CALIFORNIA
ENERGY
COMMISSION

COMMITTEE GUIDANCE ON FULFILLING CALIFORNIA ENVIRONMENTAL QUALITY ACT RESPONSIBILITIES FOR GREENHOUSE GAS IMPACTS IN POWER PLANT SITING APPLICATIONS

COMMITTEE REPORT

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Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

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CHAPTER I. INTRODUCTION

On October 8, 2008, the California Energy Commission adopted an order initiating an informational (OII) proceeding to solicit comments on how to satisfy its responsibilities under the California Environmental Quality Act (CEQA) and assess the greenhouse gas (GHG) impacts of proposed new power plants. As lead agency for power plant siting under California law, the Energy Commission has licensing authority for all thermal power plants with a capacity of 50 megawatts (MW) or more that are proposed for construction within the state. The Energy Commission's licensing process, which includes extensive environmental impact review, is the functional equivalent of the CEQA environmental impact review process. This informational proceeding raised questions related to whether power plants have a significant adverse cumulative environmental impact resulting from their contribution to atmospheric emissions of Greenhouse Gases (GHGs), and if so, how those impacts can be mitigated.

Including GHG in CEQA evaluations is part of a rapid evolution of state climate policy instigated by an increasing recognition of the threat of climate change and the urgent need to reduce greenhouse gas emissions. In 2002 with AB 1493 (Pavley, Chapter 200, Statutes of 2002), California became the first state in the nation to mandate the reduction of GHG emissions from passenger vehicles. In June 2005, declaring that "the time for action is now," Governor Schwarzenegger signed Executive Order S-03-05, calling for aggressive cuts in statewide GHG emissions through 2050. With the California Global Warming Solutions Act of 2006, AB 32 (Núñez, Chapter 488, Statutes of 2006), in September 2006, California cemented its commitment to aggressive action to address climate change. AB 32 requires the state to reduce its GHG emissions to 1990 levels by 2020.

The California Air Resources Board (CARB) is tasked with implementing AB 32, and is directed to consult with the Energy Commission and the California Public Utilities Commission on energy-related elements of its Scoping Plan to reduce GHG emissions. In October 2008, the two Commissions jointly recommended to CARB that the following key climate strategy components for the electricity sector be adopted: (1) a 33 percent renewable portfolio standard, (2) all cost-effective energy efficiency, and (3) the electricity sector in a multi-sector cap and trade program, provided that CARB finds that certain statutory requirements in AB 32 are met. The 33 percent renewable portfolio standard was subsequently endorsed by the Governor in Executive Order S-14-08 (November 2008). CARB's Scoping Plan to implement AB 32 also calls for a 33 percent renewable portfolio standard, aggressive energy efficiency targets, and a cap and trade system that includes the electricity sector.

California is at the cusp of transforming its complex system for generating and serving electricity to consumers. As this revolution takes place, the Energy Commission continues to receive numerous power plant applications to build large thermal power plants, including solar thermal and natural gas-fired facilities, and must determine how to best address the GHG emissions through the CEQA process.

Since CEQA has unique provisions that are not found in similar federal or state laws requiring environmental analysis, no clear patterns or milestones exist that are applicable and informative regarding what such environmental analysis should consider, or how it should be done. There are many issues including:

- Should the climate impacts of renewable facilities be considered, and if so how?
- Should the focus include construction as well as operation of the facility?
- Should indirect but positive impacts be considered?
- What kinds of mitigation make sense and are feasible?

AB 32 directs CARB to avoid measures that reduce in-state GHG emissions but result in these emissions being transferred to a source outside of California—called "leakage." All GHG emissions regardless of where they are produced contribute to global warming. In the electricity sector, California is part of the integrated western transmission grid and imports electricity from places as distant as Canada and Mexico. AB 32 suggests that our CEQA analysis of GHG emissions from a particular power plant proposal in California should be viewed in the broader context of the greater integrated system, or California's regulatory efforts may merely "export" GHG emissions to other states or countries.

AB 32 also defines the State's long-term, integrated plan for reducing overall GHG emissions from significant emitters in all economic sectors. This more comprehensive and programmatic Scoping Plan approach is preferable to a project-by-project analysis and mitigation of impact, as it allows CARB to require GHG reductions from all power plants, including existing ones. By contrast, CEQA provides the Energy Commission with very narrow authority to mitigate the cumulative contribution of impacts that are from the single power plant seeking licensing—often a far more efficient piece of infrastructure than the aging facility it could replace or displace in the utility dispatch order. Thus, requiring mitigation for a new efficient facility could have the paradoxical result of slowing or preventing the replacement of older, far less efficient generation that has higher GHG emissions, increasing the emissions of the system as a whole. The possibility of such a perverse outcome emphasizes the need for an approach that is comprehensive and embraces both existing facilities and proposed new ones.

Although CARB has already adopted the AB 32 Scoping Plan, the regulations to implement the Plan are still being drafted and are planned to take effect before 2012. The Energy Commission cannot rely on the prospect of future regulations to support a determination of whether power plants in the licensing process will have a significant adverse impact on the climate. Therefore, during this short interim period before the AB 32 regulations take effect, the Siting Committee believes that the Energy Commission should not rely on CARB's programmatic approach for its CEQA analysis and mitigation. Rather, during this interim period, we recommend that the Energy Commission analyze each project according to basic CEQA precepts for determining (1) whether the project has a significant adverse cumulative effect, (2) if so, whether feasible mitigation can be required for the project, and (3) if not, whether the project has overriding benefits that justify licensing the project. The Committee recommends that the Energy Commission revisit this approach once CARB's regulations are in effect.

This Siting Committee summary of the proceeding does not attempt to answer these questions, which we recommend be addressed both in individual siting cases and the *2009 Integrated Energy Policy Report (2009 IEPR).* However, the following discussion highlights principles that we find particularly useful in considering these issues, some of which will be further analyzed in the *2009 IEPR*.

CHAPTER II. PARTICIPANT COMMENTS ON THE QUESTIONS PRESENTED

The Energy Commission began this informational proceeding to solicit comments and perspectives regarding how it should perform CEQA analyses for the thermal power plants that it licenses. The Energy Commission issues such licenses according to a "certified regulatory program" that is exempt from the specific environmental impact report requirements of CEQA, but that complies with its substantive provisions. (See Pub. Resources Code, § 21080.5, Cal. Code Regs., tit. 14, §§ 15250 *et.seq.*) This inquiry emphasized the legal requirements of CEQA itself, as reflected in the principal questions provided in the October 8, 2008, "Order Instituting Informational Proceeding," paraphrased as follows:

1. Are power plant GHG emissions appropriately analyzed as a cumulative global impact pursuant to CEQA?

2. What "threshold of significance" should apply in such analysis, and might it vary by the type of power plant being considered, such as renewable or peaking power plants?

3. What is the appropriate CEQA "baseline" for such analysis (i.e., do new renewable power plants or more efficient natural gas power plants have a potentially significant adverse impact if they replace—or displace—less efficient gas-fired power plants)?

4. If a new power plant is found to have a significant adverse impact, what is appropriate mitigation?

5. Are the cumulative impacts of power plant GHG emissions best regulated and mitigated through a "programmatic approach," such as the California Air Resources Board's AB 32 program, as opposed to case-by-case determinations?

The OII Order was broadly distributed to numerous stakeholders and specifically directed the State's investor-owned and publicly owned utilities to participate. Comments were solicited from environmental groups, state and public agencies, power plant license applicants, and parties who have participated in the Energy Commission's licensing process. The Energy Commission's Siting Committee held two broadly noticed workshops and solicited a second round of comments from all interested agencies, groups, and persons. The public comment was extensive and the broad outlines of the various comments are presented below. The docket for the OII received written filings from the following participants:

AB 32 Implementation Group (representing large and small California businesses)
California Climate Action Registry
California Unions for Reliable Energy (CURE)
Center for Biological Diversity (CBD)
Clearwater Port LLC

Community Environmental Council
Communities for a Better Environment (CBE)
Delta Diablo Sanitation District
Downey Brand LLP
Earthjustice
Energy Producers and Users Coalition (EPUC)
Environmental Health Coalition (EHC)
Independent Energy Producers Association
Latham and Watkins LLP
Mirant California LLC
Natural Resources Defense Council
Northern California Power Association (NCPA)
Pacific Gas and Electric (PG&E)
Sacramento Municipal Utility District (SMUD)
San Diego Gas and Electric (SDG&E)
Southern California Edison (SCE)
Theroux Environmental

Most of the above participants attended at least one of the two public workshops held by the Energy Commission's Siting Committee on October 28 and November 19, 2008. Workshop participants in addition to those listed above include the following:

California Attorney General
California Municipal Utilities Association (CMUA)
Californians for Renewable Energy
Coalition for a Safe Environment
Competitive Power Ventures
Governor's Office of Planning and Research
Pacific Environment
Ratepayers for Affordable Energy
San Joaquin Valley LEAP
Sempra Energy
Verde Group

The Committee is pleased with this broad participation and appreciates the responsiveness of the participants to the questions set forth in the OII Order. Many of the written comments were detailed and nuanced, and there is some risk that a summary description of such comments will omit or mischaracterize the responses to the wide range of issues addressed. The following summary attempts to highlight the nature of the comments on the most important issues.

A. Applicability of CEQA

Most participants agreed that GHG emissions are a cumulative impact that should be considered by CEQA analysis, but opinions quickly diverged on how useful and appropriate CEQA is for analysis of a global impact. Most agree that CEQA analyses that ignore GHG impacts face legal vulnerability. Environmental groups, including Earthjustice and the Center for Biological Diversity, provided comments suggesting that GHG issues are no different from other cumulative impacts that currently are required to be addressed in CEQA analysis. Other participants stressed that GHG emissions present a very different kind of issue from the local and regional impacts typically addressed by CEQA because global warming is a cumulative *global* impact, with GHG emissions being released globally, and with all emissions contributing to the same impact. This presents interesting analytic problems for determining significance, for enforcing mitigation, and for determining the effectiveness of mitigation. Mitigation effectiveness is particularly problematic, as AB 32 acknowledges, if restricting emissions in California only results in greater emissions being emitted outside the state (called "leakage"). The Energy Producers and Users Coalition (EPUC) commented that CEQA focuses on how a project affects "the physical conditions within the affected area" (citing Cal. Code Regs., tit. 14, § 15126.2), and that there is nothing more than speculation for how an individual project's GHG emissions can be described or predicted in that context, making any finding of significance inappropriate.

B. Determining a "threshold of significance"

CEQA encourages public agencies to adopt "thresholds of significance" to determine the significance of environmental effects. (Cal. Code Regs., tit. 14, § 15064.7.) "A threshold of significance is an identifiable quantitative, qualitative or performance level of a particular environmental effect, non-compliance with which means the effect will normally be determined to be significant by the agency and compliance with which means the effect normally will be determined to be less than significant." (*Ibid.*) For state agencies such thresholds must be adopted as rules through a public process and be supported by substantial evidence. Thus, for the Energy Commission to establish by rule a threshold for its power plant licensing cases, it would be required to engage in rulemaking, and any threshold it adopted would have to be based on substantial evidence that GHG emissions below a determined level are less than "cumulatively considerable," and therefore, less than a significant effect.

Draft Proposed Thresholds of Significance: Other Agencies

Many participants pointed out that CARB staff has recently issued a draft proposed "interim" threshold of significance of 7,000 metric tons of CO_2 equivalent per year for industrial project operational emissions, with separate performance standards for construction and transportation emissions. (CARB, *Recommended Approaches for Setting Interim Significance Thresholds for Greenhouse Gases under the California Environmental Quality Act*, Oct. 24, 2008, p. 9.) The draft proposed threshold provides guidance for mitigation of industrial GHG emissions "until such time that performance standards, such [as] AB 32 regulatory requirements, are in place to ensure mitigation of significant impacts of GHG emissions from projects in the industrial sector." (*Ibid*.) The threshold is based on CARB's analysis of the nature and size of various industrial facilities, and includes common sub-sources of GHG emissions from industry, categories of industrial emissions, and a survey of industrial boilers by Oak Ridge National Laboratory.

The South Coast Air Quality Management District (SCAQMD) staff has developed a draft significance “threshold” that is based on a “tiered” approach. (SCAQMD, *Interim CEQA Greenhouse Gas (GHG) Significance Threshold*, Oct. 2008.) Although the threshold does not consider separately the industrial sector or power plants, its non-CEQA exempt Tier 2 threshold is 10,000 metric tons per year CO_2 equivalent. Projects exceeding that amount go to Tier 3, which incorporates various options for GHG emission reduction (30 percent from “business as usual,” or achieving “sector-based standards” reductions); projects not meeting Tier 3 requirements can provide offsets equivalent to project emissions. (*Id.*, Figure 3-1.)

Similarly, the California Air Pollution Control Officers Association (CAPCOA) has developed a white paper to assist California air districts in CEQA assessments of GHG emissions for the projects that they must either permit or provide CEQA analysis. (CAPCOA, *CEQA and Climate Change*, January 2008.) The CAPCOA white paper does not endorse a particular approach, emphasizing lead agency discretion, but discusses using a “zero threshold” or a “non-zero threshold” for significance determinations, as well as a creatively wide variety of different approaches for determining significance within these frameworks. It suggests that the drawback of a “zero threshold” is that a broad range of permitted activities, down to the single residential building permit level, become “cumulatively considerable” in a CEQA context and thus subject to potentially burdensome CEQA analysis and mitigation. (*Id.*, p. 31.) Another issue is that, “prior to 2012, there will only be limited mandatory regulations implementing AB 32 that could address the existing economy in a truly systematic way that can be relied upon to demonstrate that overall GHG reduction goals can be achieved by 2020.” (*Id.*, p. 52.) Moreover, like CARB and others, the white paper acknowledges that a zero threshold imposes significant administrative costs on permitting agencies, and may effectively preclude lead agencies from utilizing the common and efficient devices of lead agency CEQA analysis: categorical exemptions, negative declarations, and mitigated negative declarations. (*Id.*, pp. 28-29.)

The CAPCOA discussion develops several noteworthy concepts that may be useful in determining thresholds for power plant projects. Such concepts, include:

1. An agency may want to proceed without an adopted significance threshold, on a case-by-case basis, developing information on the specific project and it how relates to existing conditions and AB 32 goals, or relying on comparative thresholds for criteria pollutants.

2. An agency could use the CARB “reporting threshold” of 25,000 metric tons GHG equivalent per year.

3. An agency could use a zero threshold and calculate direct GHG emissions, modified by “what other resources are affected by projects.”

4. An agency could base its determination of significance on whether the project is consistent with AB 32 goals.

5. An agency could base its determination on an adopted air district threshold.

6. An agency could use a "percentage based reduction" threshold based on AB 32.

7. An agency could use a "percentage based reduction by economic sector" to determine if a project meets AB 32 reduction goals, as a determinant of significance.

8. An agency could use a "tiered approach" of demonstrating (1) compliance with 2020 reduction goals, (2) SB 97 exemption[1], (3) that the project is on the "green list" of projects that are "deemed a positive contribution to California efforts to reduce GHG emissions," (4) compliance with an AB 32 general plan, or (5) mitigation using the "tiered methodology" described by CAPCOA.

9. An agency could use air district "regulated emissions" (e.g., NOx and ROG) significance thresholds, and emissions inventories of such, to calculate an equivalent GHG percentage "regulated inventory" value (some air districts have used this approach, with thresholds ranging from 39,000 to 46,000 metric tons per year).

10. An agency could develop an approach "to establish an appropriate cumulative context, that, although an individual project may increase GHG emissions, broader efforts will result in net GHG reductions." (CAPCOA, at p. 52.) This approach, specifically acknowledges population and economic growth, and involves a cumulative context that results in overall *net* reductions.

The CAPCOA white paper also acknowledges that an agency could determine, consistent with traditional CEQA concepts, that a project has a less than significant impact because it does not result in an increase in GHG emissions based on the baseline that exists when the Notice of Preparation is filed.

Comments from Participants Regarding Thresholds

Comments from participants varied widely. The Independent Energy Producers (IEP), and PG&E, SCE, and SDG&E (the IOUs), contended that new power plants will have only beneficial effects on net GHG emissions because they are more efficient than older plants whose generation they would displace in the order of resource dispatch. From this point of view, thresholds of significance are simply irrelevant, because the effect of new generation is beneficial. (This issue is discussed further below under the issue of CEQA "baseline.")

Several participants, including the IOUs, SMUD, Energy Producers and Users Coalition (EPUC), Downey Brand, and Mirant, urged the Energy Commission to use the SB 1368 "performance standard" as the threshold. The SB 1368 standard was established to prevent California's utilities from entering into long-term contracts for carbon-intensive base load power, (pounds of CO_2 equivalent per MWhour). The IOUs stated that:

[1] SB 97 (Chap. 185, Stats. 2007) exempts certain categories of infrastructure projects (but not power plants) from GHG CEQA analysis.

> An interim performance standard of 1100 lbs/MWhr should also be applied . . . under SB 1368. This performance standard was established by the California Public Utilities Commission (CPUC) and the CEC under Senate Bill (SB) 1368 as a "bridge" to more permanent emissions standards and measures to be set by AB 32 effective beginning in 2012. Thus, for siting cases that come before the CEC between now and when AB 32 regulations go into effect, the CEC should quantify the GHG emissions, and apply the SB 1368 1100 lbs/MWhr standard as an interim mitigation measure under the same terms and conditions applied by the CPUC and CEC. In enacting SB 1368 the Legislature concluded that only certain facilities should be subject to interim GHG emissions performance standards during the period prior to AB 32 regulations . . . .
>
> In addition, the interim approach should consider presumptive findings of insignificance for projects such as gas fired peaking plants because of the potential for such projects to reduce system-wide GHG by firming renewable generation, displacing older generation, and/or increasing grid stability. Therefore no performance standard is necessary for these types of projects.

NCPA filed similar comments, but also urged that state agencies apply the concept of "Best Available Control Technology," or BACT, usually applicable to regulated criteria pollutants, to the licensing of new facilities. In NCPA's view, new facilities should have a less than significant impact if they emit below the performance standard limits set by AB 1368. These facilities would still be subject, presumably by type of technology and efficiency, to agency-determined BACT limits, which presumably would be set in terms of efficiency. In NCPA's view, applying a zero threshold would "jeopardize the viability of a proposed power plant and the reliability of the state's electricity supply." NCPA urges a "programmatic" approach to mitigation.

By distinct contrast to the above positions, the Center for Biological Diversity, Earthjustice, Communities for a Better Environment, and Community Environmental Council (collectively, Earthjustice) disagreed with the utilities' position and urged that a threshold must be based on the science of climate change. According to Earthjustice, the compelling aspect of such science is the "dangerous anthropogenic interference" of GHG emissions, and that such "factual data most strongly support a threshold of zero." Any other threshold would have to be factually based and effectively must show that it meets AB 32 goals. In addition, Earthjustice advocates that the same zero threshold apply to all power plant projects licensed by the Energy Commission, regardless if they are baseload, peaking, or renewable. EHC provided comments generally agreeing with Earthjustice, recommending that the same zero threshold apply to all projects and construction, and that the environmental analysis should include "life cycle" impacts such as those caused by the use of liquefied natural gas. Earthjustice, responding to the IOUs and others, argues that using the AB 1368 threshold of significance is inappropriate because it would allow gas-fired baseload facilities of unlimited size to be built in California, presumably with a conclusion that their impacts are less than significant.

The California Unions for Reliable Energy (CURE) commented that threshold proposals are of little importance since any power plant proposal subject to Energy Commission jurisdiction would presumably have GHG emissions exceeding any of the discussed thresholds.

C. Appropriate CEQA Baseline: "Single Facility" versus "Electric System" Approach

The CEQA term "baseline" reflects the requirement that CEQA analysis "should normally limit its examination to changes in the existing physical conditions in the affected area as they exist at the time the notice of preparation is published or . . . at the time environmental analysis is commenced." (Cal. Code Regs., tit. 14, § 15126.2, subd. (a).) Although the OII Order used this term, it is to some degree misleading for describing the underlying issue that the Order sought to have addressed. That question is: should the GHG/climate change impact of a new power plant be determined only by measuring the emissions emitted by that single new facility? Or, alternatively, given that GHG emissions have a global impact regardless of where they are emitted, should the impact be measured by the *overall net* impact a new power plant will have on total GHG emissions?

Although there was a strong divergence of opinion on this issue, there was some nuance and overlap between the two positions.

IEP, the IOUs, AB 32 Implementation Group, and others argued that, if one correctly acknowledges the CEQA baseline as existing conditions, no new power plant, either gas-fired or renewable, can have a significant adverse cumulative impact on climate change. This, IEP would urge, is because electric generation projects are, unlike most other kinds of projects with cumulative effects, *not additive but rather a replacement of other existing emitting projects that are less efficient*. Power plants are dispatched largely according to their economic costs which, for gas-fired facilities, means the efficiency with which they use natural gas. Thus, replacement (or displacement) of older less efficient power plants with newer ones (renewable or gas-fired) increases overall generating efficiency, reduces the burning of carbon fuel, and is a net environmental benefit rather than a significant adverse cumulative effect. This results from the economic logic of the way power plants are normally dispatched, so that less efficient facilities are pushed toward the back of the dispatch order, until they are eventually so marginal that they are retired altogether.

Some participants emphasized that the western U.S. interconnected electric system is a large integrated mechanism comprised of power plants and transmission lines that extends from Canada into Mexico and west of the Rocky Mountains. As a result, California imports electricity from throughout the western states and Canada; it includes hydro and nuclear power from the northwest, and coal power from the mountain states. Imported coal-fired electricity, which is by far the most carbon intensive, currently comprises over 16 percent of the California's electricity. Efficient new gas-fired power may displace imported coal-fired power, thereby reducing GHG emissions, particularly as carbon costs are applied to out-of-state coal; coal-fired electricity has at least twice the GHG emissions of gas-fired electricity, and because it is imported from out-of-state, is subject to significant transmission losses.

IEP further argues that using the "single facility" approach will result in a decidedly inaccurate CEQA assessment of the true impact, because it will incorrectly identify new, more efficient gas-fired facilities as harmful when in fact they are a critical component of the solution to the GHG problem. Moreover, any mitigation imposed on these new projects will discourage or make impossible the changes to the system that are necessary to reduce GHG emissions. Additionally it would force those emissions into other more distant and permissive states that will license projects in distant locations that will be less helpful in reducing GHG emissions. The resulting system will be more carbon intensive, more expensive, and less reliable, and the "leakage" or "export" of GHG emissions to other states is contrary to the admonitions of AB 32.

Earthjustice views the matter differently and suggests that the only correct approach is to consider the baseline to be "zero," and measure the direct GHG emissions from any single new project to determine the amount of cumulative contribution to climate change impacts. It cites a recent trial court decision rejecting a home builder's argument that, by building a residential/commercial development with buildings that are more efficient than elsewhere in the country, the project's impact is beneficial absent any showing that the existing homes were demolished or left unoccupied.

In Earthjustice's view, even a solar thermal power plant must be found to have a significant adverse cumulative impact on global warming because its construction or operation will result in GHG emissions, unless the project can "demonstrate, based on substantial evidence, that the project includes an enforceable reduction in an existing source of emissions that otherwise would continue to emit greenhouse gases for the same period as the proposed project." Earthjustice believes the only credit for GHG reduction that can be assumed, for the purpose of determining significance, is the enforceable shutdown of another facility; forseeable operation scenarios based on economic principles or common practice are discounted.

Earthjustice further argues that an "electric systems" approach to determining significance is "not currently available because California's electric system is not subject to a "statewide energy planning regime." Since the Energy Commission is no longer required to find that a project is "needed" by the electric system as a condition for a permit, Earthjustice reasons that the state's "ad-hoc system on power plant siting" allows "private developers to propose and site whatever they believe is necessary and then incorporat[e] any greenhouse gas regulation into a future cap and trade system that by definition relies on the free market rather than planning . . . ." Earthjustice points out that there are 10,000 MW of electric generation in the current application process, and more than 8,000 MW (gas-fired) already with permits that have not been built, suggesting that this prospective gas-fired generation is limitless and may compete with and prevent new renewable generation projects. In Earthjustice's view, the IEP/IOU position would essentially create a "categorical exemption" for power plants that is inappropriate and inconsistent with CEQA, and would prevent reaching AB 32 goals.

EHC, echoing some of the Earthjustice comments, suggests that the baseline of existing conditions does not properly effectuate AB 32's emphasis on reduction. EHC believes that the "electric systems" approach to determining cumulative impact is "unreliable" and says that such determinations must be based on quantitative data and evidence.

Natural Resources Defense Council (NRDC) approached the issues in a different way that is hard to easily categorize. NRDC urged the Energy Commission to produce a programmatic EIR (PEIR) to address the issue of GHG from a broader perspective that is essentially an "electric system" approach to determining impact for new generation facilities, and to "tier" off the PEIR in the individual siting cases to determine the significance of the cumulative impact and appropriate mitigation. The PEIR would use a scenario analysis identifying the underlying purpose of future licensed power plants. In addition:

> These objectives should include not only maintaining a reliable electricity system in the state and minimizing costs to electricity consumers, but also building the infrastructure necessary for a low-GHG future. The Program EIR should evaluate the GHG impacts of several alternative system-wide scenarios that meet these objectives. [Para.] Each scenario should incorporate existing policies to reduce GHG emissions in the electricity sector, i.e., each scenario should comply with California's loading order, assume aggressive energy efficiency savings, a 33% RPS [renewable generation required of IOUs by state law] by 2020, the emission performance standard established by SB 1368, and a GHG reduction program under AB 32. Each scenario should describe a potential resource portfolio that, in keeping with California's existing policies and objectives, attempts to minimize total cost and total GHG emissions. The scenarios should clearly identify the different system needs that must be met (i.e., base-load, peak-load, reliability and integration services) and identify the lowest GHG resources to meet those particular needs.

NRDC also urged that these issues be addressed as a matter of policy in the Energy Commission's *2009 IEPR*, considering electricity generation, the transformation to renewables, and GHG mitigation from a 20 - year perspective.

D. Appropriate Mitigation for a Significant Cumulative Impact

Most agency draft proposals such as those of CARB and CAPCOA do not attempt to address mitigation for large stationary projects in any meaningful way, but focus instead on how agencies might seek mitigation for residential and commercial projects. SCAQMD's discussion of mitigation is also more directed to residential/commercial projects, recommending approaches such as 30 percent better than "business as usual" development practice, or achieving "sector based standards" based on GHG lbs/person or lbs/cubic foot.

The lack of agency direction is also reflected in participant comments. IEP and Mirant stated that mitigation is currently not feasible, with IEP noting the current absence of well-defined protocols for offset mitigation that would be certain and acceptable. Downey Brand urged that determining mitigation was inappropriate "at this time." Earthjustice suggested broad categories of mitigation: energy efficient housing retrofits in the local community; local level renewable generation projects; permanent closure of less efficient gas facilities; and requiring new power plants (presumably gas-fired) to have a hybrid renewable component. Sempra demurred to these suggestions, saying that as a load serving entity it is already doing most of these things following aggressive directives from the CPUC.

EHC stated that mitigation must meet the same requirements as offsets for criteria pollutants according to the Clean Air Act: that it must be quantifiable, certain, enforceable, non-duplicative, and result in net GHG reductions. More specifically, EHC recommended mitigation requiring one megawatt of solar rooftop installation for every megawatt of gas-fired generation. SMUD argued that mitigation, if required, should not be held to the Clean Air Act standard, but must be more flexible to be feasible, should not be pound for pound, and should not require mitigation additional to AB 32 mitigation. EPUC indicated that AB 32 cap and trade will provide adequate GHG mitigation, and that any Energy Commission-derived mitigation would be "double mitigation." CURE suggested that there are many potential mitigation opportunities: applicants could fund energy efficiency building retrofits, water conservation measures, microturbines, community tree planting, public transportation support, cool roofs, green farm investments, and sustainable building grants.

NRDC took a different approach, stating that mitigation for GHG is "difficult" but indicating that cost-effective energy efficiency improvements could be a useful mitigation. NRDC also suggested that a license applicant should be able to argue that the project is already mitigation for the GHG cumulative effect since it reduces the carbon intensity of electricity production (essentially an "electric systems" analysis as mitigation rather than to determine significance). As NRDC explained:

> If a new plant [proponent] has reason to believe it will replace more carbon-intensive power on the grid, it should provide information about the GHG-intensity of the existing dispatch order and where its power will fit in terms of cost and GHG emission, in order to bolster its claim that it is a low-GHG option. As discussed above, intermittent renewables can not be used to meet peak load, so that would not be a feasible mitigation measure for a proposed new peaker plant and the plant would not have to analyze that alternative in its application. [Para.] Proposed new power plants should not be required to purchase carbon offsets in order to mitigate their GHG impact. Carbon offsets take the focus away from the state's goal of transforming the electricity sector. Proposed power plants should be focused on meeting electricity needs in the least-GHG intensive manner possible. They should not be required to invest money in projects in other sectors that may or may not result in real GHG reductions.

The IOUs emphasized that mitigation should be programmatic for all power plants (old and new) including all stationary projects. They urged that, if mitigation is required, it should be considered only for the interim period before the AB 32 regulatory provisions become effective, to avoid requiring power plants to "mitigate twice." The AB 32 Implementation Group suggested that meeting AB 32 requirements should be considered sufficient mitigation and that mitigation such as energy conservation could be considered.

The Energy Commission invited the California Climate Action Registry to give a presentation on how the Registry can be used to provide CEQA mitigation. The Registry is a non-profit organization created by the California Legislature and is comprised of businesses, government agencies, non-profit organizations with over 370 members and more than 650 million metric tons of GHG registered between 2000 and 2007. The Registry was created because of concerns about the validity of private offset credits being sold in the private market, and has recognized high accounting standards that make it the "recognized seal of approval" for offset credits. In addition to making sure that registered offsets are real, additional, permanent, and verified, the Registry also requires that they be "owned unambiguously," are not harmful, and are practical to implement. The Registry has developed numerous "protocols" assuring the validity of its offsets, including forestry projects (conservation, reforestation, avoided de-forestation), landfill gas capture, agricultural methane capture, and urban forestry. Offsets have been developed throughout the United States.

The Registry functions essentially as a "bank," and all projects that create emissions are verified for efficacy by a third party. All "Climate Reserve Tonnes", or CRTs, have a tracking number for each ton removed, and can be traded between accounts or permanently retired. CRTs are only issued after the carbon reduction has occurred, and were sold at $10.80/ton in September 2008. CRTs are described by the Registry as the "premium end of the market." The Registry is recognized and supported by CARB, leading environmental groups (including Sierra Club and NRDC), and PG&E and SMUD voluntary programs. Protocols for CRTs are developed through a public process and information is public.

The California Attorney General was also invited and gave a presentation on the mitigation it has achieved through litigation and settlements. Most of the settlements have occurred in the context of land development, but there have been at least two settlements with stationary emission sources. One was the Conoco- Philips refinery, which had modified its facility in a manner that would increase GHG emissions by 500,000 metric tons per year. The Attorney General creatively negotiated a settlement on the project's GHG impacts, requiring the facility to do a complete audit of facility-wide GHG emissions, pay mitigation of $7 million to the air district GHG mitigation fund, $200,000 for wetland restoration, and $2.8 million for reforestation projects. Reductions that resulted from the facility-wide audit would be credited against the settlement monies at $25/ton. In addition, there was a settlement with Great Valley Ethanol Plant requiring payment of $1 million to the local air district for GHG mitigation projects.

E. Should GHG Cumulative Impacts Be Addressed Programmatically Rather Than Case-by Case?

The current AB 32 regulatory program calls for a multi-sector program that addresses GHG emission reductions economy-wide, with specific reduction goals in 2020 and later. This program is proceeding rapidly, as required by statute, with the Scoping Plan for AB 32 adopted by CARB in the late fall of 2008. For the electricity sector, this program requires a 33 percent renewable portfolio standard by 2020 and all cost effective energy efficiency. It also includes the electricity sector in a multi-sector "cap and trade" program that all major stationary producers of GHG emissions must participate in by purchasing emission allowances under a program that "caps" available allowances at declining levels that will help meet AB 32 reduction goals. Assuming that the cap and trade program is implemented, all stationary sources of GHG, including both new and old power plants, would be subject to its provisions, and presumably required to obtain allowances for their emissions.

Power plant developers, utilities, air districts, and even environmental agencies are trying to determine how this program should effect mitigation for projects that are being permitted now, before the Scoping Plan takes effect. Many have argued that AB 32 is itself the State's program for cumulative impact mitigation of GHG, and that project-by- project mitigation for new power plants will be inconsistent, expensive, and will potentially impose a "double mitigate" burden on projects that will be subject to AB 32's Scoping Plan. CARB clearly contemplates that its AB 32 program could meet CEQA's mitigation requirements: "Once such requirements are in place, they could become the performance standard for industrial projects for CEQA purposes." (CARB, *supra*, at p. 9.) This set the stage for the question in the OII Order, querying whether the Energy Commission's licensing of power plants should recognize the near term implementation of CARB's AB 32 program.

There were two sets of opinions on this issue. The IOUs, IEP, SMUD, EPUC, Sempra, Mirant, NCPA, Downey Brand, AB 32 Implementation Group, and others are adamant that AB 32 is the essential and preeminent state program for addressing cumulative GHG effects, and that any additional mitigation required for projects currently being licensed should be only for the interim period before the AB 32 requirements become effective. CARB regulations are expected to become effective in 2012, although it is unclear when all reduction programs resulting from this regulation will be implemented, particularly for cap and trade. Alternatively, some of these participants ask assurance that any project mitigation required as mitigation by the Energy Commission be credited under any future cap and trade program.

Earthjustice, EHC, and CURE were equally adamant that projects in general, and power plants in particular, should be evaluated on a project-by-project basis without regard to AB 32 requirements that might impose similar or additional requirements. Earthjustice states that cap and trade has not been implemented, and that it will likely be unsuccessful in achieving reductions even when it is. EHC states that programmatic and project-by-project approaches are not mutually exclusive, but argues that cap and trade does not exist, that its reductions are speculative, and that the Energy Commission should ignore the AB 32 program when dealing with its license applications. In addition, the Energy Commission and CARB should be jointly seeking to shut down existing older facilities with higher carbon emissions.

The Committee compliments the OII participants and thanks them for their thoughtful comments. It apologizes if it has not mentioned or given credit to all the participants in this summary narrative, or omitted other information that a participant believes important, or if it has mischaracterized any comment. In any case, participants have provided the Committee with many ideas and differing perspectives. These ideas, and the Committee's perspectives on them, are discussed in the section that follows.

CHAPTER III. COMMITTEE DISCUSSION

This summary is the opinion of the Siting Committee, and does not represent the conclusive views of the Energy Commission on the OII topics. Any statement of broadly applicable policy that could become siting decision requirements is typically required to be adopted as regulation or as part of a statutorily required policy document such as the Integrated Energy Policy Report. GHG was addressed in the *2005 IEPR* and again, at greater length, in the *2007 IEPR*. This Committee will recommend to the full Energy Commission that it be addressed even more comprehensively in the *2009 IEPR*, to the extent time and resources allow.

The IEPR is the energy policy for the State, so it is important to review the expression of that policy in the *2007 IEPR*. Although the analysis and principles enunciated there do not answer the questions presented in this OII, the document provides context and direction for how they might best be answered. Accordingly, some relevant points from the *2007 IEPR* are listed below:

1. California's increases in population and economic activity mean that overall electricity use is projected to grow at 1.25 percent annually, and peak demand growth is 1.35 percent (850 MW) per year. (p.3) Between 1990 and 2020, the state population is projected to increase by 50 percent. (p. 4)

2. Some 16,000 MW of old, inefficient, high GHG-emitting power plants, (many using environmentally damaging once-through cooling), continue to operate for reserve capacity purposes in coastal load pockets in San Diego, Los Angeles, and San Francisco. These facilities, some more than 50 years old, are mostly steam boiler units, and must idle around the clock at a lower level (consuming fuel, emitting GHG, and running their ocean pumps) so that they can "ramp up" for "peak demand" service when needed. (p. 184.) To reduce air quality, GHG, and marine biology impacts, it is state policy to either close or repower these facilities with cleaner, more efficient power plants. These older facilities are now operating at low capacity factors to meet capacity needs in coastal urban load pocket areas. (p. 72.) For reliability purposes, some of these plants must be replaced with "dispatchable" (i.e., gas-fired) facilities. (pp. 69-70, 184.) The California Independent System Operator (ISO), the Energy Commission, and the State Water Resources Control Board are planning for the retirement of the aging facilities. (p. 70)

3. New power plants are more efficient of natural gas use than older power plants that they replace or displace in the order that plants are dispatched. (pp. 35, 184.)

4. "Since 2003, California's energy policy has defined a *loading order* of resource additions to meet the state's growing electricity needs: first, energy efficiency and demand response; second, renewable energy and distributed generation; and third, clean fossil-fueled sources and infrastructure improvements." The loading order is the accepted protocol that describes the priority sequence for actions to address increasing energy needs. (p.3, fn.3)

5. A significant amount of the state's imported energy is coal fired, and coal-fired generation is responsible for a disproportionate amount (up to 50 percent or more) of the GHG emissions associated with California's electricity use. (pp.19, 66.) The *2007 IEPR* "scenario" analysis indicates that, under given scenarios of a "carbon adder" that increases the cost of coal-fired generation, gas is the "swing fuel" for reducing out-of-state coal generation. (pp. 57-61.) As such, "[t]he displaced coal generation would be replaced by higher generation from natural gas-fired power plants, both in California and the Rest-of-WECC [Western Energy Coordinating Council]." (p. 61.)

6. Increased renewable generation in the overall supply system has consequences for system reliability. "Intermittent renewable technologies, such as wind and solar, are a challenge to traditional reliability planning, particularly given the "peakiness" of the state's electricity load." (p. 115.) This is because the wind may not blow during peak periods or it may blow too much during off-peak periods. This requires the state's infrastructure to be revamped with "appropriate infrastructure" to integrate renewables if the "33 percent by 2020" goal is to be met. (p. 118.)

7. AB 32 program efforts to maximize energy efficiency and renewables in the loading order will reduce overall energy generation from natural gas between now and 2020. (pp. 46-49.) Even so, "[n]atural gas is and will remain the major fuel in California's supply portfolio and must be used prudently as a complementary strategy to reduce greenhouse gas emissions." (p. 186.) "Even when California's 33 percent renewable target is met, two-thirds of the state's electricity will still come from conventional sources—the vast majority of which will be natural gas-fired." (p. 6.)

8. The Energy Commission has determined that the state should pursue 100 percent of cost effective energy efficiency through regulatory programs coordinated between the Energy Commission and the CPUC, affecting most categories of energy use. (p. 83.) These programs will include even more aggressive building standards and time-of-sale retrofits. In addition, the CPUC is to further develop its already aggressive utility efficiency, demand response, and load management programs. (pp. 91-98.)

The *2007 IEPR* could not foresee the current economic recession, and the respite that this may provide in terms of growing energy demand. Likewise, there is also gathering pressure by the State and by the new federal administration, to transform the electric system to one that will increasingly rely on renewable sources. Even so, the *2007 IEPR* conclusions were grounded in the hard reality of the current system's composition, and how it must be changed to achieve AB 32 goals.[2] This background informs the discussion of the issues that we offer below.

[2] In addition, the 2007 IEPR provided a far-reaching analysis of GHG emissions in California and the rest of the western interconnected electricity system, including the effect of AB 32 renewable generation and efficiency policies that the State is currently pursuing in the CARB Scoping Plan.

A. Applicability of CEQA

There are no easy answers to the conundrums raised by the commenters concerning the global nature of the GHG cumulative impact, and the consequent absence of any meaningful thresholds that could be linked to attenuating the problem. There is also a speculative quality to predicting how this impact will affect conditions "within the affected area" of a project. But the Committee believes that state law and policy dictate that the Energy Commission require GHG cumulative impact analysis in its power plant licensing decisions. If necessary, the Energy Commission should amend its regulations to require power plant applicants to address the issue of GHG project emissions for construction and operation.

In a 2007 document suggesting alternative approaches to GHG CEQA analysis, the Association of Environmental Professionals (AEP) provides a good summation of this issue. After discussing AB 32, the AEP notes that AB 32's legislative findings included an extensive discussion of the deleterious environmental impacts of global warming *and* a provision that nothing in that legislation relieves any state agency of its obligations to comply with state law, and concludes:

> When the legislative findings about the threats to the environment and the absence of relief from other laws are considered together, the act creates compelling statutory basis for addressing significant adverse effects of [GHG] in CEQA compliance. (AEP, *Alternative Approaches to Analyzing Greenhouse Gas Emissions and Global Climate Change in CEQA Documents*, June 2007, p. 9.)

B. Determining a "threshold of significance"

The Committee is impressed with the efforts of CARB, SCAQMD, CAPCOA, and others to devise defensible thresholds of significance. Such thresholds are undoubtedly useful (or even necessary) for CEQA analysis, if only to avoid the administrative crush of having to provide EIRs for extremely minor projects that should, as a practical matter, be categorically exempt, subject to a negative declaration, or relieved of the CEQA analysis requirement according to the "common sense" exception.

However, the adoption of such a threshold requires agency rulemaking, which is not the purpose of this OII. Moreover, the Committee is reluctant to endorse any threshold at this point. In the Committee's view, even relatively low construction emissions for power plant projects should be subject to "best practices" mitigation that seeks ways to reduce GHG construction emissions. Such mitigation will need to be considered by Energy Commission staff on a case-by-case basis at least for the initial set of cases heard before the Energy Commission, although measures may become more standardized over time, as the agency comes to understand what reasonable and feasible GHG-reducing construction measures can be taken for different kinds of projects.

The principal GHG impact from power plants is their operation, not their construction. Even solar facilities apparently will have operation emissions associated with the necessary continual washing of the mirrors, and require a fleet of vehicles to operate continually to perform that task. Some solar facilities will also have gas-fired boilers to improve capacity factors and extend the hours of operation of the facility. While these projects may have a net GHG impact that is a benefit to the environment—by lowering the net amount of carbon emitted to generate electricity—the Energy Commission may want to examine these emissions and the benefits of the project to determine whether impacts are cumulatively significant, and if so, whether they might feasibly be reduced. For this reason, the Committee does not propose a threshold of significance for any category of facility, including renewables. Our recommendation is that all power plant applicants are subject to CEQA analysis to determine the significance of their GHG impact, with no attempt to adopt numerical thresholds. [3] This approach was recognized among those discussed in the CAPCOA white paper.

C. Appropriate CEQA Baseline: "Single Facility" versus "Electric System" Approach

The "single facility" approach is the normal approach to CEQA analysis, as Earthjustice and EHC have pointed out. The advantage to this approach is that it is confined and relatively simple. For a power plant, the approach would basically require the calculation of GHG emissions caused by the burning of fossil fuels, which is a relatively simple exercise of measurement. Life cycle materials and fuels analysis are more difficult and subject to infinite complexity and variation, but these are refinements that can be dealt with separately or not at all, depending on what is reasonable (and what reliable information is reasonably available).

Earthjustice compared the new power plant CEQA analysis to that of a new housing subdivision, based on a trial court decision that it participated in. One might make a new subdivision with more energy efficient homes, but that does not necessarily render the project's impacts less than significant. The fact that other existing subdivisions are less efficient does not prevent the emissions from the new subdivision from being additive, and it is therefore necessary to determine whether the new subdivision has emissions that are cumulatively considerable.

The Earthjustice approach is consistent with the way the Energy Commission has traditionally looked at CEQA analysis, where power plant impacts are normally considered additive to existing ones. In air quality analysis the issue is more nuanced: if a new facility shuts down generation at the same site or nearby, this direct displacement is acknowledged, if only from a public health standpoint (offsets are still required, and are frequently from the shutdown facility). If the new power plant displaces dirtier generation in the air basin only generally, without a corresponding shutdown, all criteria emissions are considered additive (and thus subject to offsets) with no recognition at all of displacement that might logically occur somewhere else. This is because, with the operational complexities of the electricity system, it is somewhat unpredictable where those displacement reductions might occur, as they may be outside the air

[3] While the Committee does not propose an agency significance threshold, we believe that it is appropriate for siting case parties to refer to the thresholds of significance adopted by other agencies with expertise and purview, such as the local air district, CARB, or CAPCOA.

basin, and therefore not relevant to the impact of the new power plant within the basin where it is located.

However, as others have pointed out, the cumulative effect of GHG is often anomalous to traditional CEQA analysis, including air quality analysis. Unlike criteria air pollutants such as nitrogen oxides, where the effect is basin-specific, a molecule of GHG emitted in Montana (or China) has the same climate warming effect as a molecule of GHG emitted in California. Thus, if a new gas-fired power plant displaces GHG emissions in a different air basin, or even a different state, this is a GHG benefit.

IEP, the IOUs, and others argued that electricity generation additions (new power plants) are not analogous to the GHG impact of a more energy efficient new subdivision. Whereas the "green" subdivision's impact is additive, the new power plant impact is not; rather, it has the effect of displacing generation from an older gas-fired facility that is less efficient (higher emitting). While the less efficient displaced facility may or may not be physically retired, if it is not retired it drops further back in the order of dispatch because it has higher operating costs (and it then displaces the still less efficient facility behind it in the dispatch order). The effect of the new facility is that the older facility (as well as those behind it in the dispatch order) runs less often (if at all), reducing the overall carbon intensity of electric generation, until further additions eventually push the older facility into retirement. Such "chain reaction" displacement occurs both within California and in other portions of the "Western Interconnection" that provide "imported" power into California.

IEP cites to the same CEQA fundamentals relied on by Earthjustice in its argument. CEQA analysis is intended to inform the agency decision-makers and the public of the nature and extent of the environmental effect of a given project. In IEP's view, if the likely effect of a new power plant is to reduce GHG emissions from the electricity system, then it is a public policy travesty if the analysis, for reasons of methodological simplicity, or merely a desire to avoid public controversy, misleadingly reports that the project results in a significant adverse effect. The public policy consequence of such an approach is that the public and decision-makers are fundamentally misled, and projects that would reduce GHG emissions are penalized or even rejected.

The Committee agrees with IEP that new electric generation projects are different from building new shopping centers or adding new subdivisions. As the *2007 IEPR* acknowledged, new gas-fired power plants are more efficient than older power plants, and they displace these older facilities in the dispatch order. This displacement will occur even if the older plants are not retired. Natural gas prices and "heat rates" (efficiency of fuel use) are the predominant cost-determinants for gas-fired facilities,[4] and such facilities are normally dispatched in the order of facility cost. This explains why, despite California population and electricity demand increases, most aging units built for baseload operation have gradually moved down the dispatch order to

[4] Depending on the price of gas, they comprise 70 to 85 percent of a gas facility's life cycle costs. (CEC, 2005 IEPR, p. 63.)

the point where some units have capacity factors less than five percent. (*2005 IEPR*, Appendix A.) Moreover, even with the considerable expansion of electric generating capacity since 1990, GHG emissions from the state's electricity generation have hardly increased, if at all, since 1990 (with annual variability according to such factors as hydro availability). (Energy Commission and CPUC, *Final Decision and Recommendations on Greenhouse Gas Regulatory Strategies* ["Joint Decision"], (Oct. 2008, p. 112.) The *2007 IEPR* points out that one of the significant problems with the current system is that the state has not yet built enough new generation to push the oldest coastal facilities into retirement, and this has significant adverse consequences for energy efficiency, criteria air pollutants, GHG emissions, and impacts on marine life from cooling pump entrainment and aquatic thermal emissions. These old facilities provide necessary capacity even though they continue to operate at very low "capacity factors."[5] New electricity generation that can further displace or close such facilities provides clear GHG and marine biota environmental benefits.

Earthjustice parries IEP's contentions with other arguments. Even assuming displacement occurs, load growth is incessant, and new facilities will not only displace older facilities (thereby reducing GHG emissions); they will serve new electricity load (thereby resulting in an overall GHG emission increase).[6] Thus, even if a new power plant reduces the amount of carbon in each MW/hour generated, net GHG emissions increase, contrary to the express goals of AB 32. Earthjustice further contends that the absence of any centralized government resource planning authority that would determine California's need for new generation before issuing a power plant license results in a danger that the state will build unneeded gas-fired generation. Earthjustice suggests this generation will, in turn, squeeze out room for renewable generation required to meet AB 32 goals. Earthjustice points to the 8,000 MW of licensed gas-fired power plants that have not yet initiated construction, and to an equal number of gas-fired applications currently seeking licenses, as evidence of a promiscuous "overbuilding" of new gas-fired facilities.

The issues raised by Earthjustice are important. They are based on the concern that, if new power plants are not found to have a significant adverse cumulative impact, and are not rejected or required to provide mitigation, the state will rely too heavily on gas-fired generation and not meet AB 32 goals. While the Committee shares this concern, it has doubts about the correctness of Earthjustice's conclusions, and particularly about the proposed solution—to limit GHG CEQA analysis for power plants to the single project.

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[5] Capacity factor means how much electricity a plant produces in a year relative to its potential production if it were to operate at full capacity for all 8,760 hours in a year. Many of the older units, though originally built as large baseload facilities, are currently operating at less than a 15 percent capacity factor. (*2005 IEPR*, Appendix A.) This is an inappropriate use of tools and technology. Unlike newer turbine units that would replace them, the old facilities are boiler units that must operate at low levels even when they are not called on to generate power, so that they can rise to the occasion when needed.

[6] An increase in GHG emissions from the electricity sector due to load growth is not necessarily an overall adverse effect if the load growth occurs in ways that displace larger emissions from other sectors. For example, substantial new electricity load to fuel plug-in hybrid electric vehicles is well recognized to produce a substantial overall GHG benefit in all but the most heavily coal-dependent electricity systems. (See, *Environmental Assessment of Plug-In Hybrid Electric Vehicles: Joint Study of the Electric Power Research Institute (EPRI) and the Natural Resources Defense Council (NRDC)* (2007).)

The key to meeting AB 32, as the *2007 IEPR* observes, is the rapid transformation of the system to support the loading order priorities of greater efficiency and greater reliance on renewable generation. California's "procurement process" for determining what new sources of generation will receive utility contracts requires that a very high proportion of new utility contracts be for renewable generation, to meet AB 32 goals. Most important, the state loading order requires that the power from renewable generation be purchased by the utility first, before energy from conventional sources. To meet their state-required goals, utilities must purchase virtually all energy made available by renewable sources. Thus, the procurement process and the loading order prevent the possibility that new gas-fired facilities will "crowd out" new renewable facilities that are necessary for reaching AB 32 goals, even if speculators in California "overbuild" gas-fired facilities. Indeed, the result of any overbuilding would be higher reserve margins, lower profits for the owners of gas-fired generation (particularly if they lack quick-start capabilities that allow them to offer ancillary services that assist in the integration of renewable energy), and probable early retirement of the less efficient gas-fired facilities that now power the grid.

Moreover, even without "central planning" by the Energy Commission or the CPUC, there are compelling reasons that the state is unlikely to "overbuild" new gas-fired power plants. Utilities are contracting for power based on the demand assessments of the Energy Commission, as implemented by the CPUC in its procurement process[7]. Power plants require huge capital investments and elaborate financing; unless a project receives a contract through a utility procurement process such financing cannot, as a practical matter, be obtained, and the project cannot be built. There is simply too high a risk, in the turmoil of rapid change, that a project without a utility contract would not run enough (and earn enough) to justify the considerable capital investment, particularly as the electric generation system transforms to greater reliance on renewables.

Although many applicants for gas-fired power plants have sought and received power plant licenses without (or before) a utility contract, such licensed projects are not being built unless they receive utility contracts, and many have been abandoned. The best evidence of this point is the 8,000 MW of gas-fired generation that Earthjustice notes has already been licensed by the Energy Commission, but for which construction was never initiated. Notably, several Energy Commission licenses for many hundreds of MW of generation have been allowed to

[7] Since 2004, the CPUC has required the major IOUs to submit biennial 10-year plans for acquiring energy resources to meet demand growth and state targets for preferred resources – energy efficiency, demand response, and renewable energy – and for replacing expiring contracts. These long-term procurement plans (LTPPs) must balance the costs of meeting customer needs with state policy goals of minimizing environmental impacts and meeting state targets for preferred resources. In preparing the plans, IOUs do two assessments, one to identify physical and contractual resources needed to meet bundled customer needs and one to identify new resources needed in their service territories to maintain adequate reserve margins. After approving the LTPPs, the CPUC authorizes the IOUs to procure the resources needed to meet long-run growth in energy demand and cover the expiration of existing contracts. The CPUC sets targets over the next 10 years for energy efficiency, demand response and interruptible load programs, and renewable energy. The utilities provide estimates of the remaining need for energy and capacity in their LTPPs and then solicit long-term agreements through competitive requests for offers (RFOs) overseen by the CPUC.

expire[8] by applicants who could not obtain utility contracts for their projects. The number of such expired licenses for gas-fired facilities will grow over time, and the number of applicants will likely become fewer.

The decline of the role of natural gas for provision of kilowatt hours is already becoming evident, and is expected to continue.[9] At the same time, the number of thermal solar applications has grown quickly, as has the number of pre-licensing consultations. This, of course, only concerns projects jurisdictional to the Energy Commission. Numerous new renewable generation projects are being developed that are not thermal, but are photovoltaic or wind projects, and these projects are expected to contribute greatly to the transformative shift to renewable generation.

The transition, and where it is headed, is set forth in the recent forecasts of the Energy Commission and the CPUC in their "Joint Decision" regarding how AB 32 goals will be met by the electricity sector. The Joint Decision projects that under a "business as usual" approach of relying principally on gas-fired generation, GHG emissions from the State's electricity sector would grow from approximately 110 million metric tons (MMT) in 1990 to 129 MMT in 2020. (Joint Decision, pp. 111-113.) However, using "a reasonable scenario of potential achievable emissions reductions in the electricity sector compared to its historical emissions levels" (measures contemplated by *AB 32 Scoping Plan*, including renewable energy, rooftop photovoltaics, and energy efficiency), 2020 electricity sector GHG emissions could be held to 1990 levels. (*Ibid*.) Moreover, if a more aggressive program is implemented, including "combined heat and power" (cogeneration) as a program measure, emissions could be reduced to 79 MMT, a 27 percent reduction from 1990, and 38 percent lower than "business as usual" 2020 projections. These reductions would be achieved without any cap-and-trade provision, and would roughly meet the goals of CARB's Scoping Plan (40 percent electricity sector reductions), even if its cap-and -trade provisions were never implemented:

> [C]ARB's Draft Scoping Plan would assign approximately 40% of the economy-wide responsibility for mandatory emissions reductions to the electricity sector, even though electricity represents only 25% of the statewide emissions. Using ARB's assumptions, this requirement would result in electricity sector emissions in 2020 roughly equal to the level that E3 estimates under the Accelerated Policy Case. If electricity is included in the cap-and-trade program contemplated in the Draft Scoping Plan, and were to achieve the additional emissions reductions that ARB expects from the cap-and-trade program, the electricity system could, in total, deliver as much as 55% of the required emission reductions in the State . . . . (Joint Decision, p. 113.)

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[8] As of today, eight power plant licenses that had been approved by the Energy Commission have expired, which is totals of 2,531 MW of capacity (http://www.energy.ca.gov/sitingcases/all_projects.html).

[9] As noted above, natural gas-fired facilities that have quick start and ramping capabilities may still play an important role in maintaining reliability of a system that is integrating more variable energy sources like wind and solar. But those facilities will not produce power much of the time. Rather, they will produce power when the system needs it and cannot get it from renewable sources.

The conclusions of the Joint Decision are consistent with those of the *2007 IEPR*, which projects that under any of the electric system demand-supply scenarios other than "business as usual," gas-fired generation of energy will decline as a proportion of total generation by 2020 (in some scenarios by more than half). (*2007 IEPR*, Fig. 2-14, p. 49.)

The decline in the gas-fired *energy* in the system might easily mislead some to think that no more gas-fired power plants need be built. However, that misapprehends the nature of an electric system more reliant on "intermittent" renewable power such as wind and solar energy, and the need for reserve generation *capacity* when those intermittent renewable sources generate less. Wind power, for instance, is often less available on the hottest summer days when generation capacity is most needed to meet system load requirements. Thus, a system that increasingly relies on renewable generation for energy must likewise provide gas-fired dispatchable *capacity* to make the system reliable when intermittent renewable generators are providing less. This is why the *2007 IEPR* states that natural gas generation "must be used prudently as a complementary strategy to reduce greenhouse gas emissions." (p. 186.) Many of the gas-fired license applications currently before the Energy Commission are for projects that will support a transition to a more renewable-based generation system, presumably because the procurement process favors such projects. This criterion—the degree to which a project supports the transition to a more renewable system, while preserving reliability—is important to the assessment of project GHG impacts in future licensing decisions. It will also be explored in the *2009 IEPR* proceeding. (2009 IEPR Committee Scoping Order, p. 8.)

Finally, part of the transformation of the State's electricity system involves the future role of coal-fired power. The *2007 IEPR*, in reference to its scenario analysis, suggests an important potential GHG reduction role for gas-fired facilities, but this role will depend greatly on future policy decisions regarding coal. Coal is currently the largest share of electric generation in the United States, and a coal-generated megawatt hour has more than double the carbon content of a natural gas-fired megawatt hour. Although California has very limited installed coal-fired-power plants in-state, California utilities and load-serving entities import 16 percent of annual electricity energy from out-of-state coal plants. This import of coal-fired power contributes disproportionately to the GHG emissions attributable to California's use of energy.

Currently, coal power is so cheap, given the lack of any carbon tax or allowance requirement, that no other generation source (other than hydro) can compete with it economically. However, in recent years there has been a growing regulatory impulse to assume that this will change, either because of a future carbon tax or requirements (and significant costs) of future carbon sequestration. This has led the CPUC to impose a "carbon adder" assumption for utility purchases by the IOUs. The CPUC requires utilities to assume that the "carbon adder" is $8 per ton of GHG emissions. At this price coal is still the economic choice, and neither renewable nor natural gas-generated electricity can compete with it. But if the carbon adder is raised above $40 per ton, gas-fired power begins to displace coal power. At $60 per ton this displacement effect is significant, and would greatly reduce GHG emissions attributable to the State's electricity sector. (pp. 58-59, 61, 186.) Carbon sequestration is forecast to impose a cost of $50 to $90 per ton. (p. 66.) This is why the *2007 IEPR* describes gas as the potential "swing fuel" for displacing coal-fired power in the scenario analysis. If future State or federal policies require a higher carbon adder (or its equivalent in incremental coal costs), as currently seems likely, gas-fired power's displacement of coal imports could greatly reduce the carbon content of the State's electric generation.

D. Appropriate Mitigation for a Significant Cumulative Impact

Mitigation for stationary source emissions of criteria air pollutants has become standardized pursuant to the state and federal clean air acts. Air districts develop federally approved programs for creating a "bank" of emissions "offsets" from facilities that have terminated or reduced their emissions. The air district must verify that such emissions are real and permanent, enforceable, and that they would not result from other regulatory requirements, before such emissions can be "banked." There are extensive and detailed requirements to verify the validity of such "emission reduction credits," or "ERCs." Once validated and banked, projects creating new sources of pollution can purchase the banked ERCs so that the new source can operate. Offsets must often be banked and provided at a "ratio" that effectively requires the net reduction of permitted stationary emissions. This highly regulated part of the air district's "programmatic" approach to regulating criteria emissions gradually reduces the inventory of stationary source emissions over time.

Several participants correctly observed that there is no legally recognized "offset" program for GHG emissions, and that this makes it more difficult to determine what the appropriate mitigation for this cumulative impact should be. Moreover, there are many controversies over the effectiveness of many GHG mitigation measures that have been offered or required to satisfy CEQA, including the effectiveness of preserving (or planting) forests, the potential redundancy of efficiency programs, or the permanence of measures that are predictably not entirely permanent. The lack of a recognized "program" for mitigation creates a challenge (and legal vulnerability) for agencies that must fashion, on a case-by-case, *ad hoc* basis, effective mitigation for GHG cumulative impacts.

The above problem is a transitional one that will likely be sorted out over time. In the interim, participants identified a broad number of programs that should be considered as possible mitigation if the Energy Commission should determine that a power plant project results in a significant cumulative impact. These might include:

1. Projects that promote energy efficiency, particularly in housing, that would otherwise not occur pursuant to existing government and utility programs. These could include energy audits, insulation and weatherizing programs, more efficient appliances, and fluorescent light bulb "change-out" programs, to identify only a few obvious possibilities. Such programs were identified as potential mitigation by CURE, NRDC, Earthjustice, SMUD, the IOUs, and others. Some air districts are creating GHG mitigation funds that can be used to support such projects, which will facilitate implementation of such programs.

2. Projects that promote passive solar installations, including small (local) rooftop applications, as EHC and Earthjustice advocate.

3. Building retrofits, microturbines, water conservation measures, community tree planting, public transportation support, "cool roofs," sustainable building grants, and "green farm" investments," as CURE advocates.

4. Forestry projects (conservation, forestation, avoided de-forestation), landfill methane capture, agricultural methane capture, and urban forestry, as identified by the California Climate Action Registry.

5. Contributions to air district GHG mitigation funds, facility-wide GHG emission audits geared to mitigation incentives, wetland restoration, and a variety of local energy efficiency programs, as advocated so effectively by the California Attorney General in its settlement efforts.

6. The purchase of CRTs, or similar high quality offsets that are independently validated by such organizations as the California Climate Action Registry. The Registry's program provides GHG offsets that would appear to meet the requirement that offsets be real, permanent, enforceable, and non-redundant, the standard that air districts are required to use for criteria pollutants.

Earthjustice believes that such offsets should be required to be "pound for pound" with project emissions. Others disagree. Presumably a CARB cap-and-trade program, when it is implemented, will require the purchase of credits (or "allowances") based on emissions. However, such a strict approach for the Energy Commission's CEQA mitigation has drawbacks, in that it may undercut the use of many of the mitigation measures identified by Earthjustice and others that are listed above. Such programs may have high social value in addition to the reduction of GHG measures, and it would be unfortunate if the difficulty in determining their precise value (or the lack of sufficient value for the comparative expenditure) would discourage their use as mitigation measures. Moreover, given the displacement effect of new generation discussed in "C" above, even if the Energy Commission determines that a new power plant may have a significant cumulative effect, that effect will certainly be considerably less than the measure of facility emissions. Any new power plant will be reducing the carbon intensity of the electric generating system by displacing less efficient gas (and potentially coal) generation, although the precise measure of displacement will be impossible to accurately determine. Thus, even if a new power plant is determined to result in a significant cumulative impact, the magnitude of the impact cannot be quantified with any certitude, although the actual impacts would logically be significantly less than the measure of GHG emitted. This would make a pound for pound approach disproportionate, and thus inconsistent with CEQA and the U.S. Constitution. (Cal. Code Regs., tit. 14, § 15126.4, subd. (a)(4)(B).)

E. Should GHG Cumulative Impacts be Addressed Programmatically Rather Than Case-by-Case?

Probably the widest ranging cumulative impact that is currently addressed by CEQA is that of criteria pollutant emissions in California's various air basins. To effectively address such criteria pollutant problems, federal, state, and local governments have in concert created the most comprehensive and elaborate programmatic approach to environmental regulation of a problem ever devised. Paints, solvents, fireplaces, automobiles, stationary sources, agricultural burning—the list of regulated activities in the air programs is nearly endless—are all part of this multi-faceted program to reduce criteria pollutants regulated by both state and federal law, and largely enforced by local air districts within local air basins. In this context, as described previously above, stationary emitters are required to comply with thresholds of significance and if necessary provide offsets for mitigation to obtain an air district permit and comply with CEQA. When stationary sources purchase offsets for their projects, this is typically considered mitigation of the cumulative air impact that the air district's program has been fashioned to address, in a proportionate way, project by project. This approach is consistent with CEQA. (Cal. Code Regs., tit. 14, § 15064, subd. (h).)

CARB is currently creating a similar comprehensive program for regulating GHG emissions within the State, pursuant to its AB 32 duties, and as adopted in the provisions of its Scoping Plan. Like CARB's programs to reduce criteria air pollutants, the CARB program is multi-sector and embraces a wide range of human activities. The CARB Scoping Plan, adopted on December 11, 2008, lays out the architecture of the regulatory program, including a 33 percent RPS requirement and aggressive energy efficiency targets, and includes a "cap and trade" program in which all major stationary sources of GHG emissions will have to participate by surrendering approved emission allowances under a program that "caps" GHG emissions from these sources at declining levels that must meet AB 32 reduction goals.

The cap and trade program will require all power plants, both new and existing, to surrender allowances for their emissions, and will encourage the replacement or curtailment of older, less efficient power plants by newer, more efficient ones. As discussed under "II" above, many participants argued in favor of considering the CARB AB 32 program to be the programmatic approach for CEQA compliance, and urged that consistency with the requirements of that program should suffice as cumulative mitigation for CEQA that reduces impacts to being less than cumulatively considerable. These participants suggested that the Scoping Plan regulations are to be implemented in 2012, and that any mitigation required by the Energy Commission should either be only for the period prior to 2012, or be capable of being credited to cap and trade requirements. These participants cautioned the Energy Commission against requiring "double mitigation" for new power plants, meaning mitigation first required by the Energy Commission license, followed by additional mitigation resulting from cap and trade or other regulatory requirements.

Other participants urged that all projects address the program on a case-by-case basis, determining both the significance of each new power plant proposal individually on its own merits, and if necessary, prescribing customized mitigation for each project to address the GHG cumulative impact.

The CARB, CAPCOA, and SCAQMD documents discussing potential thresholds of significance acknowledge, either implicitly or explicitly, the potential for the AB 32 program to become CEQA programmatic compliance for GHG emissions. This could be by means as simple as finding that the project is consistent with the AB 32 program requirements.

CEQA certainly allows agencies to find that programmatic approaches provide the mitigation for cumulative impacts; this already occurs with many programs including air quality criteria pollutant emission programs mentioned above. There are many advantages to the use of programmatic approaches: they provide consistent, proportionate, and predictable mitigation based on a plan from an agency with both purview and expertise, vetted through a public process. By contrast, case by case mitigation is very consumptive of agency resources, and can be inconsistent as well as unpredictable for those who must plan projects based on some kind of forecast for expense. The Committee sees no conceptual or legal reason for insisting that case by case CEQA analysis be performed for all projects indefinitely. GHG cumulative impact mitigation, like criteria pollutant mitigation, is especially well-suited to being addressed programmatically, and CARB is providing the means for doing so.

It is unclear for the moment how soon the CARB Scoping Plan will be implemented, or when all of its provisions will be implemented, although implementing regulations for the measures in the Scoping Plan are supposed to be in effect by 2012. In addition, CARB may not proceed with implementation of a cap and trade program unless and until certain statutorily prescribed findings are met. This creates some uncertainty regarding when the Energy Commission might rely on the CARB program. Many of the power plants currently before the Energy Commission probably will not be built and operating before 2012. Thus, one might argue that, with the adoption of the Scoping Plan, a program already exists, and that it will be in place by the time newly licensed power plants come on line. However, the Committee is reluctant to endorse such a conclusion before the regulations are in place for the CARB program, and before it becomes clear how it will be implemented. At least for the immediate future, the Committee believes the prudent course is to address the significance of GHG as a cumulative impact on a case by case basis, and any mitigation likewise. In addition, the Energy Commission may want to fashion mitigation that is near-term for some few years following licensing or, alternatively, that is consistent and not duplicative with future CARB cap and trade regulations. In the meantime the Energy Commission should continue to work with CARB to make sure that its program will meet AB 32 goals, and to determine when the program can fairly be said to be implemented.

CHAPTER IV. RECOMMENDATION FOR FUTURE STAFF ANALYSIS

The *2007 IEPR* included considerable analysis of the implications of preferred resource additions for achieving the emission reduction goals of AB 32 and the electricity sector's role in GHG emissions. That work described the likely impacts on GHG emissions of increasing renewable and other preferred resource types in the loading order (such as energy efficiency), the need for new infrastructure (including new transmission facilities and dispatchable gas-fired facilities with the flexibility to integrate renewables), the GHG contribution of out-of-state coal, the continuing role of natural gas, and various scenarios that analyze the electricity sector effects of different levels of effort to maximize efficiency and renewables.

The work in the *2007 IEPR* was ambitious and useful, providing an analytic basis for pursuing the previously-established loading order preferences that could achieve major reductions in electricity sector GHG emissions. Further work completed in 2008 led to the joint CPUC-Energy Commission recommendations to CARB concerning electricity sector mitigation strategies. CARB largely embraced these recommendations when adopting its *AB 32 Scoping Plan* in December 2008.

Yet more analysis is needed to inform the rapid transformation of the electricity sector required to meet AB 32 goals. The Energy Commission currently has nearly two dozen applications for both gas-fired and renewable energy generation projects before us, waiting for approval to construct. The Committee knows that the renewable projects are essential to reducing the carbon content of California's electricity sector. We also know, as stated in the *2007 IEPR*, that the "prudent use" of natural gas for electricity generation is necessary to integrate intermittent renewable generation and provide reliability to the overall system. However, further analysis is required to refine this general understanding, and to help strengthen the Energy Commission's CEQA analyses of its power plant applications.

The Siting Committee makes the following recommendations to the 2009 IEPR Committee for further analysis, and urges that Committee to direct staff to perform or oversee the following analytic work to the extent feasible given timeline and resource constraints:

1. Staff should prepare or oversee the development of a "blueprint" laying out the role for different generation technologies, and identifying the amount and type of capacity required for 2013 and 2020 to support high levels of renewable additions, expansion of energy efficiency efforts and other demand-side programs, retirement of aging coastal facilities relying on once-through cooling, and providing reliability for individual load pockets.

2. Staff should prepare an analysis comparing the degree that different kinds of gas-fired power plants facilitate AB 32 goals, and whether (or the degree to which) project technology and location may make a proposed power plant more consistent with AB 32 goals. To the extent possible, this analysis should consider not only present conditions, but possible future changes in the role of electricity generated by fossil fuels, such as a

shift toward electrification of California's transportation system, and possible future "carbon adders" to coal-fired electricity imports. It would also be desirable for staff to conduct analyses that reveal the variability of the need for capacity and energy from gas-fired power plants as a consequence of important uncertainties, either in the pace and success of achieving preferred resource types (energy efficiency programs, supply-side renewables, and other demand-side program impacts), or natural uncertainties, such as from hydro-generation imported from the Northwest.

3. Staff should conduct an analysis of generation additions required in the South Coast air district to satisfy demand growth, close or repower aging coastal facilities using once-through cooling technologies, and meet other IEPR goals. This work would consider the potential for transmission reinforcements, the impacts of expansion of distributed generation applications, the current lack of available emission offsets, and other uncertainties that could affect future generation projects.

4. Staff should collaborate with the California ISO and the CPUC to provide a more detailed "systemic analysis" of new generation and transmission line additions necessary for each load pocket, considering such issues as retirement of aging and once-through cooled plants and emission offset constraints. This work would supplement the work in item 2, and would likely extend beyond the 2009 IEPR reporting cycle with the goal of providing a more precise identification of needed generation and transmission resources for California's load pockets. Staff should work with the CPUC and parties to more closely couple siting of preferred resources with the CPUC's Long-Term Procurement Plan process.

In addition to these quantitative analyses for the near- to intermediate-term, staff should continue to monitor development of AB 32 Scoping Plan implementation efforts, the role of a transitional Energy Commission effort until AB 32 Scoping Plan elements are developed and implemented, and general trends and developments affecting the electricity sector as part of refining and implementing the concept of a "blueprint" for the long-term – 2020 to 2050 – that describes the role of fossil-fueled power plants in California's electricity system.