DOCKET 07-OIIP-01
CALIFORNIA ENERGY COMMISSION
REPLY COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY ON ADDITIONAL ISSUES RELATED TO IMPLEMENTATION OF AB 32 IN THE ELECTRIC AND NATURAL GAS SECTORS

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I. INTRODUCTION

Pursuant to the rulings of the Administrative Law Judges, Pacific Gas and Electric Company (PG&E) provides its reply comments on additional issues relating to the implementation of AB 32. PG&E's reply comments follow the general topic headings in the ALJs' suggested outline, but are organized by specific commenter or issues below the topic headings.

II. GENERAL ISSUES

As a threshold matter, several of the opening comments raise general policy issues that are based on either faulty logic or inaccurate facts, and therefore would lead to policy conclusions or decisions that would be damaging to California in general and the electric sector in particular. PG&E responds to each of these threshold policy issues in the subsections below.

A. "Cap and Trade" and Programmatic Measures Are Not Mutually Exclusive Policy Choices; Both Are Essential to the Successful Implementation of AB 32

Some commenters evaluated "cap and trade" and programmatic measures as if the two were mutually exclusive policy choices under AB 32 and as if only one or the other should be implemented under AB 32.[1]

This is faulty logic, and should be rejected. First, California's successful and progressive customer energy efficiency (CEE) and renewable energy programs will continue, regardless of whether the ARB explicitly adopts those programs as AB 32 emissions reduction measures or assumes the programs will continue under the existing jurisdiction of the CPUC and Energy Commission. Thus, there is no "choice" between these programs and "cap and trade;" the programs will continue and will co-exist with all emissions reduction measures adopted under AB 32, including a cap and trade program.

Second, no proponent of cap and trade (least of all PG&E) is advocating that cap and trade be the exclusive means by which AB 32's 2020 goals are met. To the contrary, PG&E strongly supports other measures as well, both inside the electric and gas sector and across all sectors with GHG emissions sources in California. For example, PG&E for nearly 30 years has been a strong advocate of enhancing California's building codes and appliance standards in order to reduce energy use, and is continuing that advocacy because of the GHG-reducing benefits of further enhancing those codes and standards.

However, PG&E believes that California's successful energy efficiency and renewable programs are necessary—*but not sufficient*—to achieve AB 32's ambitious targets on a sustained, least-cost basis. This is where PG&E strongly disagrees with those commenters who would forego market-based compliance options under AB 32, including cap and trade, under the risky assumption that "command and control"

1/ SCPPA, pp. 3- 4, 73; LADWP, p.2; DRA; p.1; NRDC/UCS, p. 34.

programs and regulatory mandates will achieve the majority of AB 32's goals at least-cost to California consumers and businesses.[2/] Likewise, PG&E disagrees with those commenters whose opposition to cap and trade may be rooted more in their mistrust of market-based mechanisms in general, regardless of whether the market-based mechanism are designed and implemented in a way that enlarges the menu of options and measures available to California consumers and businesses to transition quickly and smoothly to the new, low carbon economy.[3/]

Moreover, the debate between cap and trade and programmatic measures unnecessarily creates a "win-lose" equation that would severely narrow the practical tools and policy options available to California to implement AB 32. The key issue for AB 32 implementation is *not* what measures and policy options to *exclude* from implementation, it is how many measures and options can be included that allow multiple paths and means to Californians to use their entrepreneurial and technological genius to meet—*and exceed*—AB 32's 2020 and 2050 goals. Policymakers and regulators should not be considering restricting these choices and flexible options – they should be seeking to expand them at every turn.

B. The E3 Economic Model Cannot and Does Not "Prove" that the Electric Sector Can Meet its AB 32 Goals Through Programmatic Mandates Only, Thus Making Cap and Trade and Other Compliance Options Unnecessary

Some commenters have reviewed the "reference case" for the electric sector in E3's economic modeling, and concluded that the electric sector has met or can meet its likely AB 32 2020 goals through existing programs and mandates only, and therefore a

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2/ See, e.g., SCPPA, pp. 3- 4; LADWP, p.1; TURN, pp. 2- 3.

3/ TURN, pp. 7- 8; LADWP, pp. 13- 14.

cap and trade program on top of existing programs is unnecessary.[4/]

First, the E3 model itself is subject to large variability and debate over assumptions and inputs, including for its reference case. For example, PG&E presented more realistic input assumptions that would increase the reference-case GHG emissions from 108.2 MMT/yr to 112.4 MMT/yr, and cut the emission benefits of the Aggressive case renewables and CEE, from 30 MMT/yr to 18 MMT/yr.[5/] When apportioning GHG reductions among sectors, the agencies must not assume that such reductions from these uncertain and unpredecented program goals will be achieved.

To date, none of the economic models, including E3, have evaluated the relative costs and benefits of different emissions reduction measures across all sectors, not just the electric and gas sector. As a consequence, any reliance on the E3 model or other assumptions regarding electric sector emissions would ignore the AB 32 mandate that regulators choose emissions reduction measures based on cost effectiveness and feasibility across *all* sectors. Otherwise, reliance on a one-sector economic model with widely debatable assumptions and inputs for just that one sector could lead to the grossly faulty conclusion that one sector—in this case, California's electricity sector—should be asked to provide a disproportionate share of emission reductions by 2020, at a high cost. As noted in PG&E's Opening Comments, the E3 results indicate that GHG reductions using additional RPS, CHP, and CSI beyond the reference case are very expensive, at $133/metric ton, $228/metric ton, and $902/metric ton respectively.[6/]

4/ TURN, p. 3; SCPPA, pp. 13- 15.

5/ PG&E Opening Comments, June 2, 2008, pp. 101, 107, 110.

6/ *Ibid.*, p. 102.

In this regard, it is important for policymakers to look at *all* emission reduction options in *all* sectors, and a well-designed, multi-sector cap and trade program is an efficient way to do so. For example, emission reductions from the transportation sector may be less expensive. Since early February, gasoline prices have increased by about \$1.00 per gallon, equivalent to about \$100/CO2 metric ton.[7/] This increase may cause dramatic changes that may provide market-based incentives to cut transportation-sector emissions, at an incremental cost lower than the additional cost of reductions in electricity-sector emissions. A cap and trade program would facilitate these market-based choices and incentives.

In its Opening Comments, the Northern California Power Agency (NCPA) notes that the electricity sector's current emissions are already below the 1990 benchmark.[8/] NCPA persuasively expresses its concern that reliance on these modeling numbers may cause some policymakers to consider calling on the electric sector for more than its fair share of emission reductions.[9/] NCPA argues that "…it is incumbent upon the Joint Commissions to … make a recommendation to CARB regarding the total feasible and cost-effective reductions that can be fairly achieved by the electricity sector. The Joint Commissions should provide CARB with a recommendation on the total emissions

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7/ The average U.S. retail price for gasoline increased from about \$3.00/gallon in early February 2008 to about \$4.00/gallon in early June 2008, as shown in the DOE graph at: http://www.eia.doe.gov/oil_gas/petroleum/data_publications/wrgp/mogas_home_page.html. Combustion of gasoline yields 8.81 kg of CO2 per gallon, according to the California Climate Action Registry protocol: http://www.climateregistry.org/resources/docs/protocols/grp/GRP_V3_April2008_FINAL.pdf p. 42). Mathematically, (\$1/gallon) * (1 gallon/8.81 kg of CO2) * (1000 kg/metric ton) equals \$113/tonne, rounded to \$100/tonne in the text.

8/ NCPA, p. 42.

9/ *Id.*

reduction requirement for the electricity sector."[10/]

PG&E shares NCPA's concern that the electricity sector might be unfairly burdened because of faulty reliance on sector-specific economic models, such as the E3 model. Electricity customers should not be asked to reduce emissions via sector-specific measures, such as a 33% Renewable Portfolio Standard at $133/metric ton, unless it is clear that lower-cost emission reductions from other sectors, including the transportation sector, are insufficient to meet the AB32 emission targets.

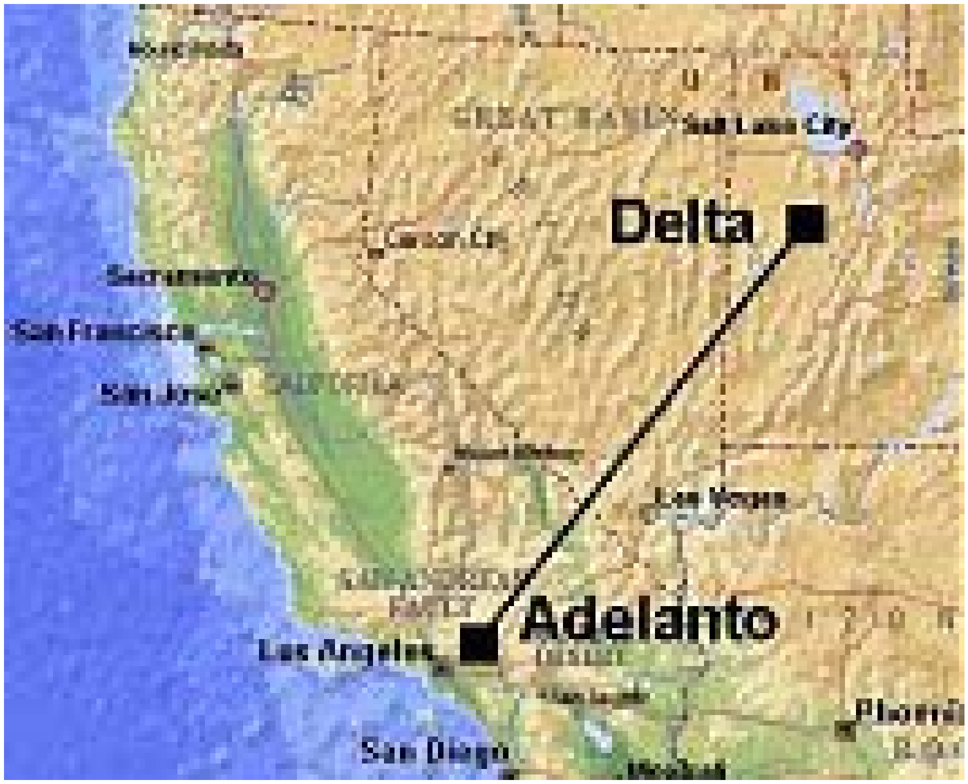
III. GHG EMISSION ALLOCATION AND AUCTION POLICIES AND METHODS

A. LADWP's and SCPPA's "Accident of Geography" Argument for Relief from AB 32 Emissions Goals Continues to Be Unsupported and Irrelevant to Allowance Allocation

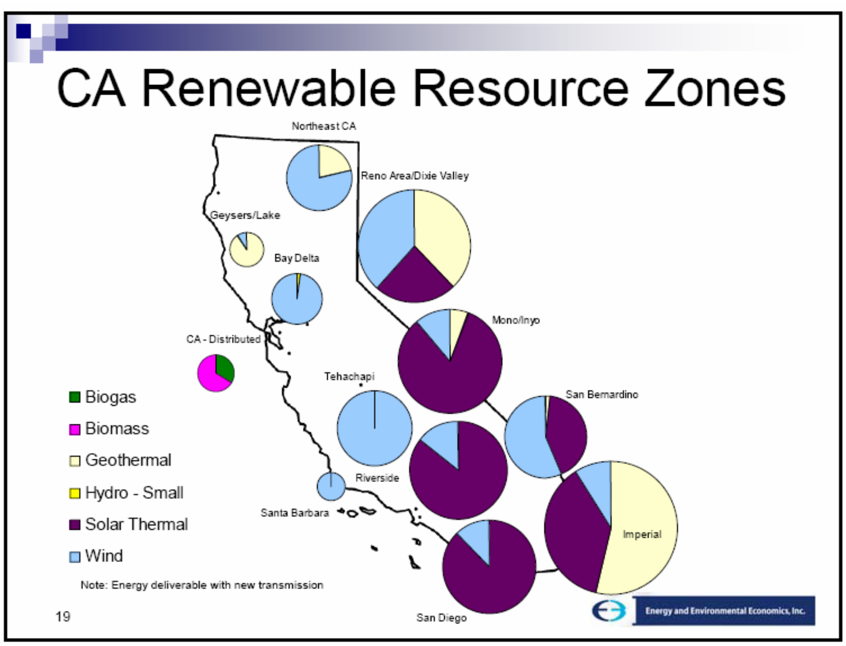
SCPPA and LADWP allude once again to the "accident of geography" argument against using an output based mechanism for allowance allocation.[11/] Their argument was unsupported and irrelevant when made in earlier comments, and continues to be unsupported and irrelevant. Rather than repeating its earlier points regarding the "non-accidental" investment of billions of dollars by its customers in clean generation and CEE programs over the last 30 years, PG&E includes below a simple map of the electric transmission paths used and built by LADWP and SCPPA to gain access to their geographically-remote coal generation facilities. Moreover, the second map, used by E3 in its presentation in this proceeding, demonstrates that LADWP and SCPPA have always been geographically closer than PG&E and other Northern California utilities to preferred and ideal sites for new renewable resources in Southern California.

10/ NCPA, p.43.

11/ SCPPA, pp. 35, 45; LADWP, p. 12.



Source:http://www.abb.com/cawp/gad02181/c6139ccf0c93c50bc1256d88004018bf.aspx



Based on these maps, it would be just as persuasive to argue that an "accident of geography" has given LADWP and SCPPA much cheaper transmission options for new renewables and low-emitting coastal powerplants than Northern California utilities, and therefore Southern California utilities should bear a greater responsibility for emissions reductions, not the reverse. But both "geography" arguments are false and irrelevant, precisely because they are based on facile references to geography which ignore the basic fundamental mandate of AB 32: California must reduce its GHG emissions and transition to a low carbon economy, and this cannot be achieved without reductions from high-emitting sources.[12/]

B. SCPPA's Request to Be Excused from Emissions Reduction Responsibility Because of Its Contracts for High-Emitting Coal-Fired Generation Would Effectively Exempt A Major Source of GHG Emissions from Regulation Under AB 32

SCPPA in its comments effectively requests an exemption for its existing coal-fired power contracts from AB 32 emissions reduction requirements:

> *"The transition schedule proposed by Staff fails to recognize that various retail providers including the SCPPA members have existing contracts with out-of-state coal plants that will not expire until later years (for example, 2019 for the LADWP contract with Navajo and 2027 for various SCPPA members' contracts with Intermountain Power Project.)"*[13//]

SCPPA is effectively requesting an exemption from AB 32 for its coal-fired contracts, in the guise of an irrelevant argument over "wealth transfer." PG&E urges the CPUC and Energy Commission to reject SCPPA's argument for an AB 32 exemption. What SCPPA proposes is an almost permanent subsidy of the customers of high-

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12/ To LADWP's and SCPPA's now-hackneyed "Why us?" complaint, PG&E is tempted to paraphrase Willie Sutton: "Because that is where the emissions are."

13/ SCPPA, p. 45.

emitting utilities funded specifically by the customers of low-emitting utilities—in violation of a cornerstone tenet of environmental law: "The polluter pays." PG&E's customers and customers of other low emitting utilities have spent billions of dollars on CEE and lower emitting generation over the course of many years. The effect of SCPPA's request is that customers of low-emitting utilities for the foreseeable future pay for CO2 reductions for SCPPA's customers as well as for themselves. SCPPA in effect is asking for an exemption from AB 32 requirements so they can continue to benefit from low-cost but high-emitting coal fired generation.

C. AB 32 Regulations Should Not Relieve Power Generators from the Terms of Their Existing Contracts. Carbon Prices and Allowance Value Will Be Passed Through to Customers As a Normal Part of Power Procurement Contracts and Ratemaking

Concerned that the value of allowances may not be used for the benefit of utility customers, NRDC and UCS propose a "use it or lose it" approach to the value of allowances it recommends the utilities receive.[14/] PG&E views a specific additional regulatory mandate as unnecessary. Under normal public utility ratemaking, revenues received by utilities on behalf of their customers are routinely allocated directly or indirectly for the benefit of those customers on an annual or other periodic basis by the regulatory authority overseeing utility rates, in PG&E's case the CPUC. Creating artificial timeframes in AB 32 regulations could conflict with this normal CPUC oversight responsibility and could create unintended outcomes such as investing in less efficient programs or rebates solely because they are expedient.

Separately, WPTF and IEP have repeated their prior stated concerns regarding the ability of power generators to pass through their costs of CO2 allowances or

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14/ NRDC/UCS, p. 12.

compliance costs as part of their ongoing power contracts with buyers.[15/] WPTF and IEP take issue with the assumptions that E3 made regarding the pass through of AB 32 compliance or allowance costs upon the expiration or renegotiation of existing power contracts. WPTF and IEP argue that buyers will not allow the increased costs of carbon allowances or AB 32 compliance to be passed through under such new or renegotiated contracts, and therefore AB 32 implementing rules should in some manner address or ensure the pass through of the costs. Similarly, EPUC/CAC argue that contract provisions will threaten the financial viability of certain high-emitting generators, and therefore AB 32 regulations should be structured to ensure the continued viability of those generators.[16/]

PG&E disagrees and urges the CPUC and Energy Commission to reject the implicit invitation by WPTF, IEP and EPUC/CAC to dictate power contract terms favorable to power generators as part of AB 32 implementation. It has been widely acknowledged that electric commodity costs will increase to reflect the cost of complying with AB32, and that customers will pay for this new cost. While market prices and market conditions will govern the give-and-take of commercial parties under AB 32 regulations, just as they have for all manner of government regulations, there should be little question that suppliers will in bilateral negotiations be able to largely recoup these increased costs. In any event, for existing contracts there are a range of types of contract structures, many of which allow for the pass through of the CO2 costs or other air pollution or environmental compliance costs. This is simply one element of

15/ WPTF, p. 29; IEP, pp. 3- 4, 45.

16/ EPUC/CAC, pp. 8- 16.

the balance of benefits and burdens inherent in any contract negotiation. There is no need to dictate through regulation the outcome of this particular contract term.

D. The Commissions Should Reject the Recommendation that Low-Emitting Utilities Receive No Allowances

A few parties suggest that there is no need for low emitting utilities to receive allowances at all based on sales or output.[17/] PG&E disagrees as it has on numerous occasions in this proceeding for the following reasons:

- Low emitting utilities have fewer and relatively more high cost reduction options available.
- Their past investments should be recognized and continued investment encouraged.
- To the extent other utilities are successful at reducing demand through energy efficiency programs and adding low emitting generation, the sales based method creates greatest reward and incentive.
- Low emitting utility customers should not have to pay twice for GHG reductions by subsidizing high emitting utility customers' reductions.
- All utilities in California should be held to the same environmental standard, allocating based on historical emissions provides permanent special treatment for a subset of retail providers in California.

The principle of rewarding "early actions" and "voluntary actions" by emissions sources, both utilities and power generators, is embedded in AB 32 itself. (Health and Safety Code 38561(f); 38562(b)(4).) Allocating allowances to sources based on output or sales is a simple and extremely effective way to incent and reward rapid and sustained reductions in emissions during the transition to 2020 and would help ensure compliance with these provisions of AB32. Excluding such incentives from AB 32's regulatory

17/ SCPPA, pp. 37- 38; LADWP, p. 12; SMUD, p. 3.

program would forego the use of a powerful tool for not only meeting, but exceeding, AB 32's emissions targets during the 2012- 2020 transition period.

IV. FLEXIBLE COMPLIANCE POLICIES

A. Price Triggers and Other Safety Valves

To prevent short-term price spikes, the Division of Ratepayer Advocates (DRA) proposes a mechanism similar to one feature of PG&E's suggested "price collar."[18/] DRA proposes a "mechanism" that would allow ARB the flexibility to take allowances from a future compliance period and offer them for sale and use in the current period, at a price certain. Environmental integrity is maintained in DRA's proposal because the number of allowances earmarked for "the subsequent compliance period" is reduced by the number of allowances shifted from that future period to the current period. PG&E's suggestion is basically the same under the condition where allowance prices are high. PG&E suggested that allowances be taken from some period several years in the future, rather than "the subsequent compliance period," but this difference is minor.

WPTF argues that "use of a safety-valve option should be limited to true damage control and should not be triggered by price volatility."[19/] With that proviso, WPTF's recommendation is similar to DRA's and PG&E's: "…[I]f the safety valve calls for loosening of the cap in one year, for instance through issuance of additional allowances, the overall integrity of the cap should eventually be restored by a reduction in the cap in

18/ DRA, p. 25.

19/ WPTF, p. 12.

future years."[20/] FPL Energy Project Management, Inc., also persuasively states the case for a price collar within the context of an overall GHG emission budget:

> "A sharp carbon price increase would be costly for existing carbon-intensive processes and ultimately consumers. Also, if the price of carbon dropped sharply it would discourage long-term investments in emissions reducing technologies. For these reasons, FPLE urges the Commissions to recommend the use of a price ceiling and price floor when auctioning carbon emissions allowances as well as using a safety valve cost control mechanism that would allow a temporary expansion of the cap against future carbon allowances."[21/]

In contrast to this general support for cost containment provisions and a "price collar" or "price trigger" mechanism, NRDC/UCS summarily reject such cost containment protections.[22/] Instead, NRDC/UCS argue that the discretion of the Governor of California to suspend AB 32's overall deadlines under extraordinary circumstances is adequate cost containment protection, and therefore no price triggers or price collars should be employed.[23/]

PG&E vigorously disagrees. The Governor's discretion is not a practical or timely substitute for an effectively designed cap and trade program that includes "self-correcting" cost containment provisions. California recently experienced the consequences of relying on political discretion to remedy a market failure – the result was that millions of California consumers and businesses experienced billions of dollars of higher electricity costs during the 2000- 2001 California energy crisis. Well-designed

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20/ *Ibid.*, p. 13.

21/ FPL Energy Project Management, p. 24.

22/ NRDC/UCS, p. 21.

23/ *Ibid.,* citing Health and Safety Code section 38599.

cost containment mechanisms, such as the "price collar" within an overall carbon budget as proposed by PG&E, are essential to the success of AB 32.

B. Offsets – Proposals by Some Parties to Restrict Offsets by Geographical Location Are Extremely Bad Public Policy and Unlawful

Most parties commenting support use of offsets, which allow entities to invest in reductions outside of the cap and trade sectors and reduce overall economic and societal costs by providing a broader array of emissions reduction opportunities, while stimulating innovative compliance solutions. The majority of parties commenting on offsets support no geographic or quantitative limits on offsets, as long as the offsets meet rigorous quality standards.[24/] Limits on offsets may increase the costs of AB32 to the California economy without environmental cause,[25/] limit innovation in uncapped sectors, and decrease the co-benefits that offsets bring. Creating a strong offset policy will highlight California's leadership in GHG policy and encourage other regions to monetize abatement measures.[26/]

No Geographic or Quantity Limitations or Discounting. Certain parties express support for limiting offsets based on quantity or geography;[27/] some going so far as to say that out-of-state offsets are precluded under AB32.[28/] On the contrary, AB32

24/ E.g., DRA, pp. 38- 39; SCPPA, p. 69; WPTF, pp. 20- 21; Sempra, p. 33; SCE, pp. 27- 28; MID, p. 10; Morgan Stanley, p. 4; EcoSecurities, pp. 7- 8; Climate Trust, pp. 1- 8.

25/ See US EPA analysis of "Lieberman-Warner" draft federal legislation, referenced in PG&E Opening Comments, June 2, 2008, pp. 61- 62.

26/ Morgan Stanley at 18.

27/ NRDC/UCS, p. 29; TURN, p. 21.

28/ CUE/CURE, p.10. Contrary to CUE/CURE, sponsors of offset projects located outside California can consent to audit and enforcement of their projects by California in order to ensure compliance with AB 32 offset standards.

specifically directs the ARB to "facilitate the development of integrated and cost-effective regional, national, and international greenhouse gas reduction programs."[29]

We believe limiting offsets by geographic origin, as opposed to by qualitative standards, would be a public policy mistake and a huge missed opportunity for California to lead by example. Climate change is a global issue, and California is leading the world in implementing a solution to climate change. If California were to step back and limit offsets from outside the State that otherwise deliver permanent, additional and verifiable emissions reductions, California would be indicating to the world that it was retreating from its global leadership on climate change. Moreover, by doing so, California could be greatly increasing the cost of compliance with AB 32 for California and California consumers and businesses. A robust offset policy as part of AB 32, based on and limited only by rigorous verification and audit standards, will *enhance and expand* the emissions reductions achievable under AB 32, including not only the direct benefits of GHG emissions reductions, but also the co-benefits of reducing other criteria pollutant emissions associated with the offset projects.

Additionally, limiting the use of offsets from outside California could run afoul of the Commerce Clause. Limitations that are based on geographic location and not the verifiability and quantification of offsets would discriminate against out of state offset providers and thus likely be unlawful under the Commerce Clause's *per se* discrimination test. The filter of quality should be the only limit on offset projects, not the location of the project.

The proposals by certain parties to strictly limit offsets by quantity or by

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29/ Health and Safety Code section 38564.

geographic location should be rejected.

Offsets Should Not Be Limited Based on Incomplete Co-benefits Analysis. A few parties incorrectly argue that offsets should be limited because they do not bring co-benefits.[30/] Co- benefits are defined as any two or more benefits that are derived together from a single measure;[31/] in greenhouse gas policy, co-benefits are any benefits that are ancillary to the GHG reduction. Co-benefits include economic co-benefits (e.g. rural development, green jobs, local enterprise) and environmental co-benefits (e.g. human health, natural ecologic systems). In evaluating co-benefits, California should not focus on one set of co-benefits from point sources to the exclusion of others.

CUE/CURE recommends quantity limitations because of the potential for offsets to hinder reductions of local pollutants near facilities that would have otherwise decreased local pollutant emissions by decreasing GHG emissions.[32/] Contrary to CUE/CURE, limiting offsets as a surrogate for increased local air pollution policy devalues the co-benefits of offsets and places almost singular emphasis on point sources in criteria pollutant emissions.

While there is a benefit from continuing to reduce emissions from stationary sources inside California, the majority of the criteria and toxic air pollutants come from transportation and interstate commerce. If the evaluation tools focus on stationary sources alone, California will not be addressing the main sources for toxic emissions. For example, electrification of transportation should bring important co-benefits of

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30/ NRDC/UCS, pp. 26- 28; TURN, p. 21; CUE/CURE, p.9.

31/ IES Handbook., http://www.epa.gov/ies/handbook.htm, pp. 8.

32/ CUE/CURE, p. 9.

decreased criteria pollutants. However, if AB 32 focuses solely on stationary sources, electricity production could be discouraged such that these important co-benefits never occur.

While certain "command and control" regulations could decrease local air pollutants in California, increased electricity imports could cause increased greenhouse gas emissions and criteria and toxic emissions elsewhere. California may decrease reliance on fossil fuel facilities, but if this is done at the cost of increasing output from coal generation facilities elsewhere, populations outside of the state will suffer and emissions overall will be higher.

Offsets Will Enhance, Not Stifle Incentives for Innovation in Capped Sectors. As stated in its opening comments, PG&E does not agree with commenters who argue that use of offsets will stifle innovation in the capped sectors.[33/] Incentives for technology know no state boundaries in our global economy; thus, incentives for innovative GHG emissions reduction technologies should be targeted at global markets, not to local markets through limitations on offsets or trading of emissions allowances. Open policies which focus less on state and national boundaries and more on global impact in addressing technology innovation will be far more effective and less expensive than limits on quality GHG reduction opportunities based on local or geographic interests.

Support Parallel Offsets Process DRA suggests launching a separate working group on protocols.[34/] PG&E supports such a process headed by the ARB. PG&E has

33/ NRDC/UCS, pp. 26- 27; CUE/CURE, p. 9.

34/ DRA, pp. 40- 42.

highlighted the urgent need for California to adopt protocols early to foment the development of the offsets market by the beginning of the cap and trade market.

V. TREATMENT OF COMBINED HEAT AND POWER

A. Contrary to Some Parties, Not All CHP is Efficient and Therefore a "One Size Fits All" Policy for CHP Under AB 32 or Other Programs Is Unworkable and Unsound

Some parties commenting on treatment of Combined Heat and Power (CHP) facilities under AB 32 present their recommendations with the implied assumption that all CHP facilities are energy or GHG emissions efficient.[35/] These comments ignore the distinction that other parties (or even the same parties) draw endorsing use of the "double benchmark" criteria to determine whether a given CHP unit is efficient or actually contributes to greenhouse gas emissions reduction.[36/] To the extent that comments recommending special treatment for CHP fail to recognize this distinction, policymakers could make the fundamental error of adopting "one size fits all" policies that apply to all CHP, rather than only to CHP that, in fact, reduces GHG emissions or is otherwise energy efficient or "emissions efficient."

The difficulty in drawing the line between "efficient" and "inefficient" CHP in a regulatory sense is precisely why PG&E has concluded that CHP *does not* require and *should not* receive special subsidies, treatment or set-asides, under AB 32 or otherwise. However, should policymakers disagree, establishing a "bright line" distinction between "CHP" and "efficient CHP" is essential to any explicit CHP program or special treatment. Otherwise, policies intended to reduce carbon emissions could

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35/ EPUC/CAC, pp. 39, 41, 54, 56; CCC, pp. 5, 11; FCE, pp. 10, 17- 22; *but see* CCDC, pp. 1- 3, distinguishing between CHP generally, and "Qualifying Customer CHP."

36/ EPUC/CAC, pp. 51- 54; CCC, p. 16; CCDC, p. 4.

unintentionally encourage CHP that actually increases emissions and exacerbates global warming.

PG&E would like to reiterate the distinction between large CHP units that export to the grid, and should compete with other generators, and small units that serve on-site load, and already receive to incentives.[37/] PG&E would support including small CHP in the Self Generation Incentive Program, and currently provides incentives to fuel cell CHP. PG&E has also filed a standard offer for qualifying facility CHP up to 20 MW. The agencies must distinguish between distributed generation and large, competitive generators.

B. CHP Should Not Be Regulated In Its Own Separate Sector Under AB 32

PG&E has recommended that CHP be regulated in the industrial sector (for thermal output and electricity used on-site) and the electric sector (for electricity exported to the utility grid).[38/] The only parties suggesting that CHP be regulated in a separate sector are EPUC/CAC, Indicated Cement Companies and CCC.[39/] Other parties that stated a position felt that CHP belonged in the industrial sector, the natural gas sector, or the electric sector (for those CHP units that export electricity to the grid).[40/]

Single sector treatment of CHP does not make sense. Because the owner of a

37/ Public Utilities Code sections 353.1- .15 exempts co-generators with capacity less than 5 MW from certain charges and provide other rate benefits. Customers may also avoid reservation charges for the period that the generator is out of service. Some customers installing CHP are exempt from some non-bypassable charges which effectively means other customers' rates increase.

38/ Other parties support separating thermal and electric outputs, including SMUD, pp. 31-32, Sempra, p. 13, CLECA, pp. 7-8.

39/ EPUC/CAC, pp. 4- 5, Appendix B, p. 17; Indicated Cement Companies, p. 5; CCC, p. 4.

40/ SMUD, pp. 31- 32; Sempra, p. 13; CLECA, pp. 7- 8.

CHP unit above a *de minimis* threshold would be the point of regulation for the entire facility, the unit should be regulated in the same sector as the facility (typically the industrial sector). Emissions associated with on-site electricity and thermal energy sources do not belong in the electric sector because they are part of an industrial process and do not interact with California's electricity market. The only exception would be for CHP units that export to the utility grid. Exported electricity should be regulated within the electricity sector, for administrative simplicity and fair treatment of all generators.

C. Contrary to EPUC/CAC, Customers that Install CHP Will Recover Their AB 32 Compliance or Allowance Costs Through the Market, Just Like Other Emissions Sources

EPUC/CAC erroneously argue that under a cap and trade program, generators would be unable to recover carbon costs and would therefore cease to supply electricity.[41/] As stated in its Opening Comments, PG&E believes that a well-designed market will reward efficient generators without the need for special subsidies, contract terms or set-asides.[42/] Efficient CHP would be financially rewarded in a cap and trade program in three ways: 1) decreased need for allowances for thermal load; 2) decreased retail electricity purchases; and 3) electricity sales that are more profitable than the marginal electricity resource.

Combined-cycle gas turbines (CCGT) are the marginal resource in California's electricity market, and under a cap and trade program, would set a market price that includes carbon costs. For example, a natural gas-fired power plant would require allowances, to cover emissions, proportional to gas burn. In other words, the facility's

41/ EPUC/CAC, pp. 8- 16.

42/ See also SCE, pp. 36- 37.

costs for natural gas and for CO_2 allowances are both operating costs. Just as current electricity prices generally cover the price-setting plant's operating cost for the natural gas it burns, future electricity prices should cover the price-setting plant's operating cost, which would cover both natural gas and CO_2 allowance costs.

Any generator, CHP or otherwise, that produces electricity that is more efficient than CCGT will receive a market price signal that includes carbon costs. Any generation source that is more emission-intensive than CCGT will compete against both marginal and more efficient resources, and emissions from those sources should not get special subsidies or set-asides to help them compete, increasing both overall costs and GHG emissions. Emissions reduction measures under AB 32, including a cap and trade program, should not be designed to preserve the profitability of individual sources that are not necessarily efficient, or to subsidize a category of sources that should compete with other sources in the electricity or other markets subject to the overall GHG regulations.

In addition, several of EPUC/CAC's cost recovery arguments are based on existing MRTU market rules, designed prior to a proposed carbon market. PG&E believes that CAISO will have opportunities, through tariff filings to FERC, to amend market mechanisms, such as price cap formulas, to account for carbon in variable costs.

EPUC/CAC imply that if costs of generation for existing CHP are not fully recovered by owners, the significant amount of power currently under QF contracts may be withdrawn from the market.[43/] PG&E believes that since most of this generation was installed decades ago, any reasonably efficient generation should be able to compete in

43/ EPUC/CAC, pp 7- 11, 58- 59.

an open market. Generators generally will include their carbon costs in the bid price and it should be expected that CHP generators will as well. If they are the most cost-effective, efficient electricity available, then they will compete well. If they are not, arbitrarily providing assistance to help them compete will simply raise prices and lead to subsidies for CHP paid for by electric customers.

CHP should not be treated as an "emissions reduction measure." Some parties representing CHP facilities, such as oil refineries, support treating CHP as an "emissions reduction measure."[44/] PG&E explained why this approach is inappropriate in its Opening Comments, and will not repeat that discussion here.[45/]

This proceeding is not the proper venue to address market barriers, incentives, or special treatment. PG&E discussed market barriers to CHP in its Opening Comments and will not repeat that discussion here.[46/] However, some parties, while responding to CPUC questions, proposed that the structure of ARB implementation include various programs and policies that will create subsidies for CHP, to be funded by electric customers.[47/] The suggestions are more appropriately addressed in other Commission or legislative venues (indeed most have already been litigated at length).

44/ EPUC/CAC, pp. 35- 36, Appendix B, p. 21; CCDC, p. 4.

45/ PG&E Opening Comments, June 2, 2008, pp. 81- 82.

46/ *Ibid.,* pp. 84- 86.

47/ EPUC/CAC, pp. 56- 60; CCDC, p. 6.

VI. NON-MARKET BASED EMISSION REDUCTION MEASURES (OTHER THAN CHP) AND EMISSION CAPS

A. Arguments For New and Expanded "Command and Control" Regulatory Mandates for CEE and Renewables Under AB 32 Are Not Supported by the E3 Model and Would Impose Excessive and Ineffective Cost Burdens on Customers

AB32 directs the ARB to reduce GHG emissions in a manner that "minimizes costs and maximizes benefits."[48/] Direct regulations that push programs goals to possibly unreachable targets run afoul of the directive to minimize costs and may place the AB32 GHG emissions reduction goal in peril.[49/] PG&E agrees with the comments of many parties urging caution in adopting expensive set-asides or new regulatory mandates for the purpose of meeting AB32 GHG reduction goals.[50/] Unrealistic programs and "command and control" mandates have high costs and implementation risks and will limit the efficiencies of the market.

For example, several parties[51/] argue that precisely because 33% renewables is too expensive to occur under a cap and trade regime, a 33% RPS "command and control" mandate is necessary "to make it happen." Such an argument presumes that the policy goal of AB32 is 33% RPS, not reducing GHG in the most cost-effective manner. Such an argument also assumes that "waving a wand" of a new regulatory mandate will make it happen. For example, some parties argue that the 33% mandate is needed to

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48/ Health and Safety Code section 38501(h).

49/ Health and Safety Code section 38501(g) states the Legislature's intent "to ensure that electricity and natural gas providers are not required to meet duplicative or inconsistent regulatory requirements" under AB 32. See also Health and Safety Code section 38562(d)(2) that requires that AB 32 regulations provide for reductions "in addition to" "any other greenhouse gas emission reduction that would otherwise occur," and Health and Safety Code section

50/ E.g., DRA, p. 47; WPTF, p. 25; Sempra, pp. 39-42; TURN, pp. 22-29

51/ Cal Wind Energy, GPI, NRDC/ UCS, p. 32.

provide investment security to renewables companies, attract investment capital, overcome regulatory barriers, and maintain stable investment in renewables.[52/]

Even as they are ignoring or minimizing the many regulatory proceedings designed to address the challenges of reaching 20% RPS, these parties are not arguing that 33% RPS is needed to meet AB32 emissions reductions goals, but are arguing that a 33% RPS *is an end in itself.*.

Fixed mandates, without regard to technical or economic feasibility, are ineffective public policy tools. As stated above, program set-asides and new regulatory mandates should only be considered when the GHG abatement measure is low-cost and other market failures exist. A 33% RPS mandate does not pass this test.

Several parties agree with PG&E's position. Parties concerned about excessive dependence on RPS and CEE to meet AB32 goals include TURN, DRA, SCE, FPL Energy Management, Morgan Stanley, and Calpine.[53/] TURN questions the value of spending over a billion dollars a year to move from the low-EE scenario to the high-EE scenario, only achieving "minimal" emissions reductions.[54/] Parties emphasize that if RPS and CEE are cost-effective carbon reduction solutions, the market will provide the incentive to enact these measures. Once the cap is put into place, programmatic approaches for the purpose of GHG reductions may include inefficient policies that may increase costs. Such approaches should be used when the GHG abatement measure is

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52/ NRDC/UCS, p. 32.

53/ TURN, p. 29; DRA, p. 50; FPL Energy Management, p. 12; Morgan Stanley, pp. 19- 20; Calpine, p. 21; SCE, pp. 40- 41, 44- 45, 49.

54/ TURN, p. 29.

assuredly low cost and other market failures (e.g. the owner-tenant problem) exist.[55/] For all these reasons, it is premature to mandate specific levels of energy efficiency and renewable power procurement outside the context of the whole portfolio of carbon reduction strategies.

Certain parties oppose a cap and trade system or desire strict limitations.[56/] These parties, including several POUs, believe that reductions should occur through programs only. PG&E notes that POUs will still be able to pursue all of these programs even if the electricity sector as a whole is part of a cap and trade program. In general, CO2 is ideally suited for management within the cap and trade context. With GHGs, the location or time of emissions is unimportant. Command and control regulations work well when technology solutions are developed and specific. On the contrary, CO2 is a pollutant emitted across industries that may have very different marginal costs of reduction. It is not likely that California policy makers will be able to achieve the same cost efficiencies of a cap and trade market only through prescriptive, command and control program measures.

B. Cap and Trade and Energy Programs Are Not Independent or Mutually Exclusive, and Therefore AB 32 Should Not Specify Percentages of Emissions Reductions from Both

The ARB, CEC, and PUC should not assume that new "command and control" programs and mandates will provide a certain percentage of reductions. While the ARB has recently stated that it may be possible for 60% of reductions to come from "programs," this figure is highly uncertain and does not account for the fact that cap a

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55/ Morgan Stanley, pp. 19- 20.

56/ CMUA, p. 2 ; CUE/ CURE, pp. 2- 3 ; NCPA, pp. 8- 9 ; SCPPA, pp. 3- 4.

trade and energy programs are not mutually exclusive. Caution should be used when citing any absolute abatement potential from any measure. If the cap is set at an extremely artificially low level because of assumptions of what aggressive regulatory mandates will bring and the mandates fail to deliver the forecast emissions reductions, high demand may put extreme upward pressure on prices. Not only will California pay for expensive mandates that may not succeed, but consumers will have to pay again as GHG abatement costs are driven up because of investment diverted to comply with the "command and control" mandates. It is very risky and expensive for policymakers to assume an unrealistic level of reductions through discrete programs or mandates, especially an exact percentage that forms the basis of the overall emissions reduction goals themselves.

C. Equal and Comparable RPS and CEE Programs Should Be Implemented by Investor Owned Utilities and Publicly Owned Utilities

PG&E agrees with WPTF and TURN that if certain energy programs and mandates are assumed in place for energy efficiency and renewable procurement as part of AB 32 emissions reductions, those programs should apply to non-CPUC jurisdictional publicly owned utilities (POUs) as well as investor-owned utilities.[57/] As PG&E noted in our opening comments, the facts indicate POUs have not pursued CEE as aggressively as investor-owned utilities.[58/] Thus, the emissions reduction potential inherent in CEE savings in POU service territories dwarfs the potential available in investor-owned utility service territories. Uneven application of state energy policy

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57/ WPTF, p. 25; TURN, pp 28- 29.

58/ PG&E Opening Comments, June 2, 2008, pp 88- 89.

results in the 30% of the load served by POUs and other electric service providers having greater GHG intensity. SCPPA, NCPA, and LADWP apparently agree that POUs should take strong programmatic measures but do not appear to agree on how to ensure that the measures actually are implemented.[59/] Extending CEE targets to POUs will support achievement of low-cost GHG abatement opportunities. It will also ensure that state policy is enforced consistently and that POUs contribute their fair share to GHG emissions reductions.

D. Natural Gas Efficiency Codes and Standards Should Be Explored

PG&E supports exploring natural gas energy efficiency measures, such as time-of-sale energy efficiency requirements, appliance feebates, and building code standards for solar water heaters.[60/] In addition, PG&E signed the state's first biomethane contracts and supports examining policies to increase use of this resource. These measures and programs can be explored through existing programs at the CPUC and Energy Commission, as well as other state agencies.

VII. MODELING ISSUES

A. Several Parties Misuse or Misinterpret the E3 Modeling to Support Their Positions

As PG&E stated in our opening comments, the E3 model provides useful policy insight. However, we have noted that a few parties have made statements in their opening comments that misinterpret E3 model results. For example, LADWP concludes:

> . . .the E3 modeling states that utility rates will increase, not decrease, under cap-and-trade, irrespective of allocation methodology with no environmental benefit over existing policies and programs (i.e. reference

59/ SCPPA, p. 15; NCPA, pp. 39- 41; LADWP, pp. 4, 6.

60/ NRDC/UCS, pp. 35- 37.

case of 20% RPS and existing energy efficiency goals).[61/]

This conclusion is incorrect because the E3 model in fact does not estimate utility costs under a multi-sector cap and trade program. The main indicator of the expense of a cap and trade program, the allowance price, is *an input* to the E3 model, not an output. To support LADWP's statement, E3 would have had to model the abatement curves across all sectors, offsets, and cost containment measures. These tasks were not part of the E3 scope of work. Additionally, policy makers and LADWP should keep in mind that the cost efficiencies from a cap and trade program also stem from what cannot be modeled, even in more sophisticated models like BEAR and Energy 2020. Uncertainty, imperfect foresight, and innovation to reduce GHG emissions from technology not currently deployable all cannot be modeled. Thus, LADWP's affirmations that the modeling supports LADWP's position that cap-and-trade is a cost adder for California consumers are without merit.

Although EPUC/CAC asserts that the "E3 model demonstrates that encouragement of CHP will further the state's emission reduction efforts in a cost-effective manner,"[62/] the model does not support such an assertion. Rather, the E3 model suggests that CHP deployed under the specific circumstances modeled lowers GHG emissions, but only under those specific circumstances. CHP with the emissions characteristics modeled in the GHG calculator that displaces BAU thermal load furthers the state's emissions reduction efforts. Unless CHP is truly efficient and serving existing or BAU needs, it will not reduce emissions. CHP assumed to meet non-existent

61/ LADWP, p. 7.

62/ EPUC/CAC, pp. iii, 41- 42, 63.

thermal needs may increase GHG emissions.

Finally, GPI claims that the E3 model "demonstrates that current programmatic goals for EE and the RPS by themselves are not sufficient to provide the level of emissions reductions needed to achieve the AB 32 targets in the electricity and natural-gas sectors."[63/] This statement presumes knowledge of what those AB32 targets in the electricity and natural-gas sectors are. As PG&E stated in the opening comments, if the emissions levels of 1990 are the goal, then E3 models the sectors meeting the goals through existing RPS and CEE mandates. GPI also states that the 33% target avoids 22 – 35 million tons CO2e compared to the 20% target. PG&E ran the calculator and found that the difference between the two in the Base and Aggressive cases is 20 MMT and 17 MMT, respectively.

B. PG&E Agrees that Some E3 Inputs Should Be Revised or Updated

Natural Gas Prices: Several parties suggest that the natural gas price forecast used for 2020 is too low.[64/] NRDC suggests both raising and lowering natural gas prices, noting both recent price trends and that GHG regulation may curb demand.[65/] PG&E notes that there are many causes of recent high natural gas prices and not all of these impact 2020 price forecasts. Fundamentals driving 2020 prices may not have changed. For purposes of consistency and to take advantage of work in another proceeding, PG&E suggests using the gas price forecast methodology developed for the 2008 MPR in this proceeding.[66/]

63/ GPI, p. 29.

64/ CalWEA, pp. 9- 10; CEERT, pp. 16- 19; Solar Alliance, pp. 3, 9- 10; NRDC/UCS, p. 47.

65/ NRDC/UCS, pp. 46- 47, 50.

66/ PG&E has also suggested that this gas price forecast methodology be used in the upcoming LTPP

Energy Efficiency: PG&E suggests using the Itron low goals case in the Aggressive Case. Comments by Sempra, SCE, and TURN bolster this recommendation.[67/] SCE states that Itron staff analysis indicates that achieving above 80% of economic potential is highly unlikely. TURN questions the cost effectiveness of the Itron mid and high goals cases.[68/] Based on parties' comments and SCE and Sempra's questioning of model results, PG&E recommends that a stakeholder working group be convened to understand the E3 inputs on energy efficiency levels and costs, including the derivation of the CEE embedded in load.

Renewables: Parties comment that the costs of renewables appear both too low[69/] and too high.[70/] Costs have been increasing for both conventional and renewable resources, perhaps even more so for renewable than conventional generation. Differing cost information highlights the need to conduct sensitivities and couch results with uncertainty. Additional uncertainty exists in the renewable resource development potential, as mentioned by NCPA. Uncertainty in renewables costs and development potential underscores the importance of not using program mandates.

Wind Capacity Factor: Wind capacity values should not be increased to unrealistic levels based on assumptions of technology improvement. NRDC suggests that the capacity factor for class 4 wind be raised to 43%.[71/] However, the CEC uses a

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analysis.

67/ Sempra, p. 40; TURN, pp. 23- 26.

68/ TURN, pp. 23- 26.

69/ SMUD, p. 36.

70/ CalWEA, NRDC/ UCS, CEERT.

71/ NRDC/UCS, p. 50.

capacity factor of 34% for class 5 wind.[72] Therefore, E3 should use the wind capacity factors it originally suggested, not inflated capacity factors based on new technology assumptions or national averages.

Transmission for Renewables: Transmission costs to integrate renewables developed far from load centers are not likely to reduce transmission needed for load growth and reliability. The full transmission costs for renewables should be attributed to the renewable generation for modeling purposes.[73] Additionally, PG&E shares EPUC/CAC's concern that wind integration costs may be higher than modeled at high levels of wind penetration.[74] To account for this, PG&E believes that E3's original estimate of wind integration costs should be used.

CHP Penetration in the Aggressive Case: The Aggressive case should assume that CHP is installed at the levels of the CEC Market Potential Report base scenario, as per E3's original intent. PG&E does not believe that the potential exists for the Moderate Market scenario, much less the CEC High Deployment scenario. Use of the High Deployment Scenario is inappropriate as, among many other assumptions, it assumes the "the rapid development and deployment of advanced technology."[75] E3 assumes no technology change in the Scenarios.

VIII. CONCLUSION

PG&E commends the CPUC and Energy Commission and parties to this

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72/ http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF.

73/ NRDC/UCS suggests that transmission for 33% RPS will defer transmission needed for load or reliability (NRDC/UCS, p. 48.)

74/ EPUC/CAC, p. 75.

75/ http://www.energy.ca.gov/2005publications/CEC-500-2005-060/CEC-500-2005-060-D.PDF, pg. vii.

proceeding for the exhaustive, comprehensive and thoughtful record that has been developed on these extremely important AB 32 implementation issues. Where parties disagree, we disagree not over AB 32's goals, but over the most cost-effective, efficient means of achieving the goals in a way that maintains and enhances California's environmental leadership while at the same time managing the costs to California's consumers and businesses.

We are about to enter a new phase of AB 32 implementation, in which the two commissions and the ARB work together on a multi-sector scoping plan that would apply AB 32 to all sectors and emissions sources in California, not just the electric and gas sector. PG&E expects in this upcoming phase that parties in the electric and gas sectors are likely to be far more in agreement than disagreement. However, the implementation details of this new phase will be no less important than in the earlier phases. In particular, modeling and evaluation of the relative costs and benefits of different emissions reduction measures in different sectors, combined with design of a multi-sector cap and trade program, will be very important priorities for all parties and the public.

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PG&E looks forward to working with all parties and the ARB, CPUC, and Energy Commission as we move forward with successful implementation of AB 32.

Respectfully Submitted,

CHRISTOPHER J. WARNER

By: /s/

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