Comments of Pacific Gas and Electric Company On the California Air Resources Board's June 2008 Discussion Draft Scoping Plan Prepared Pursuant to AB 32, The Global Warming Solutions Act of 2006 (HSC § 38500, et seq.)

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Pacific Gas and Electric Company ("PG&E") welcomes the opportunity to provide these initial comments on the California Air Resources Board's *June 2008 Discussion Draft Scoping Plan* ("Draft Plan") prepared pursuant Assembly Bill 32 ("AB 32"), the Global Warming Solutions Act of 2006 (HSC § 38500, et seq.). Our comments address the Draft Plan's overall approach and strategy for achieving AB 32's objectives and should be considered preliminary as we await the ARB's comparative analysis of the cost-effectiveness and technological feasibility of the measures proposed in the Draft Plan and continue our review of the Technical Appendices, released on July 22, 2008. We recognize that the Draft Plan represents ARB's first iteration of its AB 32 "blueprint" and look forward to reviewing and providing comments on ARB's Supplemental Analyses, as well as the subsequent draft versions of the Draft Plan later this year. In particular, we believe that analyses of the technological feasibility and cost effectiveness of the proposed measures in the Draft Plan are essential to allow meaningful public evaluation of the Plan and its impacts.

PG&E and our customers share California's desire to continue its leadership role on climate change, and this is why we were the first investor-owned utility to support enactment of AB 32. PG&E is a gas and electric utility serving one in twenty Americans and is committed to leadership on climate change. Our customers have invested and continue to invest in customer energy efficiency ("CEE") programs and a clean electric generating portfolio, so that our emissions are among the lowest of any utility in the nation. During the 2009 - 2011 period alone, PG&E expects to spend nearly $1.9 billion of customer funded revenue for various CEE programs that will save more than 5,784 gigawatt hours of electricity and 108 million therms of natural gas annually. The GHG emissions associated with the electricity we provide are among the lowest of any large utility in the country, approximately 40% of the CO^2 emitted by the average utility. Currently, over 50% of the electricity PG&E delivers to its customers comes from sources that emit no greenhouse gases at all.

PG&E approaches AB 32 implementation guided by five key objectives. We must:

- **Ensure environmental integrity** through mandatory, real and verifiable reductions;

- **Manage costs to California consumers and businesses** by pursuing cost-effective and technologically feasible reduction strategies and a consumer-oriented allowance allocation approach;

- **Solidify California's national leadership role** on climate change by creating a model program that can be integrated effectively with future regional, national and international programs;

- **Equitably apportion reduction obligations to ensure that all sectors pay their fair share.** Statewide reduction obligations should be apportioned to ensure that no single sector, nor its customers, assumes a disproportionate financial burden; and

- **Rely as much as possible on market and flexible compliance mechanisms** to encourage and accelerate the most efficient, cost-effective pathway to sustainable, available emissions reductions across all sectors.

With these objectives in mind, the following are our initial over-arching comments on the Draft Plan.

I. THE DRAFT PLAN PROPERLY TAKES A COMPREHENSIVE APPROACH TO ACHIEVING GHG REDUCTIONS.

The Legislature directed the ARB to consider three critical questions in designing its Draft Plan and emissions reduction regulations to achieve California's 2020 GHG reduction goal:

1. Will the emissions reduction measures work? For example, are they technologically feasible?

2. Are the emissions reduction measures cost effective? For example, is each measure cost effective compared to alternative measures or programs that could be undertaken to achieve the same quantity of reduction?

3. Are the emissions reduction measures fair and equitable when compared to the relative contribution of each source and sector to overall GHG emissions in California?

PG&E looks forward to providing its own full and complete comments on the Draft Plan when the required analyses are issued later this year and urges the ARB to quickly complete these three essential tasks so that the public and interested parties will have a full opportunity to comment.

It is often said that there is no single "silver bullet" to address the challenge of climate change and that is why it is critically important for California to pursue all "technologically feasible" and "cost-effective" options to achieve emission reduction targets as required by AB 32 (HSC § 38561(a)). The Draft Plan takes an important first step toward this comprehensive approach, relying on a wide range of measures, including market mechanisms and programs, to achieve AB 32's reduction targets. As a general matter, however, we firmly believe that the ARB and California should rely as much as possible on market and flexible compliance mechanisms to encourage and accelerate the most efficient and cost-effective pathways to sustainable emissions and reductions across all sectors. (Draft Plan, p. ES-3.)

As the individual programs described in the Draft Plan are unlikely to achieve the levels of reductions described, PG&E believes that the cap-and-trade system will be responsible for more GHG reductions than acknowledged in the draft. Because of this, offsets and flexible compliance policies should play a more central role in meeting the AB 32 goal than currently described.

II. TECHNOLOGICAL FEASIBILITY AND COST-EFFECTIVENESS EVALUATIONS AS DRAFT PLAN CRITERIA

While PG&E endorses several of the Draft Plan's criteria for developing preliminary recommendations for greenhouse gas reduction measures, including: **"Achieve the 2020 Cap"**; **"Maximize economic benefits and minimize economic harm;" "Provide leadership and influence other governments;"** and **"Assure that emissions reductions required of each sector are equitable"** (Draft Plan, pp. 49, 50), the Draft Plan does not list technological feasibility and cost effectiveness as evaluation criteria as required by AB 32 (HSC § 38561(a)).

The ARB is required to present clear evaluations for each measure for cost effectiveness and technological feasibility across all sectors, along with a full set of the input assumptions. For example, the outcome that the Pavley regulations will save $30 per month in fuel should include assumptions on inputs like the up-front vehicle cost, the miles driven per month, and whether the Low-Carbon Fuel Standard ("LCFS") has been considered in the avoided fuel emissions. Subjective inputs, like assumptions on decreasing costs based on experience or a maturing market, must be highlighted and tested.

Finally, PG&E requests that ARB present one set of cost-effectiveness evaluations without any co-pollutant quantification. As the ARB has acknowledged, they will not be able to quantify all of the co-benefits. Rather than choosing to quantify and include some of the co-benefits, co-pollutant quantification should be presented along side, but not on top of, cost effectiveness for GHG reductions.

III. DUE TO UNCERTAINTIES ASSOCIATED WITH SOME PROGRAMMATIC MEASURES, THE DRAFT PLAN SHOULD BE OPEN TO GREATER RELIANCE ON THE BROADER TRADING MARKET FOR COST-EFFECTIVE EMISSIONS REDUCTIONS.

We support the ARB's conclusion in the Draft Plan that a properly designed, multi-sector cap-and-trade program – and one ideally linked to the Western Climate Initiative ("WCI") – can achieve, real, quantifiable, timely and cost-effective GHG reductions (Draft Plan, p. 15). As discussed more fully at Section X, we believe market based mechanisms with clear and consistent rules and strong oversight – coupled with our current leading customer energy efficiency ("CEE"), renewables, and demand-side management programs – will reduce emissions, diversify our energy supply mix and help to minimize customer costs. Market mechanisms will drive the development of the next generation of clean, highly-efficient technologies and practices.

We are concerned, however, that the Draft Plan may place more reliance on regulatory or programmatic targets than is warranted given uncertainty regarding feasibility and costs, particularly in the areas of CEE, renewables, and combined heat and power ("CHP").

PG&E is committed to our current best-in-class energy efficiency and renewables programs, but programmatic mandates with specific, set-aside targets are not ideal and may not be achievable when outcomes are uncertain, technologies are not yet known, and costs are difficult to forecast. As mandates offer little choice in how to meet goals, these measures should be realistic. Instead, PG&E believes that more reliance should be placed on the ability of the market to deliver cost-effective, innovative and substantial emission-reduction opportunities and less on programmatic measures where California and California's businesses are already demonstrating bold leadership. The unprecedented reductions needed for AB 32 should be left to the market and not be expected or mandated through channels that may not be technologically feasible or cost effective. In doing so, and in leveraging market forces to seek out lower cost reductions, the Draft Plan could serve more nimbly and effectively as a map with multiple roads to achieving AB 32's targets. Therefore, in terms of overall program design, we believe that the ARB should pursue more reductions through market-based mechanisms, including offsets and other flexible compliance mechanisms, than are currently contemplated by the Draft Plan. Our specific concerns regarding renewables, CEE, and CHP are set forth more fully below.

IV. IT IS PREMATURE TO ASSUME GHG REDUCTIONS ASSOCIATED WITH 33% RPS IN THE AB 32 DRAFT PLAN.

Given the recognized uncertainty associated with achieving a 33% Renewable Portfolio Standard ("RPS") by 2020, PG&E does not believe that it is appropriate for the Draft Plan or AB 32 regulations to include firm reductions associated with this stretch goal. Further analysis is needed regarding the feasibility and cost of a 33% renewables target. The absence of such analysis, which is underway in a variety of initiatives including Renewable Energy Transmission Initiative and streamlined permitting and transmissions efforts may impede parties' ability to address the current challenges and understand what will be needed for resource developments and system reliability as more renewables come on line. Given the challenges and uncertainty associated with 33% RPS, the ARB should not rely on a 33% RPS measure or assume a set amount of GHG reductions from such a measure in the Draft Plan until further evaluation and consensus regarding its feasibility and cost effectiveness is completed.

A. Cost Effectiveness of 33% RPS

It is unclear whether a higher RPS target is cost effective vis-à-vis other measures to reduce greenhouse gas emissions. In studies prepared for the California Public Utilities Commission ("CPUC"), Energy and Environmental Economics, Inc. ("E3") has estimated that moving to 33% RPS results in implied costs of $100 to $200 per ton of GHG reductions.[1/] Investment to achieve a 33% renewables goal are expected to be significant – several *billion* dollars – given the costs to construct transmission to remote locations, energy storage, ramping and regulation, over-generation, and back-up dependable capacity. A comprehensive assessment of the costs to ensure system reliability and to get renewables to load centers is an essential element of measuring the cost effectiveness of a higher renewables goal. Absent such an assessment and a thorough understanding of the costs, it is premature to conclude that a fixed 33% renewables target constitutes a cost-effective measure for achieving GHG emissions reductions.

1/ http://www.ethree.com/GHG/E3_CPUC_GHGResults_13May08%20(2).pdf

Additionally, when calculating the cost-effectiveness of this measure, it is inappropriate for the ARB to divide all of the GHG reductions from going to current levels to 33% only by the costs of moving from 20% to 33%. Rather, the ARB needs to determine the cost effectiveness of 33% on its own merits, without assuming that the reductions in getting to 20% come for free. The appropriate formula is to divide the GHG reductions in moving from 20% to 33% by the costs in moving from 20% to 33%.[2/]

B. Uncertainty with Draft Plan Numbers

The Draft Plan states that moving to 33% RPS will add 48,000 GWH and reduce emissions by 21.2 MMT. PG&E understands that these numbers are against a 2005 baseline, unlike E3's *Business As Usual* ("BAU") case, which includes meeting 20% RPS and current energy efficiency goals. The Draft Plan should make clear that these numbers are not incremental to the 20% RPS goals but inclusive of them. Additionally, the ARB should ensure that the energy calculation is made after CEE is subtracted out of the load; the RPS does not apply to load served through energy efficiency. Finally, in accounting for the GHG savings of renewables, the ARB should net out any emissions associated with dispatchable facilities needed to firm the renewables deliveries and ensure system reliability. It is conceivable that these facilities will have to operate at lower minimum loading levels to firm renewables and will therefore be required to operate at a higher heat rate.

C. Current Experience with RPS: Technological Feasibility and Barriers to Achieving 33% Renewables

PG&E is trying to obtain as much renewable energy as possible, while protecting customers against unreasonable costs or threats to service reliability. A number of critical issues must be assessed prior to increasing the existing 20% RPS target. These include: (1) adequacy of supply; (2) adequacy and availability of transmission infrastructure; (3) how to integrate new renewable resources into the grid; (4) managing over-generation and storage; and (5) how developers will finance renewables projects without a multi-year extension of federal investment tax credits ("ITC") and production tax credits ("IPC").[3/] For example, regardless of our shared commitment to increased renewables, if ITC and IPC credits are not extended, some developers

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2/ Draft Plan, C-78.

3/ Pacific Gas and Electric Company, "Docket 07-OIIP-01, California Energy Commission, Opening Comments of Pacific Gas and Electric Company (U 39 E) on Economic Modeling Issues Under AB 32," pp. 17-23.

may face significant delays or simply not be able to proceed with their projects. PG&E is committed to working with state agencies and other parties to address these barriers.

1. The Renewables Market and Adequacy of Supply

Developing additional renewable resources to meet increased demand in California and the Western Electricity Coordination Council ("WECC") will become increasingly challenging. These challenges grow as more and more states adopt RPS programs and, globally, there is increased demand for renewables. As this demand has grown, manufacturing of key components has lagged, yielding "a seller's market" as demand exceeds supply. The National Renewable Energy Laboratory ("NREL") estimates that the demand for clean energy will outpace supply by 37% in 2010.[4/] Order backlogs of up to two years are common with wind turbines and solar photovoltaic cells, largely attributed to increased global demand. Additionally, as new renewables may be located in less accessible locations where new transmission lines are needed, renewables developers frequently encounter permitting and siting-related problems in the remaining undeveloped locations.

2. Transmission Infrastructure

The limited availability of new transmission capacity is one of the key obstacles to increasing renewable supply. Given the remote locations of a substantial portion of the remaining undeveloped renewable resources, significant upgrades in the transmission infrastructure will be required, both in California and throughout the WECC. Additional transmission infrastructure will be very costly and will require many years to construct, which is generally considerably longer than it takes to construct a renewable generating facility. The California Independent System Operators ("CAISO") estimates that, in California alone, the 33% RPS case will require 128 new or upgraded transmission line segments and upgrades to accommodate new generation resources, at an estimated cost of $6.4 billion, excluding land and right-of-way costs.[5/] Transmission limitations will have a direct impact on how quickly and at what total cost California will be able to increase renewables.

4/ Paul Davidson, "USA Today," October 4, 2007.

5/ California ISO, "Integration of Renewable Resources," November 2007, pp. 21.

3. Renewables Integration

The resources needed to integrate renewables to achieve a 33% goal will be substantial. The state will have to add dispatchable generation (hydro or fossil fired) and storage to provide capacity, ramping, and regulation services. A study finalized by the CAISO in November 2007 for achieving 20% RPS found that to integrate 6,700 MW of wind generation (~ 2,600 MW existing and ~ 4,100 MW new), the system would need about 250 MW for "Up Regulation" and up to 500 MW for "Down Regulation."[6/] The CAISO also found that it needed approximately 800 MW of ramping capacity to meet multi-hour ramps during the morning load increase coupled with declining wind generation[7/], plus significant increase of the supplemental energy stack for load following. Ramping and regulation resources to achieve a 33% target would, accordingly, be much greater.

4. Over Generation and Energy Storage

Over generation occurs when significant amounts of uncontrolled generation exceed minimum loads. This usually occurs at night during periods of high "as available" generation and low loads. For example, one of the largest contributors to new renewables will be the Tehachapi wind resource, whose output peaks in May and June, during periods of abundant hydroelectric power and minimum loads.

The CAISO minimum load operating conditions will limit how much off-peak energy can be accepted. While the CAISO can pay adjacent control areas to take this excess power or pay generators to curtail output, this issue will only intensify in the future as surrounding control areas, potentially with their own RPS standards and significant levels of intermittent power, will be in a similar situation, and be faced with uneconomic dispatch or shut down.

Energy storage will be critical to successfully integrating significant levels of intermittent generation and maintaining system reliability. However, current storage technologies are not commercially feasible or geographically available for integrating intermittent resources on a large-scale basis. New commercially ready technologies will be required and may not be commercially available for many years.

6/ CAISO Integration of Renewables Study, November 2007, at 7.
7/ CAISO Integration of Renewables Study at 11.

5. Uncertainty of Federal Tax Credits

A multi-year extension of federal tax credits is crucial for the development of additional renewable resources at reasonable prices for PG&E's customers. Federal tax credits, specifically the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") provide significant benefits to California and can assist in the creation of jobs and billions of dollars in investments in green technology. Such tax credits directly benefit Californians by lowering development costs and enabling the operation of more renewables. These tax credits serve to reduce renewables costs to customers by approximately 30%. PG&E, other IOUs, legislators, and renewable generators have strongly supported extensions of these tax credits; however, it is unclear if or when such an extension will be granted. Without an extension of these credits, hundreds of megawatts of renewable generation are in jeopardy, which may hinder PG&E's ability to reach the 20% RPS, much less an expanded RPS of 33%.

PG&E has also supported the extension of the California Property Tax Exclusion for a five-year period. Extension of this state tax provision will help foster growth in both utility scale and residential solar programs and serve to reduce total customer costs for solar-generated renewable energy.

6. Contract Delay and Failure

PG&E has signed forty contracts for nearly 3500 MW of renewable energy since the 20% RPS statute was enacted. However, performance under those contracts has been susceptible to delays and failures due to problems encountered by suppliers, including siting and permitting delays. Numerous other issues have been encountered that have led to contract delays including problems with avian mortality impacting wind re-powering, cultural resource restrictions affecting land usage for geothermal development, wind turbines causing radar interference issues with Air Force bases, and the lengthy process of negotiating leases for use of federal land. Unanticipated issues such as these can cause significant delays and ultimately impact compliance. In addition, increases in equipment prices are making it difficult for suppliers to obtain project financing, resulting in potential needs for contract renegotiation and project delay, or potential project default.

7. The Need for Equal Application of RPS Standards to Publicly-Owned Utilities

While many POUs have voluntary programs that establish numerical targets equal or greater than the 20% RPS for IOUs, POUs may not be using the same counting conventions that state law, as implemented by the California Energy Commission ("CEC"), requires IOUs to use. As POUs have different eligibility requirements than the IOUs, POUs may "green" their power by using (some) large hydro and renewable energy credits ("RECs") to meet their goals. In 2003, while POUs represented their renewable deliveries as being 7.6% of their combined retail sales, only 5.1% were CEC-eligible renewable sales. This uneven playing field results in customer confusion and results in a state energy policy that is applied to only two-thirds of the energy consumers in the state - that is, those energy consumers served by the IOUs. Before requiring IOUs to achieve higher levels of renewables, the state should require POUs to achieve the same RPS mandate as the IOUs and to use the same counting conventions.

V. ENERGY EFFICIENCY TARGETS ARE HIGHLY UNCERTAIN.

While the state should strive to implement all cost-effective and technologically feasible energy efficiency measures, we do not believe it prudent for ARB to assume a single numeric target for energy efficiency in the Draft Plan. The Draft Plan recommends an energy efficiency measure that would be expected to deliver statewide energy demand reductions of 32,000 GWh and 800 million therms over the 2020 BAU for a reduction of 19.4 MMT CO2e. The ambitious scope, cost, and scale of these goals should be fully acknowledged in the development of the final Scoping Plan. Achieving these goals will require unprecedented coordination and extraordinary action by multiple governmental agencies at federal, state and local levels, as well as coordination among between state agencies, utilities, and end users to create processes and new measures and mandates for energy efficiency that do not exist today. Among other conditions, the success of these goals depends on additional research and development, technology improvements, changes in end-user preferences, declining measure costs, federal waivers for California codes and standards, and compliance and enforcement with new codes and standards. Additionally, the overall energy savings assumed in the Draft Plan are acknowledged as provisional and subject to revision by the PUC. Therefore, the ARB must factor uncertainty into the Draft Plan targets and acknowledge a more realistic range of emissions reductions associated with CEE.

A. Energy Efficiency Cost Effectiveness Analysis

ARB must include cost assessment and evaluation to make sure these measures are cost effective relative to other carbon reduction strategies. PG&E is concerned that the cost numbers presented thus far by the CPUC's Energy Division Draft Plan and The Itron Goals Report ("Itron") are under-estimated and not accurate. As cost figures presented to date have no supporting documentation,[8/] PG&E is not able to ascertain what the value represents and why it does not seem to include the very significant increase in funding for CEE programs needed when utilities provide the full incremental cost of incentives. PG&E also believes that the levelized costs used in the E3 model are too low and needs more information on how these numbers were derived; PG&E has requested supporting documentation.[9/] This month, PG&E has proposed 2009-2011 energy efficiency programs that will cost $1.9 billion; these programs do not come close to funding customer incentives at the full incremental cost of measures. Given the costs of the programs as they are currently designed, PG&E is concerned that offering customer incentives at the full incremental cost of the energy efficiency measures may not be the most efficient use of resources. PG&E concurs with other California stakeholders[10/] that a careful cost-effectiveness analysis of these unprecedented energy efficient initiatives is needed.

Cost calculations should also reflect the additional cost of replacing efficient technologies which do not remain in service to 2020 (for example, if an efficient copying machine[11/] is installed in 2010, it would be expected to last six years and the customer may need an incentive to retire it and replace it with another efficient measure); costs for early retirement of inefficient but still-functioning measures; and the opportunity costs of businesses during energy efficiency

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8/ The ($9.4 billion) value presented in the CPUC Energy Division Staff Paper, May 12, 2008 seems orders of magnitude too low, given that the recommended Itron mid/high level scenario reflects a very significant increase in funding for CEE programs, where utilities provide the full incremental cost of incentives.

9/ The TRC levelized costs for PG&E is shown as $0.057 for the Mid/High Itron cases. This appears low given that these costs were $0.049 for programs in the 2006-2008 period when the level of rebates was significantly lower than is projected in the Mid and High Itron Scenarios, where rebates are set at full incremental cost.

10/ Indeed, the Division of Ratepayer Advocates in their comments on the CPUC Proposed Decision on Interim Energy Efficiency Goals for 2012-2020, July 21, 2008 state on page 4, "The Commission has never authorized full incremental funding of energy efficiency measures, but doing so would result in bigger energy efficiency budgets and higher ratepayer costs of unknown magnitude, with overall lower cost effectiveness of energy efficiency programs."

11/ See the Database of Energy Efficiency Resources at http://eega.cpuc.ca.gov/deer for "High Efficiency Copiers", measure id D03-901, which has an effective useful life of 6 years.

measure installation. Modeling should incorporate the entire cost of the measure, costs related to decay rates, additional incentives for early retirement, opportunity costs for businesses, and contingency costs.

Finally, the CEE goals should evaluate the relative cost effectiveness of CEE programs across different sources within the electric and gas sector, including the relative feasibility and cost effectiveness of CEE measures and programs undertaken by POUs, whose CEE programs have lagged behind those of investor-owned utilities' matured programs.

B. Uncertainty with Draft Plan Numbers

The Draft Plan suggests basing the energy efficiency goals on the high end being considered by the CPUC. However, adopting the high end numbers may be problematic given the level of uncertainty. The Itron Goals Report,[12/] the source of the goals' ranges, contains considerable discussion of substantial uncertainties and recommends the use of a 20% "uncertainty band."[13/] This recommendation does not appear in the CPUC's Proposed Decision or the Draft Plan. The Draft Plan must account for these wide uncertainty bands, as suggested by the Itron.

The high- and mid-level goals assume the implementation of very aggressive CEE rebates at or near 100% of incremental measure costs, followed by much higher participation rates by customers. However, evidence suggests that other behavioral factors may be more significant than full incremental measure cost rebates. For example, consumers may care more about the size of the dishwasher than its energy consumption. Additionally, the goals are predicated on the discovery of new technology, the commercialization of emerging technology, and associated declining measure costs.[14/] The setting of an absolute target for energy efficiency that depends on emerging and uncertain technologies conflicts with AB 32's mandate for measures to be "technologically feasible."

As acknowledged by the CPUC, the current Itron numbers are provisional, subject to revision,[15/] and will be updated in 2010. Detailed workpapers of Itron's work are not yet

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12/ Itron was hired by the Energy Division to assist in setting EE goals for 2012 and beyond. Itron has expertise in measuring and evaluating EE savings.

13/ Ibid, Page 82, "*Each forecast is for the expected case with the high and low values being roughly plus or minus 20% of the expected value*."

14/ Itron, Inc. Consulting and Analysis Services, Assistance in Updating the Energy Efficiency Savings Goals for 2012 and Beyond, April 15, 2008, see page v and 71.

15/ Proposed Decision, p. .30.

available, so Itron's specific calculations cannot be confirmed. Already, needed revisions have surfaced. Subsequent to release of the initial Itron analysis, Itron acknowledged an incorrect inclusion of 2,000 GWh of 2007 savings in the 2012-2020 figures.[16/] The PUC final decision appears to have accounted for this change, and the Scoping Plan should be modified accordingly. Such changes will continue to occur in the future, highlighting the need for flexibility to be built into the Scoping Plan.

In addition to vetting for quality assurance, PG&E recommends that the CEE goals not be adopted until revised to reflect the latest adopted DEER[17/] parameter values (using the most recent adopted Net to Gross, End of Useful Life, Cost data, energy unit savings and load shapes). In total, these updated parameters are likely to result in downward revisions to savings estimates. The CPUC Energy Division has indicated that their CEE goals timeline does not permit updating the CEE potential and goals to be consistent with the new DEER values until 2010.[18/] In PG&E's view, these updates are essential to providing more accurate, reliable, and achievable estimates of the CEE goals.

To acknowledge the ambitious and uncertain nature of its proposed goals, ARB should associate the probabilities with a range of CEE savings. Additionally, PG&E recommends the ARB develop a procedure to update the energy efficiency targets.

In addition to the great uncertainties described in the CEE goals above, it is not apparent to PG&E which CEE goals the ARB is referencing. While the Draft Plan suggests that the high end of the goals be adopted, the PUC PD suggests adopting the Mid Case.

16/ Itron has recently confirmed that its 2008-2020 estimates of energy efficiency potential that underlie the cumulative 28,000 Gwh of savings in the Proposed Decision for the utilities' service areas incorrectly includes 2000 Gwh of 2007 savings. In terms of total savings, the Proposed Decision's calculation of cumulative savings for the 2008-2020 period needs to be adjusted accordingly.

17/ Database of Energy Efficiency Resources (DEER) contains the results of EE measurement and evaluation studies which are then used to determine what EE savings are actually realized. Targets are often set on theoretical values which then need to be revised in the light of empirical analyses. Recent DEER studies have revised mainly downward many estimates of potential EE savings.

18/ Page 32.

Estimated Savings in the High, Mid, and Low Straw Man Cases
(Cumulative GWh savings in 2020)
Page 104, Itron Goals Update Report

Savings Mechanism	Low Case	Mid Case	High Case
Utility programs (gross)	12,240	19,278	19,278
Huffman Bill	6,983	4,064	5,419
Codes & standards	1,800	2,771	3,137
BBEES initiatives	1,734	2,197	3,372
Total	**23,135**	**28,783**	**31,930**

The Draft Plan target of 32,000 Gwh could either be consistent with the High Case Itron goals of 31,930 from IOU service territories alone or this figure could reflect the sum of the Mid Case Itron goals of 28,783 Gwh plus 4,000 Gwh from POU service territories. Additionally, as the PUC decision corrected an error in the Itron report, the Mid Case total is now 2,000 GWh less, around 26,000 GWh. If the ARB is referencing the Mid Case, municipal utilities, with a fourth of the state's electric load, are only being assigned a total of 4000 Gwh of cumulative savings, an amount that is one-seventh of the utility service area goals. If the ARB is referencing the High Case, municipal utilities would appear to have no energy efficiency responsibility in the Draft Plan. As CEC staff noted at the ARB's May 2, 2008, public workshop, despite serving 22% of the electricity load and being responsible for nearly 42% of the utility CO2 emissions,[19/] POUs only contribute 5.4% of energy efficiency savings. If SMUD is removed from those figures, the remaining POUs only contribute 2.7% of energy efficiency savings while serving 18% of the load. These figures show the considerable CEE savings potential in POU territory, savings that the IOUs have been accumulating for years given their thirty-year history of successful and cost effective CEE. Additional targets for energy efficiency should be applied to POUs before looking to expand already ambitious IOU programs. The state should require POUs to achieve a CEE savings target that is proportional to their emissions and generation levels and should mandate similar measurement and evaluation protocols for these POU service territories.

PG&E is also concerned that the Draft Plan may be double counting reductions for energy efficiency. For example, it is unclear if ARB has adequately accounted for energy efficiency already incorporated in load growth. When adding the High Case measures, E3 only added 20,000 GWh additionally as 12,000 GWh is already incorporated in the load growth calculations.

19/ Schulock CAISO presentation.

Additionally, to get the reductions stated in Draft Plan from 32,000 MWh, 15.2 MMT, one has to use an avoided heat rate of 8950 btu/KWh. This heat rate is much higher than the heat rate the CPUC uses to calculate the avoided emissions from a CCGT, 6704 btu/KWh. At this heat rate, 32,000 GWH saves 11.4 MMT, almost four MMT less than the number claimed in the Draft Plan. The E3 calculator shows a 10 MMT reduction in moving from the reference case goals to the High Case CEE goals. PG&E suggested the emissions savings be lowered to ~7 MMT for additional energy efficiency.

C. Current Experience with Energy Efficiency

PG&E is a leader in Energy Efficiency programs, and proactively supports state implementation of new codes and standards, and the demonstration of new energy efficiency technologies. However, there are uncertainties in implementing energy efficiency that are beyond the control of utilities and must be recognized and modeled explicitly. As previously stated, PG&E recommends that ARB take into account the range of uncertainty associated with the realization of these aggressive CEE goals.

For example, many savings are projected to come from improved building codes and appliance energy efficiency standards. However, there are acknowledged compliance issues with these codes and standards. As referenced in the April 25, 2008 edition of California Energy Markets, William Callahan, president of the Bay Area Associated Roofing Contractors, explained that many residential roofing projects require a permit, but often contractors and customers just skip the permit process. In that same article, Erik Emblem, an attorney representing sheet-metal and heating, ventilation and air-conditioner contractors, said 90% of HVAC projects have no permit. Permitted projects that meet code can run $2,000 more than projects that do not, he said.

California may create rigorous codes and standards, but if these standards are not enforced, noncompliance ('permits not pulled') will result in lower realized gross energy efficiency savings and GHG emissions reductions will not occur. Further, if the ARB assumes these reductions will occur, then electricity load will increase, putting pressure on the complying entities and potentially increasing costs to consumers as part of the cap and trade program. Uncertainty in achieving these programmatic goals may create undue scarcity in the cap and trade market, leaving it more vulnerable to price run-ups.

VI. THE DRAFT PLAN OVERESTIMATES THE POTENTIAL FOR GHG REDUCTIONS FROM COMBINED HEAT AND POWER.

The Draft Plan places undue reliance on CHP electric generation sources as a GHG reduction measure. Before adopting CHP as a measure, PG&E recommends that the ARB substantiate that thermal load exists to support these estimates. CHP is a GHG producing, fossil-fuel based source of electricity, so it must not be grouped with energy efficiency, which actually decreases load.[20/] CHP is typically a baseload, must-take resource that provides virtually no operational flexibility. As such, it could potentially displace or make more difficult integrating renewable electricity, also a must-take resource. Must take CHP might increase PG&E's and other utilities' GHG footprint and make integrating renewables more difficult and expensive.

A. The Draft Plan Overestimates CHP Potential and Accompanying GHG Abatement.

The Draft Plan sets an ambitious goal for increased energy production from CHP - 30,000 GWh - engendering GHG reductions of 6.9 MMT. PG&E is doubtful that this magnitude of technologically feasible, cost effective, GHG-reducing potential for CHP actually exists. For example, consider the 50 MW CHP unit installed in 2002 at the Valero Refinery in Benicia, California. According to the CEC's Fact Sheet, that size was selected because it ". . . produced the amount of electrical power that closely matched average re finery consumption and also could efficiently produce the proper amount of 600 psi stream to match the refinery's demand . . ." The Benicia Refinery has a capacity of 153,000 barrels per day, which corresponds to about 8% of California's total refining. In the unlikely case that the other 92'% of California's refining capacity has similar steam demands that are not already being met, via CHP, those steam demands would support just 540 MW of new, efficient CHP. As ARB evaluates the use of CHP for emissions reductions, it should be clear that only efficient CHP in place of existing, business-as-usual thermal load may meaningfully reduce electric sector GHG emissions. If ARB hopes to rely on CHP to reduce GHG emissions, it must first affirmatively establish that thermal load associated with 30,000 GWh of efficient, technologically feasible, cost effective CHP actually exists. Otherwise, the reduction goal tasked to CHP will not be achievable. PG&E supports use of efficient CHP, as long as the CHP projects that are implemented are truly efficient and cost effective, compared to alternative GHG emissions reduction opportunities within the electric

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20/ PG&E notes that this mistaken grouping in the Draft Scoping Plan has been corrected in Appendix E.

sector and within PG&E's portfolio, and provided there is a fair distribution of costs and benefits between CHP owners and non-CHP owners.

The ARB has derived the Draft Plan estimate on a dated draft 2005 CEC consultant study on CHP potential in California. This draft has not been updated.[21/] The ARB based the CHP measure estimate of 4000 MW on the CEC CHP Assessment's "Moderate Market Case" scenario of 4,400 MW – 1,574 MW from new onsite CHP and 2,804 MW of new export MW from very large CHP facilities over 100 MW per site.[22/] As we noted in our comments to the PUC and CEC on the E3 Aggressive Case (which also adopts the CEC CHP Moderate Market Case) PG&E cannot support this estimate for large installations. PG&E suggested using large capacity additions of 393 MW, over 2,400 MW less, because PG&E does not believe that this magnitude of sites with large CHP potential exists.[23/]

In California, favorable CHP sites have were heavily developed as a result of the popularity of Standard Offer 4, resulting from implementation of PURPA in California. While there has been some new thermal load added at large facilities in California, e.g. Valero, additional sites with the ability to use such large amounts of steam are limited in CA. When PG&E asked during the E3 conference call for the CEC/PUC proceeding where this potential would come from, a CHP representative suggested "refinery expansion." PG&E believes that with the passage of AB 32 and the increased focus on the environmental impacts of refineries, it cannot be assumed that refineries will substantially expand and therefore will have large amounts of expanded thermal load. As a great deal of the potential for large CHP may not exist, it may be inappropriate to assume that GHG emissions can be abated through installation of large CHP. The thermal load that the CHP is assumed to replace may not exist or ever be installed.

PG&E offers caution against overly ambitious estimates of CHP potential. A 2007 Lawrence Berkeley National Laboratory ("LBNL") paper, "Preliminary Estimates of Combined Heat and Power Greenhouse Gas Abatement Potential for California in 2020," states:

21/ See footnote 34, on page C-73 of Appendix C, which cites: Assessment of California CHP Market and Policy Options for Increased Penetration (CEC CHP Assessment), PIER Collaborative Report, November 2005, CEC-500-2005-173California Energy Commission, Draft Consultant report, Assessment of California CHP Market and Policy Options for Increased Penetration. Prepared by Electric Power research Institute, April 2005.

22/ Ibid, page C-74.

23/ While PG&E has queried the basis of the CHP capacity with EPRI, we have not been given access to the database on which this capacity figure is based. The model that produced the estimates is proprietary, therefore PG&E cannot reproduce the work or independently verify any assumptions.

We note that for many sectors, carbon emissions reductions increase from the low to the medium penetration scenarios, but decrease in the high and/or maximum penetration scenarios. CHP system efficiency decreases as penetration increases: the most attractive sites, i.e. those with a use for much of the waste heat, are assumed to adopt first; however, as penetration levels increase, CHP becomes less favorable.

Prior to reliance on the CEC "moderate" scenario for CHP potential in California, the ARB should make available an independent estimate.

B. Draft Plan Numbers for CHP GHG Abatement are Uncertain and Need Further Scrutiny.

CHP will be a GHG-reduction measure only under certain circumstances and if it does not interfere with the expansion of renewables and other non-carbon resources. In addition to questioning the potential to add 4,000 MW of CHP; PG&E questions how 4,000 MW equates to savings of 32,000 GWh and how 32,000 GWh of CHP results in 6.9 MMT of GHG emissions reductions. The ARB appears to have used a capacity factor of 85% for all CHP, but smaller CHP facilities have much lower capacity factors. Per the E3 calculator, adding almost 4,400 MW of CHP saves only 4.9 MMT, 2 MMT less with more MWs added. CHP generation should not be evaluated assuming it displaces old and inefficient steam units that operate in a peaking mode. CHP generation may be displacing a new gas fired CCGT plus a new gas-fired boiler, or possibly a baseload or intermittent renewables resource plus a new gas-fired boiler.[24/] The result is unlikely to produce significant GHG reduction benefits.

Further, Reduced line losses should not be attributed to large CHP. The 2005 CEC assessment of the CHP market showed the most potential coming from large CHP units, which would primarily export to the electricity grid.[25/] Therefore, this large CHP will export fossil-fuel based electricity to the grid, causing the same amount of line losses as CCGTs, which may be more efficient than CHP units. Additionally, there appear to be some mistakes in the ARB's calculations 7.8%. The line loss quantity attributed to 30,000 GWh is 2,340 GWh. Even with

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24/ The CEC market potential study bases most of its assumptions about the benefits of CHP by comparing old, low efficiency, old steam turbine-based electrical generation versus thermally optimized high efficiency CHP facilities. In simple terms, the alternative to CHP baseload generation should not be an aging power plant with a higher than 10,000 Btu/kWh heat rate. Because the CEC potential study does not conduct the correct comparison, CHP benefits are over stated. CEC CHP Assessment, p. 2-20.)

25/ California Energy Commission (CEC-500-2005-173). Assessment of California Combined Heat and Power Market and Policy Options for Increased Penetration. November 2005.

the addition of distributed solar, the lines losses of 36,500 GWh would be 2,691 GWh. In total, the ARB shows that these two programs reduce line losses by 5,500 GWh.[26/] PG&E requests that the ARB recalculate the line losses to account for the fact that large CHP will export electricity to the grid and to provide the calculations to the public.

C. CHP is Not Primarily an Emissions Reduction Measure, Nor is it Energy Efficiency.

PG&E does not recommend that CHP be included in the "Energy Efficiency" category, because while CHP, when it is a customer choice option, will reduce demand, it is fundamentally different from energy efficiency and other demand management measures. Energy efficiency creates a demand reduction by reducing the amount of energy needed to accomplish the same end use application. Demand response programs reduce demand through reductions in activity by participating customers. CHP, on the other hand, like all customer generation, simply exchanges one electricity source with another. It does not reduce total electricity demand; it simply reduces the demand that the utility must serve.

D. CHP Competes with Renewable Energy in the Utility Procurement Portfolio.

Finally, in developing the framework for CHP treatment, the ARB must address the challenges associated with adding a must take, base load, non-dispatchable, fossil-fuel resource. As noted in the aforementioned LBNL study,[27/]

> *Typically, CHP is only more carbon efficient than the grid electricity it displaces when the waste heat from the generation offsets additional fuel consumption. Given the quite clean grid generation being displaced, inefficient CHP systems can ultimately lead to a net increase in emissions.*

Because CHP electricity, like renewable energy, is typically a non-dispatchable base load resource, adding fossil fuel-based CHP to the base load utility portfolio could crowd out renewable sources. Such challenges demonstrate the importance of understanding how energy resources are dispatched in California and how new CHP installations fit into this resource mix, before creating a one-size-fits-all approach to CHP treatment under AB 32.

It is critical to analyze the effect that CHP base load additions will have on resources on the margin. For example, natural gas combined cycle plants often run in “standby” mode, rather

26/ Draft Plan, p. 58, fn. 1.
27/ *Ibid.*

than being shut down altogether, in preparation for peak load deployment. However, plants operating less than at full capacity, or in stand-by mode, are less efficient. Must-take base load additions could force natural gas plants running efficiently at the margin into the less efficient "standby" mode, resulting in increased overall emissions and making maintaining grid reliability more difficult. In certain circumstances, the CAISO may need to pay to sell power outside of the CAISO if too many "must-take" generators result in excess off-peak generation.

E. Cost Effectiveness

As outlined in recent comments to the CPUC on "Additional Issues Related to Implementation of AB32 in the Electric and Natural Gas Sectors," PG&E envisions CHP units as fundamental components of a cap-and-trade regime. PG&E believes that if CHP truly represents a cost-effective means of GHG abatement, an efficient market will create financial incentives for new installations. However, the Draft Plan includes increased energy production from CHP among the list of proposed programmatic measures. It is not clear how CHP would be regulated under a mandatory programmatic regime, and PG&E looks forward to further detail and opportunity to comment on the ARB's proposal. For smaller CHP installations – which tend to serve on-site load and are less likely to actively participate in external electricity markets – economic incentives can be addressed through non-market measures, such as expanding the CPUC's Self-Generation Incentive Program to include appropriately efficient installations.

F. Current Experience with CHP-Market Barriers

The Draft Plan mentions that there are institutional barriers to CHP[28/] without elaborating on what those barriers are. Evidence shows that the market barriers for some CHP have little to do with the economics that drive other forms of electricity generation and may prove resistant. For example, many customers with a thermal load are simply not interested in learning how to own and operate a generator.

Before issuing the 2005 CHP market potential study, the CEC completed an extensive examination of distributed generation in California.[29/] CHP received ample attention in this examination, including a workshop devoted to the CHP market. CEC consultants and market participants discussed the (then) sluggish CHP market and identified the primary market barriers

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28/ Appendix C refers to the draft CEC report, but did not further discuss what they were. (Appendix C, page C-73.)

29/ "Distributed Generation OII (Order Instituting Investigation)" 2004-DIST-GEN-01.

as: 1) a two-year payback hurdle (this is the equivalent of a 50% return on investment); 2) low priority accorded to energy issues; 3) reluctance to acquire necessary engineering skills for generation operation; 4) market uncertainty; and 5) complexity of ISO tariffs.[30/]

PG&E agrees that barriers to CHP development do exist; but many barriers would not respond to incentive treatment and each of these barriers would be better addressed in the appropriate forum. In fact, many issues surrounding CHP expansion – such as participation in incentive programs, obligations to fund customer programs, improvements to interconnection processes – have already been decided by the legislature or regulatory bodies. It may not be advisable to use the AB 32 implementation process as an opportunity to undo existing well-analyzed legislative and regulatory measures.

VII. RENEWABLES, ENERGY EFFICIENCY, AND CHP HAVE LIMITED IN-STATE PUBLIC HEALTH BENEFITS.

The Draft Plan appears to be operating under the assumption that electricity sector programs will have clear co-benefits in terms of reduction of co-pollutants emitted within California. The Draft Plan should be conservative in ascribing with pollutant reductions to electricity sector programs, as these programs are unlikely to show significant reductions in local criteria air pollutants or air toxics.[31/]

According to ARB data, power plants and CHP facilities together contribute between 0.27% and 1.44% of criteria air pollutants on a state-wide basis.[32/] Electricity generating facilities rank low in facilities that emit air toxics. The South Coast Air Quality Management District released a 2008 report which ranked roughly 300 facilities with air-toxics emissions in decreasing order of "Cancer Risk in a million."[33/] The highest-ranked power plant is SCE's diesel plant on Catalina Island (9 MW), which is number 88 on the list, with a Cancer Risk of

30/ Presentations by Nick Lenssen of Primen and David Dyck of Valero Energy Corporation, "Combined Heat and Power Distributed Generation market and Policy Workshop" California Energy Commission, April 28, 2005.

31/ Toxics are benzene, formaldehyde, polycyclic aromatic hydrocarbons, etc., which are associated with cancer and other health issues. Criteria air pollutants are ozone, carbon monoxide, nitrogen dioxide, sulfur dioxide, and PM10 and PM2.5.

32/ http://www.arb.ca.gov/app/emsinv/emssumcat_query.php?F_YR=2006&F_DIV=-4&F_SEASON=A&SP=2007&F_AREA=CA

33/ http://www.aqmd.gov/prdas/AB2588/pdf/Annual_Report_2007.pdf

4.98.[34/] The big power plants in the LA Basin are also in the list, but are well above 200 in the list and have cancer risks less than 0.63.[35/]

Based on this information, CEE, CHP, and RPS measures should be evaluated for cost effectiveness based solely on GHG emissions reductions. Additionally, compliance flexibility mechanisms in the electricity sector, which have the potential for substantial cost savings, should not be limited because of limited co-pollutant emissions impacts.

VIII. THE DRAFT PLAN MAY PLACE AN INEQUITABLE BURDEN ON THE ELECTRIC SECTOR AND ITS CUSTOMERS.

Statewide reduction obligations should be apportioned under AB 32 to ensure that no single sector, nor its customers, assumes a disproportionate financial burden. PG&E is concerned that the Draft Plan places an inequitable compliance burden on utility sector customers by imposing programmatic targets that have not been shown to be cost effective or technologically feasible.

The most cost-effective measures should be pursued first to reach the state's overall GHG-reduction targets, regardless of sector. Any deviation from pursuing the most cost-effective reductions will impose needless costs on Californians. Of course, regardless of which sector actually performs the reductions, ARB should insure that all sectors bear their equitable share of overall GHG-reduction costs based on their relative contribution to overall emissions.

As noted above, ARB's Draft Plan does not yet include analyses and evaluations based on cost effectiveness and technological feasibility. For example, the Draft Plan's heavy reliance on emission reductions in the electricity sector raises concerns both in terms of technological feasibility and cost effectiveness. We expect to provide further comments after reviewing the ARB's economic analyses and Technical Appendices but are, at this time, are concerned that the electricity sector seems to be singled out for more emission reduction costs than other sectors relative to each sector's contributions to overall emissions.

34/ The worst facility in the list, Quemetco Inc., has a Cancer Risk of 22.00 Consolidated Film Industries in Hollywood, number 2 in the list, has a Cancer Risk of 21.00.

35/ Alamitos (963 MW) is number 218, with a Cancer Risk of 0.63; Redondo Beach (967 MW) is number 232, with a Cancer Risk of 0.40; Haynes (1768 MW) is number 245, with a Cancer Risk of 0.17; Valley (563 MW) is number 248, with a Cancer Risk of 0.15; Scattergood (975 MW) is number 266, with a Cancer Risk of 0.03.

IX. THE USE OF ENVIRONMENTALLY SOUND AND VERIFIABLE OFFSETS WILL BE NECESSARY TO MEET AB 32's TARGETS IN A COST-EFFECTIVE MANNER.

As PG&E believes that the cap-and-trade mechanism will play more of a critical role in reducing GHG emissions than is currently suggested in the plan, we strongly support the use of offsets as an indispensable tool in abating greenhouse gases in a cost-effective fashion. PG&E believes that there should be no geographic or quantitative limits on the use of offsets for compliance purposes, as long as the offsets meet rigorous standards. Offset protocols should be thorough, and qualifying projects which meet the protocol standards should not be subject to further case-by-case review or discounting.

For these reasons, we do not support the Draft Plan's 10% individual entity limitation on the use of offsets (Draft Plan, p. 19). The Draft Plan justifies such a limit to address ". . . the risk that unconstrained offsets could weaken the stringency of the overall cap-and-trade program" (Id.). If the need for "stringency" reflects concern that offsets may not provide real reductions in GHG emissions, the solution is strict requirements for offset quality – which PG&E supports – not arbitrary limits on offset quantity. Likewise, because climate change is a global challenge, we do not support geographic limitations on offsets, provided those offsets meet strict requirements for quality.

X. PG&E SUPPORTS THE DRAFT PLAN'S ENDORSEMENT OF CAP-AND-TRADE MARKET MECHANISMS TO ACHIEVE VERIFIABLE, TIMELY, AND COST-EFFECTIVE GHG REDUCTIONS.

PG&E supports the ARB's and the Draft Plan's conclusion that a properly designed, multi-sector cap-and-trade program - ideally linked to the WCI - can achieve, real, quantifiable, timely, and cost-effective GHG reductions (Draft Plan, p. 15). We believe market based mechanisms with clear and consistent rules and strong oversight – coupled with our current leading CEE, renewables and demand-side management programs – will reduce emissions, diversify our energy supply mix and help to minimize customer costs. Market mechanisms will drive the development of the next generation of clean, highly-efficient technologies and practices. Integration with WCI will also begin to provide the necessary harmonization of California's market - including full recognition and fungibility of allowances, offsets and other program design elements - with emerging regional, national and, ultimately, international programs. For these reasons, although the AB 32 statute provides that a cap-and-trade program must be “necessary” or “desirable,” we believe it is both. (HSC § 38561(b)). A well-designed market is necessary for leveraging lower cost reductions and desirable for spurring innovation that may not come from traditional regulatory programs. We believe cap and trade program elements should include:

- **Standardized emissions’ reporting** is an essential first step and must form the basis of AB 32’s implementation. We believe the ARB’s recent greenhouse gas reporting regulations as modified consistent with PG&E’s comments will provide a sound basis for AB 32 implementation.

- **Equitable apportionment** of reduction obligations to ensure that all sectors pay their fair share. State-wide reduction obligations should be apportioned under ARB’s Draft Plan and AB 32 regulations to ensure that no single sector, nor its customers, assumes a disproportionate cost burden.

- **Early actions should be recognized and credited** under specific ARB-adopted protocols and regulation, not penalized. ARB should implement expedited “early action” rules under AB 32 to recognize “early actors” that have already made investments resulting in significant greenhouse gas reductions. Ignoring prior efforts sends a signal that stepping up, taking risks and taking responsibility is not something valued by policymakers. Those that have pursued a significant amount of energy efficiency and renewables resources have already achieved the lowest cost emission reductions, while those that have not taken action have significant low cost reduction options still available to them. For example, incremental investment opportunities to avoid purchasing high emitting power are fewer and more expensive for low carbon utilities than those available to high carbon utilities that have more low-hanging fruit available, such as energy efficiency. Put more simply, customers of lower emitting utilities should pay less than customers of higher emitting utilities to achieve the goals of AB 32.

- **A clear glide path of emissions “caps” and limits** must be established over the 2012-2020 period that takes a gradual but sustained approach to meeting reductions to help create a smooth transition to a low-carbon economy.

- **A broad and liquid emissions trading market** should be created. Climate change is unlike any other air quality challenge, as it is truly a global issue. A robust market can be assured by including a broad spectrum of industry sectors and participants, ensuring that program design elements are scalable and consistent with other regions, and creating linkages to other existing and emerging regional programs such as the Western Climate Initiative and, ultimately, a federal or international program.

- **Compliance flexibility** should be provided to meet AB 32’s targets in a cost effective manner. These can include banking of emissions allowances, the use of environmentally sound and verifiable carbon offsets and multi-year compliance periods. This last element is critically important to the power sector, where rain and snow-fall variability have a significant effect on year-to-year emissions.

- **Cost containment mechanisms** such as an allowance "price collar" imposing a price floor and ceiling. In the context of managing the overall GHG emission budget, a "price collar" approach can help manage volatility and macro-economic costs of a cap-and-trade program, especially during its early years, and at the same time to provide a clear and sustained CO2 price for technology investors and emissions sources that is recognized in all sectors of the economy. The price collar could function using a pre-specified ceiling price, at which any entity could purchase allowances from a reserve, for use within the current compliance period. This ceiling price should be consistent with expectations regarding technology availability and should be set to avoid massive re-dispatch of existing gas-fired plants in place of existing coal-fired plants. The reserve would contain allowances from future years under an overall GHG emission "budget." Allowances purchased from the reserve would be useable in the current year, or bankable, like other allowances. However, purchases from the reserve would mean fewer allowances distributed in future years, thereby maintaining the overall long-term GHG emission budget. The price collar would also include a minimum acceptable bid for allowances in centralized auctions, to establish a price floor. This minimum price should be sufficient to encourage adequate investment in low- and zero-carbon generation and end-use efficiency technologies. Current-year allowances that are not purchased at auctions would be transferred to future years, so that more allowances would be distributed in future years. Both the ceiling and floor price would increase annually by at lest the inflation rate.

- **A "point of regulation" should be selected under AB 32 that will promote real emissions reductions and serve as a model for emerging regional, national and international programs.** The point of regulation for AB 32 should be simple to administer, provide for the most accurate accounting of GHG emissions, and minimize leakage of GHG emissions. For these reasons, we are encouraged that the CPUC and CEC have recommended that ARB adopt a "First Deliverer" point of regulation for the electric sector. This would place the point of regulation on electric generators within California and on those that first import power generated outside of the state for delivery and consumption within California. Taking this approach will: (1) ensure environmental integrity through real and more verifiable greenhouse gas emissions reductions and by allowing for more accurate accounting and attribution of emissions and minimizing "leakage" of GHG emissions; (2) more directly impact generation investment decisions; (3) internalize GHG compliance costs in electric dispatch; and (4) because it focuses on actual emissions sources, it will enhance California's leadership position on climate change by serving as a model for emerging regional and national programs.

- **Emission allowances should be allocated and distributed in a manner that most directly mitigates costs to customers**, rewards – rather than punishes – early action; promotes early investment in clean technologies; advances energy efficiency; avoids windfalls; and positions California as a model for federal, regional and international programs. These allocation principles can be implemented by:
    - Recognizing that the customer at the end of the energy supply chain – like the households and businesses that we serve – will ultimately bear a substantial share of the costs associated with the regulation of greenhouse gas emissions. The allocation of allowances under a cap-and-trade system should be used to help mitigate these costs.
    - Avoiding creating unintended economic benefits for companies by granting free allowances to generators who would not be required to pass on this value to utility customers.
    - Avoiding penalizing early actors and their customers for investments made prior to AB 32 that has resulted in significant greenhouse gas benefits to date.
    - Ensuring that customers of lower emitting utilities pay less than higher emitting utilities to achieve the ultimate goals of AB 32.
    - Quickly transitioning AB 32's overall emissions limits to a system that requires all emitting resources to take full responsibility for their climate related costs.
    - Accelerating the development and deployment of new technologies, including renewable generating technologies, end-use energy efficiency technologies, and carbon capture and storage technologies.
    - Successfully positioning California as an overall low-emitting state in the emerging federal debate on greenhouse gas allowance allocation among higher- and lower-emitting states.

Decisions made regarding the point of regulation and to whom emissions allowances are allocated are separate and distinct public policy issues with significant economic and environmental implications, and should be addressed as such. California has an opportunity to develop an allowance allocation methodology that can both achieve the public policy objectives listed above and also serve as a model for regional, federal and international policymakers.

In the utility sector, customers will bear the lion's share of greenhouse gas reduction costs regardless of where the point of regulation is placed. For this reason, the National Commission on Energy Policy, the California Market Advisory Committee, and the Natural Resources Defense Council in separate reports have each outlined an allowance allocation methodology that we find compelling and believe can avoid the inequities and the inefficiencies that stem from an Acid Rain-style generator based allocation approach, while benefiting electricity consumers. Rather than allocating free allowances to power plants, PG&E recommends that allowances be allocated to utilities on behalf of their customers. Utilities would in turn be required to sell allocated allowances to sources regulated by the program through independently administered auctions, returning the proceeds to their customers through rebates, credits or other programs that help to mitigate costs or reduce demand. In this way, the value of the allowances flows directly to energy consumers, who ultimately bear the costs of the program. Of course, the management and sale of allowances should be subject to oversight by the state and by local boards of customer-owned utilities, and allowances should be sold to utility-owned and merchant generation on a non-discriminatory basis.

In addition to achieving the goal of mitigating consumer and business costs, the allocation of allowances among different sources of emissions can help achieve the other public policy objectives listed above. For example, by allocating allowances based on a metric that rewards efficiency, as suggested in the California Market Advisory Committee Report, as opposed to an historical emissions based approach that continues to support the use of higher-emitting, less-efficient resources, the allocation approach can send appropriate investment signals and simultaneously encourage early action. Therefore, allowances should be allocated based on an updating output metric such as retail sales, adjusted for verified energy efficiency savings. Allocation of allowances for the benefit of consumers also must take into account any disproportionate impacts on low income communities, as required by AB 32.

We are encouraged that many of the above-listed design features -- including the need for a broad market, accurate reporting, point of regulation, compliance flexibility, and clear compliance glide path -- were endorsed in the WCI's July 23, 2008 Draft Design of the Regional Cap-And-Trade Program. In this regard, we encourage ARB and the State of California to work further with the WCI Partners to address the apportionment of compliance responsibility across the WCI. It is important for California to resolve how it intends to apportion compliance responsibility among all the states in a regional cap and trade program, particularly for GHG emissions sources located outside California, such as coal- and gas-fired power plants outside California who export their power to California, but whose emissions would be regulated directly by the states in which they are located.

XI. USE OF AUCTION REVENUE

For the electric sector, PG&E supports the distribution of allowance value for the benefit of electricity consumers, while promoting investment in new low-carbon technologies or programs that also benefit customers and the communities we serve. This is because, regardless of the point of regulation, households and businesses at the end of the electricity supply chain will ultimately bear the costs - in the form of higher electricity prices - of a GHG cap-and-trade program. Moreover, AB 32 requires that good faith efforts be made to make available to disadvantaged communities in California opportunities to benefit from measures undertaken to reduce greenhouse gas emissions in the state. This is particularly important because low income earners are a large and growing segment of California's population. Therefore consumers should be entitled to the value inherent in the allowances in order to partially offset increased costs as well as provide capital to help these consumers transition to a low-carbon economy.

Auction revenues can be recycled to electric sector customers through a variety of methods. The CPUC/CEC's April 16, 2008 Ruling identified two methods for returning revenues from allowance auctions: (1) Using auction revenues to augment investments in energy efficiency and renewable energy, or (2) Using revenues to maintain affordable rates. PG&E supports the use of auction revenues for both these purposes, including use for CEE programs, direct bill reduction for all customers and targeted rate relief and CEE for low-income customers. Direct bill reductions can be designed in a way that is not tied to the volume of electricity used by the customer and thus preserve the carbon price signal benefits of a cap-and-trade program. Other funds could be dedicated to utility procurement and development of carbon-free technologies, if targeted toward applied technologies most likely to directly benefit California's electricity consumers.

Auction revenues used for energy efficiency and renewable energy investments should be allocated for this purpose based on objective and transparent emissions abatement cost-effectiveness criteria. Based on this assessment, there should be no more and no less funding than is necessary and effective, taking into account the experience of CPUC- and CEC-approved programs. Furthermore, the funding mechanism should be as streamlined and market responsive as possible, (e.g., tax credits, rebates or incentives directly to energy users or producers for demonstration of new technologies or applied research, instead of grants or pure research, in order to focus the development of new, commercially-available "green" technologies for the benefit of utility customers.) A worse outcome would be for auction revenues to be allocated for programs or projects which are less efficient and less cost effective than those that can be developed and implemented directly by consumers, businesses, and energy market participants, and which do not focus on benefits accruing to the customers of California utilities across all income groups.

In summary, we recommend that the value of the allowances be used to mitigate customer costs in a way that preserves a carbon-based price signal, assists all customers and businesses in transitioning to a low-carbon economy, advances energy efficiency, and pays particular attention to those customers who are disproportionately impacted by increases in electric rates.

XII. NATURAL GAS

Of the alternatives available to regulate and control greenhouse gas emissions, we support the use of a well-designed cap-and-trade market and generally favor bringing as many sectors as practicable into a cap-and-trade market. However, for natural gas, there is a natural division between large customers and small customers. We recommend bringing large customers into a regional cap-and-trade market but do not support bringing small natural gas customers (small commercial and residential customers) into that same cap-and-trade market at this time.

For small customers, the emissions reduction opportunities are limited almost exclusively to natural gas end-use efficiency improvements. Further, in contrast to the large industrial and transportation sectors, there are relatively fewer reduction opportunities in this sector. Most important, the bulk of these savings can best be achieved through a well-integrated set of programmatic measures directed at small customer natural gas consumption, which would include state appliance and building efficiency codes and standards, complementary utility or third-party customer energy-efficiency programs, and point-of-sale energy efficiency programs.

We support continued market assessment and modeling of emissions reductions opportunities in the small customer natural gas segment to reaffirm these observations that they should not be under a cap-and-trade regulatory regime. If it is confirmed that there will likely be little or no incremental benefit to including this segment of the natural gas sector, then it should continue to be excluded, as the cost of expanding the cap-and-trade may exceed the benefits.

Consumption of natural gas by small customers occurs literally at millions of different customer premises and end uses. Further, for some premises owners pay the bills but occupants control the usage. It is likely to be too costly and impractical for individual small customers in this segment to be directly regulated through a cap-and-trade system. Moving further upstream to the gas local distribution company would reduce, though not eliminate, the complexity and cost of moving this segment into a cap-and-trade program; however, it may have unintended consequences due to some of these unique market characteristics of the natural gas sector.

Finally, a structural and programmatic approach will not result in stranded costs or de-position California in any transition to a federal program. The reduction in GHG emissions from pursuing efficiency measures will benefit end-use consumers of natural gas throughout California under any future federal program.

While PG&E supports continued market assessment, given the small number of emission reductions available in the natural gas small commercial and residential sector, the challenge with regulating the large number of sources in this sector and the availability of effective alternative measures to reduce emissions in this sector, we recommend that the ARB not include this segment of the natural gas sector within a cap-and-trade program at this time. Instead, we recommend that GHG reductions from the residential natural gas sector be pursued through an integrated set of programmatic measures, including state appliance and building efficiency codes and standards, complementary utility, or third-party customer energy efficiency programs, and point-of-sale energy efficiency programs.

XIII. CONCLUSION

PG&E commends the ARB for its comprehensive, multi-sector approach to implementing AB 32. We are especially encouraged by the Draft Plan's embrace of market-based measures and a trading program, but recommend and hope that ARB continues to move toward an even broader and scalable market that will link with regional, national, and international efforts. More reliance on market forces will lead to great, more innovative emissions reductions sooner, and at a lower overall cost, to California and Californians. We look forward to continuing to work with the ARB to fulfill AB 32's promise.

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Submitted by:

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