothermal | Hydro - Small | Solar Therma | Wind | Not Used | Not Used |
|---|---|---|---|---|---|---|---|---|
| Heat Rate (BTU/kWh) | 11566 | 15509 | 0 | 0 | 0 | 0 | 0 | 0 |
| Capital Costs (WECC Average) 2008$/kW | 2554 | 3737 | 3011 | 2402 | 2696 | 1931 | 0 | 0 |
| Tax Credits in Use? (1=Yes, 0=No) | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 |
| Capacity Factor | 85% | 85% | 90% | 50% | 40% | 37% | 100% | 100% |
| On-Peak Capacity Contribution | 100% | 100% | 100% | 65% | 85% | 20% | 100% | 100% |

**USER DEFINED SCENARIO: KEY INPUTS, PG. 2** **Scenario Name:** NRDC 3i
**Party Name and Scenario Number:** NRDC/UCS 3i - ARR 23%em/77%sa to 100%sales, $7.85/MMBTU, $30/t, 33%RPS/

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

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

**Fuel Prices**

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

**CO2 Market**

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

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

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

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

| **Auction Revenue Redistribution to LSEs** | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|
| Percent of auction revenue returned to LSEs | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Method for Returning Revenues** | | | | | | | | | |
| Return based on LSE Sales (updated yearly) | 77% | 80% | 83% | 86% | 88% | 91% | 94% | 97% | 100% |
| Return based on 2008 emissions | 23% | 20% | 17% | 14% | 12% | 9% | 6% | 3% | 0% |

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

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

**Deemed CO2 emissions intensity for imported electricity**

Unspecified imports emissions intensity

| | lbs/MWh |
|---|---|
| Northern | 1100 |
| Southern | 1100 |

Emissions intensity of previously unspecified imports, that become specified

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

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

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

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

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

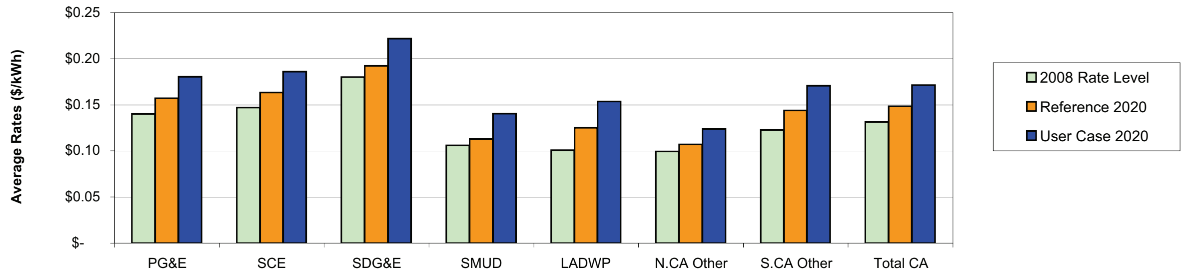
Contract expiration: 2
2 = Generator sells to the power pool after bilateral contract ends (reference case assumption)
1 = Assume renewal of contract ownership (alternative scenario)

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

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

**USER DEFINED SCENARIO: KEY OUTPUTS, PG. 3** **Scenario Name:** NRDC 3i
**Party Name and Scenario Number:** NRDC/UCS 3i - ARR 23%em/77%sa to 100%sales, $7.85/MMBTU, $30/t, 33%RPS/

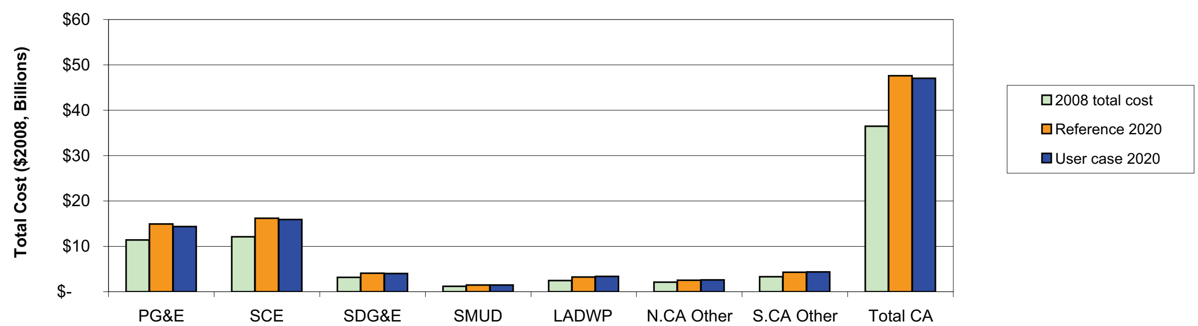
**Comparison of 2008 and 2020 Rates**




**Impact on Rates**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | Total CA |
|---|---|---|---|---|---|---|---|---|
| 2008 Rate Level | $ 0.14 | $ 0.15 | $ 0.18 | $ 0.11 | $ 0.10 | $ 0.10 | $ 0.12 | $ 0.13 |
| Reference 2020 | $ 0.16 | $ 0.16 | $ 0.19 | $ 0.11 | $ 0.13 | $ 0.11 | $ 0.14 | $ 0.15 |
| User Case 2020 | $ 0.18 | $ 0.19 | $ 0.22 | $ 0.14 | $ 0.15 | $ 0.12 | $ 0.17 | $ 0.17 |
| Change 2020 User to Reference | 14.8% | 13.7% | 15.3% | 24.5% | 23% | 15.5% | 18.5% | 15.4% |
| Change 2008 to 2020 User Case | 29% | 27% | 23% | 33% | 52% | 24% | 39% | 31% |

**Comparison of 2008 and 2020 Total Cost**




**Impact on Cost**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | Total CA |
|---|---|---|---|---|---|---|---|---|
| 2008 total cost | $ 11,374 | $ 12,108 | $ 3,141 | $ 1,184 | $ 2,492 | $ 2,138 | $ 3,285 | $ 36,462 |
| Reference 2020 | $ 14,936 | $ 16,231 | $ 4,068 | $ 1,485 | $ 3,266 | $ 2,563 | $ 4,266 | $ 47,639 |
| User case 2020 | $ 14,337 | $ 15,906 | $ 4,039 | $ 1,450 | $ 3,404 | $ 2,602 | $ 4,363 | $ 47,007 |
| Change 2020 User to Reference | -4.0% | -2.0% | -0.7% | -2.4% | 4.2% | 1.5% | 2.3% | -1.3% |
| Change 2008 to 2020 User Case | 26% | 31% | 29% | 22% | 37% | 22% | 33% | 29% |

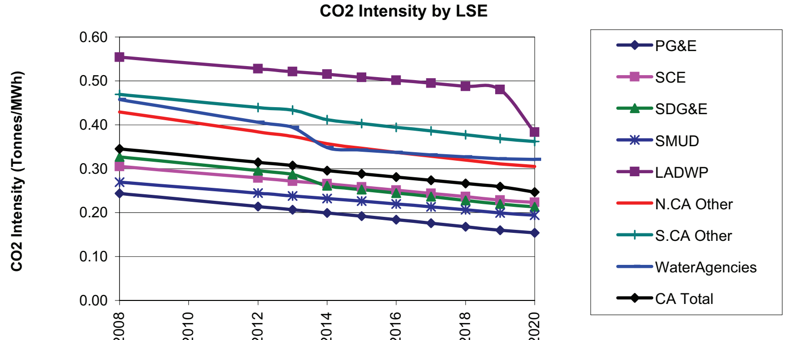
**2020 Producer Surplus ($M)**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | WaterAgenci | Total CA |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | $ 180.50 | $ 215.77 | $ 38.31 | $ 15.04 | $ 32.48 | $ 77.44 | $ 66.07 | $ 41.67 | $ 667.27 |

**Greenhouse Gas Emissions Intensity (tonnes CO2/MWh)**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | WaterAgenci | CA Total |
|---|---|---|---|---|---|---|---|---|---|
| 2008 | 0.24 | 0.31 | 0.33 | 0.27 | 0.55 | 0.43 | 0.47 | 0.46 | 0.34 |
| 2012 | 0.21 | 0.28 | 0.30 | 0.24 | 0.53 | 0.38 | 0.44 | 0.41 | 0.31 |
| 2013 | 0.21 | 0.27 | 0.29 | 0.24 | 0.52 | 0.37 | 0.43 | 0.39 | 0.31 |
| 2014 | 0.20 | 0.27 | 0.26 | 0.23 | 0.51 | 0.36 | 0.41 | 0.35 | 0.30 |
| 2015 | 0.19 | 0.26 | 0.25 | 0.23 | 0.51 | 0.35 | 0.40 | 0.34 | 0.29 |
| 2016 | 0.18 | 0.25 | 0.24 | 0.22 | 0.50 | 0.34 | 0.39 | 0.34 | 0.28 |
| 2017 | 0.18 | 0.24 | 0.24 | 0.21 | 0.49 | 0.33 | 0.39 | 0.33 | 0.27 |
| 2018 | 0.17 | 0.24 | 0.23 | 0.21 | 0.49 | 0.32 | 0.38 | 0.33 | 0.27 |
| 2019 | 0.16 | 0.23 | 0.22 | 0.20 | 0.48 | 0.31 | 0.37 | 0.32 | 0.26 |
| 2020 | 0.15 | 0.22 | 0.21 | 0.19 | 0.38 | 0.31 | 0.36 | 0.32 | 0.25 |

**CO2 Intensity by LSE**



# ATTACHMENT B:

# NRDC/UCS ALTERNATE MODELING SCENARIOS DOCUMENTATION
# (REVISED REFERENCE CASE AND REVISED AGGRESSIVE CASE)

## USER DEFINED SCENARIO: KEY OUTPUTS, PG. 1

**Scenario Name:** Revised reference case

**Party Name and Scenario Number:** NRDC/UCS 34 (Revised reference case)

### Greenhouse gas emissions summary information

| MMT CO2e | California | Total Offsets | Non-CA WECC | Total |
|---|---|---|---|---|
| 2020 User Case | 106.5 | 0.0 | 327 | 433 |
| 2020 Reference Case | 108.2 | n/a | 327 | 435 |

### Summary of change in electricity sector average rates & costs

| | |
|---|---|
| Change in 2020 rates relative to reference case ($/kWh) | $ 0.000 |
| % change in 2020 rates relative to reference case | 0.3% |
| % change in 2020 rates relative to 2008 | 13.4% |
| Change in 2020 utility cost relative to reference case ($M) | $ (343) |
| Change in 2020 utility cost relative to 2008 ($M) | $ 10,834 |

## USER DEFINED SCENARIO: KEY INPUTS

### Loads

| | |
|---|---|
| Change in annual growth rate from ref. case | 0.0% |

### Energy Efficiency

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

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

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

### Demand Response

Demand Response

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

### Rooftop Photovoltaics

| | |
|---|---|
| CA rooftop solar PV: 2020 nameplate installed MW | 3000 |

### Combined Heat and Power

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

| | |
|---|---|
| CHP receives thermal credit | FALSE |
| Boiler efficiency | 0.8 |

Grid Connected CHP Characteristics

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

CHP Time of Use (TOU) shares, Operating Hours

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

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

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

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

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

### New Renewable Resources & New Non-Renewable Resources

Renewable resources by transmission cluster

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

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

Year to hit RPS Target: 1

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

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

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

| | Biogas | Biomass | Geothermal | Hydro - Small | Solar Therma | Wind | Not Used | Not Used |
|---|---|---|---|---|---|---|---|---|
| Heat Rate (BTU/kWh) | 11566 | 15509 | 0 | 0 | 0 | 0 | 0 | 0 |
| Capital Costs (WECC Average) 2008$/kW | 2554 | 3737 | 3011 | 2402 | 2022 | 1931 | 0 | 0 |
| Tax Credits in Use? (1=Yes, 0=No) | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 |
| Capacity Factor | 85% | 85% | 90% | 50% | 40% | 43% | 100% | 100% |
| On-Peak Capacity Contribution | 100% | 100% | 100% | 65% | 85% | 20% | 100% | 100% |

**USER DEFINED SCENARIO: KEY INPUTS, PG. 2** **Scenario Name:** Revised reference case
**Party Name and Scenario Number:** NRDC/UCS 34 (Revised reference case)

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

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

**Fuel Prices**

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

**CO2 Market**

| **Price for Emissions Permits** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|---|---|---|---|
| Price for permits ($/tonne CO2e) | $ - | | | | | | | | $ - |
| **Administrative allocation** | | | | | | | | | |
| Percent of permits administratively allocated | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Percent of permits auctioned | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Basis of allocation** | | | | | | | | | |
| Energy Output (updated yearly) | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Historic 2008 emissions | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Basis of energy output allocation | 1 | 1 = Use all GWh for output-based allocations | | | | | | | |
| | | 2 = Exclude non-fossil GWh from output-based allocations | | | | | | | |
| % of CO2 cost reflected in MCP under output-based allocation | | 100% | | | | | | | |
| **Offsets Price ($/tonne CO2e)** | | | | | | | | | |
| California offsets | $ - | | | | | | | | $ - |
| Regional offsets | $ - | | | | | | | | $ - |
| International offsets | $ - | | | | | | | | $ - |
| **Maximum % of emissions requirement that can be met with offsets** | | | | | | | | | |
| California offsets | 0% | | | | | | | | 0% |
| Regional offsets | 0% | | | | | | | | 0% |
| International offsets | 0% | | | | | | | | 0% |

| **Auction Revenue Redistribution to LSEs** | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|---|
| Percent of auction revenue returned to LSEs | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Method for Returning Revenues** | | | | | | | | | |
| Return based on LSE Sales (updated yearly) | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Return based on 2008 emissions | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Scope of auction revenue return | 1 | 1 = Constant Auction Return (Default Assumption) | | | | | | | |
| | | 2 = Sector-Only Auction Return (Alternative Scenario) | | | | | | | |

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

**Deemed CO2 emissions intensity for imported electricity**

Unspecified imports emissions intensity

| | lbs/MWh |
|---|---|
| Northern | 1100 |
| Southern | 1100 |

Emissions intensity of previously unspecified imports, that become specified

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

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

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

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

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

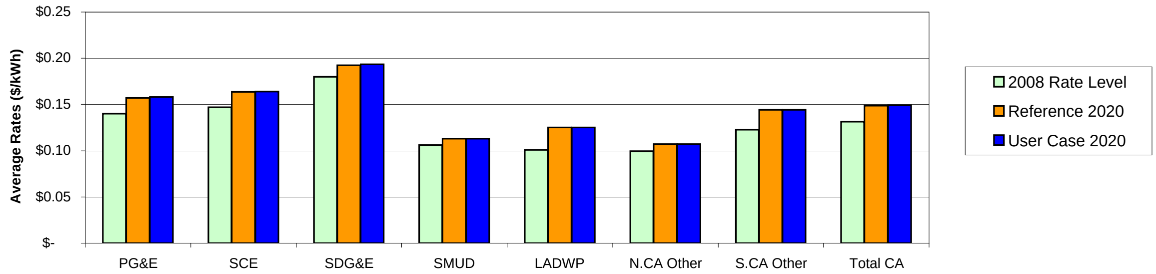
Contract expiration: 2
2 = Generator sells to the power pool after bilateral contract ends (reference case assumption)
1 = Assume renewal of contract ownership (alternative scenario)

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

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

**USER DEFINED SCENARIO: KEY OUTPUTS, PG. 3** **Scenario Name:** Revised reference case
**Party Name and Scenario Number:** NRDC/UCS 34 (Revised reference case)

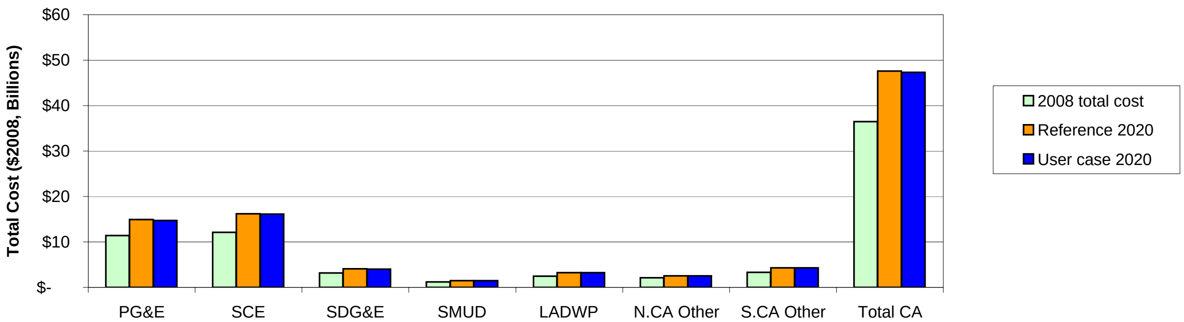
**Comparison of 2008 and 2020 Rates**




**Impact on Rates**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | Total CA |
|---|---|---|---|---|---|---|---|---|
| 2008 Rate Level | $ 0.14 | $ 0.15 | $ 0.18 | $ 0.11 | $ 0.10 | $ 0.10 | $ 0.12 | $ 0.13 |
| Reference 2020 | $ 0.16 | $ 0.16 | $ 0.19 | $ 0.11 | $ 0.13 | $ 0.11 | $ 0.14 | $ 0.15 |
| User Case 2020 | $ 0.16 | $ 0.16 | $ 0.19 | $ 0.11 | $ 0.13 | $ 0.11 | $ 0.14 | $ 0.15 |
| Change 2020 User to Reference | 0.6% | 0.3% | 0.6% | 0.0% | 0% | 0.0% | 0.1% | 0.3% |
| Change 2008 to 2020 User Case | 13% | 12% | 8% | 7% | 24% | 8% | 17% | 13% |

**Comparison of 2008 and 2020 Total Cost**




**Impact on Cost**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | Total CA |
|---|---|---|---|---|---|---|---|---|
| 2008 total cost | $ 11,374 | $ 12,108 | $ 3,141 | $ 1,184 | $ 2,492 | $ 2,138 | $ 3,285 | $ 36,462 |
| Reference 2020 | $ 14,936 | $ 16,231 | $ 4,068 | $ 1,485 | $ 3,266 | $ 2,563 | $ 4,266 | $ 47,639 |
| User case 2020 | $ 14,737 | $ 16,138 | $ 4,032 | $ 1,482 | $ 3,260 | $ 2,562 | $ 4,261 | $ 47,296 |
| Change 2020 User to Reference | -1.3% | -0.6% | -0.9% | -0.2% | -0.2% | -0.1% | -0.1% | -0.7% |
| Change 2008 to 2020 User Case | 30% | 33% | 28% | 25% | 31% | 20% | 30% | 30% |

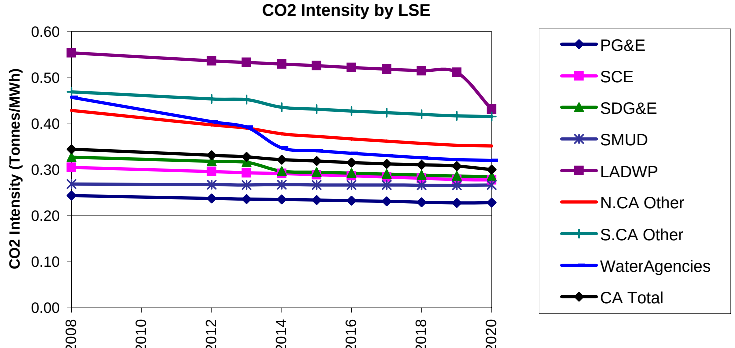
**2020 Producer Surplus ($M)**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | WaterAgenci | Total CA |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**Greenhouse Gas Emissions Intensity (tonnes CO2/MWh)**

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

**CO2 Intensity by LSE**



## USER DEFINED SCENARIO: KEY OUTPUTS, PG. 1

**Scenario Name:** -25% CSP, High CF wind, Full CSI, -$0.5/MMBtu NG, 33% RPS/High EE goals

**Party Name and Scenario Number:** Insert your party name and scenario number in cell H5

**Greenhouse gas emissions summary information**

| MMT CO2e | California | Total Offsets | Non-CA WECC | Total |
|---|---|---|---|---|
| 2020 User Case | 77.6 | 0.0 | 327 | 404 |
| 2020 Reference Case | 108.2 | n/a | 327 | 435 |

**Summary of change in electricity sector average rates & costs**

| | |
|---|---|
| Change in 2020 rates relative to reference case ($/kWh) | $ 0.016 |
| % change in 2020 rates relative to reference case | 10.4% |
| % change in 2020 rates relative to 2008 | 24.9% |
| Change in 2020 utility cost relative to reference case ($M) | $ (2,656) |
| Change in 2020 utility cost relative to 2008 ($M) | $ 8,521 |

## USER DEFINED SCENARIO: KEY INPUTS

**Loads**

| | |
|---|---|
| Change in annual growth rate from ref. case | 0.0% |

**Energy Efficiency**

| | | |
|---|---|---|
| Electricity energy efficiency (EE) scenario | 4 | 1= Reference case, 2=low goals case, 3=mid goals case, 4=high goals case |
| Natural gas energy efficiency scenario | 4 | 1= Reference case, 2=low goals case, 3=mid goals case, 4=high goals case |

| | |
|---|---|
| % change in EE achieved from selected scenario | 100% |

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

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

**Demand Response**

Demand Response

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

**Rooftop Photovoltaics**

| | |
|---|---|
| CA rooftop solar PV: 2020 nameplate installed MW | 3000 |

**Combined Heat and Power**

| | <5 MW | >5 MW |
|---|---|---|
| Combined Heat and Power (CHP) new capacity | 1574 | 2804 |

| | |
|---|---|
| CHP receives thermal credit | FALSE |
| Boiler efficiency | 0.8 |

Grid Connected CHP Characteristics

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

CHP Time of Use (TOU) shares, Operating Hours

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

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

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

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

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

**New Renewable Resources & New Non-Renewable Resources**

Renewable resources by transmission cluster

| | |
|---|---|
| Alberta | 0 |
| Arizona-Southern Nevada | 0 |
| Bay Delta | 0 |
| British Columbia | 0 |
| CA - Distributed | 500 |
| CFE | 0 |
| Colorado | 0 |
| Geysers/Lake | 0 |
| Imperial | 6000 |
| Mono/Inyo | 0 |
| Montana | 0 |
| NE NV | 0 |
| New Mexico | 0 |
| Northeast CA | 0 |
| Northwest | 0 |
| Reno Area/Dixie Valley | 0 |
| Riverside | 1500 |
| San Bernardino | 0 |
| San Diego | 1500 |
| Santa Barbara | 0 |
| South Central Nevada | 0 |
| Tehachapi | 4394 |
| Utah-Southern Idaho | 0 |
| Wyoming | 0 |

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

Year to hit RPS Target: 9

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

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

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

| | Biogas | Biomass | Geothermal | Hydro - Small | Solar Therma | Wind | Not Used | Not Used |
|---|---|---|---|---|---|---|---|---|
| Heat Rate (BTU/kWh) | 11566 | 15509 | 0 | 0 | 0 | 0 | 0 | 0 |
| Capital Costs (WECC Average) 2008$/kW | 2554 | 3737 | 3011 | 2402 | 2022 | 1931 | 0 | 0 |
| Tax Credits in Use? (1=Yes, 0=No) | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 0 |
| Capacity Factor | 85% | 85% | 90% | 50% | 40% | 43% | 100% | 100% |
| On-Peak Capacity Contribution | 100% | 100% | 100% | 65% | 85% | 20% | 100% | 100% |

**USER DEFINED SCENARIO: KEY INPUTS, PG. 2** **Scenario Name:** -25% CSP, High CF wind, Full CSI, -$0.5/MMBtu NG, 33% RPS/High EE goals
**Party Name and Scenario Number:** Insert your party name and scenario number in cell H5

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

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

**Fuel Prices**

| | Gas in CA | Coal in WY |
|---|---|---|
| Fuel price in 2020 ($2008/MMBTU) | $ 7.35 | $ 1.01 |

**CO2 Market**

| **Price for Emissions Permits** | **2012** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|---|---|---|---|---|
| Price for permits ($/tonne CO2e) | $ - | | | | | | | | $ - |
| **Administrative allocation** | | | | | | | | | |
| Percent of permits administratively allocated | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Percent of permits auctioned | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Basis of allocation** | | | | | | | | | |
| Energy Output (updated yearly) | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Historic 2008 emissions | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |

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

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

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

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

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

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

**Deemed CO2 emissions intensity for imported electricity**

Unspecified imports emissions intensity

| | lbs/MWh |
|---|---|
| Northern | 1100 |
| Southern | 1100 |

Emissions intensity of previously unspecified imports, that become specified

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

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

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

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

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

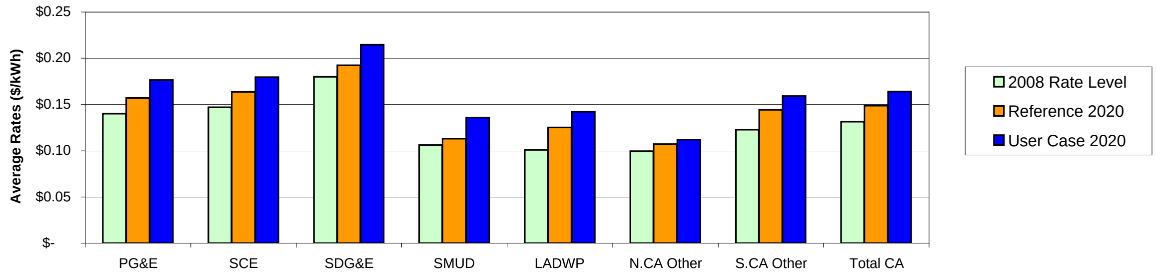
Contract expiration: 2
2 = Generator sells to the power pool after bilateral contract ends (reference case assumption)
1 = Assume renewal of contract ownership (alternative scenario)

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

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

**USER DEFINED SCENARIO: KEY OUTPUTS, PG. 3** **Scenario Name:** -25% CSP, High CF wind, Full CSI, -$0.5/MMBtu NG, 33% RPS/High EE goals
**Party Name and Scenario Number:** Insert your party name and scenario number in cell H5

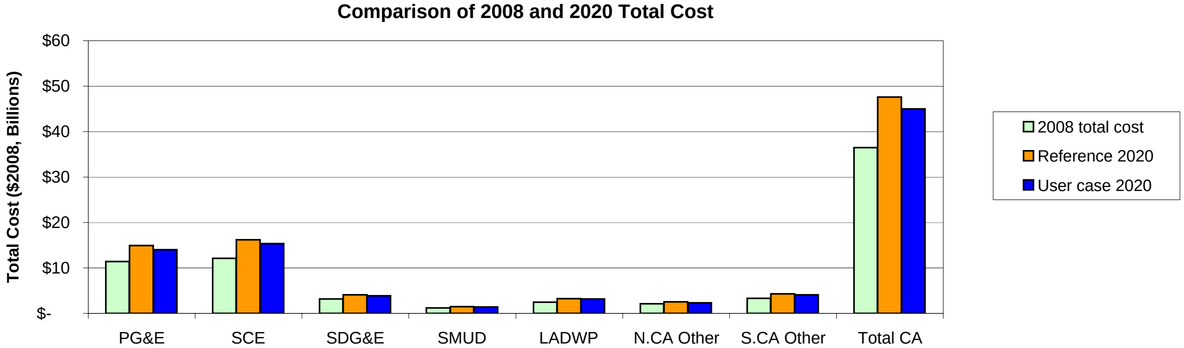
**Comparison of 2008 and 2020 Rates**




**Impact on Rates**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | Total CA |
|---|---|---|---|---|---|---|---|---|
| 2008 Rate Level | $ 0.14 | $ 0.15 | $ 0.18 | $ 0.11 | $ 0.10 | $ 0.10 | $ 0.12 | $ 0.13 |
| Reference 2020 | $ 0.16 | $ 0.16 | $ 0.19 | $ 0.11 | $ 0.13 | $ 0.11 | $ 0.14 | $ 0.15 |
| User Case 2020 | $ 0.18 | $ 0.18 | $ 0.21 | $ 0.14 | $ 0.14 | $ 0.11 | $ 0.16 | $ 0.16 |
| Change 2020 User to Reference | 12.3% | 9.9% | 11.5% | 20.5% | 14% | 4.7% | 10.4% | 10.4% |
| Change 2008 to 2020 User Case | 26% | 22% | 19% | 28% | 41% | 13% | 30% | 25% |

**Comparison of 2008 and 2020 Total Cost**




**Impact on Cost**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | Total CA |
|---|---|---|---|---|---|---|---|---|
| 2008 total cost | $ 11,374 | $ 12,108 | $ 3,141 | $ 1,184 | $ 2,492 | $ 2,138 | $ 3,285 | $ 36,462 |
| Reference 2020 | $ 14,936 | $ 16,231 | $ 4,068 | $ 1,485 | $ 3,266 | $ 2,563 | $ 4,266 | $ 47,639 |
| User case 2020 | $ 14,018 | $ 15,368 | $ 3,907 | $ 1,403 | $ 3,151 | $ 2,359 | $ 4,064 | $ 44,983 |
| Change 2020 User to Reference | -6.1% | -5.3% | -4.0% | -5.5% | -3.5% | -8.0% | -4.7% | -5.6% |
| Change 2008 to 2020 User Case | 23% | 27% | 24% | 18% | 26% | 10% | 24% | 23% |

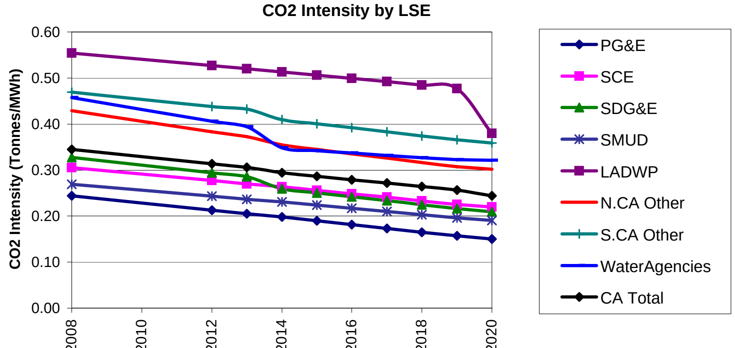
**2020 Producer Surplus ($M)**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | WaterAgenci | Total CA |
|---|---|---|---|---|---|---|---|---|---|
| 2020 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**Greenhouse Gas Emissions Intensity (tonnes CO2/MWh)**

| | PG&E | SCE | SDG&E | SMUD | LADWP | N.CA Other | S.CA Other | WaterAgenci | CA Total |
|---|---|---|---|---|---|---|---|---|---|
| 2008 | 0.24 | 0.31 | 0.33 | 0.27 | 0.55 | 0.43 | 0.47 | 0.46 | 0.34 |
| 2012 | 0.21 | 0.28 | 0.29 | 0.24 | 0.53 | 0.38 | 0.44 | 0.41 | 0.31 |
| 2013 | 0.20 | 0.27 | 0.29 | 0.24 | 0.52 | 0.37 | 0.43 | 0.39 | 0.31 |
| 2014 | 0.20 | 0.26 | 0.26 | 0.23 | 0.51 | 0.35 | 0.41 | 0.35 | 0.29 |
| 2015 | 0.19 | 0.26 | 0.25 | 0.22 | 0.51 | 0.34 | 0.40 | 0.34 | 0.29 |
| 2016 | 0.18 | 0.25 | 0.24 | 0.22 | 0.50 | 0.34 | 0.39 | 0.34 | 0.28 |
| 2017 | 0.17 | 0.24 | 0.23 | 0.21 | 0.49 | 0.33 | 0.38 | 0.33 | 0.27 |
| 2018 | 0.17 | 0.23 | 0.22 | 0.20 | 0.48 | 0.32 | 0.37 | 0.33 | 0.26 |
| 2019 | 0.16 | 0.23 | 0.22 | 0.20 | 0.48 | 0.31 | 0.37 | 0.32 | 0.26 |
| 2020 | 0.15 | 0.22 | 0.21 | 0.19 | 0.38 | 0.30 | 0.36 | 0.32 | 0.24 |

**CO2 Intensity by LSE**



# ATTACHMENT C:

## MAY 20, 2008 COALITION LETTER TO COMMISSIONERS REGARDING ALLOWANCE DISTRIBUTION

May 20, 2008

***Re: Distribution of Allowances in the Utility Sectors***

Dear President Peevey, Chairwoman Pfannenstiel, and Commissioners:

We appreciate the California Public Utilities Commission (CPUC) and California Energy Commission's (CEC) efforts to advise the California Air Resources Board (CARB) on the best structure for a cap and trade program for the utility sectors, should CARB determine that such a program is a desirable part of the package to implement AB 32 and meets the requirements of the law. As you know, a cap and trade program creates "allowances," or a limited number of permits to emit GHGs. These allowances should be seen as a public asset, since they represent permission to use the atmosphere, which belongs to all of us, to dispose of pollution. Appropriate distribution of allowances is crucial to the success of any cap and trade program.

On April 16th, the CPUC and CEC asked for comments on the "Joint California Public Utilities Commission and California Energy Commission Staff Paper on Options for Allocation of GHG Allowances in the Electricity Sector" (hereinafter "Staff Paper"). Some of our organizations will submit detailed comments in response to the Staff Paper. This letter summarizes our major concerns with the Staff Paper's preliminary allocation options and our principal recommendations for how allowances should be distributed in the public interest. We have also attached a position paper by a number of environmental organizations summarizing our perspective on cap and auction programs overall.

## Allowances should NOT be allocated for free to deliverers.

We oppose giving away any allowances for free to deliverers. Free allocation to deliverers will result in windfall profits to at least some deliverers at the expense of California consumers. Allowances provide permission to use the public atmosphere, and there is no reasonable policy rationale for giving away a public asset for free to private companies. We are extremely concerned that four of the six preliminary allocation options presented in the Staff Paper, and ***all three*** of the staff-preferred options, suggest allocating some allowances for free to deliverers. While we remain open to possible free allocation to ***customers***, through their retail provider, in a manner that would aid consumers and further the state's energy efficiency and pollution reduction goals, we strongly oppose any free allocation to ***deliverers***.

## Allowances should NOT be grandfathered.

Allowances should not be grandfathered, i.e.: given away for free based on historical emissions. Grandfathering allowances rewards pollution, penalizes early action, and can also result in windfall profits at the expense of consumers if given to certain types of deliverers. We are very concerned that four of the six allocation options presented in the Staff Paper suggest grandfathering some or all allowances. Grandfathering does not further the goals of AB 32 and it sets a very bad precedent for California in a future national global warming reduction scheme. California should not grandfather any of its allowances.

## Allowances SHOULD be auctioned.

We believe that auctions are the fairest, simplest way of distributing allowances. Auctioning avoids unfair windfall profits, encourages innovation and rewards early action. [1] In addition, auctions will benefit consumers and further AB 32's goals if the revenues are used for the public good. An important way that auction revenues from the utility sectors should be used for the public good is to recycle the revenue back to benefit utility customers through specified investments by their retail provider (see below).

## Auction revenues should be used in the public interest and to further the goals of AB 32.

The majority of auction revenue from the utility sectors should be returned to benefit consumers through specified investments by their retail provider. Some revenue could be invested through statewide programs that would also benefit consumers. Investments should benefit consumers and also help the state meet other environmental and economic goals specified in the statute. These investments could include:

- energy efficiency, especially for low-income and disadvantaged consumers;
- Research, development, and demonstration (RD&D) and deployment of low-carbon technologies;
- support for air and toxic pollution reduction efforts, especially in historically burdened communities;
- protection for low-income and disadvantaged communities, including through direct rebates;
- provision of economic opportunities for low-income and disadvantaged communities; and
- support for green collar jobs.

[1] Many RGGI states are auctioning their allowances beginning this year. *RGGI Press Release* (March 17, 2008), available at http://www.rggi.org/docs/20080317news_release.pdf

In summary, we strongly urge you to reject any recommendation for distributing allowances, a public asset, for free to private polluters. We urge you to recommend that, if CARB decides to adopt a cap-and-trade program, it should auction allowances and invest the revenue in a manner that benefits consumers and furthers the goals of AB 32. Thank you for considering our recommendations.

Sincerely,

Kristin Grenfell
NRDC

Chris Busch
UCS

Jason Barbose
Environment California

Tim Carmichael
Coalition for Clean Air

Bill Magavern
Sierra Club

Mike Sandler
Climate Protection Campaign

cc: Darren Bouton
Mary Nichols
James Goldstene
Chuck Shulock
Kevin Kennedy
Julie Fitch
Karen Griffin

# ATTACHMENT D:

# MAY 9, 2008 COALITION POSITION PAPER REGARDING CAP AND AUCTION

# Cap and Auction Design Position Paper

*Supporters as of May 9, 2008*

**A package of policies is needed to meet AB 32's 2020 emissions limit and the state's 2050 goal.** Meeting the Global Warming Solutions Act's 2020 pollution limit, and the Governor's deeper reduction target by 2050, will require many different policy tools to reduce emissions in many parts of the economy. We firmly believe that continuing and expanding the state's regulatory policies that reduce global warming pollution and provide air pollution reduction co-benefits should be the foundation of the AB 32 implementation plan. This includes multiple regulatory and market-based policy tools, including the energy efficiency standards and programs, renewables portfolio standard, emissions performance standard for generation investments, clean car standards and incentives, and low-carbon fuel standard. We urge CARB to deploy tools to assess the potential cumulative impacts of this package of policies.

We support CARB's consideration of several types of market mechanisms, as discussed at the January 16th workshop, including a cap and trade program, incentives, fees, and rebates. We recognize that every policy tool has strengths and weaknesses, and we urge CARB to adopt a package of multiple policy tools that takes advantage of the relative strengths of each of the different policies to meet the multiple requirements of AB 32. This document focuses on only one of these tools - a cap and trade program - without pre-judging whether any of our organizations will ultimately support any particular cap and trade program.

**Process and requirements in AB 32 must be met.** We support CARB's plan to hold workgroup meetings to hear perspectives from all interested stakeholders on cap and trade as a policy tool and how to best design a program. This process must include, at a minimum, meeting the requirements of Health and Safety Code Section 38570 to consider the impact on criteria and toxic air pollutants,[1] and providing opportunities for the Environmental Justice and Economic and Technology Advancement Advisory Committees and all stakeholders to provide input.

---

1. Health and Safety Code Section 38570(b) requires that CARB do all of the following before including a market-based compliance mechanism in its regulations: "(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."

**Any cap and trade program must meet the objectives of AB 32.** A cap and trade program is a regulatory and market-based policy tool in which a limited number of allowances to emit greenhouse gases would be created and regulated entities would be required to hold enough allowances to match their emissions. AB 32 makes clear that CARB must seek to achieve at least the following objectives when adopting any cap and trade program:

- ♦ Distribute allowances in an equitable manner
- ♦ Seek to minimize costs and maximize total benefits to California
- ♦ Encourage early action to reduce GHG emissions
- ♦ Not disproportionately impact low-income communities
- ♦ Provide appropriate credit for voluntary early action
- ♦ Design the program to prevent any increase in emissions of toxic or criteria air pollutants
- ♦ Minimize administrative burden and leakage

**Elements of a Well-Designed Cap and Trade Program**

Any cap and trade program is comprised of many inter-dependent design elements that ultimately must be evaluated as a package. We offer our general views on each individual design element below.

- ♦ **Tight Declining Cap.** A tight cap that declines over time and provides real emission reductions is the <u>most important</u> design element, as it determines the program's environmental impact and contribution to AB 32's 2020 limit and the state's 2050 reduction goal. The cap should eventually cover, at a minimum, the main sectors that burn fossil fuels, including the electricity, large industrial, natural gas, and transportation sectors; other sectors should also be considered for inclusion where capable of being effectively monitored and verified. A tight cap is essential in order to ensure real emission reductions are achieved. In addition, a tight cap will ensure that the cap and trade program drives innovation and thereby contributes to the transition to a low carbon economy and in particular supports California's rapidly growing clean tech industries.
- ♦ **Auctions and Using Allowances in Public Interest.** Allowances should be seen as a public asset, since they represent permission to use the atmosphere, which belongs to all of us, to dispose of pollution. Therefore, the value of allowances should accrue to, and be used in, the public interest and to further the goals of AB32. Auctioning allowances and using the auction revenue to provide consumer and emission reduction benefits is the preferred method of distributing the value of allowances. Allowances should not be grandfathered (i.e. freely distributed to covered emitters based on historical emissions). Objectives for distributing the value of allowances should include the following, and we urge CARB to provide a detailed description (and take further public input on) how the value of allowances would be distributed.
    - o Prevent the creation of large profits (or "windfall profits") for businesses that are unrelated to actions to reduce GHG emissions;
    - o Reduce the cost and maximize the benefits of the program to consumers, especially in low-income communities, primarily through programs to help permanently reduce energy costs, such as energy efficiency and weatherization programs, as well as through direct payments such as per capita rebates, and through job skills training

programs that can help transform the state's economy into a low-carbon economy and help transition affected workers;
    - Support additional investments in, and deployment of, technologies and strategies to reduce GHG emissions, such as energy efficiency, renewable energy and transit, as well as research, development and demonstration of innovative technologies to reduce emissions;
    - Encourage action that will reduce emissions prior to the start of the overall AB32 program in 2012 and ensure fair treatment for "early actors" that have proactively reduced GHG emissions;
    - Direct investments to disadvantaged communities to support air pollution reduction efforts and enforcement programs, enhance their adaptive capacity, green community development, energy efficiency improvements and renewable energy technologies;[2] and
    - Protect natural resources that can help sequester carbon dioxide and enhance the adaptive capacity of those resources to climate change.

- **Limited Offsets.** AB 32 sets an economy-wide limit on global warming pollution, so reductions will be needed from every major sector of the state's economy. Offsets do not provide additional reductions towards the 2020 limit, but rather provide emission reductions in a sector outside the cap and trade program *instead of* emission reductions in a capped sector. Therefore, CARB should use regulatory programs and other policies to achieve emission reductions in sectors outside the scope of the cap and trade program, so that they can contribute to meeting the statewide 2020 limit, and the further reductions necessary to meet the state's 2050 reduction goal. A necessary precondition to including offsets in a cap-and-trade program is a tight cap; *if* offsets are allowed, they should be subject to at least the following conditions:
    - Represent a limited portion of covered entities' compliance obligation, to ensure that offsets are a limited fraction of the reductions the overall program would achieve;
    - Discounted where appropriate to compensate for loss of local or in-state environmental benefits and for the uncertainty of the emission reductions;
    - Limited to specific project types that have stringent protocols to ensure the emission reductions are real, quantifiable, additional (beyond business as usual), permanent, subject to independent third-party verification and enforceable by CARB; and
    - Priority should be given to projects that will provide environmental co-benefits to California, especially in communities suffering from excessive levels of pollution.

- **Complementing Air Quality and Toxic Reduction Goals.** Any program should be designed to explicitly consider the impact on air quality and toxic emissions, both in local communities and statewide, and to complement state efforts to reduce these emissions, as AB 32 requires. CARB must design any cap and trade program to prevent any increase in toxic and criteria air pollutant emissions. In addition, CARB should strive to achieve additional air quality co-benefits from greenhouse gas emission reductions measures to provide near-term public health benefits, especially in communities that have traditionally been impacted by multiple sources of air pollution.

---

2 Health and Safety Code Section 38565.

- **Strong Monitoring and Enforcement.** Vigorous monitoring and enforcement of emissions, trades, and regulatory compliance is of paramount importance. The program will only limit emissions and provide an environmental benefit if enforcement is strong, consistent, and prompt. Every regulated entity within the cap and trade system must be subject to mandatory annual reporting. Enforcement against an entity whose emissions exceed its allowances should include fines, a requirement to surrender a multiple of the allowances not surrendered, and the other legal remedies (including civil and criminal penalties) contained in AB 32. In particular, there should be a clear penalty up-front for any excess emissions that is large enough that that no rational covered entity would choose to pollute and accept the penalty.
- **Benefit environmental justice communities.** CARB should ensure that any cap and trade program carefully follows all the guidelines in AB 32 for evaluation and prevention of environmental justice impacts. CARB should also design the program to provide benefits to the communities that suffer the greatest cumulative impacts from air pollution. Potential approaches that should be considered include: (i) directing auction revenues to benefit these communities, (ii) limiting the geographical or sectoral scope of the program; (iii) requiring entities purchasing allowances contribute to a community benefits fund.
- **Flexibility and Cost-Containment.** Trading of allowances, banking, and a multi-year compliance period are preferred methods to provide flexibility and lower the costs of the program. (This document does not make specific recommendations about whether trading should be allowed among capped sectors, or be limited to specific geographical areas based on cumulative impact assessments.) *A price cap on allowances (a "safety valve") should not be included, because it would break the program's cap and allow emissions to increase.*
- **Transparency.** The program should make data on emissions, allowances, trades, prices, and evaluations of compatibility with air quality and toxic reduction efforts transparent and publicly available by source and sector in a timely manner to establish a well-functioning program.
- **Linkage with Comparable Programs.** Linkage (i.e. allowing covered entities to surrender allowances issued by another jurisdiction) can provide benefits such as reducing leakage and lowering costs, but should only be considered if the other jurisdictions' programs meet stringent criteria (e.g., comparably stringent caps, comparable mandatory reporting, strong enforcement, limited offsets, etc.) in order to maintain the integrity of the program.