UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
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Responses to Comments Regarding Consent Decree
for Gateway Generating Station

I. CASE BACKGROUND

The enforcement case and proposed settlement at issue involve a power plant, the Gateway Generating Station ("GGS"), which is currently owned and operated by the Pacific Gas & Electric Company ("PG&E"). The regulatory and permitting history of this case is quite complex. To understand the comments received regarding the proposed settlement and the Government's responses to those comments, it is necessary to explain this regulatory and permitting background.

1. Facility

GGS is a 530 megawatt natural gas-fired, combined cycle unit at the existing site of the Contra Costa Power Plant, located near Antioch, California, in the eastern portion of the San Francisco Bay Area. The combustion turbines at GGS are GE Frame F7A, which are F class turbines. GGS burns only pipeline quality natural gas. Combined cycle units have one or more gas-fired turbines which directly generate electricity. In addition, the waste heat from the combustion in the turbines is captured to make steam. This steam is also used to power an electric-generating steam turbine.

Natural gas-fired, combined cycle units such as GGS are by far the cleanest and most efficient electric generating units using the combustion of fossil fuels. *See* App. C1-Frey Declaration at ¶7. By way of comparison, the smaller 500 megawatt coal-fired power plant in Nevada known as North Valmy Generating Station emitted in 2008 approximately 37.6 times more oxides of nitrogen ("NOx"), 1.7 times more carbon monoxide ("CO"), 3.7 times more particulate matter of 10 microns or less ("PM-10") and 167.6 times as much sulfur dioxide ("SO2") as the maximum allowed under the 2001 permit for GGS. *See* App. C2-NDEP Data. For another comparison to a large source in the San Francisco Bay Area, the Valero Benicia refinery emitted in 2007 approximately 12.9 times more NOx, 2.4 times more CO, 2.1 times more PM-10, and 130.5 times more SO2 as the maximum allowed under the 2001 permit for GGS. *See* App. C3-CARB Data.

PG&E acquired GGS on November 30, 2006, and the Bay Area Air Quality Management District ("BAAQMD") transferred the existing permits for GGS to PG&E on January 4, 2007. Prior to PG&E's acquisition, GGS was owned by Mirant Corporation ("Mirant"). PG&E recommenced construction of GGS on February 5, 2007. PG&E began operating GGS in January 2009.

2. Regulatory Background

I. Prevention of Significant Deterioration Program

Title I, Part C of the Clean Air Act, 42 U.S.C. §§ 7470-7492, contains the Prevention of Significant Deterioration ("PSD") program. As declared by Congress, the purposes of the PSD program are to: protect public health and the environment from the adverse effects of air pollution notwithstanding attainment of all national ambient air quality standards ("NAAQS"); preserve and enhance the air quality in national monuments, parks, and wilderness areas; insure that economic growth is consistent with preserving clean air resources; assure that emissions from any source will not cause significant deterioration in air quality; and assure that any decision to permit increased air pollution in any area is carefully evaluated and informed by public participation. 42 U.S.C. § 7470.

The PSD program applies where an area has attained the NAAQS for a given pollutant. 42 U.S.C. § 7470-7492. The NAAQS are established on a pollutant-by-pollutant basis and are currently in effect for six air contaminants: SO2, particulate matter ("PM")[1], CO, ozone (measured as volatile organic compounds ("VOCs")), nitrogen dioxide ("NO2"), and lead ("PSD pollutants"). 40 C.F.R. § 50.4-.12.

The backbone of the PSD program is the requirement for any new major source of PSD pollutants and any major modification to an existing major source of PSD pollutants to apply for and obtain a PSD permit prior to commencing construction of the source or modification. 42 U.S.C. § 7475. The permit must comply with the Clean Air Act and the federal regulations implementing the PSD program as set forth at 40 C.F.R. § 52.21. The EPA's Environmental Appeals Board ("EAB") has held that BACT is a range of emission rates and can include a margin of compliance. *See In Re Newmont Nevada Energy Investment, LLC, TS Power Plant*, PSD Appeal No. 05-04, Order Denying Review, 12 E.A.D. 429, 441-48 (EAB 2005) ("*Newmont Nevada*").

A major source is defined as any source within 28 established source categories which emits or has the potential to emit 100 tons per year ("tpy") or more of any PSD pollutant, and any source not within the 28 established source categories which emits or has the potential to emit 250 tpy or more of any PSD pollutant. 40 C.F.R. § 52.21(b)(1). GGs falls within the 28 established source categories and, therefore, is a major source of any pollutant for which it would emit or have the potential to emit 100 tpy or more.

If a proposed new source is a major source for any PSD pollutant, the source must also use BACT for any PSD pollutant which is below the major source threshold, but is above the level of significance. 40 C.F.R. § 52.21(j)(2). The significance levels for PSD pollutants are set forth at

[1] Particulate matter, or "PM," is "the generic term for a broad class of chemically and physically diverse substances that exist as discrete particles (liquid droplets or solids) over a wide range of sizes." 62 Fed. Reg. 38,652, 38,653 (July 18, 1997). Particulate matter with an aerodynamic diameter of ten micrometers or less is referred to as "PM-10." *Id*. at 38,653 n.1. PM-10 is a pollutant at issue in this case.

40 C.F.R. § 52.21(b)(23). These levels are 40 tpy for NOx, 100 tpy for CO, 15 tpy for PM-10, and 40 tpy for SO2.

The alleged violations at issue in this case involve the PSD program. The PSD pollutants involved are NOx, which includes NO2; PM-10; CO; and SO2. GGS was projected to be, and now is, a major source of NOx and CO and, therefore, these are the two pollutants of concern. While GGS was permitted as a being above the significance level for PM-10, its actual emissions are below the significance level. While GGS was permitted as being above the significance level for SO2, its actual emissions are well below the significance level. GGS is located in an area, the Bay Area Air Basin, which is in attainment of the NAAQS for PM-10, NO2, SO2, and CO. This is why a PSD permit was needed for the construction of GGS. However, GGS is located in an area which is not in attainment of the NAAQS for ground-level ozone. NOx is also a precursor for ground-level ozone. Therefore, as a major source of NOx, a nonattainment new source review ("NNSR") permit was also required for the construction of GGS. These dual PSD and NNSR requirements are reflected in the combined Authority to Construct ("ATC") and PSD permit issued by the BAAQMD for GGS on July 24, 2001("July 2001 ATC/PSD permit"). *See* App. B7-Permit-ATC. Some conditions in the July 2001 ATC/PSD permit indicate "PSD" in parentheses following the condition. Other conditions list other sources of authority such as NNSR requirements. The difference between a permit and an ATC, and how these function together in one document, is discussed below.

ii. Permits and Authorities to Construct

Under the BAAQMD rules, an ATC is a time-limited type of permit. An ATC allows its holder to construct the source of air pollution described in the document. BAAQMD Rule 2-1-301. An ATC is time limited because it either expires after an established term (BAAQMD Rule 2-1-407), or its terms and conditions are transferred, after a start up period, to an operating permit once the source is fully constructed and operational. BAAQMD Rules 2-1-210, 2-1-302, and 2-1-411.

As noted above, the July 2001 ATC/PSD permit combined, among other things, the required elements of the PSD and NNSR programs. The federal PSD regulations do not make the distinction between an ATC and an operating permit. A federal PSD permit covers both construction and operation. *See* 40 C.F.R. § 52.21(r)(1). Therefore, if the PSD portion had not expired, the July 2001 ATC/PSD permit would continue to function as a federal operating permit even though the ATC portion of the permit would eventually expire and its terms and conditions would be transferred into an operating permit. In addition, the BAAQMD has independent authority for establishing terms and conditions in both ATCs and operating permits. *See* BAAQMD Regulation 2, Rule 2. Therefore, even if the PSD portion of the July 2001 ATC/PSD permit did expire, it would be enforceable through the ATC as long as the ATC remained in effect, and through the operating permit once the ATC expired and its terms and conditions were transferred to that operating permit.

3. <u>Permitting History</u>

Almost immediately after Mirant received the July 2001 ATC/PSD permit for the construction and operation of GGS, Mirant commenced construction of the facility. *See* App. B37-Proposed Decision at p. 2. Mirant had previously purchased in December 2000 the two identical natural gas-fired turbines (General Electric Frame 7FA) and the steam turbine ultimately used at GGS. *See* App. B15-SU Response. In February 2002, Mirant ceased on-site construction of GGS due to financial troubles. In response to the BAAQMD's October 27, 2003 request, on November 5, 2003, Mirant supplied information to the BAAQMD concerning "substantial use" of the July 2001 ATC/PSD permit. *See* App. B15-SU Response. The BAAQMD determined that Mirant had made such substantial use of the July 2001 ATC/PSD permit and, pursuant to BAAQMD rules, the term of the permit was automatically extended until July 2005. *See* App. B17-Extension to 2005. In June 2005, Mirant applied for another extension of the July 2001 ATC/PSD permit. Pursuant to the version of BAAQMD Regulation 2-1-407 in effect at that time, the permit remained in effect until the BAAQMD acted upon the request. The BAAQMD granted this extension in September 2005. *See* App. C14-Extension to 2007. After acquiring GGS from Mirant in November 2006, PG&E received the transferred July 2001 ATC/PSD permit from the BAAQMD in January 2007. PG&E applied for an extension of that permit in April 2007 and received an extension in June 2007. *See* App. C4-Extension to 2009. PG&E recommenced construction of GGS in February 2007. *See* App. B37-Proposed Decision at p. 2.

The July 2001 ATC/PSD permit received by Mirant and transferred to PG&E in 2007 has the following provision regarding expiration of the permit:

"Expiration
In accordance with Regulation 2-1-407, this Authority to Construct expires two years from the date of issuance unless substantial use of the authority has begun."

4. Nature of Comments Received

All of the comments received concerning this case have strongly criticized the proposed settlement. The comments center around a theory that: 1) the PSD permit for GGS had clearly expired, 2) PG&E knew it needed a new or modified PSD permit prior to recommencing construction of GGS, and 3) the proposed settlement does not require the level of emission controls and limits that are required under the PSD program. In supporting this theory, the commenters: 1) confuse the emissions control and procedural requirements of the PSD program with the requirements of the NNSR program, the federal Standards of Performance for New Stationary Sources ("NSPS") program, and other separate BAAQMD permitting requirements, and 2) fail to acknowledge the legal risks in the Government's enforcement case which fully justify the proposed settlement.

II. RESPONSE TO COMMENTS

A. Comments Submitted on Behalf of the Contra Costa Branch of Associations of Communities for Reform Now ("ACORN") and Communities for a Better Environment ("CBE") by the Environmental Law and Justice Clinic at Golden Gate University School of Law

Comment #1:
The PSD permit issued by the BAAQMD to Mirant in July 2001 had expired because Mirant did not request or receive a timely extension of the PSD permit from EPA. The clear language of the March 3, 2003 letter rescinding delegation of the PSD program to BAAQMD withdrew all PSD authority from the BAAQMD. The March 3 letter is further supported by the March 21, 2003 Federal Register notice (68 Fed. Reg. 19371) announcing the recision of delegation of the PSD program to the BAAQMD. Therefore, after March 3, 2003, only EPA could extend the PSD permit issued to Mirant and the purported extensions by the BAAQMD were not valid.

Response to Comment #1:
EPA disagrees with this comment for the reasons set forth in the Memorandum In Support of Motion to Enter Consent Decree.

Comment #2:
The proposed settlement is based upon the inaccurate premise that PG&E proceeded in good faith to construct and operate GGS without knowledge of its PSD violations. PG&E was aware of the need for an amended PSD permit before it recommenced construction of GGS. The evidence of PG&E's knowledge that it did not have a valid permit can be seen in its December 18, 2007 Application to the Bay Area Air Quality Management District for Modifications to the Authority to Construct for the Gateway Generating Station Antioch, California ("December 2007 Application") for a new PSD permit which it later withdrew. Finally, the protracted and lengthy communications between PG&E and the BAAQMD regarding the December 2007 Application demonstrate that PG&E knew it needed a new or amended PSD permit.

Response to Comment #2:
The comment inconsistently references PG&E's need for a new PSD permit and PG&E's application for what is sometimes referred to as a new PSD permit and other times referred to as an amended PSD permit. PG&E did, in fact, apply to amend the July 2001 ATC/PSD permit transferred to it by the BAAQMD. *See* App. B19-BAAQMD App for Mod. In its December 2007 Application, PG&E sought amendments to the permit, and not to obtain a new permit, because the BAAQMD transferred from Mirant to PG&E what both PG&E and the BAAQMD believed to be a valid ATC/PSD permit. PG&E's December 2007 Application to amend that ATC/PSD permit is not evidence that PG&E knew the PSD portion of the transferred permit was not valid. Assuming it was still legally valid, whether the amendments to the July 2001 ATC/PSD permit sought by PG&E in its December 2007 Application were required under the PSD program, and the level of agency review and public participation involved in obtaining such amendments, is addressed in our Response to Comment #3, below.

Comment #3:
The GGS facility as permitted in 2001 was fundamentally changed by the time it was fully constructed and operational in 2009. This modified GGS utilizes dry cooling rather than wet cooling, the permitted fuel preheater was replaced with a dew-point heater with increased hours of operation, and the proposed electric-powered fire pump was replaced with a diesel-powered fire pump. PG&E sought to make these changes in its December 2007 Application to amend the ATC/PSD permit for GGS. While PG&E eventually withdrew the December 2007 Application, PG&E could not construct or operate this changed configuration of GGS without obtaining

either a new PSD permit or a major modification to the PSD permit as originally issued by the BAAQMD. In fact, in its December 2007 Application, PG&E states that it was not planning to begin construction of GGS until the modified ATC/PSD permit had been issued. PG&E also stated in its December 2007 Application that construction of GGS had been suspended longer than 18 months and, therefore, admitted "triggering NSPS."

Response to Comment #3:

EPA's response to this comment assumes that the July 2001 ATC/PSD permit either remained legally valid or would be used as part of a reasonable reliance defense by PG&E.

Triggering the Standards for Performance of New Stationary Sources (commonly know as New Source Performance Standards or "NSPS") is irrelevant to this settlement, which involves alleged violations of the PSD program. NSPS and PSD are completely separate programs under the Clean Air Act and the NSPS program does not, by itself, require owners and operators to get permits prior to construction or operation of the source which is subject to NSPS.

PG&E's statement in its December 2007 Application regarding its intended construction schedule, which is set forth in a section entitled "Estimated Construction Date," is not relevant. For purposes of the PSD program, the real issue is whether the changes made by PG&E to the design of GGS could be accomplished under the July 2001 ATC/PSD permit transferred to it by the BAAQMD or would require a new or modified PSD permit.

The comment lists three changes in the design of GGS which, the comment asserts, required PG&E to obtain a new or modified PSD permit prior to recommencing construction of GGS. The first change is switching from wet cooling to dry cooling. Wet cooling towers are sources of PM-10 emissions. While this switch was certainly a change in the design of GGS, by switching to dry cooling, all of these potential PM-10 emissions were very significantly reduced. *See* App. B33-CEC Staff Analysis at pp. 6-7. In addition, dry cooling is a more environmentally friendly process because it eliminated the discharge of warmed water back into the California Delta and eliminated the entrainment and destruction of biological organisms such as fish. *See* App. B33-CEC Staff Analysis at p. 14.

The second change is switching from the fuel preheater listed in the July 2001 ATC/PSD permit to what is called a dew-point heater with longer potential hours of operation. A dew-point heater is, in fact, a type of fuel preheater. While the dew-point heater chosen by PG&E had longer potential hours of operation than the unit it replaced, the dew-point heater burned less fuel per hour. As demonstrated to the BAAQMD by PG&E, switching to the dew-point heater resulted in lower annual emissions. *See* App. C5-PG&E Request for Exemptions.

The only change which resulted in any emissions increase was switching the emergency fire system for the plant from using an electric-powered fire-quenching water pump to a diesel-powered pump. This switch was ordered by the Contra Costa County Fire Marshal as a safety measure after the July 2001 ATC/PSD permit was transferred to PG&E. Pursuant to a settlement agreement between the BAAQMD and PG&E, PG&E shall install what is known as a "Tier 3" engine as certified by the California Air Resources Board. *See* App. B36-Settlement Agreement. A Tier 3 diesel engine currently produces the lowest emission rate of any engine in its class and meets or exceeds the best available control technology ("BACT") as required by the PSD program. *See* App. C1-Frey Declaration at ¶8. In addition, this emergency engine is limited to 50 operating hours per year, which is standard for reliability testing and to keep a stand-by emergency engine in operating condition. 50 hours of operation would result in annual emissions of approximately 100 pounds per year of NOx, 90 pounds per year of CO, and 5 pounds per year of PM-10. *See* App. C1-Frey Declaration at ¶9 and Attachment 1. This increase in emissions of NOx, CO, and PM-10 from this switch is far below the level of significance under the PSD program which is 40 tpy for NOx, 100 tpy for CO, and 15 tpy for PM-10.

The PSD regulations set forth at 40 C.F.R. § 52.21 and the provisions for issuing and modifying PSD permits set forth at 40 C.F.R. Part 124 do not make completely clear what changes can be made to a facility that is under construction without obtaining a major modification to the PSD permit. In 1985, EPA issued a draft policy for handling these and related permitting issues. This draft policy was issued in a memorandum entitled "Revised Draft Policy on Permit Modifications and Extensions," which was signed by Darryl D. Tyler. *See* App. B13-Tyler Draft Policy. The Tyler Draft Policy is cited as the source for the definitions of the terms "administrative" and "minor" modifications to PSD permits in the EPA's 2004 re-delegation of the PSD program to the BAAQMD. *See* App. B16-2004 Delegation at p. 1.

The comment asserts that the three switches of equipment described above "fundamentally changed" GGS. A "fundamental change" is generally one which alters the basic character of the facility, such that the facility would fall within "a different 2-digit SIC Code" or would result in a large increase in the size of the facility. *See* App. B13-Tyler Draft Policy at pp. 17-18. The three equipment changes did not fundamentally change GGS, which as proposed and built is a 530 megawatt natural gas-fired, combined cycle unit. Switching from wet cooling to dry cooling and from the permitted fuel preheater to the dew-point heater lowered air emissions, reduced environmental impacts, and did not change the basic purpose of the equipment. The switch from an electric-powered emergency fire pump to a diesel-powered emergency fire pump resulted in a de minimis emissions increase, and obviously did not change the basic purpose of the equipment.

In describing how small changes might be made to a PSD permit for a facility which was not yet operating, the Tyler Draft Policy stated:

> Today's policy proposes to provide a new and less cumbersome route by which changes can be accommodated while ensuring equivalent environmental protection. In doing so, it extends the Alabama Power concept of de minimis to include changes which are so small in terms of impacts that such changes could be excluded from the full rigors of processing.

App. B13-Tyler Draft Policy at p. 4.

In describing potential changes to a PSD permit, the Tyler Draft Policy categorizes these changes by their importance and impact. An "administrative change" is one that "involves no increase in either emissions or impacts and no fundamental change in either the source of one of the emission units at that source. Application or permit revisions may be necessary, but additional review or analysis would not normally be required . . . ." App. B13-Tyler Draft Policy at p. 5. “Minor changes” are those which “require revisions to permit application or issued permits and a certain amount of additional review and analysis, but do not constitute either a fundamental or significant change. Emissions or impacts increase as a result of minor changes, but not above the significance level.” App. B13-Tyler Draft Policy at p. 5.

Similarly, in describing the level of review for changes to a PSD permit, the Tyler Draft Policy categorizes these changes by their level of review. “Amendments” are changes to a permit which “are administrative in nature and result in no increase in either the emissions or the air quality impact of a PSD source. In addition, neither the nature nor the size of the source or emissions unit can be altered to the extent the change would be considered fundamental.” In addition, “[t]he lack of emissions and impact increases for an amendment results in little or no review.” App. B13-Tyler Draft Policy at p. 11. “Revisions” are changes which involve some emissions increase, but these increases do not qualify as “major modifications” under the PSD regulations and are not fundamental changes. The permitting agency should perform a screening analysis to determine the impact the proposed revision has on the adequacy of the original PSD analysis. However, “[i]n many cases, it is anticipated that little or no revised analysis will be required of nonsignificant emissions increases.” App. B13-Tyler Draft Policy at p. 12-13.

As described above, switching from wet cooling to dry cooling and from the permitted fuel preheater to the dew-point heater lowered air emissions and reduced environmental impacts Applying the guidelines in the Tyler Draft Policy, making these changes would have required administrative amendments to the July 2001 ATC/PSD permit. This process would have involved little review by the BAAQMD, no application of the PSD permitting process, and no public participation.

The switch from an electric-powered emergency fire pump to a diesel-powered emergency fire pump resulted in a de minimis emissions increase. Applying the guidelines in the Tyler Draft Policy, making this change would have required a minor revision to the July 2001 ATC/PSD permit. Given the nature of the source - a relatively small Tier 3 diesel engine - this process would have involved a minimal screening review by the BAAQMD and no other application of the PSD permitting process. The public would be given notice of this change, but public participation would be limited to the proposed emergency fire pump.

The failure of PG&E to obtain these very minor changes in the July 2001 ATC/PSD permit had extremely little or no impact on the environment and public health. As discussed in other responses to comments, EPA believes GGS is meeting current-day BACT emissions levels. In addition, the air quality analysis performed by the BAAQMD and reviewed by EPA Region 9 during the process leading to the July 2001 ATC/PSD permit shows no significant impact on air quality. *See* Response to Comment #12.

On February 17, 2010, the California Energy Commission (“CEC”) issued Order No. 10-0217-2 dealing with the fuel pre-heater and fire pump issues. The CEC found there was no harm from the change in fuel pre-heaters since the new dew-point heater would produce fewer emissions than the unit it replaced. The CEC did find the change in the fire pump system to be a violation, but found that the change was made in good faith to meet the directives of the local fire marshal and the emissions increases from the change were not significant. While the CEC did fine

PG&E $10,000, the CEC stated, "In sum, the violations are few and of little practical consequence." *See* App. B38-Adoption of Proposed Decision.

Comment #4:
Extensions of the PSD permit issued to Mirant by the BAAQMD were not valid because there was no notice given to the public regarding the proposed extensions and the public was not given an opportunity to comment on or object to the extensions.

Response to Comment #4:
Neither 40 C.F.R. § 52.21 ("Prevention of significant deterioration of air quality") nor 40 C.F.R. Part 124 ("Procedures for Decisionmaking") contain a requirement that extensions of PSD permits must be given public notice either prior to the extension or after the extension is granted. While EPA often does provide public notice prior to extending a PSD permit, this is not a legal requirement and the absence of such notice does not affect the validity of the PSD permit or the extension of it. The applicable BAAQMD regulations also do not require public notice and an opportunity to comment on the extension of a PSD permit.

Comment #5:
It appears the BAAQMD did not grant Mirant an extension of the ATC/PSD permit in 2003 because there is no written record of such an extension. Without such an extension, PG&E could not have reasonably relied upon the allegedly invalid ATC/PSD permit transferred from Mirant to PG&E by the BAAQMD in 2007.

Response to Comment #5:
Pursuant to the version of BAAQMD Regulation 2-1-407 in effect at the time, once Mirant made "substantial use" of the July 2001 ATC/PSD permit, the term of that permit was automatically extended from two years to four years. Mirant submitted to the BAAQMD a copy of the purchase contract for the two combustion turbines and the steam turbine which were eventually installed at GGS. Pursuant to Regulation 2-1-227, this purchase constituted "substantial use" of the July 2001 ATC/PSD permit. The BAAQMD recognized this "substantial use" in correspondence to Mirant. *See* App. B17-Extension to 2005.

In subsequent comments on this issue, CBE has stated that Mirant's purchase contract predated the July 2001 ATC/PSD permit and, therefore, could not be used as a basis for "substantial use" of the permit. Regulation 2-1-227 contains no such limitation and the BAAQMD did not appear to impose one. In addition, Mirant made numerous monthly payments pursuant the purchase contract after the July 2001 ATC/PSD permit was issued. In fact, Mirant paid nearly 100% of the purchase price of the turbines by March 2002. *See* App. C13-Mirant payments. We believe a court would find these payments to be a continuing "substantial use" of the permit.

Comment #6:
The consent decree does not require current-day BACT as required by the PSD program. BACT is defined in the federal Clean Air Act as "an emissions limitation based on the maximum degree of [pollutant] reduction . . . which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for [the] facility." BACT is further defined by the BAAQMD as "the more stringent of":

> 206.1 The most effective emission control device or technique which has been successfully utilized for the type of equipment comprising such a source; or
>
> 206.2 The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or
>
> 206.3 Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO; or
>
> 206.4 The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations.

Response to Comment #6:

This comment confuses the difference between the federal PSD and NNSR programs. This confusion can be traced, in part, to the different use of the term BACT in the federal PSD program and the BAAQMD NNSR rules, and to the status of the state implementation plan (“SIP”) for the BAAQMD.

As a point of comparison to explain the confusion, it is helpful to compare the definitions of control technology in the PSD and NNSR programs. The applicable control technology under federal NNSR is the lowest achievable emission rate (“LAER”). In function, it is virtually identical to the BAAQMD BACT definition in Comment #6. The definition for federal LAER is set forth at 40 C.F.R. § 51.165(a)(1)(xiii).

> *Lowest achievable emission rate (LAER)* means, for any source, the more stringent rate of emissions based on the following: (A) The most stringent emissions limitation which is contained in the implementation plan of any State for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or (B) The most stringent emissions limitation which is achieved in practice by such class or category of stationary sources. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within or stationary source. In no event shall the application of the term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source standard of performance.

The definition of BACT, in pertinent part, is:

> an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act

> which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.

40 C.F.R. § 52.21(b)(12).

In the federal new source review program, PSD BACT is the technology which applies to areas which have attained the NAAQS for a given pollutant and, therefore, have cleaner air. The purpose of the PSD program is to make sure no source causes a significant deterioration in air quality and keep the area in attainment of the NAAQS. When determining BACT for a source, the permitting agency takes into account energy usage and cost of potential control technologies. The EAB has held that BACT is: 1) a range of emission rates, 2) determined on a "case-by-case basis, taking into account energy, environmental, economic and other costs", and 3) can include a margin of compliance. *See Newmont Nevada* at 430, 434, and 441-48.

The more stringent NNSR applies to areas which have not attained the NAAQS for a given pollutant. The applicable control technology under NNSR is the lowest achievable emission rate ("LAER"). In determining LAER for a source, the permitting agency applies the most stringent and effective emission controls which have been achieved in practice, regardless of the cost. The NNSR program also requires that new major sources and major modifications to existing sources offset any emissions increases. In fact, these new and modified sources must provide more offsets than their actual emissions increases. The purpose of the NNSR program is to push technological advancement in emissions controls and make sure that new sources and major modifications to existing sources result in cleaner air.

California uses the term BACT to describe the emissions controls which are required under its NNSR program. California BACT is really federal LAER. This somewhat unfortunate choice of terminology has caused a good deal of confusion over the years, as is reflected in Comment #6. *See* App. C1-Frey Declaration at ¶10.

Compounding this confusion is the fact that the rules of air pollution control districts in California, including the BAAQMD, tend to apply California BACT to all sources and pollutants, including pollutants for which the area has achieved the NAAQS. *See* App. C1-Frey Declaration at ¶10. While BAAQMD's rules have been approved into the SIP, they have been approved for the purposes of the NNSR program. The BAAQMD has not submitted an approvable PSD program for inclusion into the SIP. As has been discussed, the BAAQMD implements the federal PSD program set forth at 40 C.F.R. § 52.21 pursuant to a delegation of authority. When using this delegation of authority to issue a PSD permit, the BAAQMD is only required to implement the less stringent federal BACT rather than California BACT. Therefore, the BAAQMD's definition of BACT is not legally relevant to this case.

The confusion between federal BACT and California BACT has led ACORN and CBE to submit comments that erroneously assert that California BACT is required rather than federal BACT.

The standards for establishing federal BACT and reviewing BACT determinations made in PSD permits have been addressed by EPA's Environmental Appeals Board ("EAB"). *See Newmont Nevada*. The responses below address comments concerning federal BACT for the four pollutants at issue in this proposed settlement.

<u>Comment #7:</u>
The emissions limitation for CO required by the settlement is not current-day BACT as required by the PSD regulations. BACT for CO should be 2 parts per million by volume ("ppmv") on a one hour average. In addition, BACT for CO should include limits for startup, shutdown, and an annual mass emission cap.

<u>Response to Comment #7:</u>
No natural gas-fired, combined cycle unit has additional control technology to reduce CO emissions during startup or shutdown. *See* App. C1-Frey Decl. at ¶ 11. The primary reason for higher CO emissions during these events is that the control device used to reduce CO emissions during normal operation, an oxidation catalyst, is not effective at these times. The EAB has held that while BACT is an emission rate, it is inextricably tied to a given control technology. *See Newmont Nevada* at 469. Where no emission controls exist or have been shown to be achieved in practice and cost-effective for the startup and shutdown of a type of emitting equipment, BACT is the uncontrolled emissions rate for such a source during these startup and shutdown events.

The July 2001 ATC/PSD permit limited CO emissions during each startup to 990 pounds for a cold start and 291 pounds for a hot start. Emissions of CO during each shutdown were limited to 73 pounds. *See* App. B7-Permit-ATC at p. 9. In addition, startups were limited to the shorter of 256 minutes or being in compliance with the CO limit for two consecutive continuous emissions monitor readings. Shutdowns were limited to 30 minutes. *See* App. B7-Permit-ATC at p. 3. The annual emissions cap for CO was 259.1 tpy. *See* App. B7-Permit-ATC at p. 10. Even if the PSD portion of the ATC/PSD permit for GGS has expired, all of these limits are still enforceable through the BAAQMD's ATC, which remains in effect.

On February 3, 2010, the BAAQMD issued a PSD permit for the Russell City Energy Center ("RCEC"), which has F class turbines similar to those at GGS. RCEC is rated at 600 megawatts, which is approximately 12% larger than GGS. In that permit, CO emissions during each startup are limited to 2514 pounds for a cold start or a warm start, and 891 pounds for a hot start. Emissions of CO during each shutdown were limited to 100 pounds. *See* App. C6-RCEC PSD permit at p. 10. The duration limitations for startup and shutdown events at RCEC are limited to the shorter of 300 minutes for cold starts, 180 minutes for hot or warm starts, or being in compliance with the CO limit for two consecutive continuous emissions monitor readings. Shutdowns are limited to 30 minutes. *See* App. C6-RCEC PSD permit at p. 4. The annual emissions cap for CO is 330 tpy. *See* App. C6-RCEC PSD permit at p. 11. These limitations are significantly more lenient than 12% above those in the GGS ATC/PSD permit.

As noted above, in stating that BACT for CO at GGS is 2.0 ppmv, ACORN and CBE incorrectly assert that BACT is the lowest emission rate which has been achieved in practice or can be achieved. The EAB has held that BACT is: 1) a range of emission rates, 2) determined on a “case-by-case basis, taking into account energy, environmental, economic and other costs”, and 3) can include a margin of compliance. *See Newmont Nevada* at 430, 434, and 441-48. In the past few years, other facilities in California similar to GGS have recently received PSD permits with a CO limit less stringent that 2.0 ppmv. The PSD permit issued in October 2008 for the Colusa Generating Station contains a CO limit of 3.0 ppmv. *See* App. C7-Colusa PSD permit at p. 6. The PSD permit issued in April 2007 for the Blythe Energy Project Phase II contains a CO limit of 4.0 ppmv. *See* App. C8-Blythe PSD permit at p. 6. The 4.0 ppmv limit in the proposed settlement appears to fall within the range of BACT. *See* App. C1-Frey Declaration at ¶19.

The comment also assumes that a court would require PG&E, under the circumstances presented in this case, to obtain a new PSD permit and achieve current-day BACT. We have already set forth legal and equitable reasons why we believe a court might find that the July 2001 ATC/PSD permit either did not expire or was reasonably relied upon by PG&E in finishing construction and commencing operation of GGS. In addition, there are design and space constraints which might preclude lowering the emissions of CO from GGS without the incurrence of exorbitant costs. The catalytic oxidizer which controls CO emissions at GGS is co-located with the catalyst which controls NOx emissions. To lower CO emissions, this combined catalyst bed would have to be completely replaced with a significantly larger unit. In addition to its direct costs, this larger unit might present engineering challenges such as changes in air flow and back pressure, and physical modifications to the existing design of the facility to make it fit. *See* App. C1-Frey Declaration at ¶18.

In our Response to Comment #12, we describe the insignificant impact to human health and the environment from GGS’s CO emissions. In view of all the legal and equitable considerations, EPA does not believe a court after a full evidentiary hearing would require PG&E to lower the CO emissions from 4.0 ppmv to 2.0 ppmv.

Comment #8:
The emissions limitation for NOx required by the settlement is not BACT as required by the PSD regulations because it does not include emission limits for periods of startup and shutdown.

Response to Comment #8:
As the recognized in the comment, the normal operational NOx emissions limit for GGS of 2.0 ppmv is current-day BACT. The consent decree imposes this requirement. The comment focuses on the fact that the proposed settlement does not require a specific emissions limit for NOx during periods of startup and shutdown and that the original PSD permit had limits which are higher than those contained in more recently issued PSD permits.

No natural gas-fired, combined cycle unit has additional control technology to reduce NOx emissions during startup or shutdown. *See* App. C1-Frey Declaration at ¶12. The primary reason for higher NOx emissions during these events is that the control devices used to reduce NOx emissions during normal operation, selective catalytic reduction and low NOx burners in the turbines, are not effective at these times. *See* App. C1-Frey Declaration at ¶12. The EAB has held that while BACT is an emission rate, it is inextricably tied to a given control technology. *See Newmont Nevada* at 469. Where no emission controls exist or have been shown to be achieved in practice and cost-effective for the startup and shutdown of a type of emitting equipment, BACT is the uncontrolled emissions rate for such a source during these startup and shutdown events. Given the lack of technology to control NOx during startup and shutdown events, it is EPA's experience that, historically, permitting agencies often did not fully quantify the emissions from these events. *See* App. C1-Frey Declaration at ¶17. In the press of business and the desire to issue permits, agencies put in limits from older permits with higher emissions rates. This "path-of-least-resistance" is tempting precisely because there are no viable emission control options. While a more rigorous analysis might have arrived at more accurate NOx limits for periods of startup and shutdown in the July 2001 ATC/PSD permit for GGS, such a change would have no effect on the actual NOx emissions during these events since no controls currently exist.

Very recently, the BAAQMD performed a rigorous analysis of the available options for controlling NOx emissions during startup and shutdown from the same class F type of natural gas-fired, combined cycle unit in use at GGS. The BAAQMD similarly concluded that limitations on the duration and number of startups and shutdowns is the only available method to control emissions from these events. *See* App. C9-BAAQMD RCEC Responses.

The only methods for controlling NOx emissions during startup and shutdown emissions are requiring the source to reach running temperature and stabilize combustion in the turbine as quickly as possible without damaging the equipment during startup and requiring that the source shutdown as quickly as possible, again without damaging the equipment. Therefore, the truly effective limitations on NOx emissions during startup and shutdown are limitations on the time duration of these events. *See* App. C1-Frey Declaration at ¶13.

The July 2001 ATC/PSD permit for GGS limited NOx emissions during each startup to 452 pounds for a cold start and 189 pounds for a hot start. Emissions of NOx during each shutdown were limited to 59 pounds. *See* App. B7-Permit-ATC at p. 9. In addition, startups were limited to the shorter of 256 minutes or being in compliance with the NOx limit for two consecutive continuous emissions monitor readings. Shutdowns were limited to 30 minutes. *See* App. B7-Permit-ATC at p. 3. Even if the PSD portion of the July 2001 ATC/PSD permit for GGS has expired, all of these limits are still enforceable through the BAAQMD's ATC, which remains in effect, and will be enforceable through any operating permit issued by the BAAQMD for GGS.

In the RCEC permit, NOx emissions during each startup are limited to 480 pounds for a cold start, 125 pounds for a warm start, and 95 pounds for a hot start. Emissions of NOx during each shutdown are limited to 40 pounds. *See* App. C6-RCEC PSD Permit at p. 10. The duration limitations for startup and shutdown events at RCEC are limited to the shorter of 300 minutes for cold starts, 180 minutes for hot or warm starts, or being in compliance with the NOx limit for two consecutive continuous emissions monitor readings. Shutdowns are limited to 30 minutes. *See* App. C6-RCEC PSD Permit at p. 4. These limitations are similar to those in the GGS ATC/PSD permit.

Comment #9:
There is no emissions limitation for PM-10 in the settlement and the ATC/PSD permit limit is not BACT as required by the PSD regulations.

Response to Comment #9:
GGS is required to burn only natural gas which meets the specifications for "pipeline quality" natural gas established by the California Public Utilities Commission ("CPUC natural gas"). For natural gas-fired, combined cycle units, BACT for PM-10 is limiting the fuel burned to CPUC natural gas. This is noted in Condition #13 in both the original 2001 ATC/PSD permit issued to Mirant and in PG&E's 2007 permit as renewed by the BAAQMD. No natural gas-fired, combined cycle unit limited to CPUC natural gas has additional control technology to reduce PM-10 emissions because these emissions are low. *See* App. C1-Frey Declaration at ¶14. Given this absence of control technology and low emissions rates, it is EPA's experience that, historically permitting authorities have tended to use higher emissions limits from older permits. *See* App. C1-Frey Declaration at ¶17. In the press of business and the desire to issue permits, this "path-of-least-resistance" is tempting precisely because there is no existing control technology. This sometimes does result in unnecessarily high permit limits. For example, the PM-10 limits in the July 2001 ATC/PSD permit for GGS are 624 pounds per day and 112.2 tpy. *See* App. B7-Permit-ATC at p. 9-10. However the highest actual emissions rate of PM-10 from GGS in the second and third quarters of 2009 was 4.5 pounds per hour, which would be 108 pounds per day if GGS emitted at that rate for 24 hours. *See* App. C10a-GGS Mass Emission Report for Q2-2009; and C10b-GGS Mass Emission Report for Q3-2009. If GGS emitted PM-10 at this highest rate for a full year (8,760 hours), its total PM-10 emissions would be 19.71 tons, far below its permitted limit.

While the permit limits for PM-10 emissions from GGS do not reflect the real emissions from the facility, those real emissions meet current-day BACT for two reasons. First, there is no existing control technology which is BACT for PM-10 for this type of source and, therefore, BACT is the uncontrolled emissions rate. *See* App. C1-Frey Declaration at ¶16. Second, the recently-issued RCEC PSD permit contains a BACT limit of 7.5 pounds per hour. *See* App. C6-RCEC PSD Permit at p. 10. The highest measured PM-10 emissions from GGS are 40% lower than RCEC's BACT limit.

Comment #10:
There is no emissions limitation for SO_2 in the settlement and the ATC/PSD permit limit is not BACT as required by the PSD regulations.

Response to Comment #10:
GGS is required to burn only CPUC natural gas. For natural gas-fired, combined cycle units, BACT for SO_2 is limiting the fuel burned to CPUC natural gas. This is noted in Condition #13 in both the original 2001 ATC/PSD permit issued to Mirant and in PG&E's 2007 permit as renewed by the BAAQMD. No natural gas-fired, combined cycle unit combusting CPUC natural gas has additional control technology to reduce SO_2 emissions because these emissions are extremely low and not environmentally significant. *See* App. C1-Frey Declaration at ¶15. Given this absence of control technology and very low emissions rates, it is EPA's experience that, historically, permitting authorities have tended to use higher emission rates from older permits. *See* App. C1-Frey Declaration at ¶17. In the press of business and the desire to issue permits, this "path-of-least-resistance" is tempting precisely because there is no existing control technology. This sometimes does result in unnecessarily high permit limits. For example, the SO_2 limit in the July 2001 ATC/PSD permit for GGS is 297 pounds per day. *See* App. B7-

Permit-ATC at p. 9. However, the highest actual emissions rate of SO2 from GGS in the second and third quarters of 2009 was 1.29 pounds per hour, which would be 30.96 pounds per day if GGS emitted at that rate for 24 hours. *See* App. C10a-GGS Mass Emission Report for Q2-2009; and C10b-GGS Mass Emission Report for Q3-2009. If GGS emitted SO2 at this highest rate for a full year (8,760 hours), its total SO2 emissions would be 5.65 tons, well below the PSD significance level of 40 tpy. If a PSD permit reflected GGS's real potential to emit SO2, the SO2 emissions from GGS would not be subject to BACT or any permitting requirement aside from the requirement to combust only CPUC natural gas.

Comment #11:
The penalty in the proposed settlement, $20,000, is far too low and does not comply with either the Clean Air Act penalty criteria or long-standing EPA policy regarding the calculation of minimum penalty amounts.

Response to Comment #11:
EPA disagrees with this comment for the reasons set forth in the Memorandum In Support of Motion to Enter Consent Decree.

Comment #12:
The proposed settlement is unfair because it fails to consider the impacts on the local community, which is predominately low income, minority, and is already overburdened by pollution.

Response to Comment #12:
The pollutants at issue in this case are NOx (as NO2), PM-10, CO, and SO2. This is a PSD case, rather than an NNSR case, because the Bay Area Air Basin is in attainment of the NAAQS for each of these pollutants. The comment mischaracterizes the situation by incorrectly claiming that the community surrounding GGS is overburdened by these air pollutants and that the community is disadvantaged due to its demographic characteristics.

As part of the permitting process in 2001, the BAAQMD performed a modeling analysis of the projected maximum emissions from GGS. The modeled worst case emission impacts on ambient air quality from GGS' emissions of NO2, PM-10, CO, and SO2 were for PM-10 at 3.02% of the NAAQS. For the remainder of the pollutants, the impact was very near or much less than 1% of the NAAQS. *See* App. C12-Bohnenkamp Declaration, Attachment 1. For all of these pollutants, the maximum increases allowed under the permit for GGS are below the significant impact levels ("SILs") established by EPA. *See* 40 C.F.R. § 51.165(b)(2).

The concept and meaning SILs were recently discussed by EPA in a Federal Register notice concerning PM. *See* 72 Fed. Reg. 54112 (September 21, 2007) ("Notice"). SILs are "numerical values that represent thresholds of insignificant, i.e., *de minimis,* modeled source impacts." Notice at 54112. The genesis of SILs is described:

The concept of a significant impact level is grounded on the *de minimis* principles described by the court in Alabama Power Co. v. Costle, 636 F.2d 323, 360 (D.C. Cir. 1980). In this case reviewing EPA's 1978 PSD regulations, the court recognized that "there is likely a basis for an

implication of *de minimis* authority to provide exemption when the burdens of regulation yield a gain of trivial or no value." 636 F.2d at 360. Based on this *de minimis* principle from the court's opinion, EPA developed significant emissions rates and significant monitoring concentrations in our 1980s regulations for PSD. The significant emission rates reflect levels below which EPA considers an emissions increase to be *de minimis* and thus not a major modification that requires a PSD permit or NA–NSR permit. 45 FR 52676, 52705–07. *See* also 40 CFR 51.166(b)(23); 40 CFR 52.21(b)(23).
Notice at 54139.

The discussion concludes that SILs "are intended to identify a level of ambient impact on air quality concentrations that EPA regards as *de minimis*. The EPA considers a source whose individual impact falls below a SIL to have a *de minimis* impact on air quality concentrations." Notice at 54139.

It is also important to note that the original modeling analysis for GGS was performed using higher emissions limits for NOx and CO than are required under the proposed settlement. As discussed earlier, the NOx limit for GGS was lowered from 2.5 ppmv in the original permit to 2.0 ppmv under the settlement. The CO limit for GGS was lowered from 6.0 ppmv under the original permit to 4.0 ppmv under the settlement. These reductions, especially the 33% reduction in the CO emission rate, will make the emissions from GGS, which are already below the SILs, even less significant for purposes of air quality.

EPA Region 9's Geographic Information Systems ("GIS") Center prepared an analysis using census data for the area surrounding GGS. This data shows that the area scores medium to low on EPA's social vulnerability index ("SVI"). A low SVI score indicates a less vulnerable community and, conversely, a high SVI score indicates a more vulnerable community. The weighted average score within a 10-kilometer radius of GGS is 8. In the area immediately surrounding GGS, the score is much lower. *See* App. C11-Chambers Declaration, Attachment 1. The SVI is made up of data from the 2000 U.S. Census, collected at the block group level. The fields included are: percent minority population, per capita income, age (under 18 and over 64 being the more vulnerable populations), population without a high school diploma, and linguistically isolated populations.

For each block group, each of these fields is assigned an index score of 0-3, based on whether the value of that dataset falls in the top quartile (score=3), second quartile (score=2), third quartile (score=1), or bottom quartile (score=0). The scores for each field are then added together to assign a comprehensive score to each block group (0-18). The highest scores are block groups that have the highest percentage of vulnerable populations (highest percent minority, lowest per capita income, highest percent of population under 18 and over 64, highest percentage of population without a high school degree, and highest percent of population linguistically isolated). *See* App. C11-Chambers Declaration, Attachment 2.

In sum, the community surrounding GGS does not appear to have demographic characteristics which makes it more vulnerable than average. In addition, the emissions from GGS are very low and do not significantly impact the air quality of this community regardless of its demographics.

Comment #13:
ACORN, CBE and community members have not received information that was requested and should have been provided by EPA and the BAAQMD. ACORN and CBE reserve their right to supplement their comments as these records are provided.

Response to Comment #13:
The Freedom of Information Act ("FOIA") request submitted by Deborah Behles to EPA Region 9 on May 21, 2009 ("May 21 Request), was inadvertently assigned to EPA Region 9's Waste Division rather than Air Division. EPA Region 9 discovered this mistake in the process of responding to comments on the consent decree. Prior to this discovery, the EPA Region 9 personnel working on GGS neither received the May 21 Request nor knew of its existence. When the May 21 Request was traced using the requestor's name, the mistake was discovered.

On March 10, 2010, EPA Region 9 personnel sent an e-mail message to Ms. Behles. Through this message, EPA Region 9 was seeking to clarify the scope of the May 21 Request and inform Ms. Behles that many of the of the documents in EPA Region 9's possession were publically available and possibly already in her possession. Ms. Behles subsequently stated she was narrowing the scope of her May 21 Request to exclude documents which were publically available. On March 18, 2010, EPA personnel contacted Ms. Behles to inform her that Region 9's response to her May 21 Request would include all documents in Region 9's possession through our response. Normally, the cutoff date for documents provided in a response is the date the FOIA request is logged in by Region 9's FOIA Officer. On March 23, 24 and 26, 2010, EPA provided to Ms Behles the documents responsive to her request, except those which were withheld as being privileged.

Comment #14:
ACORN was not included in the negotiation process between PG&E and EPA.

Response to Comment #14:
EPA responds to this comment in the Memorandum In Support of Motion to Enter Consent Decree.

Comment #15:
The mitigation project required under the proposed settlement, OpFlex technology, should have been required as injunctive relief because it would be required as BACT. OpFlex has been installed and proven effective at the Palomar Energy Center. In addition, the settlement only requires PG&E to "install and make fully operational" this technology and does not require its continued use.

Response to Comment #15:
Under the proposed settlement, PG&E is required to install two different OpFlex technologies at GGS. One technology will shorten the duration of startup events at GGS. We assume this technology is being addressed in Comment #15. The other OpFlex technology allows PG&E to run GGS at 11% of its rated capacity rather than shutting down the facility. This technology allows PG&E to avoid these shutdowns and associated startup events.

EPA disagrees that OpFlex would be required as BACT. Opflex was not installed at the Palomar Energy Center pursuant to a BACT determination. It was installed because the facility was having trouble meeting the emissions limits of a San Diego Air Pollution Control District prohibitory rule during startups. This rule is part of the state implementation plan for San Diego. Currently, San Diego is a nonattainment area for the ground-level ozone NAAQS. 40 C.F.R. § 81.305. As discussed earlier, control requirements for nonattainment areas are more stringent than for attainment areas. San Diego promulgated its rule regarding emissions during startup as part of its effort to attain the NAAQS for ground-level ozone, not to preserve existing clean air under the PSD program.

As noted in the comment, the emission reductions achieved by Opflex are 47 pounds per startup. Installation of OpFlex costs several hundred thousand dollars. Any permitting agency would be within its discretion to find that OpFlex is not a cost-effective control for the purposes of BACT. As discussed earlier, the comment erroneously assumes that BACT requires any control which has been achieved in practice. Finally, ACORN and CBE repeatedly refer to the BAAQMD's draft permit for the RCEC regarding what should be required as current-day BACT for GGS. BAAQMD issued the final permit for RCEC on February 3, 2010. BAAQMD specifically rejected requiring OpFlex as BACT for RCEC. *See* App. C9-BAAQMD RCEC Responses at pp. 116-17.

The proposed settlement does require PG&E to use the Opflex technology to shorten the duration of startup events. Paragraph 15 of the proposed settlement states: "EPA is requiring use of this product [OpFlex startup] in order to reduce the higher NOx emissions associated with startups." In addition, the proposed settlement, the rolling 12-month NOx emissions cap for GGS was lowered from 174.3 tpy to 139.2 tpy. To achieve compliance with this lowered emissions cap and maintain an adequate compliance margin, PG&E will be required, from a practical perspective, to operate the OpFlex technology

<u>Comment #16:</u>
The proposed settlement allows PG&E to wrongfully benefit from the installation of OpFlex technology by allowing PG&E to acquire saleable emission reduction credits or emission reductions which can be used to avoid future emission reductions.

<u>Response to Comment #16:</u>
The Amendment to the Consent Decree (¶¶ 43-45) unequivocally resolves this concern, but the contention in this comment that PG&E might somehow generate emission reduction credits ("ERCs") from the installation of the OpFlex technology is legally incorrect. ERCs cannot be generated where, as here, the control technology is installed under a legal requirement to control the pollutant at issue. *See* Clean Air Act section 173(c)(2), 42 U.S.C. § 7503()(2). ("Emission reductions otherwise required by this chapter [the Clean Air Act] shall not be creditable as emissions reductions for purposes of any such offset requirement."); 40 C.F.R. Part 51, Appendix S ("Emission Offset Interpretive Ruling"); and BAAQMD Regulation 2-2-201(emission reductions claimed as offsets must exceed reductions required by federal law).

B. Comments Submitted on behalf of Californians for Renewable Energy ("CARE") by Michael Boyd

Comment #17:

EPA, the California Energy Commission ("CEC"), and the BAAQMD are engaged in a criminal conspiracy to violate "local, state, federal, and international law and treaty" through their actions regarding GGS. "Let us call that Conspiracy A."

Response to Comment #17:
EPA denies the existence of this so-called Conspiracy A. However, to the degree that the description of so-called Conspiracy A is relevant to this case, we have addressed those portions of the comment in our responses to comments submitted by ACORN and CBE.

Comment #18:
EPA, the BAAQMD, the City and County of San Francisco, and Lennar BVHP have engaged in an unlawful conspiracy regarding the exposure of the Bay View Hunters Point community to toxic dust containing asbestos. "Let us call that Conspiracy B."

Response to Comment #18:
EPA denies the existence of this so-called Conspiracy B. In addition, all comments and "evidence" provided concerning this so-called Conspiracy B are not relevant to this case.

Comment #19:
The proposed settlement is inadequate because it does not require an analysis of carbon dioxide ("CO2") and other greenhouse gases ("GHGs") as PSD pollutants subject to BACT requirements.

Response to Comment #19:
EPA's EAB found in November of 2008 in *Deseret Power* that EPA as an agency has the discretion to determine whether greenhouse gases should be subject to PSD regulation or not, but had not at that time adopted any definitive policy position on the issue.[2] The EAB also suggested that it may be more appropriate for EPA to address this issue through a nationwide rule making, rather than through individual case-by-case PSD permitting decisions. On December 18, 2008, EPA issued a policy memorandum in response to the EAB's *Deseret Power* opinion. The impact of EPA's December 18 memorandum was that EPA was not requiring greenhouse gases to be regulated under the Federal PSD permitting program, at least as of that time.[3] EPA has recently determined that greenhouse gases endanger public health and welfare,

[2] *See In re Deseret Power Electric Cooperative*, PSD Appeal No. 07-03, slip op. at 63-65 (EAB Nov. 13, 2008).
[3] *See* Memorandum, Stephen L. Johnson, Administrator, *EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program*, December 18, 2008 (hereinafter, "PSD Interpretive Memo"); notice provided at 73 Fed. Reg. 80300 (Dec. 31, 2008). EPA has proposed to reconsider the position set forth in the PSD Interpretive Memo, but it is proposing to affirm its interpretation with respect to whether

which will pave the way for EPA to adopt regulations limiting greenhouse gases from motor vehicles and other sources.[4] EPA has also proposed new regulations for greenhouse gas emissions from cars and trucks which, if finalized, would make greenhouse gases subject to PSD regulation.[5] On March 29, 2010, EPA completed its reconsideration of the PSD Interpretive Memo. The final action confirms that any new pollutant that EPA may regulate becomes covered under the PSD program on the date when the EPA rule regulating that new pollutant takes effect. It then clarifies that for GHGs that date will be January 2, 2011 when the cars rule is expected to take effect.

Comment #20:
PG&E used a Long Term Services Agreement ("LTSA") with General Electric ("GE") to permit, construct, and service GGS. Doesn't this mean GE is a part or complete owner of the facility? Shouldn't GE's name be on the Consent Decree too?

Response to Comment #20:
Even if GE had constructed GGS, obtained permits for the construction and operation of GGS on behalf of Mirant and/or PG&E, and continued to service equipment such as the turbines at GGS, these activities are not legally sufficient to establish liability for GE as an "owner or operator" as required under the Clean Air Act. GE obviously constructed the turbines being operated at GGS, but fabricating emitting equipment used at a facility does not mean that GE constructed the facility. In addition, while GE may have provided Mirant and subsequently PG&E with information necessary to obtain permits from the BAAQMD, this does not mean GE obtained permits on behalf of Mirant or PG&E. Finally, we have been informed by PG&E that GE's involvement in GGS is limited to service and repair of the turbines at GGS under the LTSA. Such activities do not establish GE as an owner or operator of GGS.

C. Comments Submitted Via Form Letters Signed by Approximately 28 Individuals

Comment #21:
The proposed settlement does not provide an adequate penalty or appropriate injunctive relief.

Response to Comment #21:
See Responses to Comment # 6 through #11.

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greenhouse gases are subject to regulation under the PSD program. *See Prevention of Significant Deterioration (PSD): Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by the Federal PSD Permit Program, Proposed Rule*, 74 Fed. Reg. 51,535, 51,545-46 (Oct. 7, 2009).

[4] *See* Final Rule, Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act (Dec. 7, 2009).

[5] *See Proposed Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards* (GHG Light Duty Vehicle Rule), 74 Fed. Reg. 49,454 (Sept. 28, 2009), issued jointly by EPA and the National Highway Transportation Safety Administration (NHTSA); *see also Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule,*74 Fed. Reg. 55,292 (Oct. 27, 2009).

Comment #22:
PG&E's violations resulted in tons of emissions without proper controls and allowed PG&E to circumvent the public process.

Response to Comment #22:
GGS went through a full public process leading up to issuance of the original PSD permit in July 2001. As discussed in our Responses to Comments #1 through #5, it is not clear that the original PSD permit expired or that the only relevant change in the design of GGS since the original PSD permit was issued, the change from an electric-powered emergency fire pump to a diesel-powered emergency fire pump, required any substantive change to that PSD permit. In addition, we believe the current emission controls on GGS are BACT. See Responses to Comments #6 through #10.

Comment #23:
PG&E's violations are especially troubling since GGS is located in a small geographic area with too many other emitting facilities.

Response to Comment #23:
See Response to Comment #12.

D. Comments Submitted by Robert Sarvey

Comment #24:
PG&E's application for an amended permit shows that PG&E knew it could not build GGS without a new or amended PSD permit and, therefore, PG&E knowingly violated the Clean Air Act in constructing and operating GGS without such a permit.

Response to Comment #24:
See Responses to Comments #2 and #3.

Comment #25:
PG&E knew that construction of GGS had been discontinued more than 18 months and, therefore, knew it needed a new PSD permit.

Response to Comment #25:
See Response to Comment #3.

Comment #26:
The remedies requested in the complaint are the appropriate remedies and those in the proposed settlement are inadequate.

Response to Comment #26:
For a discussion of the appropriate remedies in this case, see Responses to Comments #1 through #12 and #14 through #16.

Comment #27:

The settlement should require BACT for CO at a rate of2.0 ppmv rather than 6.0 ppmv.

<u>Response to Comment #27:</u>
See Response to Comment #7.

<u>Comment #28:</u>
The settlement should require BACT for PM2.5/PM-10 at a rate of 7.5 pounds per hour. The proposed settlement does not address PM2.5/PM-10.

<u>Response to Comment #28:</u>
See Response to Comment #9.

<u>Comment #29:</u>
The proposed settlement does not require BACT during startup and shutdown. GGS should be required to install available technology to shorten the duration of startups.

<u>Response to Comment #29:</u>
See Response to Comment #8.

<u>Comment #30:</u>
PG&E should be required to shut down GGS until a valid PSD permit is issued.

<u>Response to Comment #30:</u>
We do not believe a shutdown of GGS is an appropriate remedy in this case. For a discussion of what we see as the legal considerations in this case, see Responses to Comments #1 through #5.

<u>Comment #31:</u>
The $20,000 penalty in the proposed settlement is far too low.

<u>Response to Comment #31:</u>
See Response to Comment #11.

E. Comments Submitted by Rob Simpson

<u>Comment #32:</u>
Any settlement should include a new full PSD permitting process for GGS. The proposed settlement should not serve as a shortcut or substitute for that PSD permitting process.

<u>Response to Comment #32:</u>
GGS went through the PSD permitting process. This process resulted in a PSD permit being issued in July 2001. As discussed in our Responses to Comments #1 through #5, it is not clear that the original PSD permit expired or that the only relevant change in the design of GGS since the original PSD permit was issued, the change from an electric-powered emergency fire pump to a diesel-powered emergency fire pump, required any substantive change to that PSD permit. In view of these considerations, we do not believe it is necessary for GGS to go through the PSD permitting process again.

Comment #33:
PG&E owns two other power plants in California which are being constructed without necessary permits.

Response to Comment #33:
This comment is not relevant to this case.

Comment #34:
The entire siting and permitting process for power plants in California is seriously flawed. The CEC has worked with California air districts and power plant developers to violate the Clean Air Act.

Response to Comment #34:
This comment is not relevant to this case.

F. Comments Submitted by Pacific Environment

Comment #35:
The proposed settlement would set a bad precedent because PG&E would get a better deal regarding GGS than other power plant operators that go through the permitting process.

Response to Comment #35:
GGS went through the PSD permitting process. This process resulted in a PSD permit being issued in July 2001. As discussed in our Responses to Comments #1 through #5, it is not clear that the original PSD permit expired or that the only relevant change in the design of GGS since the original PSD permit was issued, the change from an electric-powered emergency fire pump to a diesel-powered emergency fire pump, required any substantive change to that PSD permit.

In addition, we believe the current emission controls on GGS are BACT. See Responses to Comments #6 through #10. In view of these considerations, we do not believe PG&E is getting a better deal than other power plant operators, nor is it necessary for GGS to go through the PSD permitting process again.

Comment #36:
The proposed settlement does not require BACT for CO.

Response to Comment #36:
See Response to Comment #7, above.

Comment #37:
The proposed penalty is too low and does not create adequate deterrence to future violations.

Response to Comment #37:
See Response to Comment #11, above.

Comment #38:

The proposed settlement does not take into account the environmental justice aspect of this case.

Response to Comment #38:
See Response to Comment #12, above.

Comment #39:
It is not even clear that GGS in necessary for grid reliability in the Bay Area.

Response to Comment #39:
According to the CEC, the generation needs of the Bay Area Local Capacity Requirements ("LCR") area is in a state of flux and could change significantly over the next few years. Numerous factors will be affecting the amount of generation available in this LCR area. For example, the Trans-Bay transmission line may eventually allow the Potrero Hill power plant to finally shut down. In addition, several generating units in the Pittsburg area may be subject to the once-through cooling requirements and it may be more economic to shut down these units instead of retrofitting them with the necessary cooling technologies. Finally, having a reserve of readily available gas-fired power plants could be critical to California's efforts to develop clean energy sources such as wind and solar which are intermittent.