U.S. Environmental Protection Agency
November 2012

Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Pio Pico Energy Center

I. Introduction

Summary of the Formal Public Participation Process

The U.S. Environmental Protection Agency, Region 9 (EPA) proposed to issue a Clean Air Act (CAA or Act) Prevention of Significant Deterioration (PSD) permit to Pio Pico, LLC (PPLLC or applicant) for the Pio Pico Energy Center (PPEC or Project) on June 20, 2012. The public comment period on the proposal (Proposed Permit)[1] began on June 20, 2012 and was proposed to close on July 24, 2012. Due to an inadvertent mailing list error, EPA extended the public comment period for the Proposed Permit to September 5, 2012.[2] During the public comment period EPA took comments on its Proposed Permit decision and specifically requested comments regarding: 1) the best available control technology (BACT) determinations; 2) the effects, if any, on Class I areas; 3) the effect of the proposed facility on ambient air quality; and 4) the effects, if any, on the attainment and maintenance of the National Ambient Air Quality Standards (NAAQS).

EPA announced the public comment period through public notices published in the *San Diego Union-Tribune* on June 20, 2012 and August 3, 2012, *La Prensa San Diego* (in Spanish only) on June 22, 2012 and on August 3, 2012 and on Region 9's website (in English and Spanish) on June 20, 2012 and August 3, 2012. EPA also distributed the English and Spanish public notices to the necessary parties in accordance with 40 CFR Part 124, including notices sent by mail and email on June 20, 2012 and August 3, 2012. Parties notified by EPA included agencies, organizations, and public members for whom contact information was obtained through a number of different methods, including requests made directly to EPA through Region 9's website (or through other means) from parties seeking notification regarding permit actions in Region 9, California, within the San Diego County Air Pollution Control District (SDAPCD or District), San Diego County , or specific to the PPEC; appropriate contacts from the California Energy Commission's (CEC) PPEC mailing list; and other parties known to EPA that may have an interest in this action. EPA provided notice to numerous government agencies in accordance with 40 CFR Part 124, including, but not limited to, the CEC, the District, the City of San Diego, and Indian tribes in the area. We also sent notice of our Proposed Permit to more than 90 individuals on the email contact list of the San Diego-Tijuana Air Quality Task Force, which is composed of government and non-government stakeholders from both the U.S. and Mexico.

The administrative record for the Proposed Permit was made available at EPA Region 9's office. EPA also made the Proposed Permit, the Fact Sheet and Ambient Air Quality Impact Report (Fact Sheet) and certain other supporting documents available on Region 9's website, at the District office in San Diego, CA and at the following public libraries: the San Ysidro Public Library in San Diego, CA, the Chula Vista Public Library in Chula Vista, CA, the Otay Mesa-Nestor Library in San Diego, CA, the San Diego Central Library in San Diego, CA, and the National City Public Library in National City, CA.

[1] We note that EPA's permitting regulations at 40 CFR Part 124 refer to proposed permits as "draft permits." See 40 CFR 124.6.

[2] EPA allowed one individual additional time, until September 20, 2012, to provide comments on the PPEC Environmental Justice Analysis (EJ Analysis). *See* Response to Comment 46 below for more information.

EPA held a formal public hearing on July 24, 2012 in San Diego, California. A court reporter was present at the hearing, as was a Spanish language interpreter for oral translation. We did not receive any oral public comments at the hearing. We received one set of written comments at the hearing, which was also transmitted to us via email. EPA's initial public notice for the Proposed Permit provided the public with notice of the July 24, 2012 public hearing, and our second public notice in August 2012 informed the public about the opportunity to request an additional public hearing. No party requested an additional public hearing. During the public comment period, EPA also received several comment letters by mail and email. All comments received equal weight, regardless of the method used to submit them.

During the public comment period, EPA held two teleconferences, one with the applicant on August 2, 2012, and one with the City of Tijuana on August 23, 2012. We have summarized these teleconferences in two memoranda, which are part of the administrative record for this action.

II. EPA's Responses to the Public Comments

The purpose of this document is to respond to every significant issue raised in the public comments received during the public comment period and explain what changes have been made in the final permit (Final Permit) as a result of those comments.

This section summarizes all significant public comments received by EPA on our Proposed Permit decision and provides our responses to the comments, including an explanation of what changes have been made, if any, in the Final Permit as a result of those comments. In some instances, similar comments may be grouped together by topic into one comment summary, and addressed by one EPA response. The full text of all public comments and many other documents relevant to the permit are available through a link at our website, www.epa.gov/region09/air/permit/r9-permits-issued.html#psd, or at www.regulations.gov (Docket ID # EPA-R09-OAR-2011-0978).

On August 24, 2012, the applicant submitted a letter to EPA that contained its responses to a subset of the public comments on the Proposed Permit that EPA had received by that date. In this Response to Comments document, we have included these responses from the applicant following the summary of public comments they are associated with.

Comments Submitted by Sierra Research on behalf of PPLC

1. **Comment:** The commenter states that each turbine is described as "100 MW (gross) combustion turbine generator (CTG)…." The permit application makes clear that the power rating is a nominal rating. Furthermore, the 100 MW is a nominal net capacity. Please clarify each turbine description as follows: 100 MW (~~gross~~ nominal net) combustion turbine generator (CTG).

   Response: While the application consistently describes the facility as being capable of a net capacity of 300 MW (with each turbine's net capacity at 100 MW), emissions from the facility were calculated assuming the gross output for each engine is 100 MW – see Table 1C.1 on page PSD-App-1.51, and the permit already limits the emissions and operation of the facility based on the information 100 MW per turbine information in Table 1C.1. So, while we agree that the description of the power rating as "nominal" and not "gross" is accurate and it also does not change the emissions profile used in the application. We have made the requested change – see the Equipment List on page 2 of the Final Permit.

2. **Comment:** The commenter states that the partial dry cooling system is described in the proposed permit as a "Dry cooling tower with a 16,520 gallons per minute (GPM) maximum circulation rate, supplemented by 7,000 GPM wet cooling tower."
   The circulation rate for the dry cooling component is a nominal, not maximum, value, and the actual value is 9,600 GPM, as shown in Table 3.5-2A of the Application for Certification filed with the CEC. Cooling water in the dry cooling component of the cooling system circulates in a closed loop, and has no impact on emissions. Because it has no effect on emissions, there is no regulatory reason for having this value in the permit.

The commenter further states that the wet cooling component of the cooling system has a circulating water flow rate of 23,520 gpm, as shown in Appendix 1.C, Table 1.C.2, of the PSD permit application (page PSD-APP-1.52). The 5,600 ppm TDS concentration applies to the water circulating in the wet section of the cooling system, not to makeup water.

The applicant suggests the following changes to the cooling system description:

- Dry cooling tower component ~~with a 16,520 gallons per minute (GPM) maximum circulation rate~~, supplemented by ~~7,000~~ 23,520 GPM wet cooling ~~tower~~ component.
- Total dissolved solids (TDS) concentration in ~~makeup~~ wet cooling circulation water of 5,600 ppm (560 mg/L)
- Drift eliminator with drift losses less than or equal to 0.001 percent based on wet cooling water circulation rate

Response: EPA notes that our review and equipment description is based on the applicant's PSD application, not the Application for Certification submitted to the CEC.

The commenter's request to include "23,520 GPM wet cooling component" in the equipment description conflicts with other information in the administrative record. (The applicant's letter to EPA dated November 8, 2011 states that the Partial Dry Cooling System contains a 7,000 gpm circulation rate wet cooling component; and the permit application describes a "7000 gallon per minute (gpm) fluid cooler" p. PSD-App-1.89). In an email dated August 31, 2012, the applicant clarified this discrepancy, stating:

> *A closed loop containing cooling water passes first through the dry cooling component, then through the wet cooling component. The resulting cold cooling water is then used in the turbine intercooler, cooling the turbine gas and heating the water, which is finally returned to the dry cooling component. The cooling water loop is closed; no evaporation of this cooling water occurs.*
>
> *The flow rate of this circulating water is nominally 9,600 GPM, as shown in Figure 3.5-2A of the revised PSD Application. This flow rate was erroneously described as 7,000 gpm in our November 8, 2011 letter.*
>
> *The wet cooling component operates by applying a different water stream to the outside surface of the cooling water tubes. The evaporation of this externally applied water is the source of the drift emissions from the wet cooling component. The circulation rate for the water on the evaporative side of the wet cooling component is 23,250 gpm as shown in Appendix 1.C, Table 1.C.2, of the PSD permit application (page PSD-APP-1.52). This circulation rate, together with the drift rate, was used to calculate PM emissions from the wet cooling component of the cooling system. Because the circulation rate of the evaporative water stream affects emission calculations, and the circulation rate of the cooling water does not, we suggested using this flow rate in the equipment description.*

We have revised the equipment description in the Final Permit according to the commenter's request, except that we have retained the dry cooling component (but corrected the GPM to 9,600 and identified this rate as a nominal value) as part of the description. While it is true that the dry cooling component has zero emissions, it is a significant component of the facility's cooling system upon which EPA based its BACT determination. See Equipment List on page 2 of the Final Permit.

3. **Comment**: The commenter states that Condition IX.B.1 provides emission limits for the turbines. The proposed limit for PM, PM_{10}, and $PM_{2.5}$ is 0.0065 lb/MMBtu. The limit is imposed as a BACT requirement. This emission rate can be complied with at full load; however, the record shows that at low load this level may not be achievable at all times. The commenter believes that an emission limit at a specific benchmark condition (full load operation) should be specified: 0.0065 lb/MMBtu at full load. There is no evidence in the record to support the application of that particular emission limit at all loads for this generating technology.

   Response: Since BACT applies during all periods of turbine operation, EPA cannot grant the commenter's request to limit the PM emission limit to periods of full load operation. Consistent with information provided by the applicant in the permit record the turbines may not be able to comply with the 0.0065 lb/MMBtu limit at low loads.[3] The limit in the Proposed Permit is the expected emission rate that can be achieved at high loads. The same PM emissions per fuel input may not be achievable at lower loads, as compared to high loads, since the turbines will be less fuel efficient at lower loads. Because there is no control device for PM emissions, the applicant cannot take measures to improve the lb/MMBtu PM emissions at lower loads.

   To address this issue, we have revised the permit to specify that the lb/MMBtu emission limit applies at loads of 80% and higher, and have added a 5.5 lb/hr emission limit that applies at all times – see Condition IX.B.1. The lb/MMBtu limit is being applied at high loads because it represents the testing conditions that will be used to demonstrate compliance during performance testing. Compliance with the lb/MMBtu limit at high loads demonstrates that the turbines are meeting BACT by using good combustion practices. The 5.5 lb/hr limit is the emission rate that was used in the application to demonstrate compliance with the PM_{10} and $PM_{2.5}$ NAAQS. This limit is achievable at lower loads because PM emissions per unit of time will be less at lower loads when less fuel is being used. We believe these revisions are appropriate, given the nature of peaking turbine operation (intermittent operation at varying loads) and the fact that the PPEC will not use any PM control device to comply with these emission limits.

4. **Comment**: The commenter states that the CO_2 emission limit is not consistent with the project as proposed. The record shows that (1) individual turbines of the same make and model vary in initial thermal efficiency due to variations in manufacture and construction; (2) even with recommended maintenance, normal wear and tear results in a reduction in thermal efficiency over time; and (3) there are not enough LMS100 installations to predict the magnitude of either effect on turbine performance.

[3] See December 8, 2011 letter from Steve Hill to Gerardo Rios.

The commenter asserts that because of these factors, any efficiency-based permit limit that applies over the lifetime of the turbine would, of necessity, be arbitrary, because no data exist to support any selected value. The value in the Condition IX.B.1, for example, was apparently set at 6% above an unspecified initial operating efficiency.

The commenter further states that it is possible that the proposed condition provides margin to account for variability in turbine construction and installation, and it is also possible that the proposed condition allows margin for normal expected performance degradation; however, it does not adequately take into account low-load operation. The record shows that turbines operate less efficiently at low loads. One of the project features, acknowledged by EPA in its BACT determination, is that these turbines are intended to be dispatched by the power system operator to follow transient loads. This means that each turbine is typically operated somewhere between minimum and maximum load, so that it may increase or decrease its operation to adjust to demand. In setting the limit proposed in the permit, EPA took into consideration variability in initial performance of turbines, and losses in efficiency over time, but failed to consider operation at partial loads. It is not possible to predict the extent of part load operation during each year of the facility's 30-year (nominal) life; hence, it is possible to calculate an 8760 operating hour average only for the extremes of 100% operation at minimum load and 100% operation at maximum load.

The commenter states that it was for these reasons that the applicant proposed that GHG BACT for this project be comprised of an initial efficiency demonstration at a benchmark condition (to ensure that the turbines were properly designed, constructed and installed), coupled with ongoing maintenance requirements (to ensure that turbine performance is maintained).

The commenter concludes that the BACT limit in the proposed permit at Condition IX.B.1 does not allow the turbine to operate at low load as necessary, even though this was part of the project presented to EPA. The BACT limit proposed by EPA therefore is not consistent with the project that was submitted to EPA for review, is not supported by the record, and alters the project in an impermissible way. The applicant requests specific changes to Condition IX.B.1 to address these issues.

Response: As a general matter, EPA disagrees with the commenter that an efficiency-based permit limit that applies for the life of the turbine operation is arbitrary. In fact, because the commenter itself subsequently proposed an efficiency-based limit in a later set of comments submitted during the extended public comment period, we believe the commenter would now agree that there is an adequate basis in the permit record upon which to establish this type of limit. As we explained in our Fact Sheet for the Proposed Permit, an efficiency-based standard must account for factors such as degradation in performance over time, variations in the manufacturing, assembly, and construction of the turbines, and variations in ambient conditions, as they all affect turbine performance. However, upon consideration of these comments, EPA also agrees with the commenter that the limit we initially proposed is inconsistent with the purpose of the Project because it does not adequately account for part load operation. The commenter is correct that our proposed limit does not adequately allow for part load operation since the turbines are less efficient at lower loads and it is not possible to predict the extent of part load operation during each year of the facility's life. As a result, we are revising the limit to properly account for part load operation in a way that is consistent with the purpose of the Project. The commenter is directed to our Response to Comment 13 for further details regarding the revised limit.

5. **Comment**: The commenter states that the definition of the startup period in Condition IX.C.5 differs from definitions previously used by EPA in PSD permits, and the difference introduces unnecessary potential for non-compliance. For example, it is possible during startup for a turbine to reach operating conditions, briefly achieve the emission limits, and then temporarily drift above emission limits while the system achieves equilibrium. Under the new definition of startup proposed in the permit, the temporary period of operation above the limit could count towards a violation, even though it occurs within 30 minutes of first fire.

   The applicant requests consistency in permit requirements, and requests that EPA use the definition of startup that is contained in the Palmdale and Avenal PSD permits:

   > 5. Startup is defined as the period beginning with combustion turbine ignition and lasting until the equipment has reached ~~a continuous operating level and the emissions from the turbines are at or below the emission limits specified in~~ and maintains its operating temperature and pressure, and including the time required by the unit's emission control system to reach full operations and demonstrate compliance with Condition IX.B.1.

   Response: EPA agrees with the commenter's concern, but notes that the commenter's proposed definition differs from that in both the Palmdale and Avenal PSD permits. The definitions in the cited EPA-issued PSD permits are not applicable to this Project because the entire startup period for the Project is limited to a maximum of 30 minutes. Given that the short startup period is part of what constitutes BACT during this period, it is not necessary to end the startup period when the emission limit is met. Therefore, EPA has revised the definition of startup in Condition IX.C.5. of the Final Permit to read as follows:

   Startup is defined as the period beginning with ignition and ending 30 minutes later.

6. **Comment**: The commenter states that Condition IX.D.1 limits the hours of operation to 4,000 hours per calendar year. The applicant did not propose to limit hours of operation to 4,000 per calendar year—rather, the applicant indicated that annual emissions were based on a scenario of 4,000 hours at full load per year, plus 500 startups and shutdowns.

   The applicant proposes a limit based on fuel usage rather than hours of operation, which is consistent with the application and the regulatory analysis performed by EPA, and equally enforceable:

> 1. The quantity of fuel ~~hours of operation~~ for each turbine (Turbine 1, Turbine 2, and Turbine 3) shall not exceed ~~4,000 hours~~ 3,914,556 MMBtu (HHV) in any calendar year.

Response: We agree with the commenter that the 4,000-hour limit in the Proposed Permit does not accurately reflect the operating scenario for the Project as it does not take into account the hours of operation allowed during startup and shutdown. The operating scenario provided by the applicant (4,000 hours at full load per year plus 500 startups and shutdowns) was used to calculate the worst-case emission rates from the facility – and is equivalent to about 4,337 hours per year.

As requested by the commenter, we have revised Condition IX.D.1 from the proposed hours of operation limit to an annual limit on the heat input for each turbine, which will limit the fuel use of each turbine. Limiting the fuel use achieves the same objective as limiting the hours of operation of each turbine to 4,337 hours per year – to ensure the Project's operation is based on the maximum emissions profile used to demonstrate compliance with the NAAQS. As indicated in Table 1C.7 on page PSD-App-1.55 of the application, this worst-case operating scenario for the Project corresponds to an annual fuel use of 3,914,556 MMBtu (HHV) per turbine. Condition IX.D.1 in the Final Permit states:

> The annual quantity of fuel used by each turbine (Turbine 1, Turbine 2, and Turbine 3) shall not exceed 3,914,556 MMBtu (HHV) in any 12-month rolling period.

7. **Comment**: The commenter states that Condition IX.D.2 requires ammonia injection to be initiated as soon as the SCR catalyst temperature exceeds 575 degrees F.

The commenter asserts that this permit condition is unnecessary. Condition IX.B.1 already limits NO_x emissions to 2.5 ppm, which cannot be achieved without ammonia injection. Condition IX.C.2 limits the startup period to 30 minutes, which means that the period of time during which emissions may exceed 2.5 ppm is strictly constrained. Furthermore, as written, Condition IX.D.2 specifies the temperature at which ammonia injection is to be initiated. On its face, it prohibits injection at lower temperatures.

The commenter argues that if EPA chooses to retain this condition, it should at the very least be revised to be consistent with the similar condition previously imposed by the District in the Final Determination of Compliance (FDOC). Using the District's language allows ammonia injection at lower temperatures if appropriate, covers all operating conditions (not just startup), and avoids the possibility that temperature will have to be monitored at two different places.

> 2. ~~During any~~ When a combustion turbine is operating ~~startup~~, ammonia shall be injected~~ion shall be initiated as soon as~~ whenever the SCR catalyst outlet temperature exceeds 575 degrees F.

Response: We have retained this condition because we believe it is useful to ensure that NO_x emission reductions are achieved as soon as possible after a turbine startup. We agree with the commenter's suggested language for Condition IX.D.2, and have revised the Final Permit accordingly.

8. **Comment**: The commenter states that permit condition IX.D.5 requires monitoring for SF_6 leaks from circuit breakers. The facility will be subject to the California Air Resources Board's (CARB's) SF_6 regulation (CCR Subchapter 10, Article 4, Subarticle 3.1, §95350 et seq.). This regulation requires annual SF6 measurement and reporting, and limits annual emissions to 1% or less by 2020.

   The commenter asserts that the proposed permit condition is redundant to, but different than, the applicable regulation. It imposes different monitoring requirements, but does not result in reduced emissions. Furthermore, the amount of GHG emissions (40 TPY CO2eq) is trivial compared to up to 685,000 TPY of combustion CO_2 emitted from the facility. The applicant requests that the monitoring in this condition be replaced by a reference to the requirements of the state regulation:

   > 5. ~~The circuit breakers shall be equipped with a 10% by weight leak detection system. The leak detection system shall be calibrated in accordance with manufacturer's specifications. The manufacturer's specifications and records of all calibrations shall be maintained on site.~~ SF_6 at the facility shall be monitored in conformance with the requirements of California Code of Regulations §95354.

   Response: EPA disagrees with the commenter that the PSD permit's BACT requirements to equip the circuit breakers with a leak detection system and appropriately calibrate such system are redundant. Regardless of whether a state may impose other requirements on these emissions, EPA is required to include a BACT limit for all emissions of GHGs from this facility. The CARB requirements referenced by the commenter require annual reporting of SF_6 emissions based on inventories of the facility's gas insulated equipment and gas containers. We found no monitoring requirements in the cited regulation for the specific circuit breakers, and we believe that the requirement in our permit for a leak detection system serves as an adequate backstop in the event of a catastrophic failure.

9. **Comment**: The commenter notes that Condition IX.E.3 requires monthly measurement of fuel sulfur content. This is in contrast with the District permit, which requires quarterly testing (which may be satisfied by appropriate documentation from the fuel supplier). It is also in contrast with the applicable requirements of the Acid Rain program, which requires sampling annually or whenever the fuel supply source changes (which may be satisfied by appropriate documentation from the fuel supplier). The testing required by the proposed permit condition imposes additional expense without any corresponding environmental benefit or enhancement of enforceability.

   The applicant requests that this permit condition be revised to be consistent with the requirements of the Acid Rain program, as follows:

   > 3. The Permittee shall sample and record the sulfur content of the natural gas fuel on a ~~monthly~~ quarterly basis, and whenever the fuel supply source changes. The results

of sampling conducted by the fuel supplier and/or a valid contract or tariff sheet may be provided in lieu of sampling by the Permittee.

Response: We agree with the commenter that monitoring consistent with the Acid Rain program will ensure compliance with this requirement. In general, the natural gas fuel supply is very consistent and high variability in the sulfur content of fuel is unexpected. We have revised Conditions IX.B.1, IX.E.1 and IX.E.3 accordingly.

10. **Comment**: Condition IX.F.1 requires a CO_2 CEMS to monitor CO_2 emissions. This requirement imposes an expense with no accompanying environmental benefit. Unlike other pollutants, emissions of CO_2 can be calculated from fuel combustion with a high degree of accuracy, if fuel flow and heat content are known. The fuel used at PPEC will be utility-supplied natural gas, a commodity with highly consistent fuel properties. A CO_2 CEMS would be redundant to fuel flow measurements. The monitoring required by the proposed permit condition imposes additional expense without any corresponding environmental benefit or enhancement of enforceability. The applicant requests that the CO_2 CEMS requirement be replaced with calculation provisions consistent with the requirements of EPA's acid rain regulations for gas-fired units:

> 1. Before Turbines 1, 2, and 3 commence commercial operation (as defined in 40 CFR § 72.2), the Permittee shall install and calibrate CEMS to measure stack gas NOX~~, CO2,~~ and O2 concentrations and a continuous monitoring system (CMS) to calculate ~~measure~~ exhaust gas flow and CO_2 emission rates ~~and moisture content~~ to demonstrate compliance with the emission limits in Conditions IX.B.1, IX.C.7, and IX.C.8.

Response: EPA agrees with this comment for the reasons outlined by the commenter. We have generally revised the permit as requested by the commenter, with the additional provision that CO_2 emissions shall be calculated using the procedures set forth in 40 CFR Part 75[4] See Condition IX.F.1. We note that the revised permit language provided by the commenter would also have eliminated the reference to moisture content in this permit condition, but the commenter did not explain the reason for this proposed change. We have retained this language in the Final Permit, as explained in Response to Comment 27 below.

11. **Comment**: The commenter notes that with respect to the turbine, Condition IX.G.1 requires initial and annual compliance tests for NO_x, CO_2, PM, PM_{10}, and $PM_{2.5}$.

The commenter asserts that virtually all PM emissions from combustion of gaseous fuels are $PM_{2.5}$. Stack tests for PM and PM_{10} are therefore redundant, and the additional expense

[4] As discussed in the Fact Sheet for the Proposed Permit, EPA proposed a GHG emission limit in the form of a CO_2 limit for two reasons. First, the GHG emissions from the gas turbines are overwhelmingly in the form of CO_2 and an efficiency-based limit for CO_2 emissions inherently limits other GHG emissions resulting from combustion such as methane and nitrous oxide. Second, we stated that expressing the GHG limit in terms of CO_2 would facilitate the use of CO_2 CEMS for compliance monitoring. While we are now accepting the commenter's suggestion to base compliance with the GHG limit based on fuel flow and heat content data, the first reason we articulated for expressing the GHG limit in terms of CO_2 emissions nevertheless stands and we believe it is still appropriate to express the limit in such terms in this particular case.

of conducting them results in no environmental benefit, nor does it add any compliance assurance. The applicant proposes to demonstrate compliance with all of the PM requirements through $PM_{2.5}$ source tests.

The commenter notes that with respect to the cooling tower, testing of emissions from cooling system cells and cooling towers is not straightforward. There are no approved source tests for this source category. Modified EPA Method 306 (the method referenced in the proposed permit), for example, is for determination of chromium emissions from chrome plating operations; it is not applicable to cooling systems.

The commenter states that even if the source test were possible, emissions from this source are so low (1.4 TPY) that testing is not justified. Although EPA has not published cost-effectiveness thresholds for evaluating the reasonableness of control technologies under PSD, other agencies have, including both South Coast AQMD and San Joaquin Valley APCD. These districts face the most challenging air quality conditions in the country. Their published BACT cost-effectiveness thresholds are a measure of how far these agencies are willing to go to reduce emissions from new sources.

The commenter states that the San Joaquin Valley APCD cost effectiveness threshold for PM_{10} is \$11,400 per ton. The SCAQMD cost effectiveness threshold for PM_{10} is \$13,400 per ton. Using the SCAQMD cost effectiveness value, a cost of \$19,000 to conduct the cooling tower tests would exceed SCAQMD's cost effectiveness criteria for eliminating these emissions. This is likely to be comparable to the cost of conducting the source test required by the Proposed Permit. Conducting a source test to measure the emissions would be an expensive undertaking with no corresponding environmental benefit.

The commenter concludes that the permit condition requires a very expensive source test to be conducted for the cooling system, using a method that is not approved for this source category, to measure emissions from an insignificant emission source. The applicant therefore requests that this requirement be eliminated, as shown below.

The applicant also requests that the permit requirements for the redundant turbine stack tests described above (specifically, PM and PM_{10}) be eliminated, as follows:

G. Performance Tests

1. Stack Tests

a. Within 60 days after achieving normal operation, but not later than 180 days after the initial startup of equipment, and, unless otherwise specified, annually thereafter (within 30 days of the initial performance test anniversary), the Permittee shall conduct performance tests (as described in 40 CFR § 60.8) as follows:

i. NOX, CO2, ~~PM, PM10,~~ and PM2.5 emissions from each gas turbine (Turbine 1, Turbine 2, and Turbine 3);

~~ii. PM, PM10, and PM2.5 emissions from the cooling tower (annual testing not required).~~

iii. Heat rate performance according to the requirements of the American Society of Mechanical Engineers Performance Test Code on Overall Plant Performance (ASME PTC 22).

Response: EPA agrees that all of the expected particulate emissions from the turbines will be $PM_{2.5}$ or smaller. Because $PM_{2.5}$ is a subset of PM, measuring total filterable PM emissions through Method 5 can be used to determine filterable emissions of PM, PM_{10}, and $PM_{2.5}$ by assuming all PM is $PM_{2.5}$. In the Final Permit, we have revised Condition IX.G.1.c.iv, which specifies the Test Methods to be used, to require Method 5 for measuring filterable emissions of PM, PM_{10} and $PM_{2.5}$. The Final Permit continues to use Method 202 to measure total condensable particle emission. As a result, these two test methods provide the data necessary to determine compliance with the total PM emission limits (filterable and condensable) for all three forms of particulate matter, *i.e.*, PM, PM_{10}, and $PM_{2.5}$,. This testing is also consistent with the testing requirements of the FDOC issued by SDAPCD, which also requires Method 5 and Method 202 testing.

We have retained the requirement for a one-time performance test of the cooling tower. While the PM emissions from the cooling tower are expected to be low, EPA believes it is important to conduct an initial performance source test to ensure that the cooling tower was constructed properly and operating as designed. The cost-effectiveness thresholds referred to by the commenter are for determining whether a particular control technology is cost effective, and not whether performance testing is justified. Because we are only requiring an initial performance test for the cooling tower, we do not find the cost of this one-time requirement to be prohibitive.

The commenter is correct that EPA Method 306 was originally designed for chrome emissions. However, the Cooling Tower Institute has compared its test method to modified Method 306, and found that both yield comparable results. EPA has revised Condition IX.G.1.c.v in the Final Permit to also allow the Cooling Tower Institute's Heated Bead Isokinetic (HBIK) procedure to determine PM emissions from the cooling tower.

12. **Comment**: The commenter states that the applicant has identified a number of minor editorial corrections and clarifications that should be made to the text of the Air Quality Impact Report.

- P. 3 – 100 MW capacity should indicate “nominal” (3 occurrences on this page)
- P. 8 – BACT analyses were conducted for the Partial Dry Cooling System and circuit breakers, in addition to the three combustion turbines
- P. 9 – BACT limit for the cooling tower is a drift rate and a TDS level; not a PM emission rate.
- P. 14 – the PM BACT analysis should indicate that 0.0065 lbs/MMbtu is the maximum (not expected) PM emission rate. Also, NO_x emissions are compared to other permit limits, but PM emissions are compared to source test results. PM should be treated consistently with other pollutants and compared to permit limits.
- P. 19 – The heat rate for IC engines shown in Table 7-7 is LHV basis, not HHV. It should be corrected to ~8,200 BTU/kWh.

- P. 24 – the cooling tower drift rate has nothing to do with the TDS level. The regulatory justification for including the TDS limit is to ensure that emissions are consistent with the values used to demonstrate compliance, not BACT.
- P. 33 – Peak firing rate is said to occur at 30F. This is not correct. Peak firing rate is at 63F, as indicated on page 3.

Response: EPA acknowledges this comment; however, we do not produce a revised Fact Sheet as part of our Final Permit decision. The commenter does not appear to suggest that a change to the Final Permit or additional analysis for the basis of our determination is required. Nonetheless, we have reviewed these editorial comments and determined that they do not result in a change in our Final Permit decision or require additional analysis for the basis of our determination.

13. **Comment**: The commenter states that the applicant indicated in its comments submitted on July 24, 2012 that the permit conditions limiting CO_2 emissions changed the project by imposing emission restrictions that cannot be met by the facility. The applicant believes that this result was unintended by EPA. The applicant understands EPA's desire that the BACT permit limit be expressed in units of lb CO_2 per MWh. After reviewing available turbine design specifications, the applicant proposes that the permit condition be modified as shown below.

The commenter states that, as shown in Figure 5 in the applicant's January 5, 2012 response letter to EPA, heat rate increases (efficiency decreases) as load decreases. The relationship between heat rate (efficiency) and load is also slightly non-linear. However, the commenter believes that a realistic, enforceable condition can be created based on the minimum load and full load information provided in Table 1B of the applicant's April 13, 2012 letter as follows:

Heat rate at 100% load, ISO conditions: 8,738 BTU/kWh (HHV, gross).
Heat rate at 50% load, ISO conditions: 10,576 BTU/kWh (HHV, gross).

The commenter goes on to state that the average of these two values, 9,657 Btu/kWh (HHV, gross), would represent the estimated heat rate at 75% load at ISO conditions. As shown in the PSD permit application at pages PSD-3.77 through PSD-3.80, the heat rate (at full load) varies with ambient temperature between 7,856 Btu/kWh (LHV, gross) at 59F ambient and 7,964 Btu/kWh (LHV, gross) at 93F ambient. Because the limit must be met at all conditions, the estimated 75% load heat rate should be increased by 1.4% (7964 / 7856 = 1.014) to 9,792 Btu/kWh (HHV, gross) to account for operation at non-ISO conditions.

The commenter asserts that this value, in turn, should be increased by 3% (to account for the variability in initial performance for new units); another 3% factor should be applied to account for expected efficiency degradation over time. The calculations supporting the limit in the applicant's proposed condition are shown below.

Heat rate at 100% load, ISO conditions: 8,738 Btu_{HHV}/kWh_{gross}.
Heat rate at 50% load, ISO conditions: 10,576 Btu_{HHV}/kWh_{gross}.

Heat rate at 75% load, ISO conditions: 9,756 Btu_{HHV}/kWh_{gross} (average of heat rates at 50% and 100% load)
Adjustment for ambient temperature range: 1.014
New unit variability: 1.03
Margin for performance degradation: 1.03
Convert BTU_{HHV} to kg CO_2: 53.02 (basis: Table C-1 to Subpart C of Part 98)
Convert kg CO_2 to lb CO_2: 2.205
Conversion from kWh to MWh: 0.001

The commenter states that the heat rate above which values are included is the average of the fuel use rate at 100% load, ISO conditions (903 $MMBtu/hr,_{HHV}$) and the fuel use rate at 50% load, ISO conditions (546 MMBtu/hr).

The applicant selected quarter-clock-hours for consistency with several federal requirements. The applicant selected 30 operating days to provide a long enough period for the averaging to reflect overall performance, while providing a short enough period to be practically enforceable. The commenter proposes the following CO_2 BACT limit:

IX.B.1 DELETE CO2 limit

IX.B.4 ADD the following:

4. CO_2 emissions at or above 75% load shall not exceed 1,215 lb/MWh_{gross} (rolling 30 day average). MWH_{gross} is the total electrical generation (MWe) for use within the plant and for sale (40 CFR 72.2; definition of "unit load")

i. 30 day average CO2 emission rate shall be the arithmetic mean of the CO2 emission rates over 30 consecutive operating days for all quarter-clock-hours during which the turbine firing rate was equal to or greater than 725 $MMBH_{HHV}$ for the entire quarter clock hour.

Response: As stated in our Response to Comment 4, EPA agrees with the commenter that it is not possible to predict the extent of part load operation during every year for the life of the facility. Furthermore, we recognize that the facility is specifically designed to have a practical operating range of 50 to 300 MW, and we believe it would be inappropriate to establish a permit limit that prevents the facility from generating electricity as intended. As stated by the commenter, since turbine efficiency decreases as the load decreases, the limit in our Proposed Permit could preclude the facility from operating within its designed operating range, which accommodates loads between 50 and 100%. Therefore, we agree with the commenter that the limit should be revised. However, we disagree with the commenter's proposal to restrict applicability of the BACT limit to periods of operation at or above 75% load. The commenter averaged the heat rate for each gas turbine at 50% and 100% load to estimate the heat rate at 75% load. The commenter then suggests setting the BACT limit based on the estimated heat rate at 75% load and to only apply the limit to loads at or above 75%. The commenter did not provide a technical justification for why the limit should be based on the heat rate at 75% load or why the limit should only apply to loads at or above 75%. For the reasons explained below, we have selected a limit that applies at all loads.

EPA must ensure BACT is achieved at all times. The permit record is clear that each turbine is designed to operate from 100% down to 50% load during normal operation. As such, we must set a limit that is achievable at all times, including 50 to 75% load. Neither the Proposed Permit limit nor the limit suggested by the commenter would achieve this requirement.

While we considered setting alternative BACT limits to cover the load ranges above and below the 75% load proposed by the commenter, upon further examination of the load ranges, turbine efficiency, and operating parameters, we find no justification for setting multiple limits based on an arbitrary load level. As discussed in the Fact Sheet (see pp. 20), BACT for GHGs for each turbine has been determined to be efficient equipment design and does not include add-on control equipment. As a result, BACT is achieved in the same manner at 50% load as it is at 75% and 100% load (and any other load level), even though the actual GHG emissions resulting from application of BACT may vary at different loads. Our determination must account for the fact that the turbines can operate at a number of different load levels within one period of operation and within the averaging period used to determine compliance. Therefore, in order to ensure that the emission limit resulting from application of BACT for GHGs is set at a level that can be achieved from the turbines at all times, the final BACT limit has been set at a level achievable during the "worst-case" of normal operating conditions – 50% load. This will give the facility the ability to operate within its BACT emission limit and within its designed operating range at all times. However, to ensure that the turbines are operating efficiently as a general matter at all loads, we have also added a requirement in the Final Permit to prepare and follow a maintenance plan for each turbine (see Condition IX.D.6).

Table 1B of the applicant's April 13, 2012 letter indicates that the heat rate at 50% load under ISO conditions is 10,576 BTU/kWh (HHV, gross). As stated in the comment and in our Fact Sheet, turbine performance varies with ambient conditions, and we agree with the commenter that a 1.4% adjustment is appropriate. This results in an adjusted heat rate of 10,724 BTU_{HHV}/kWh_{gross}. We further agree with the commenter that it is necessary to adjust the heat rate for variability in the new unit and degradation in performance over time. We have further adjusted the heat rate by an additional 3% for each of these factors.

As noted by Sierra Research elsewhere in its comments, there are only a limited number of LMS100 installations, which makes it difficult to predict the magnitude of all of these effects on turbine performance. We applied similar adjustments when initially proposing the permit (see Fact Sheet at pp. 20-21) and we believe their continued use is appropriate given the uncertainty involved in establishing an efficiency-based limit for this type of source, resulting in a final heat rate of 11,358 BTU_{HHV}/kWh_{gross}. For clarification, we note that this discussion pertains to the heat rate that is used to calculate the GHG emission limit in terms of lbs/MWh for the gas turbines and it does not apply to the initial heat rate demonstration in Condition IX.D.4 of the permit. The initial heat rate limit in Condition IX.D.4 remains unchanged. Using conversion factors of 53.02 kg CO_2/mmBTU and 2.205 lb/kg, and converting kWh to MWh, results in an emission limit of 1,328 lbs/MWh_{gross}. We have revised Condition IX.B.1 accordingly.

We also note that while the limit in the Proposed Permit was based on net electrical output, we are accepting the commenter's suggestion implicit in its comments (and previously stated in its April 13, 2012 letter to EPA) to base the limit in the Final Permit on gross output. Doing so avoids further uncertainty in calculating the emissions and therefore reduces the need to include an additional compliance margin when establishing the limit. This limit will apply at all times that the turbines are in operation. As suggested by the commenter, we also agree that a 30-day averaging period is appropriate in this case as it allows for some variation in overall performance but it is still practically enforceable; we are thus revising the permit in a manner which is similar to the averaging period suggested by the commenter. The only difference is that the limit will be based on a 720-hour rolling average (which is how many hours are in 30 days). We believe this is more appropriate given the potentially sporadic operation of the facility. See Conditions IX.B.1 and IX.H.9.

Comments Submitted by the San Diego County Air Pollution Control District (SDAPCD)

14. **Comment**: The commenter states that Condition II.D should also reference 40 CFR Part 75.

    Response: Condition II.D incorporates the requirements of 40 CFR 60.13(c), which specifies the frequency of required performance evaluations of the CEMS. EPA is issuing this permit pursuant to PSD regulations; therefore, it is not necessary to include applicable requirements from the Acid Rain program, including those in 40 CFR Part 75. The District can more appropriately address these and other applicable requirements when issuing the title V permit for the facility. We have therefore not revised Condition II.D.

15. **Comment**: The commenter states that Condition V.C should read "inspect or test."

    Response: The permit already includes EPA's authority to conduct performance testing in Condition V.D, which states that EPA shall be permitted "to sample materials and emissions from the source(s)." We have therefore not revised Condition V.C.

16. **Comment**: The commenter states that because the three turbines are not likely to initially startup at the same time, Condition IX.A should read:

    > "As soon as practicable following initial startup of ~~the power plant~~ each turbine (startup as defined in 40 CFR § 60.2) but prior to commencement of commercial operation of that turbine (as defined in 40 CFR § 72.2), and thereafter, except as noted below in Condition IX.C, the Permittee shall install, continuously operate, and maintain the water injection system and SCR system for control of NOX on Turbine 1, Turbine 2, and Turbine 3. The Permittee shall also perform any necessary

operations to minimize emissions so that emissions are at or below the emission limits specified in this permit."

Response: EPA agrees with the commenter and has revised Condition IX.A in the Final Permit accordingly.

17. **Comment**: With respect to Condition IX.B.1, Averaging Times, although it may be implicit, it should be clarified that hourly averages are clock-hour averages and not rolling 60-minute averages.

    Response: The commenter is correct that each reference to an hourly average is a clock-hour average, unless otherwise specified.

18. **Comment**: The commenter states that with respect to Condition IX.B.1, NO_x, the NO_x emission limits for the combustion turbines in this condition apply on and after initial startup except for startup and shutdown periods. The District FDOC conditions require that a CEMS that measures NO_x and CO emissions be operational on initial startup. Even though the CEMS may not yet be fully certified, compliance with the proposed NO_x limits, which can be based on any credible evidence, is problematic during the time period after initial startup until an SCR system is installed and operational. The District suggests exempting the turbines from the proposed limits and imposing alternative limits until the SCR system is operational.

    The commenter also states that for NO_x, it is not clear if the proposed limits ensure compliance with the NSPS for combustion turbines (40 CFR Part KKKK).

    Response: Condition IX.I of the Proposed Permit exempts the facility from the limits in Conditions IX.B, IX.C and IX.D during the shakedown period after initial startup. However, to make this clearer in Condition IX.B, we have revised the language of the Final Permit so that Condition IX.B.1 now references Condition IX.I. We are also clarifying that during the shakedown period, the turbines will be subject to Condition III, which requires that the Permittee, to the extent practicable, maintain and operating the Facility, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. While BACT must apply at all times, we do not find numerical emissions to be enforceable as a practical matter during the shakedown period.

    The commenter does not provide any explanation as to why it is not clear if the proposed limits ensure compliance with 40 CFR Part KKKK. According to Table 1 of 40 CFR 60 Subpart KKKK, the turbines will be required to comply with a NO_X limit of 15 ppm at 15% O_2 or 54 ng/J (0.43 lb/MWh) of useful output. Pursuant to Subpart KKKK, the owner/operator may choose to comply with either limit. In this case, the BACT limit of 2.5 ppm at 15% O_2 ensures each unit will meet the NSPS emission limit for NO_x.

19. **Comment**: With respect to Condition IX.B.1, Particulate Matter, the commenter states that for the proposed particulate matter standard of 0.0065 lb/MMBtu based on the fuel higher heating value over a 9-hour average, it is not clear if:

- This is a rolling 9-hour average or a 9-hour block average.
- A 9-hour source test is required to verify compliance.
- Is the averaging time over nine consecutive operating hours in a 9-clock-hour period (i.e., nine consecutive hours when the turbine is operating) or over nine consecutive hours even if they are separated by nonoperational periods? If it is the former, it is likely that the standard would rarely apply given the operational characteristics of peaking turbines. If it is the latter, it is not clear what type of performance test would be required to verify compliance. There also may be compliance issues for the latter interpretation [9-hour block average] for a peaking turbine with many startups.

The commenter states that manufacturers typically provide performance guarantees for particulate matter in pounds per hour that are constant for all loads. If the manufacturer estimates are accurate, this could result in higher values of an emission factor expressed as lb/MMBtu at low loads. The District notes that a one-hour source test of a large combined-cycle turbine during a cold startup at about 10% load resulted in a particulate emission factor of 0.021 lb/MMBtu while the annual compliance test for the same turbine at full load had a particulate emission factor of 0.0034 lb/MMBtu. The particulate emission rates for the two tests were both less than the permitted emission rate of 14 pounds per hour (about 10 pounds per hour for the cold start and 6.5 pounds per hour for the full load compliance test). The commenter suggests that the particulate emission limit be clarified and consideration given to an emission rate limit expressed in pounds per hour.

Response: EPA recognizes that the Proposed Permit's language may be confusing regarding the averaging period for the PM emission limits. Our intent in specifying a 9-hour averaging period was to make it explicit that the usual 3-hour test average (based on three one-hour tests) used to demonstrate compliance through stack testing is not appropriate for the Facility. Because of inherently low emissions from a gas-fired turbine, PM emission rates are generally below the detection limit for the test methods (Method 5 and 202) when using one-hour sampling times. As a result longer sampling times are needed to ensure the test results are accurate. Specifying the averaging period with the BACT limit implied that PM emissions would need to be monitored on a 9-hour average basis. This was not our intent, as there are no specific continuous PM monitoring conditions in the permit for the turbines. Compliance with the PM limits is based on the performance test requirements in Condition G.

Upon review of this comment, we believe it is more appropriate to address our concern through the testing requirements for PM emissions. Because PM emissions will not be monitored continuously (although quarterly fuel sampling is required), we have revised the permit to not specify an averaging period for the PM emission limits. Instead, we have revised the PM testing requirement to make it clear that extended sampling times of three hours are required. See Conditions IX.B.1 and IX.G.1.c.iv. The commenter is generally referred to Condition IX.G.1 (and 40 CFR 60.8) for the specific performance testing conditions for the turbines.

PM emissions averaged over a 9-hour (or shorter) performance test still ensure that compliance is demonstrated within the necessary NAAQS averaging periods for PM_{10} (24-hour) and $PM_{2.5}$ (24-hour and annual).

Note that we have also revised the source testing frequency in the Final Permit to account for possible limited turbine operation and to avoid making a turbine start solely for testing purposes. See our Response to Comment 29 below for a more detailed explanation of this revision.

As discussed in more detail in our Response to Comments 3, we have revised the Final Permit requirements for the PM emission limit expressed in lb/MMBtu (HHV) by specifying that this limit applies at loads of 80% and higher, and adding a 5.5 lb/hr emission limit that applies at all times.

20. **Comment**: The commenter notes that Condition IX.C.2 proposes startup and shutdown periods of 30 minutes and 10.5 minutes, respectively. Because it appears that the other proposed permit conditions regarding the CEMS only require one-hour averages of emissions and only require sampling and measurement of the emissions every 15 minutes by the CEMS, it is not clear how compliance with the proposed startup and shutdown periods can be determined. The commenter suggests requiring minute-by-minute CEMS data. For simplicity, the commenter also suggests that the allowed shutdown period be 11 minutes for ease of enforcement and to avoid having to keep CEMS measurements and records at 30 second intervals or less.

    Response: We agree that the permit should require the CEMS to record minute-by-minute data for startup and shutdown periods in order to ensure accurate measurements. To address this issue, we have revised Condition IX.F.3 in the Final Permit to require the CEMS to record emission rates in one-minute increments during these periods. (The condition still requires the permittee to reduce CEMS and CMS data to one-hour averages for all operating hours except startup and shutdown.) In addition, we have revised Final Permit Condition IX.C.2 to require that shutdowns not exceed 11 minutes, instead of 10.5, as suggested for the reasons stated by the commenter. This change does not affect the mass emission rates allowed during shutdowns and, as a result, does not affect the modeling used to demonstrate compliance with the NAAQS.

21. **Comment**: Regarding Condition IX.C.3, the commenter states that because a high level of monitoring is being required for this facility including, for example, a CEMS for NO_x, the District FDOC conditions limit annual emissions directly with practicably enforceable annual emission limits that ensure compliance with ambient air quality standards and other regulatory requirements rather than by limiting annual startups explicitly. The commenter suggests that EPA consider this or a similar approach since, although 500 startups is a reasonable estimate for this type of facility at this time (one peaking turbine in San Diego had about 470 startups in 2010), there are indications that the number of startups may increase as the fraction of electrical energy provided by renewable energy resources increases as it is mandated to do in California.

Response: The PSD permit application did not request source-wide limits, and we do not find them necessary in this case. See also our Response to Comment 23 below. We believe it is appropriate that our PSD permit limit operation of the facility to the conditions used to evaluate the facility's emissions. In this case, the source modeled the impacts of 500 startup and shutdowns per year, thus we have limited operation of the plant to match the operating scenario proposed and modeled by the applicant.

22. **Comment**: The commenter states that Condition IX.C.7 should read:

> "NO_x emissions during any clock-hour with one or more startups or shutdowns from each CTG shall not exceed 26.6 lb/hr based on a 1-~~hr~~clock-hour average."

Response: All references to "1-hr averages" are clock hour averages, unless otherwise stated. We do not believe it is necessary to revise the text of the permit conditions to provide this clarification.

23. **Comment**: With respect to Condition IX.D.1, the commenter states that the limit on operating hours should be clarified to indicate whether it is 4000 hours or 4000 unit operating hours per 40 CFR Part 75 (*i.e.*, does a partial hour count as a full hour for purposes of determining compliance with the limit). The difference can be significant for peaking turbines. The commenter suggests not basing the limit on Part 75 unit operating hours because annual emission estimates, upon which the permit evaluation is based, are assumed to be emissions for a full hour.

The commenter further states that assuming 500 full hours with a startup, 500 full hours with a shutdown and 3000 full hours of operation, this condition appears to limit annual NO_x emissions for the facility to less than the 70.4 tons per year of estimated annual emissions in Table 6.2 in the supporting Fact Sheet for this proposed action. The commenter notes that the annual NO_x emission limit of 70.4 tons per year in the FDOC is based on an expected 4335 hours of operation for each turbine including 500 hours with a startup and 500 hours with a shutdown.

The commenter suggests that it may also be worth considering an alternative annual limit on emissions rather than a limit on hours of operation. Another alternative is having an hour limit for the facility as a whole (*e.g.*, 13,000 hours per year for all three turbines combined), which would provide more flexibility.

Response: In Response to Comment 6 above, submitted by the applicant, we have revised Condition IX.D.1 in the Final Permit to convert the previous annual hours of operation limit to an annual fuel use limit. These revised permit limits take into account the facility's startup and shutdown hours, and are based on information provided in the PSD application. We believe these revised limits are appropriate and provide adequate operational flexibility in this case.

24. **Comment**: The commenter states that in Condition IX.D.4, the term "normal operation" should be defined.

Response: Generally speaking, EPA regards any period of operation that does not meet the definition of a shakedown, startup, shutdown, or malfunction period, as defined in the permit, to be normal operation. We do not believe it is not necessary to include a definition for this term in the permit.

25. **Comment**: The commenter recommends that for clarity, Condition IX.E.2 should read:

> "<u>For each turbine</u>, the Permittee shall keep a monthly record of the quantity of natural gas used in Turbine 1, Turbine 2, and Turbine 3."

Response: EPA believes that Condition IX.E.2. is reasonably clear, but has revised the permit for additional clarity, as suggested by the commenter.

26. **Comment**: With respect to Condition IX.E.3, the commenter suggests that, with the approval of EPA, sulfur content information provided by the local serving utility be allowed to satisfy this condition as an alternative to facility sampling and testing of the sulfur content.

Response: EPA agrees that an alternative to facility sampling and testing should be allowed and would be consistent with other PSD permits issued by EPA Region 9. It is not clear how the commenter envisions how this permit condition should be revised, but we have revised Condition IX.E.3 in the Final Permit to allow the permittee the option of obtaining laboratory analysis of the fuel sulfur content.

27. **Comment**: Regarding Condition IX.F.1, the commenter notes that moisture and flow continuous monitoring systems are usually only required on facilities burning highly variable fuel such as coal. For a facility burning natural gas, the commenter suggests that monitoring the fuel higher heating value should be sufficient.

Response: CEMS typically measure pollutant concentrations in units of parts per million by volume in dry air. In order to convert this concentration into a mass emission rate in pounds per hour or tons per year, the moisture content of the exhaust gases and the total exhaust flow through the stack must be considered. Because the permit requires a NO_x CEMS used to monitor a mass emission limit, the moisture content and exhaust flow data is required.

28. **Comment**: The commenter recommends that Condition IX.F.2 read:

> "…appropriate performance standards and quality assurance requirements in the appendices of either 40 CFR Part 60 ~~or~~ <u>and</u> 40 CFR Part 75, <u>as applicable</u>."

Response: EPA's intent in this condition is to ensure appropriate performance standards and quality assurance requirements are used, which will ensure the equipment is installed, calibrated, operated, audited, tested, and maintained in the appropriate manner. We believe that the standards in either Part 60 or Part 75 meet our intent and this condition gives the permittee flexibility in choosing the most appropriate option. Accordingly, we did not revise this permit condition.

29. **Comment**: With respect to Condition IX.F.5.c, the commenter suggests that the specified annual frequency be changed to a frequency corresponding to the frequency specified in 40 CFR Part 75. In the commenter's experience, peaking turbines may operate to a very limited extent making annual source testing a waste of resources and a source of unnecessary emissions. The commenter notes that, for a source test, the peaking turbine must schedule a time when it would not normally be operating.

Response: Condition IX.F.5.c requires the permittee to conduct annual relative accuracy test audits (RATA). Due to the nature of peaking turbine operation, including little or no expected operation during winter months, EPA recognizes the possibility that annual RATA testing regardless of turbine operation may cause emissions that could otherwise be avoided. To address this issue, while also ensuring an appropriate RATA testing frequency, EPA has revised Condition IX.F.5.c in the Final Permit. Rather than requiring annual RATA for the NO_x CEMS, we have revised the condition to require RATA "once every four consecutive operating quarters (which is defined as a calendar quarter in which there are at least 168 clock hours during which a turbine combusts any fuel, either for part of the hour or for the entire hour), or after 8 consecutive calendar quarters, whichever occurs first." This is approach is consistent with the RATA requirements in the Acid Rain regulations (40 CFR Part 75).

We also made corresponding revisions to the other turbine source testing requirements in Condition IX.G.1. Together, these revisions ensure that performance testing and RATA are conducted regularly to verify the accuracy of the CEMS and determine compliance with emission limits, while eliminating emissions from turbines that have not operated enough hours to warrant their next source test and RATA.

30. **Comment**: The commenter states that the timing of future annual tests in Condition IX.G.1.a conflicts with the District's usual annual test timing, which is based on the month of the District permit renewal. This could result in the source being subject to two periods of source testing in a year. The commenter recommends that annual source tests be conducted as specified in the FDOC.

In addition, the term "normal operations" should be defined.

Response: Condition IX.G.1.a in the Proposed Permit is EPA's standard source testing condition. We agree that it is preferred that these overlapping conditions are met at the same time. However, in Response to Comment 29, we have revised the annual testing requirement for the Project. We believe this revised condition provides sufficient flexibility for the Facility to avoid overlapping testing requirements.

Further, as noted in our Response to Comment 24 above, EPA regards any period of operation that is not shakedown, startup, shutdown, or malfunction to be normal operation.

31. **Comment**: Regarding Condition IX.G.1.a.ii, the commenter states that it is not clear if there is a stack available from the cooling system that meets the usual requirements for stack testing.

Response: There are few, if any, cooling tower stacks that are designed to meet EPA Method 1 criteria. In the late 1980s EPA developed a chromium test method that combined the features of the Cooling Technology Institute's test method and a modified EPA Method 306. However, the Agency never published the method. EPA has reviewed the Cooling Technology Institute's, Acceptance Test Code (ATC 140) - Isokinetic Drift Measurement Test Code for Water Cooling Tower (also referred to as the Heated Bead Isokinetic (HBIK)) test procedure and believe it provides the appropriate directions to obtain an isokinetic sample and we have approved its use to determine drift rates from cooling towers. Comparative testing has shown no significant differences between the HBIK and modified EPA Method 306.

For drift testing, EPA has no preference between the use of CTI ATC 140 or a modified EPA 306. However, because of a lack of specific test procedures, the permittee must submit a test protocol to EPA for review and approval to ensure that testing and operational parameters, including isokinetic conditions, are met.

32. **Comment**: In Condition IX.G.1.c.iii, the commenter believes the correct test method is Method 3A not 3B.

    Response: EPA agrees and has made this change in the Final Permit.

33. **Comment**: Regarding Condition IX.G.1.d.ii, the District classifies sources as a "high NO_2 emitting site" or "low NO_2 emitting site" with each source test. The condition should be revised to be consistent with the District's procedures.

    Response: EPA agrees and has made the suggested change (replacing "emissions" with "emitting") in Condition IX.G.1.d of the Final Permit.

34. **Comment**: With respect to Condition IX.G.1.e.i, the commenter states that for 40 CFR Part 75, RATA testing is done at "normal" load.

    Response: This condition allows the permittee to use a RATA in lieu of conducting the required NO_x performance test. While RATAs are conducted at normal load, performance tests are required to be conducted under conditions that cause the highest rate of emissions. As such, we have not revised this condition.

35. **Comment**: The commenter suggests that Condition IX.G.2.a.i be clarified as to whether the permittee or an independent laboratory is to do the testing.

    Applicant's comments: The permit condition indicates that the permittee is to do TDS testing. There is no reason to require testing by an outside lab.

    Response: EPA assumes the commenter is referring to Condition IX.G.2.a of the Proposed Permit, not Condition IX.G.2.a.i, which does not exist. Condition IX.G.2.a requires weekly tests of the blow-down water quality. The permittee is responsible for ensuring the water is tested and records of the results maintained. The permittee can do this by performing its own test or sending out a sample for laboratory testing. We have not revised the condition.

36. **Comment**: Regarding Condition IX.H.4, the commenter recommends that the semiannual reporting requirements be synchronized to the extent possible with the District's Title V reporting dates, which are March 1 and September 1 each year.

Applicant's comments: Generally, the applicant supports and concurs with the comments submitted by the District. In particular, the applicant urges EPA to align periodic requirements (testing, reporting, etc.) with applicable federal requirements such as Acid Rain and NSPS, as well as those already imposed by the District in the FDOC. For example, the District has given all semiannual compliance reports under Title V in the District the same due date. EPA should remove conflicting reporting due dates from the PSD permit, and rely on the Title V reporting schedule.

Response: Condition IX.H.4 requires the facility to submit "a written report of all excess emissions and any other noncompliance with permit conditions" on a semi-annual basis. The reporting periods in the Proposed Permit and title V permits are identical: January through June, and July through December. The only difference is the time allowed for sources to compile and submit their data. The District's permit allows 60 days, while EPA's Proposed Permit allows 30 days. Because the amount of information included in our reporting requirement is narrower in scope than the District title V reporting requirement, we believe 30 days is sufficient time for the applicant to prepare its submittal, and this time frame will provide us data in a timely manner. We also prefer that this permit be consistent with other PSD permits issued by Region 9, which allow 30 days for the compilation and submittal of excess emissions data. We have not revised the permit in this regard.

The applicant's comment concerning the desire to align the timing of periodic testing and monitoring requirements in the Proposed Permit with District permit requirements does not identify which of the Proposed Permit's provisions it believes should be aligned with particular District permit requirements or explain how any such modified timeframes would be consistent with the PSD requirements in the permit. Therefore, we cannot provide further response to this comment.

37. **Comment**: The commenter states that Condition IX.I should be clarified to indicate whether the 90-day limit is based on operating days or consecutive calendar days. The vagaries of initial startups may result in long periods of inactivity.

Response: As the commenter's request, we have revised Condition IX.I so that the shakedown period is clarified to be "90 consecutive days".

Comments Submitted by the Sierra Club

38. **Comment:** The commenter asserts that the particulate matter (PM, PM_{10} and $PM_{2.5}$) BACT limit lacks a basis in the record. The permit establishes a limit of 0.0065 lb/MMBtu (HHV) on a 9-hour average for PM, PM_{10} and $PM_{2.5}$. The basis for this limit does not appear in the Region's Fact Sheet. Nor is it apparent anywhere else in the record. In the Fact Sheet, the

Region says that it evaluated "recent PM performance test data from other similar simple cycle plants in southern California." The test data that the Region refers to, however, are significantly lower than 0.0065 lb/MMBtu. The data in the Fact Sheet show averages from 0.0008 lb/MMBtu to 0.0049 lb/MMBtu, with three of the five plants averaging 0.0031 lb/MMBtu. The Fact Sheet does not explain how the Region derived a 0.0065 lb/MMBtu limit based on these emission data. The proposed limit represents more than eight times the average from El Cajon Energy and is higher even than even the maximum from the Region's data: Orange Grove Unit 2 (0.0049 lb/MMBtu). The BACT limit should be based on the lowest rate achieved in practice with the same technology (efficient combustion)—0.0008 lb/MMBtu.

The commenter states that even assuming that the Region should set the limit based on the highest emission rate from similar facilities, 0.0065 lb/MMBtu is well above the emission data the Region provided in the record. To the extent the Region intends to include a "margin" above demonstrated emission rates, it must do so on an adequate record and with sufficient explanation. That record and explanation does not exist here. Additionally, the record does not explain why a 9-hour averaging period is appropriate, especially where the emission data reviewed by the region for other combustion turbines are likely based on measurements taken over shorter periods.

Response: When making a PM BACT determination for natural gas-fired combustion turbines, EPA must set a limit that is technically feasible to meet on an ongoing basis. In this particular case where the emission unit does not use add-on control equipment, it is not appropriate to set the limit based on the lowest emission rate measured during a single source test for other equipment. The two primary contributors of PM emissions from natural gas-fired turbines are the sulfur content of the natural gas and the burning off of various lubricating oils. The quantity of PM emissions produced by this oil is low in new turbines, but increases over time until maintenance is performed. Following maintenance, PM emissions produced by the oil decrease, and this cycle of increasing and decreasing PM emissions produced by the oil repeats over time as periodic maintenance is performed. Therefore, the PM BACT limit that EPA sets must account for this PM emission variability. While the sulfur content of the natural gas to be used in the Project is limited to 0.25 grains per 100 dscf on an annual average, the sulfur content of the fuel used in the referenced source test data is unknown.

The commenter states that "the BACT limit should be based on the lowest rate achieved in practice". As described above, the final limit that is chosen must consider several factors, including the ability to achieve the limit under varying normal operating conditions and over the life of the equipment. The fact that an emission rate is measured in a single source test does not mean that the emission unit will be able to achieve that rate on an on-going basis. In fact, the source test data that EPA presents in the Fact Sheet also shows measured amounts much higher than 0.0008 lb/MMBtu, yet all tests were conducted on the same model turbine (GE LM6000). Some of these turbines are subject to the same PM_{10} emission limit of 3.0 lb/hr – Orange Grove Units 1 and 2, and El Cajon Energy Unit 1. This demonstrates that source test results vary, even on identical turbine models, based on actual operating conditions including fuel sulfur content and how recently turbine maintenance was performed. It is also important to note that the referenced source test data are a different turbine model and size than the turbines for the PPEC – the LM6000 has a nominal rating of 50 MW and the LMS100 has a nominal rating of 100 MW.

As discussed in more detail in Responses to Comments 3, we have modified the PM limits in the Final Permit. Considering the lack of test data for the specific turbine model we are evaluating, we do not believe there is sufficient evidence to set a PM BACT limit lower than the 0.0065 lb/MMBtu and 5.5 lb/hr limit in the Final Permit.

Also, as explained in more detail in our Response to Comment 19, we initially specified a 9-hour averaging period to make explicit the circumstances needed to properly conduct the required compliance testing. Given the inherently low PM emissions expected from the turbines, a longer sampling time is needed for each test run since PM emissions are generally below the detection limit when using-one hour sampling times. The requirement to conduct a three-hour sample run increases the accuracy of the results.

39. **Comment:** The commenter states that combined cycle gas turbines are technically feasible for the Project. In the Fact Sheet, the Region contends that using CCGT is not technically feasible because:

- The purpose of the project is to supply SDG&E with energy to meet SDG&E's 2009 Request for Offers and resulting contractual requirements.
- The Request for Offers and contract with SDG&E requires the applicant to "support[] renewable power generation… whose overall output varies," requiring the applicant "to come online quickly to make up the lost grid capacity."
- To fulfill its contractual obligation, the applicant must therefore construct units that can provide energy during morning and evening "ramps," can be repeatedly started and shut down," and can be brought online quickly (even from a cold start).

The commenter asserts that the Fact Sheet then states that because of the longer startup process, a CCGT cannot complete a cold start as quickly as a combustion turbine (CT). Specifically, the Fact Sheet states that a complete (cold) start for a CT is less than 30 minutes, whereas the cold start period for a CCGT is up to 3.5 hours. This does not demonstrate technological infeasibility.

Response: EPA disagrees with the commenter that combined cycle gas turbines are technically feasible for this project for the reasons explained in detail in our Fact Sheet. For example, EPA has long held that when assessing the technical feasibility of a control technology, it is appropriate to consider whether the technology may reasonably be deployed on, or is applicable to, the source type under consideration. Our Fact Sheet for the Proposed Permit clearly explained that the longer startup times are not compatible with the operational characteristics of the proposed facility and that these technical difficulties would preclude successful deployment of a combined cycle operation in this case. Because the commenter did not explain why he believes the Fact Sheet does not demonstrate technical infeasibility, we cannot provide a more detailed response. See also Responses to Comments 40 and 41 below.

40. **Comment:** The commenter states that the project "purpose" in EPA's Fact Sheet does not match that in the facility's application to the CEC. EPA's Fact Sheet does not appear to rely on the additional wear to combined cycle units from frequent startups to find CCGT technology infeasible, although that issue is mentioned. See Fact Sheet at17. Any such finding would require, at a minimum, actual documentation in the record that the number of startups expected would render the technology infeasible, instead of merely more costly due to increased maintenance needs. The latter, which is more likely, would be considered in the cost effectiveness analysis but would not render the technology infeasible. First, according to the application that the Pio Pico plant submitted to the CEC, the "purpose" is not to provide 300 MW of peaking power. Rather, the purpose according to that application includes a "minimum of 100 megawatts (MW) of peaking and intermediate-class resources." CEC Staff Report at p.3-1. According to EPA's Fact Sheet, a 107FA power block combined cycle plant can achieve quick start capacity of at least 160 MW. That technology would fulfill the energy requirement in the project "purpose" of at least 100 MW.

Applicant's comments: While this statement is correct, it is out of context and, as a result, subject to misinterpretation. The project's purpose is to provide 300 MW of peaking and intermediate-class resources consistent with SDG&E's RFO. A more complete statement of SDG&E's criterion related to plant capacity is that SDG&E was seeking projects with a minimum of 100 MW, and up to 400 MW of capacity.

Response: The statement cited to by the commenter originates from SDG&E's June 2009 Request for Offers (RFO). The commenter is referred to page PSD – 3.2 of the PSD permit application, which contains an excerpt from the RFO. In part, it states:

> Product 2 - New Local Generation Projects, online in 2010 – 2014.
>
> SDG&E seeks a minimum of 100 MW of peaking or intermediate-class resources as new construction or expansion projects within SDG&E's territory. Any resulting contract will be a tolling agreement with a term of 20 years…

In response to this RFO, the applicant proposed to construct a 300 MW power plant and SDG&E subsequently accepted that offer by establishing a 20-year power purchase agreement with the applicant. In our view, the statement that the Project should include "a minimum of 100 megawatts" merely specifies a minimum requirement for any offers that SDG&E would consider during its procurement process. The Project is appropriately defined at this time, and for our current purposes, by the applicant's ultimate contractual obligation and its proposal to meet that obligation, which in this case is a 300 MW generating facility. For the reasons we have already explained in detail in our Fact Sheet and in our Response to Comments 39 and 41, we do not believe a combined cycle plant is technically feasible in this case.

We note that our determination that combined-cycle units are not technically feasible does not rely on additional wear on combined-cycle units, but the fact that the longer startup times are not compatible with the operational characteristics of the proposed facility. The Fact Sheet explained that even if the necessary startup times were available the additional wear on the combined-cycle equipment may make them infeasible. We agree this would likely be a matter of cost feasibility. The commenter is generally referred to Table 2 of the applicant's April 13, 2012 letter which shows the higher annual maintenance costs for two combined-cycle configurations (the GE 7FA.05 and the Siemens SGT6-5000F) when compared to the LMS100.

41. **Comment:** The commenter argues that the Region's own analysis highlights why a CCGT is not actually technologically infeasible. Moreover, even if the project purpose required the ability to achieve a full 300 MW within a short (~30 minutes) period, a CCGT, either alone or when paired with a supplemental simple cycle turbine, fulfills that project purpose while offering the increased efficiency and therefore lower emissions of a combined cycle unit.

The commenter states that a CCGT consists of one or more gas turbines, followed by a heat recovery steam generator (HRSG) that turns the waste heat from the CT combustion into steam that produces energy. The front half of a CCGT, however, is the same as the simple cycle CTs in the draft permit. Thus, the project purpose could be met with a CCGT that is sufficiently sized so that it could produce 300 MW with the turbines alone in 30 minutes (and ~100 MW in 10 minutes), while also allowing the turbines' fuel use and operating rate to be scaled back after the HRSG comes online. In other words, making a CCGT meet a project purpose of 300 MW of quick-start energy production simply requires the appropriate sizing of the plant so that the turbines provide the quick-start capacity needs before the additional capacity of the HRSG is available.

The commenter further states that properly sizing the plant provides both the faster start time for the full 300 MW (if that were the project purpose), while also providing the opportunity for lower fuel usage per MW after the steam cycle is brought online a few hours after cold start occurs. In other words, by increasing the size of the turbines or using an additional turbine, the plant could provide the full needed capacity immediately, and for the first 1-3 hours of operation, with just the turbines; however, by designing a HRSG into the system, once the system was warmed up and synchronized, the turbine fuel use could be scaled back and/or one or more turbines taken off-line as the HRSG generates some of the required energy. This could be done in a number of different ways—none of which were analyzed for the draft permit. First, the plant would be constructed as a 2x1 CCGT paired with a single simple cycle turbine. This allows the three turbines with a combined capacity of 300 MW to be fired and reach capacity over a short time period while the HRSG is being prepared. Once the HRSG is prepared and ready for operation, the simple cycle turbine can be turned off and its generation provided by the HRSG. Second, with appropriate engineering upgrades, see Henkel, et al., supra, all three of the planned combustion turbines can deliver close to their rated capacity quickly while also allowing them to be ducted to a single HRSG in a 3x1 formation.

The commenter also argues that the examples used in the Fact Sheet are not representative of all CCGTs. The Region's Fact Sheet notes that a GE 107FA power block CCGT could only provide 160 MW of power in 30 minutes, compared to the 300 MW that the proposed three CTs could provide. However, with certain upgrades, a 400 MW CCGT can reach full power within 40 minutes after a cold start. See Henkel, et al., Operational Flexibility Enhancements of Combined Cycle Power Plants, Siemens AG (2008).

Applicant's comments: This comment suggests that the project's response time goal could be met by building a much larger (approximately 600 MW) combined cycle plant and using the gas turbine portion for demand response. This would conflict with another project objective - to build a project that is responsive to SDG&E's RFO. A 600 MW combined cycle unit would not have been responsive to SDG&E's RFO.

This comment misstates what Henkel's document says. In Henkel's report, the 40-minute startup is a "hot" start, not a cold start.

Response: As evidenced by the opening paragraph to this comment, the commenter's primary concerns appear to be achieving the greater efficiency and lower emissions that are sometimes associated with combined cycle facilities. While these are appropriate considerations, we continue to believe that a combined cycle plant is not technically feasible for this particular project and, even if it were technically feasible, the commenter has not shown that it would be any more efficient than the proposed simple cycle design. The commenter suggests, for example, that a combined cycle plant could be sized so that it is capable of producing 300 MW in the first 30 minutes without the aid of the HRSG and steam generator. The commenter then suggests that once the HRSG and steam generator are fully functional, the fuel supply could be scaled back. We find this notion to be ill-supported and unpersuasive. To follow the commenter's suggestion would be to grossly oversize the facility and require the applicant to procure, construct, and maintain additional generating capacity that it may never use and that is inconsistent with the power purchase agreement that serves as the fundamental basis for the project. Furthermore, gas turbines (whether simple cycle or combined cycle) are much less efficient when operated at lower loads. The commenter has not demonstrated that a combined cycle plant that is larger than necessary but then operated at partial loads would be more efficient than this Project. We also note that the commenter has misrepresented what the Henkel report says. The report in fact states that with certain upgrades, a start-up time of less than 40 minutes is possible for a 400 MW combined cycle plant after an overnight shutdown. This describes hot start, not cold start conditions. As a result, we have not modified the permit in response to this comment.

42. **Comment:** The commenter argues that the Fact Sheet does not establish a basis for determining that 5,600 ppm TDS limit is BACT for the cooling water system. In the BACT limit for the recirculating water cooling system the Region assumes a drift rate of 0.001% and explains that a lower drift rate for wet cooling is not representative of a semi-dry cooling system drift. However, the drift rate is only part of the equation. The concentration of solids in the circulating water also determines the particulate matter emission rate. The

Region provides no basis for its decision to limit TDS in the cooling tower water to 5,600 ppm.

The commenter asserts that a lower TDS concentration results in lower particulate matter emissions. The commenter states that water filtering can reduce TDS to nominal values, yet the Region's BACT analysis fails to consider any filtration to reduce TDS as part of the BACT analysis. Modern filtration technologies for recirculating water can reduce dissolved solids to nominal concentrations. Doing so would significantly reduce the particulate emissions (PM, PM_{10} and $PM_{2.5}$) from the cooling system at the plant. This was not considered in the Fact Sheet or in EPA's review.

The commenter states that the application shows that the two sources of water to be used at the plant (recycled and potable) have TDS concentrations of 887 and 545 ppm, respectively. It is unclear how the Region derived 5,600 ppm from these sources. In fact, nowhere in the permit record is any apparent consideration of filtration of these sources prior to use in cooling water, which would further reduce the TDS concentrations. While the application states that the upper limit of TDS in the system design is "<5000" ppm, it does not identify the actual concentration, nor discuss whether this considers the use of filtration and reverse osmosis or why the cooling water concentration of TDS cannot be reduced through available filtration technologies.

The commenter further states that most cooling towers have a TDS upper limit of 2,000 ppm. (Stainless steel tubes often can stand only up to 2,400 ppm TDS.) Any concentrations above 2000 ppm usually result in automatic blowdown of the cooling water into a sewer, water treatment, or other use. In other words, the TDS limit used in the BACT analysis here is almost three times the typical technological maximum TDS concentration that most cooling towers are limited to.

Applicant's comments: This statement is not correct. The basis is in the permit application; this is the design TDS in order to minimize water use at the facility. The water system is designed to minimize plant water use. Lowering the TDS level of the circulating cooling water results in an increase in water consumption and wastewater production.

(re : "most cooling towers have a TDS upper limit of2,000 ppm") Sierra Club offers no support for this statement and, in fact, this statement is not correct. AP-42 shows a range of 380-91,000 ppm for TDS levels in cooling towers.

Response: The TDS limit is needed as a permit condition to ensure the Project is operated under the conditions used to evaluate the Project's emissions and thus to ensure compliance with the resulting BACT limit – 0.001% drift rate. Emissions from the cooling tower were very conservatively estimated, assuming the circulating water is always at the maximum TDS limit of 5,600 ppm, yet potential emissions are only 1.4 tpy of PM, PM_{10},and $PM_{2.5}$. The Fact Sheet (p. 24) makes clear that the 5,600 ppm TDS limit was included to ensure that the 0.001% drift rate determined to be BACT for the cooling tower is achievable. The TDS limit was not intended to itself reflect a BACT limit separate from the drift rate limit. The TDS limit is a design parameter set by the manufacturer of the cooling tower.

Through the use of water filtration, the commenter suggests that a lower TDS limit should be considered as BACT because a lower concentration of solids in the circulating water would allow for lower PM emissions from the cooling tower. However, the commenter provided no supporting information for its assertions regarding modern water filtration technologies for circulating water, what TDS limits are being achieved by these technologies, or the actual emission reductions that could be achieved by such systems. It is unclear how this broad argument should change the Region's determination. We were not able to find any information regarding the TDS limits of such systems or the emissions reductions being achieved.

Second, Table 3.5-5 of the Application shows that the average of the TDS of the makeup water will be 887 or 545 ppm. It is not expected that these values directly correlate to the TDS concentration of the circulating water.[5] The TDS concentration of the circulating water increases over time due to evaporating water and particulates entrained from the air. The TDS limit represents the upper limit of the amount of TDS that is allowed to accumulate in the circulating water for this particular system. Filtering the makeup water would have no effect on the manufacturer's designed upper operating limit for the cooling tower.

Third, the commenter did not provide supporting information for its assumption that "most cooling towers have a TDS upper limit of 2,000 ppm". For example, the Region has issued PSD permits with TDS limits of 8,190 and 5,000 ppm (Caithness Blythe II and Palmdale Hybrid Power Project, respectively).

In addition, the application contains a general comparison of the environmental, energy and cost impacts of the chosen partial dry cooling system with the other identified technologies. This analysis ranked partial dry cooling as the top technology, even though it has higher energy and cost impacts, because it minimizes water use and wastewater treatment requirements (see Table 1E.14 on page PSD-App-1.94).

Without any supporting information, it is difficult to further consider the general assertions provided by the commenter, which do not provide a sufficient basis on which to establish BACT limits that could be consistently achieved in practice by the Project. The facility will mostly rely on a dry cooling system to meet its cooling needs, which does not generate any emissions and minimizes water use at the facility. We find that the applicant has adequately balanced the collateral impacts associated with the facility's cooling needs, including the minimization of water use and wastewater discharge, which has resulted in very low potential emissions from the cooling system – 1.4 tons per year of $PM/PM_{10}/PM_{2.5}$. As such, the proposed cooling system for the facility is appropriate, consistent with past PSD permits issued by the Region, and meets BACT.
However, we have revised the TDS limit in the Final Permit to be consistent with the manufacturer's design parameter for TDS of <5000 ppm as provided in Table 3.5-6 of the application. Elsewhere, the application identifies the TDS limit of the system as 5600 ppm, but doesn't identify a specific basis for that value. We believe it is appropriate to set the

[5] Please see our Response to Comment 2, which corrects an error in the Proposed Permit that identified the TDS limit as applying to the makeup water instead of the circulating water.

TDS limit as the upper operating limit identified by the manufacturer. See Conditions IX.B.1 and IX.D.3.

43. **Comment:** The commenter asserts that the GHG BACT limit should include a shorter averaging time. The draft permit's BACT limit for GHG emissions (specifically CO_2 emissions) from the combustion turbines is based on an average of 8,760 operating hours. However, according to page 7 of the draft permit, each turbine is only permitted to operate 4000 hours per year. That means compliance is based on an average that extends more than two years. In fact, if used only as backup to other generation, the actual operating hours will likely be fewer, so compliance will likely be based on an average spanning three or more years. EPA's guidance on Practical Enforceability, http://www.epa.gov/region9/air/permit/titlev-guidelines/practicalenforceability.pdf, suggests that limits on potential to emit be averaged over short time periods that are no longer than one day or on a rolling basis calculated no less frequently than every day. One concern is the need to wait multiple years before compliance can be determined, at which time it may be too late to take corrective actions that could have minimized the violation. There is no reason that this EPA guidance should only apply to PTE limits. It should apply equally to the GHG limit here.

    The commenter also states that it is highly unusual (if not unprecedented) for a BACT limit to include an averaging period that spans more than two years of operation. The CO_2 emission limit should be calculated based on a shorter averaging period, such as 24 hours or at most 30 days. The commenter notes that EPA has proposed to average emissions over 12 months in the proposed New Source Performance Standard for certain generating units. While this may still be too long for the plant at issue here, it is significantly shorter than the 2-3 years that the draft permit limit will be averaged over.

    Response: As a general matter, EPA believes that annual averaging periods are appropriate for GHG limits in PSD permits because climate change occurs over a period of decades or longer, and because such averaging periods allow facilities some degree of flexibility while still being practically enforceable. However, as explained in Response to Comment 13, we are revising the GHG emission limit, and as a result, we no longer believe that an annual averaging period is necessary for this permit. Instead, we are basing compliance with the revised limit on a rolling 30-day average, as proposed by the applicant. We continue to believe that it is appropriate to calculate the average in terms of operating hours rather than discrete days. Thus, the revised averaging period is 720 operating hours. While we recognize that it may take some time initially to accrue 720 hours of operation, once that occurs, the rolling average will be calculated on an hourly basis. This is consistent with the commenter's reference to the EPA guidance document on Practical Enforceability and its suggestion for a rolling average that is calculated no less frequently than once per day. We believe the averaging period we are now finalizing is protective of the environment and addresses the commenter's concerns.

44. **Comment**: EPA should not use a monitored three-year 98% average concentration as background when combined with a 98th percentile of modeled concentrations to determine cumulative impact. According to the Fact Sheet, the background concentration used in

EPA's 1-hour NOx NAAQS analysis was determined based on the 98th percentile average of three years. (Fact Sheet p. 36.) If this is true, the facility's modeled impact (98th percentile of 3 year average for NOx) would be added for a cumulative impact that does not represent the worst case (as required by the Modeling Guidelines).

According to EPA's own guidance, a combination of the modeled 98th percentile and the monitored/background 98th percentile does not represent the maximum 98th percentile of total impacts and therefore not protective of the NAAQS. Therefore, EPA guidance cautions that if the 3-year 98th percentile design value is used as background, then the modeled concentration used in the cumulative impact analysis should be the average of the highest modeled concentration—not the 98th percentile concentration. See e.g., Memorandum from Stephen Page, Modeling Procedures for Determining Compliance with PM2.5 NAAQS at p. 8 (March 23, 2010). Alternatively, if the modeled result is expressed based on the form of the standard (e.g., 98th percentile), then it should be added to the single highest monitored value and not the 98th percentile of the monitored values. See Memorandum from Anna Marie Wood, EPA OAQPS, General Guidance for Implementing the 1-hour NO_2 National Ambient Air Quality Standard in Prevention of the Significant Deterioration Permits, Including an Interim 1- hour NO_2 Significant Impact Level at p. 18 (June 28, 2010).

Therefore, because EPA's air quality impact analysis appears to fail to account for maximum possible ambient concentrations due to the form of the standard, the analysis must be redone. Once redone, the results must be included in a new public notice and EPA must provide for a new public comment period.

Response: EPA believes that that the air quality impact analysis for PPEC is consistent with applicable Clean Air Act requirements and EPA guidance, and disagrees with the commenter that the analysis must be revised and reissued for public comment.

Contrary to the commenter's assertions, neither the applicant nor EPA used a monitored three-year 98% average concentration as background and combined it with a 98th percentile of modeled concentrations to determine cumulative NO_2 impact, nor does the PPEC Fact Sheet state that this is the case.

Although this method was not used, we note that the form of the new 1-hour NO_2 standard does have implications regarding appropriate methods for combining modeled ambient concentrations with monitored background concentrations for comparison to the 1-hour NO_2 NAAQS in a cumulative modeling analysis. As the commenter notes, EPA issued a 1-hour NO_2 modeling guidance memo in June 2010 ("Memorandum from Anna Marie Wood, EPA OAQPS, General Guidance for Implementing the 1-hour NO_2 National Ambient Air Quality Standard in Prevention of the Significant Deterioration Permits, Including an Interim 1- hour NO_2 Significant Impact Level"). On page 18, this memo states:

> As noted in the March 23, 2010 memorandum regarding 'Modeling Procedures for Demonstrating compliance with $PM_{2.5}$ NAAQS'…,' combining the 98th

> percentile monitored value with the 98th percentile modeled concentrations for a cumulative impact assessment could result in a value that is below the 98th percentile of the combined cumulative distribution and would, therefore, not be protective of the NAAQS. However, *unlike the recommendations presented for $PM_{2.5}$*, the modeled contribution to the cumulative ambient impact assessment for the 1-hour NO_2 standard should follow the form of the standard based on the 98th percentile of the annual distribution of daily maximum 1-hour concentrations averaged across the number of years modeled. (Emphasis added).

The June 2010 memo further states that a "first tier" assumption that may be applied without further justification is to add the overall highest hourly background NO_2 concentration from a representative monitor to the 'modeled design value' for comparison to the NAAQS. *Id*. The 1-hour NO_2 'modeled design value' refers to the highest (across all modeled receptors) of the 5-year average of the 98th-percentile (8th-highest) of the annual distribution of daily maximum 1-hour values based on representative meteorological data. In March 2011, EPA's issued another 1-hour NO_2 modeling memorandum ("Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard", Memorandum from Tyler Fox, EPA Air Quality Modeling Group to EPA Regional Air Division Directors), which supplements the earlier memo and offers another "first tier" method for how to combine modeled results and monitored background to determine compliance with the NAAQS. Specifically, on page 17 this March 2011 memo discusses the use of an alternative "first-tier" approach, which uses the 98th percentile of the annual distribution of daily maximum 1-hour values averaged across the most recent three years of monitored data as a uniform background contribution to be added to the 1-hour NO_2 'modeled design value'. We note that this technique is the same as the one the commenter asserts should not be used.

This March 2011 memo also offers other recommended approaches (pages 19 and 20) for incorporating background concentrations in the cumulative impact assessment for the 1-hour NO_2 standard. In the case of PPEC, the applicant and EPA relied on one of these approaches -- month-by-hour-of-day temporal pairing -- as an alternative background methodology for incorporating background concentrations from the Chula Vista monitor in the cumulative impact analysis. The March 2011 EPA guidance also recommends that if the monthly pairing is used, the first highest values from the distribution for each temporal combination should be used, which is what the applicant did.[6] Therefore, EPA believes that the applicant's overall approach to the 1-hour NO_2 analysis for the Project, including its method for combining modeled results with monitored values, is adequately conservative, and is based on methods recommended in EPA's latest 1-hour NO_2 guidance memo.

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[6] This month-by-day temporal pairing approach was also used in the additional cumulative impact analysis conducted by the applicant using NO_2 data from the El Cajon monitor. For the limited modeling analysis using the Otay Mesa NO_2 monitoring data, the applicant used another alternative approach recommended by the same guidance on page 19 --temporal pairing by season and hour of day. The applicant also followed the guidance recommended for this approach, which is to use the 3rd highest value for each season and hour-of-day combination in the evaluation period.

45. **Comment:** The background concentrations used in EPA's NAAQS analysis do not meet the requirements of the Guidelines and are not representative. The NO_x and particulate matter (both PM_{10} and $PM_{2.5}$) background concentrations used by EPA are from a monitor located 9 miles northwest of the site at an urban location referred to as Chula Vista. This location was apparently chosen because a closer existing monitor was located close to the Mexico-United States border and influenced by vehicle emissions blowing in from Mexico. However, EPA has not:

- explained why consideration of air quality impacts from Mexican vehicles should be avoided when determining background concentrations near the Pio Pico plant site;

- determined that the vehicle emissions monitored by the Otay Mesa-Paseo International station are not representative of the air quality anywhere within the area that will be impacted by the Pio Pico plant;

- considered requiring the applicant to collect site-specific monitoring, which is supposed to be the default option under agency guidance and the binding Modeling Guidelines; or

- shown that the background air quality from a monitor located 9 miles away, with likely little or no impact from vehicle emissions, is a better representation of air quality in the Pio Pico's plume.

The Region must provide a better explanation for why it chose the Chula Vista monitor—specifically, why that monitor is representative of the ambient air at and around the areas of peak impact from the proposed Pio Pico plant.

We note that the wind rose data in the record shows that the prevailing winds are rarely from the area northwest of the plant site (where the Chula Vista monitor is located). Instead, the predominant winds are from the northeast or southwest. A significant number of hours appear, from the wind roses in the record, to come from Mexico. This means that background concentrations including emissions from Mexico are likely more representative then monitoring results from the Chula Vista monitor.

Moreover, the Chula Vista monitor does not appear to meet the requirements for substituted existing regional monitoring data. First, the Chula Vista monitoring station does not meet the requirements for the use of an off-site monitor. PSD permitting must include an analysis of the permittee's air quality impacts, combined with the impacts from nearby sources and background concentrations. NSR Manual at C.3; Ambient Monitoring Guidelines § 2.4.1, at 6-8; see also 42 U.S.C. § 7475(a)(7), (e); 40 C.F.R. § 52.21(m)(f). There are limited instances where background concentrations can be taken from existing regional monitors (such as the Chula Vista station here).

However, to do so, specific criteria of location, data quality, and the currentness of the data must be met by the existing monitor. See NSR Manual at C.18-.19. For example, if data from an existing off-site monitor are used, the monitor must be located in the area of maximum concentration increase from the proposed facility, the maximum concentration from existing sources, and the area of maximum combined impact from existing and new sources. Moreover, the applicant and the permitting agency must provide a specific basis in the permit record for using off-site monitors for background concentrations. These requirements are not met by the Chula Vista monitor.

Second, the Pio Pico site and the area of its peak impacts (especially 1-hour NO_x) are near to large international highways. As EPA's background documents for the 1-hour NO_x NAAQS make clear, the highest background levels of 1-hour NO_x are near to roadways. Impacts of regional monitors, that is, those located more than a few hundred feet from a major roadway, are expected to be 50 to 60% lower than the concentrations around transportation corridors. Thus, EPA noted when promulgating the 100 ppb 1-hour NO_x NAAQS, that if it were to rely on regional monitoring instead of concentrations closer to transportation sources, it would likely have set the standard at 50 ppb. Here, under EPA guidance and the binding Guidelines, the background concentrations for purposes of PSD NAAQS analysis should be from monitors located at the points of highest existing concentrations—which is almost certainly closer to the major international roadways near the Pio Pico plant than the Chula Vista monitor.

Response: The background concentrations used in the NO_2 and $PM_{2.5}$ cumulative impacts analyses[7] for the PPEC are appropriately representative for this source and consistent with EPA's Guideline on Air Quality Modeling, in Appendix W to 40 CFR Part 51 (GAQM or Appendix W) and EPA guidance.

EPA considered whether site-specific monitoring was required for PPEC and determined that it was not required. Generally, a source that is required to prepare a PSD cumulative impact analysis may be exempt from conducting site-specific preconstruction monitoring if emissions result in predicted impacts that are less than the Significant Monitoring Concentration (SMC) for a particular pollutant. 40 CFR 52.21(i)(5). We note that even where such predicted impacts are at the SMC or above, acceptable existing ambient data that are adequately representative of the areas that may be affected by emissions from a proposed project may be substituted in place of data generated through site-specific monitoring. In this case, the PPEC modeling predicted $PM_{2.5}$ impacts from the Project of 2.6 ug/m^3, which are less than the SMC for $PM_{2.5}$ (4 ug/m^3, 24-hour average), and NO_2 impacts of 0.3 ug/m^3, less than the SMC for NO_2 (14 ug/m^3, annual average). As a result of this showing, and the fact that existing data adequately representative of the air quality for the areas that may be affected by emissions from the proposed Project was available, EPA determined that its regulations do not require site-specific preconstruction monitoring in this case. Although the exemption in 40 CFR 52.21(i)(5)(i) applies to relieve the applicant in this case of the need to provide site-specific monitoring for $PM_{2.5}$ and NO_2, because the source in this case has a significant impact (*i.e.*, above the SILs) on 24-hour $PM_{2.5}$ and 1-hour NO_2 concentrations, it was still necessary in this instance for EPA and the applicant to identify a representative background concentration for the affected area to be used in an air

[7] As discussed in the Fact Sheet, PPEC impacts exceed the significant impact levels (SILs) only for 1-hour NO_2 and 24-hour $PM_{2.5}$, and EPA determined that cumulative impact analyses were required for only these two pollutants and averaging periods. The applicant nevertheless also conducted a cumulative impact analysis for annual $PM_{2.5}$.

quality modeling analysis to make the demonstration required by 40 CFR 52.21(k) that the source will not cause or contribute to a violation of the NAAQS. Consistent with Section 8.2 of Appendix W, a combination of ambient data and explicit modeling of nearby sources was used to determine background concentrations for purposes of estimating cumulative impacts for the NAAQS compliance demonstrations, as explained in more detail below.

The applicant used the Chula Vista monitor to provide ambient background data for both $PM_{2.5}$ and NO_2 for the cumulative impacts analyses for the PPEC, and also conducted some additional analysis of data for NO_2 from the Otay Mesa and El Cajon monitors to provide additional assurance that PPEC emissions would not cause or contribute to a violation of the 1-hour NO_2 NAAQS, as explained in more detail below. Given the overall approach to the modeling conducted in this case, and the specific characteristics of the monitoring sites and data that were considered, EPA believes that this approach provides adequately representative and appropriately conservative background data for the cumulative impacts analyses for $PM_{2.5}$ and NO_2, which would also be the case even if the emissions from the PPEC were above the SMCs for the relevant pollutants.

More specifically, with respect to the NAAQS analysis for 1-hour NO_2, the applicant's modeling analysis used background concentrations from the Chula Vista monitor, and also considered modeled impacts from relevant nearby existing sources and Project emissions, predicting a result[8] of 179 ug/m^3, below the 1-hour NO_2 NAAQS. While EPA determined that use of the Chula Vista monitor was generally appropriate for use in the 1-hour NO_2 NAAQS analysis for the PPEC, to provide additional assurance that PPEC emissions would not cause or contribute to violations of the 1-hour NO_2 NAAQS, as discussed in Section 8.2 of the Fact Sheet, EPA also requested that the applicant perform some additional NO_2 modeling using background data from other locations.

First, EPA requested that the applicant conduct an additional cumulative impacts analysis using El Cajon NO_2 data for all receptors closer to El Cajon than to Chula Vista. The applicant subsequently used a more conservative approach than that requested by EPA, and performed an additional cumulative modeling analysis using the El Cajon background data that considered all the receptors previously used when modeling with the Chula Vista data; this analysis also included modeling of relevant nearby sources as well as Project emissions. The cumulative modeling analysis using the El Cajon monitor predicted 1-hour NO_2 impacts of 173 ug/m^3, also below the 1-hour NO_2 NAAQS.

EPA also requested that the applicant use Otay Mesa background monitoring data to conduct a limited assessment of cumulative impacts of NO_2 at receptors within 0.5 km of the Otay Mesa monitor site, in order to further characterize the Project's NO_2 impacts in that specific area. This analysis also included modeling of relevant nearby sources and Project emissions. The 0.5 km radius was sufficient to include the impacts of roadway emissions because maximum roadway emissions are generally measured 50-100 m from a heavily travelled roadway. We also note that this range of distance is being proposed by the SDAPCD for the location of NO_2 monitors used in EPA's near-road NO_2 monitoring

[8] See Fact Sheet section 8.4.3.5 and Table 8-7.

program.[9] The results of this assessment showed no predicted impacts from the Project above EPA's interim 1-hour NO_2 Significant Impact Level (SIL)[10] at the Otay Mesa monitor site, and only one receptor that had a Project impact above the interim 1-hour NO_2 SIL within 0.5 km of the Otay Mesa monitoring site. The predicted 1-hour NO_2 impact from the modeling using the Otay Mesa ambient monitoring data was 164 ug/m^3, again below the 1-hour NO_2 NAAQS and less than the predicted impacts for 1-hour NO_2 from the analyses using the El Cajon monitor (173 ug/m^3) and the Chula Vista monitor (179 ug/m^3).[11]

EPA determined that the NO_2 data collected at the Chula Vista monitor was adequately representative in general of background concentrations for the PPEC cumulative impact modeling for determining compliance with the 1-hour NO_2 NAAQS, based on location, currentness of data and data quality, consistent with EPA's GAQM. The Chula Vista site is located approximately 9 miles or 15 km from the Pio Pico Project site, with no intervening geological features that would affect regional dispersion of pollutants. The Chula Vista site is an urban site, and generally urban sites measure higher values than would be measured in the more rural area characterizing the Project site. Traffic at the Chula Vista site was estimated at 2,000 vehicles per day, which is less than the 5,900 vehicles per day at the Donovan Correctional Facility located next to the Project site; however, we did not consider this difference to be significant given the overall characteristics of the site including its urban location. Wind rose data shows that the winds blowing from the area of the Chula Vista site are from the west and west northwest around half the time, as discussed later in this section. In light of all these factors, EPA determined the location of the Chula Vista site to be adequately representative for purposes of the PPEC 1-hour NO_2 NAAQS analysis, particularly given that all relevant existing sources nearby the Project site were modeled as part of the cumulative impact analysis conducted to determine compliance with the 1-hour NO_2 NAAQS using the data from the Chula Vista site. The fact that the results of the additional modeling assessments that were conducted using monitoring data from the El Cajon site and, to a more limited extent, the Otay Mesa site, also showed impacts below the NAAQS, and less than the impacts shown using the data from Chula Vista, provided extra assurance that the data from the Chula Vista site was adequately representative and appropriately conservative. The NO_2 data collected at Chula Vista are current, from the period 2004-2008. We note that NO_2 monitoring data from Chula Vista from 2009-2011 show lower design value concentrations, and therefore using 2004-2008 data is a more conservative approach than would be the use of more recent data from this site. NO_2 data recovery for this monitor was over 90% and was therefore determined to be adequate.

As noted above, NO_2 data was also used from the El Cajon monitor, and to a more limited extent from the Otay Mesa monitor, to conduct additional analyses in order to provide further assurance that Project emissions would not or contribute to violations of the 1-hour

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[9] SDAPCD 2011 Ambient Air Quality Network Plan, Section 5, p.10 of 17 (June 30, 2012).

[10] The justification for the interim 1-hour NO_2 SIL is set forth in EPA's June 2010 memorandum cited above.

[11] As noted above in Response to Comment 44, EPA determined that the applicant's overall approach to the 1-hour NO_2 analysis for the Project, specifically including its method for combining modeled results with monitored values, is adequately conservative, and is based on methods recommended in EPA's latest 1-hour NO_2 guidance memo.

NO_2 NAAQS. The NO_2 data used from these monitors are current, from the period 2004-2008. As with the Chula Vista monitoring data, for these monitors, 2009-2011 data showed lower design value concentrations than 2004-2008 data, and thus the use of the 2004-2008 data was more conservative than the use of more recent data from the sites would be. NO_2 data recovery for these monitors was approximately 90% and was therefore determined to be adequate.

EPA determined the NO_2 data quality from all of these monitors to be adequate as the data was collected by the SDAPCD as part of its Ambient Air Quality Network Plan, which is required by EPA to be updated every year. SDAPCD performs quality assurance activities with the collection of this data. NO_2 data was collected with continuous instrumentation as required for gaseous pollutants.

The commenter suggests that background monitoring data from the Otay Mesa monitoring station would be more representative for purposes of the PPEC cumulative impacts analysis than data from the Chula Vista site.[12] As described above, at EPA's request, the applicant in fact used data from the Otay Mesa monitor to conduct a limited analysis of 1-hour NO_2 impacts from the Project at receptors within 0.5 km of the Otay Mesa monitor site. However, we disagree that the Otay Mesa data would be more representative in general of background concentrations for the PPEC cumulative impact analysis than data from the Chula Vista monitor. We noted in the Fact Sheet that pollutant concentrations recorded at the Otay Mesa monitoring station are heavily influenced by the emissions from hundreds of trucks queued and waiting at the Otay Mesa-Paseo International border crossing[13], and that in consultation with the District, the applicant instead chose the Chula Vista monitoring station, which is approximately 9 miles (15 km) from the Project site, to generally represent background air pollutant concentrations for the area near the Project site. As discussed in detail above, EPA determined that the general use of background data from the Chula Vista site was adequately representative and appropriate in this case, considering the fact that all relevant nearby sources were explicitly modeled in the analysis using the Chula Vista data, and also, in the case of 1-hour NO_2, considering the additional assurance provided by the results of the additional analyses conducted using NO_2 background data from El Cajon and Otay Mesa monitoring sites. The District's 2011 Ambient Air Quality Network Plan (Network Plan) gives further background information on NO_2 concentrations measured in the area with respect to the Otay Mesa monitor. In 2010, the Otay Mesa sampling location designation was changed from neighborhood scale to microscale and from representative concentrations to source impact, due to heavy truck traffic crossing the border within 100 m[14] of the sampling location. According to information provided in the Network Plan, the North American Free Trade Agreement (NAFTA) greatly increased the heavy truck traffic across the Otay Mesa border crossing. It is now the second busiest commercial truck border crossing in the United States and the busiest in California. The heavy duty vehicular emissions at the Otay Mesa site result in artificially high NO_2 levels compared to the region, and, according to the District, the present monitor is no longer measuring

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[12] We note that there is no $PM_{2.5}$ monitor at the Otay Mesa site.
[13] These emissions result from vehicles queued and waiting on both sides of the border crossing.
[14] Network Plan, Section 5, p.3 of 17.

representative concentrations for the regional area.[15] Because of this, in order to measure concentrations representative of the air quality in the south San Diego region, the District is actually proposing to decommission the Otay Mesa border location and relocate the station about 3.3 km northeast off the entrance road to the Donovan State Prison grounds sometime later in 2012 or 2013. The high impacts from the Otay Mesa monitor would be within 50-100 m of the edge of the nearest traffic lane of heavy truck traffic. These impacts would not represent the air quality in the area close to the Project, for instance, because the traffic counts are much lower in the area close to the Project (from 40,000 vehicles per day at Otay Mesa to 5,900 vehicles per day at Donovan, adjacent to PPEC). And, to the extent that the commenter is concerned about impacts from traffic near the border crossing, as noted above, the applicant's limited assessment of NO_2 cumulative impacts from the Project at receptors within 0.5 km of the Otay Mesa monitor site using the Otay Mesa background data showed compliance with the 1-hour NO_2 NAAQS.

Regarding the commenter's argument concerning the wind rose data, the wind rose information summarized by the commenter is inaccurate. The commenter states that the wind rose data in the record shows that the prevailing winds are rarely from the area northwest of the plant site (where the Chula Vista monitor is located), and that the predominant winds are from the northeast or southwest. The commenter further asserts that a significant number of hours appear, from the wind roses in the record, to come from Mexico, and that therefore background concentrations including emissions from Mexico are more likely representative than monitoring results from the Chula Vista monitor. In fact, the three-year average wind roses for both Chula Vista and Otay Mesa show winds from the west and west northwest around half the time, with winds blowing from the border area of the Otay Mesa monitor only around 15 percent of the time. Therefore, the airflow over the two monitors would be similar, and the prevailing winds come from the west and northwest where the Chula Vista monitor is located.

With respect to background monitoring data for $PM_{2.5}$, the PPEC cumulative impact analysis for $PM_{2.5}$ used data from the Chula Vista monitor; there is no $PM_{2.5}$ monitor at Otay Mesa. As discussed above, $PM_{2.5}$ project-only impacts were less than the SMC of 4 ug/m^3 (24-hour average), and therefore, along with the fact that existing data that was adequately representative of air quality for the areas that may be affected by emissions from the proposed Project was available, EPA determined that it was not necessary for the source to conduct site-specific preconstruction monitoring for $PM_{2.5}$. The closest District monitors of $PM_{2.5}$ are located at Chula Vista and El Cajon. EPA considered the Chula Vista monitor to be the most representative of the two monitors because it was closer to the Project site (only 9 miles instead of 15 miles as is El Cajon) and otherwise adequately representative for purposes of conducting the $PM_{2.5}$ cumulative impacts analysis for the PPEC.

[15] The Network Plan explains that the SDAPCD established this Otay Mesa monitor site in 1990 with the intent of measuring representative concentrations of all collected pollutants for the southern section of San Diego County, as well as capturing any northbound pollutant transport. However, the artificially high values have resulted in the District considering this monitor to be source-impacted and no longer representative. Network Plan, Appendix 10, p.1 of 7.

EPA determined that the data collected at the Chula Vista $PM_{2.5}$ monitor was adequately representative for determining background concentrations to be used in the cumulative impact modeling for determining compliance with the $PM_{2.5}$ NAAQS, based on location, currentness of data and data quality, consistent with EPA's GAQM. As noted above, the Chula Vista site is located approximately 9 miles or 15 km from the Pio Pico Project site, with no intervening geological features that would affect regional dispersion of pollutants. This monitor is the closest existing $PM_{2.5}$ monitor to the Project site. Wind rose data shows that the winds blowing from the area of the Chula Vista monitor are from the west and west northwest around half the time. In light of these factors, EPA determined the location of the site to be adequately representative, particularly in light of the fact that all relevant existing sources nearby the Project site were modeled as part of the cumulative impact analysis conducted to determine compliance with the $PM_{2.5}$ NAAQS.[16] The $PM_{2.5}$ data collected at Chula Vista is current, from the period 2004-2008. 2009-2011 $PM_{2.5}$ data from the Chula Vista site showed lower design value concentrations as compared with data from 2004-2008, thus the use of 2004-2008 data is more conservative than would be the use of more recent data from this site. EPA determined the $PM_{2.5}$ data quality to be adequate as the data was collected by the SDAPCD as part of its Ambient Air Quality Network Plan, which is required by EPA to be updated every year. SDAPCD performs quality assurance activities with the collection of this data. Data recovery for this monitor was over 88% and was therefore determined adequate.

The commenter argues that the Chula Vista monitor does not appear to meet the requirements for substituted existing regional monitoring data. The commenter states that the Chula Vista monitoring station does not meet the requirements for the use of an off-site monitor, because specific criteria of location, data quality, and the currentness of the data must be met by the existing monitor, citing EPA's 1990 Draft New Source Review Workshop Manual (1990 NSR Manual) at C.18-.19. In response, EPA has determined that the background monitoring data that were used were adequately representative in terms of location, data quality, and currentness for purposes of the cumulative impact analyses for the PPEC, as discussed in detail above. We have already addressed in detail above the specific points raised by the commenter concerning whether the location of the Chula Vista background monitor was adequately representative of the air quality for the areas that may be affected by emissions from the proposed Project. The commenter did not raise any specific issues concerning the currentness or data quality of the background data from Chula Vista that was used for the PPEC analysis.

The commenter further contends that if background data from an existing monitor is used, the monitor must be located in the area of maximum concentration increase from the proposed facility, maximum concentration from existing sources, and the area of maximum combined impact from existing and new sources, which appears to be based on language in section 2.4.1 of EPA's 1987 Ambient Monitoring Guidelines for PSD (1987 Guidelines). We disagree with the commenter's contention as applied to the facts of this case. First, we note that guidance documents on representativeness of data identify important factors to consider in evaluating the need for site-specific data collection, but do not dictate exactly

[16] We also note that the applicant modeled $PM_{2.5}$ as 100% of PM_{10}, which lends additional conservativeness to the overall $PM_{2.5}$ modeling approach.

when site-specific data must be used rather than data from nearby locations. *In Re Knauf Fiber Glass, GMBH*, 8 E.A.D. 121, 147 (EAB 1999). Further, the 1987 Guidelines themselves state that in situations where there is no existing monitor in such areas, monitors outside these areas may be used as determined on a case-by-case basis. 1987 Guidelines at p.6. Moreover, to the extent the 1987 Guidelines suggest that the use of existing background data is permissible only if it reflects all of the areas to which the commenter refers, or otherwise should be limited based on the discussion of specific examples provided in section 2.4.1 of the 1987 Guidelines, we do not believe that the language in the 1987 Guidelines is controlling here given the specific facts involved with the modeling that was conducted in this case, for the reasons discussed below.

Appendix W contemplates two methods to represent background concentrations in air quality modeling. Data from monitors may be used to reflect one component of the background concentration used in an air quality modeling exercise. 40 CFR Pt. 51, App. W, Table 8-2 n.9 ("Generally, the ambient impacts from non-nearby (background) sources can be represented by air quality data unless adequate data do not exist."); *id*. § 8.2.3.f. (referencing § 8.2.2 of Appendix W which describes air quality data from monitors); 72 Fed. Reg. 54112, 54141 (Sept. 21, 2007) (discussing this topic but referencing § 9.2 prior to a revision that moved this content to § 8.2). But background concentrations may also be represented by explicitly modeling the impact of "nearby sources." 40 CFR Pt. 51, App. W, §§ 8.2, 8.2.3.b; 72 Fed. Reg. at 54,141; *see also* 40 CFR Pt. 51, App. W, Table 8-2 (describing three types of source emissions data that are needed to complete a cumulative impacts analysis on a PSD permit application).

As a critical component of the cumulative impact analyses that were conducted for the PPEC using the data from the Chula Vista monitor, emissions from nearby sources expected to cause a significant concentration gradient in the vicinity of the PPEC, including, for example, the nearby Otay Mesa Power Plant, were explicitly modeled, in accordance with section 8.2.3 of Appendix W. These modeling analyses considered the emissions from these nearby sources along with modeled emissions from the PPEC and appropriately representative background data from the Chula Vista monitor reflecting natural background and other sources not explicitly modeled, as explained in detail above.[17] This modeling approach appropriately captured the maximum concentrations relevant for purposes of the cumulative impact analyses designed to ensure compliance with the applicable NAAQS, consistent with section 8.2.3.e of Appendix W, obviating the need for the background monitoring data to reflect all such concentrations as suggested by the commenter.[18] As a result, the analyses conducted in this case using the Chula Vista data are consistent with the principles from the 1987 Guidelines cited by the commenter and achieve the objectives reflected in these Guidelines in an alternative manner. Furthermore, the use of modeled emissions from nearby sources such as the Otay Mesa Power Plant, rather than background data in the immediate vicinity of those sources, is a more conservative approach to determining NAAQS compliance, because such modeling takes

[17] As mentioned above, the additional 1-hour NO_2 modeling analyses that were conducted using El Cajon and Otay Mesa background monitoring data also included modeling of relevant nearby sources and Project emissions along with consideration of background data.

[18] We also note that no one monitoring location would be able to capture all such concentrations in this case.

into account potential emissions, which could be higher than the actual emissions from the sources at issue that would be reflected in the background data. In sum, EPA believes that the background monitoring data from the Chula Vista monitor that was used for the PPEC cumulative impact analyses was appropriately representative for considering whether the PPEC's emissions would cause or contribute to a violation of the applicable NAAQS, when considering the overall modeling approach as discussed above.
Last, with respect to the commenter's reference to background monitoring data for PM_{10}, we note that PM_{10} is monitored at Otay Mesa and also at Donovan, in close proximity to the Project; however, since the initial Project-only PM_{10} maximum modeling impact was below the SIL for PM_{10} of 5 ug/m^3, EPA determined that a PM_{10} cumulative impact analysis was not required, and no such analysis was conducted for purposes of the PPEC PSD permit. Therefore, the use of monitoring background concentrations was not required in this case for PM_{10}.

Comments Submitted by Bob Sarvey

46. **Comment:** The commenter states that although he is on EPA's official notification list he failed to receive notice of this draft permit for the Pio Pico Energy Center. He learned about the permit a couple of days prior to submitting his comments from a friend who is engaged at the CEC proceeding for this project. The commenter officially requests an extension of one month to properly comment on this proposed permit. The commenter also requests a copy of EPA's environmental justice analysis for this project as it is not posted to EPA's website along with other critical material needed to assess this proposed permit. The commenter states that he is providing initial comments from his extremely cursory review of the draft permit.

Response: Due to an inadvertent mailing list error that EPA discovered upon receiving this comment, whereby several parties that had requested to receive public notice of proposed PSD permits in the area at issue were not provided individual notice of the Proposed Permit, EPA extended the public comment period for the Proposed Permit to September 5, 2012. EPA notified the commenter that the comment period would be extended in an email dated July 26, 2012.

This commenter also notified EPA by email on September 6, 2012 that although he had requested a copy of EPA's EJ Analysis for the Proposed Permit in his comment letter transmitted on July 24, 2012, he had not received a copy of the analysis, and he requested a copy of the analysis so that he could comment on it. Later that day, EPA provided the commenter with an electronic copy of the EJ Analysis for the Proposed Permit by email, but also explained that the EJ Analysis document had been available to the public in EPA's electronic docket on regulations.gov since the public comment period for the Proposed Permit started on June 20, 2012. EPA notified the commenter that although the public comment period closed on September 5, 2012, because he specifically requested the EJ Analysis from EPA on July 24, 2012 and EPA had not yet responded to that request, EPA was extending to him two additional weeks (until September 20, 2012) to comment only on the EJ Analysis for the Proposed Permit. EPA noted that it was not extending the public comment period for the Proposed Permit for the PPEC generally.

47. **Comment:** The EPA top down BACT analysis eliminates EMX for NOx control. On page 10 of the fact sheet EPA states:

With the exception of EMxTM, all of the available control options identified in Step 1 are technically feasible. EMxTM technology (formerly SCONOx) is a relatively newer technology that has yet to be demonstrated in practice on CTs larger than 50 MW. The manufacturer has stated that it is a scalable technology and that NOx guarantees of <1.5 ppm are available. However, this technology is designed to operate at a maximum temperature of approximately 700°F. Simple cycle gas turbines operate with exhaust gas temperatures of up to 1100° F, which exceeds the maximum temperature that EMx catalysts can tolerate while remaining effective.

GE has a low temperature SCR available for the LMS-100 turbine that can operate at temperatures less than 800° F. This option should be analyzed and discussed in the top down analysis as EMX can achieve lower NOx emissions without the collateral impacts from ammonia slip.

Response: Upon review of this comment, we have determined that the Fact Sheet over-generalized the typical exhaust gas temperatures for simple cycle turbines. In fact, the GE LMS100 turbines for the Project have an exhaust temperature of 770°F. Below, we further consider this technology in our top-down BACT analysis.[19]

EMx technology (formerly SCONOx) is a relatively newer technology that has yet to be demonstrated in practice on CTs larger than 50 MW. The manufacturer has stated that it is a scalable technology and that NO_x guarantees of <1.5 ppm are available.[20] As a result, EMx is considered technically feasible for this facility. However, it is unclear what NO_x emission limit can actually be achieved by the technology.

EPA has found only one BACT analysis that determined that SCONOx (the former name of EMx) was BACT for a large CT. However, the accompanying permit for the facility, Elk Hills Power in California, actually allowed the use of SCR or SCONOx to meet a permit limit of 2.5 ppm, and the actual technology that was installed in that case was SCR.

We also note that the Redding Power Plant in California, a 43 MW gas-fired CT, was permitted with a 2.0 ppm demonstration limit using SCONOx. However, it was determined that the unit could not meet the demonstration limit and, as a result, the limit was revised to

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[19] However, small amounts of SO_2 in the exhaust gas causes catalyst masking, which can only be addressed by periodically removing and washing the catalyst. This process requires additional turbine downtime and could interfere with plant operations. The City of Redding Power Plant in California has experienced catalyst masking, which required EMx system catalyst washings more frequently than anticipated during the first three years of operation. This resulted in substantial downtime of the combustion turbine with EMx. While these facts might weigh in favor of continuing to find EMx infeasible for this type of facility, in order to provide a complete permit record, we are continuing to consider use of the technology as BACT, as explained in the response.

[20] Information available at http://emerachemnew.ciplex.us/emx-product.html. See EMx White Paper 2008.

2.5 ppm.[21] Based on these two examples, it appears EMx has been demonstrated to achieve only 2.5 ppm of NOx, and we are therefore evaluating it at this limit.
As a result of the facts stated above, EMx ranks equivalent to SCR as the top-ranked technology proposed by the applicant (at 2.5 ppm of NO_x). We will now consider the collateral impacts to determine if either technology should be eliminated.
As noted by the commenter, there are potential collateral environmental impacts associated with ammonia slip from the use of SCR. The fact that a control device causes collateral environmental impacts does not necessarily argue against selection of that technology as BACT, particularly if the control device has been applied to similar facilities.

In this particular case, the proposed technology, SCR, is one of the most widely applied control devices for reducing NO_x emissions. Section 7.1.1 of the Fact Sheet includes a discussion of the environmental impacts associated with SCR, which explains the nature and magnitude of potential health concerns associated with ammonia emissions from the Project due to ammonia slip and how they are addressed and minimized, and concludes that the possible risks associated with onsite storage and use of ammonia do not appear to outweigh the benefits associated with the significant NO_x reductions from use of SCR. In addition, the use of SCR provides the benefit of more consistent energy availability, since use of EMx has been associated with substantial downtime for maintenance (see footnote 12).

Here, the commenter generally refers to the "collateral impacts from ammonia slip", but does not specify what impacts he believes EPA should consider. To the extent that the commenter is concerned about the health impacts of secondary $PM_{2.5}$ formation that results from ammonia slip, EPA does not believe such impacts would be significant. As noted in our Response to Comment 49 below, any ammonia slip emissions contributing directly to PM formation will be measured at the time PM testing is completed and are already included in the BACT limit for $PM/PM_{10}/PM_{2.5}$. As a result, these direct $PM_{2.5}$ emissions from ammonia slip were considered as part of the air quality impact analysis for the facility. In addition, as described in Section 8.4.3.2 of the Fact Sheet, secondary $PM_{2.5}$ impacts generally occur at some distance from the source of its gaseous emissions precursors, and are unlikely to overlap with maximum primary $PM_{2.5}$ impacts that are close to the facility. As discussed in our Response to Comment 49 below, we are not aware of any reason to believe that ammonia slip from the Project will result in significant impacts associated with nitrogen deposition, nor has the commenter provided any information to support such a conclusion. Therefore, we have determined that ammonia slip emissions from SCR will not result in any significant or unusual environmental impacts associated with $PM_{2.5}$ emissions that would preclude its selection as BACT.[22]

[21] See letter from the Shasta County Air Quality Management District (Shasta County AQMD) to the Redding Electric Utility (dated June 23, 2005), available at pages 2-3 of http://www.baaqmd.gov/~/media/Files/Engineering/Public%20Notices/2010/18404/Footnotes/EMx%20Redding%202005%20Letter.ashx.
[22] Our analysis in Section 7.1.1 of the Fact Sheet also concluded that the environmental impacts from using water injection with SCR are not significant enough to warrant elimination of SCR with water injection as BACT for the project. Potential impacts of water injection with SCR as compared with low NOx burners with SCR are further discussed in Response to Comment 48 below.

However, because EMx is another option that potentially could achieve the same level of control as SCR without *any* ammonia slip emissions, we have further considered this option. The EMx catalyst regeneration process requires steam for regeneration, which is not readily available at simple cycle facilities. Since steam production is not part of PPEC's project design, it would require the addition of a natural gas-fired boiler to produce the necessary steam. Operation of a steam boiler in the EMx scenario would cause additional emissions of several criteria pollutants, including NO_x emissions that would not occur with the use of SCR. Alternatively, the operation of an electric boiler powered by electricity produced from the plant would create a parasitic load that would decrease overall energy efficiency by increasing the Facility's NO_x emissions on a lb/MW output basis. Accordingly, use of EMx would result in collateral environmental or energy impacts that do not occur with the use of SCR.

After considering the collateral energy and environmental impacts of both technologies, EPA has determined that neither technology has significant or unusual energy or environmental impacts that would justify their removal from the BACT analysis. However, even if the collateral energy and environmental impacts of both technologies were equal, it appears that EMx technology would be significantly more expensive than SCR, with costs that could be many times greater than that of SCR, making the economic impacts of EMx greater than those of SCR, which would also justify the removal of EMx from the BACT analysis.[23]

After consideration of the above information, we concur with the applicant's selection of SCR for NO_x BACT for the PPEC.

48. **Comment:** The commenter states that on page 12 of the Fact Sheet, EPA provides an inadequate discussion of the collateral impacts of the use of SCR with water injection for NO_x control. While both water injection and dry low NO_x combustors (DLE) will meet the 2.5 ppm NO_x limit, the water injection for NO_x control has collateral impacts which must be discussed in the evaluation of NO_x control options. EPA states in the Fact Sheet:

> The applicant has proposed to use water injection with SCR to control NO_x from the Project. As noted above, this technology is expected to achieve the same level of control as would SCR with low NO_x burners. We have determined that the amount of water needed for water injection will not result in a significant environmental impact warranting elimination of this technology as BACT for the Project. Therefore, we concur that the applicant's selection of SCR with water injection as BACT is appropriate in this case.

The commenter asserts that there are more collateral impacts from the use of water injection for NO_x control that need to be analyzed and discussed in the final permit. The water injection option leads to more water use with an associated increase in particulate matter emissions. The use of water for NO_x control injects water with impurities, which

[23] See, e.g., Section 3.6.7 of the BACT analysis prepared for the JEA – Greenland Energy Center by Black & Veatch, available at: http://www.dep.state.fl.us/air/emission/construction/grreenland/bact.pdf , where the estimated capital cost of SCR and CO catalyst was $5,243,000 and SCONOx (EMx) was $27,912,000.

increase particulate matter emissions. In a recent hearing at the CEC BAAQMD witness Brenda Cabral testified that the use of demineralized water for water injection for NO_x control would lead to a 0.14 pound per hour per turbine in additional particulate matter emissions for an LM-6000 turbine utilizing water injection instead of low NOx combustors.[24] The amount would be higher for the larger LMS-100 turbines. The use of the DLE technology also reduces greenhouse gas emissions as the DLE equipped turbine is more efficient than the water injected version of the LMS-100.[25] The LMS 100 equipped with DLE should have been chosen as BACT or some analysis must be presented which eliminates the LM100 DLE option.

Response: SCR with water injection and SCR with Dry Low NO_x combustors can achieve NO_x emissions of 2.5 ppm and are tied as the top control technology in Step 3 of EPA's NO_x BACT analysis for the turbines. The commenter believes that the collateral environmental impacts of PM and GHG emissions from water injection may be sufficient to eliminate it as BACT for NO_x for this project.

As part of the collateral environmental impacts analysis, we may examine trade-offs between emissions of various pollutants resulting from the application of the specific technology. In this particular case, the commenter has not shown that the collateral impacts on PM and GHG emissions from using water injection in conjunction with SCR to control NO_x are significant or unusual enough to warrant a different NO_x control technology.

Regarding additional PM emissions from water injection, the commenter has not provided sufficient information (*e.g.*, stack test data, emission guarantees, or other BACT limits) to demonstrate that this potential impact is significant and not part of the normal variability in PM emissions from a combustion turbine. We are unaware of any documented evidence, and the commenter has not provided any, that using the DLE version of the LMS100 would result in less PM emissions. While the Bay Area AQMD may have made a general estimate regarding how much water injection could contribute to PM emissions, there is no information to support the assertion that the LMS100 DLE achieves lower PM emissions.[26] The testimony cited by the commenter does not demonstrate that the LMS100 DLE achieves lower PM emissions than the LMS100 with water injection.

The water used for water injection must be of boiler feedwater quality so as to prevent damage and corrosion to the turbines. It is in the best interest of the facility to keep water impurities at a minimum, which minimizes the contribution of water injection to the PM emissions. As such, we find that the commenter has not demonstrated that water injection has a significant environmental impact on PM emissions that requires use of the LMS100 DLE option.

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[24] http://www.energy.ca.gov/sitingcases/mariposa/documents/2011-02-24_Corrected_Transcript.pdf , see Page 379.

[25] http://www.scribd.com/doc/61153709/Lms100-Brochure

[26] We also disagree that the Bay Area AQMD concluded that water injection *would* cause an increase of 0.14 lb/hr. The actual conclusion was that water injection will not be a significant contributor to particulate emissions -- *less than* 0.14 lb/hr.

Regarding GHG emissions, the commenter pointed to a brochure about the GE LMS100 turbine as evidence that the DLE option reduces GHG emissions and should be BACT. There is no evidence in this brochure that supports the statement that the DLE option "reduces GHG emissions" – that is, we are not aware that the use of dry low NO_x combustion causes a turbine to be more efficient. We do acknowledge that the use of water injection can cause a small decrease in overall turbine efficiency, while at the same time increasing the power output of the turbine. The fuel energy required to vaporize the water will cause a small decrease in the fuel efficiency of the turbine, but the added heat capacity from the vaporized water is recovered in the turbine and causes a small increase in power output. As such, we consider the decrease in turbine efficiency from the use of water injection to be a collateral environmental impact of the technology chosen as BACT for NO_x emissions. The use of the highly efficient turbine design of the GE LMS100 turbine remains BACT for GHG emissions. In this case, using the commenter's brochure on the GE LMS100, the decreases in overall efficiency appears to be 2%. However, it is unknown what the actual impact would be on a BACT GHG emission limit, considering the other factors that must be considered when setting a BACT limit as discussed in our Response to Comment 52. As such, we do not find this difference to be significant or unusual enough to warrant the use of a different NO_x control technology.

There is nothing in the comment (or the existing record) to suggest that the potential collateral impacts from water injection on PM and GHG emissions are significant and unusual enough to warrant a different NO_x control technology for this project.

49. **Comment:** The commenter states that in step 4 of the top down BACT analysis, EPA discusses the collateral impacts of the use of SCR for NOx control. EPA discusses the health impacts from the ammonia emissions but fails to quantify or analyze the impacts of secondary particulate formation of particulate matter from the ammonia emissions or the nitrogen deposition that will occur from the use of ammonia in the SCR catalyst.

Response: Any ammonia slip emissions contributing directly to PM formation will be measured at the time PM testing is completed. Secondary PM formation is likely to occur relatively far downwind, and unlikely to overlap with primary $PM_{2.5}$ impacts that are very nearby. EPA found that the applicant adequately followed the recommendations for considerations of modeling primary and secondary $PM_{2.5}$ emissions in "Modeling Procedures for Demonstrating Compliance with PM2.5 NAAQS", memorandum from Stephen D. Page, Director, EPA OAQPS, March 23, 2010 – see Section 8.4.3.2 on page 37 of the Fact Sheet.

Regarding nitrogen deposition, we are not aware of any specific reason that ammonia slip emissions from the Project will cause significant impacts associated with nitrogen deposition, nor has the commenter provided any information to support such a conclusion. Nevertheless, we note that the applicant submitted a biological assessment to EPA as part of the Endangered Species Act (ESA) consultation, in which the applicant addressed the possible effects of nitrogen deposition from the Project on the Otay tarplant and other Federally-listed species. Subsequently, pursuant to section 7 of the ESA, the EPA requested the initiation of formal consultation with the U.S. Fish & Wildlife Service (FWS). On

September 28, 2012, the FWS issued its biological opinion (BO) on the matter, imposing specific requirements on the applicant determined necessary and appropriate to ensure protection of Federally-listed species from potential effects associated with possible nitrogen deposition. We believe the robust analysis performed as part of this ESA consultation process and the resulting requirements in the BO adequately address potential nitrogen deposition from the Project.

In sum, we do not expect significant collateral impacts to result from the Project's ammonia emissions.

50. **Comment:** The commenter states that the EPA BACT analysis selects a 0.0065 lb/MMBtu or 5.5 pounds per hour of PM per turbine. The CPV Sentinel Project utilizes the LM-100 turbine. GE has provided vendor guarantees for that project that assure that the LMS-100 can achieve a 5 pound per hour limit. GE revised the PM10 emissions from the CTG to 5 lb/hr instead of 6 lb/hr, see guarantee e-mail dated 10/21/09 (see CPV Sentinel Addendum to the FDOC March 2, 2010 at:

http://www.energy.ca.gov/sitingcases/sentinel/documents/others/2010-03-02_South_Coast_AQMD_Addendum_to_DOC_TN-55739.PDF)

The commenter states that the 5 lb/hr limit represents BACT for the LM-100 for PM-10 emissions. That level has been achieved in practice as evinced by the data presented in Table 7-5 from the fact sheet. The 5 pound per hour limit is BACT as it has been permitted and achieved in practice.

The commenter states that PM emissions can also be reduced by requiring the use of dry low NOx combustors for NOx control rather than the water injection for NOx control. This is also a method of PM control that is not analyzed or discussed in the proposed permit.

The commenter notes that the Proposed Permit also limits the facility to the use of PUC natural gas. As stated in the FDOC for this project, "In addition, there is the potential for the PPEC facility to combust fuel derived from imported liquefied natural gas, which can have a higher VOC content than the natural gas fuel historically used in San Diego and would be expected to have higher VOC emissions compared than the historical gas supply. Compliance with a 1.0 ppmvd limit when combusting higher VOC content natural gas has not been demonstrated, and it may not be technologically feasible to achieve a 1.0 ppmvd limit when combusting such gas. It should be noted that the applicant's vendor considered natural gas with higher VOC amounts when guaranteeing controlled emission rates." The final permit should contain a discussion of how the use of imported LNG can affect the BACT determination for PM.

Applicant's comments: The comment is factually incorrect on two counts. First, to the best of our knowledge, GE has not provided a vendor guarantee that the LMS-100 can achieve a 5 pound per hour limit at the stack. Second, the data presented in Table 7-5 do not establish that 5 pounds per hour has been "achieved in practice." Neither a permit condition nor a vendor guarantee establishes that a particular emission level has been *achieved in practice. Limited source test data do not establish that a particular emission control has been achieved in practice. The proposed limit must be capable of being complied with under all conditions and throughout the project's life.*

The project will use PUC-quality natural gas. It is possible that, in the future, imported LNG may be blended with other natural gas and made part of the SDG&E fuel supply; however, that fuel supply will remain PUC-quality natural gas. The project is required to comply with all permit limits regardless of any variation in fuel composition. The use of PUC-quality natural gas containing imported LNG will therefore not affect the BACT determination for PM, or any other pollutant.

Response: Upon review of the amended FDOC for the CPV Sentinel project, which utilizes the same GE LMS100 turbines with water injection as the PPEC, we confirmed that those units were permitted at a rate of 5 lb/hr of PM. We generally agree with the commenter that the turbines for the PPEC should be able to achieve the same PM emission limits as the turbines for the CPV Sentinel project. However, there is a significant difference between the emission rate used by the applicant (5.5 lb/hr) and the emission limit contained in the CPV Sentinel permit.

The PM emission limit for the CPV Sentinel project only contains one significant figure. That is, the limit is 5 lb/hr and not 5.0 lb/hr. When determining compliance, a stack test average of up to 5.49 lb/hr would be considered in compliance because it is considered 5 lb/hr when rounded to one significant figure. However, if the limit contained two significant figures (i.e. 5.0 lb/hr), a test average of 5.49 lb/hr would round to 5.5 lb/hr.

The emission rate used in the application contains two significant figures – 5.5 lb/hr. Because of the difference in significant figures, we do not have sufficient technical justification to warrant inclusion of the 5 lb/hr limit from the CPV Sentinel Project over the 5.5 lb/hr emission rate used in the application – the difference between the two limits is trivial.[27] In this case, we prefer to use a limit with two significant figures because the margin for compliance is significantly smaller than compared to one significant figure (approximately, 10% for one significant figure versus 1% for two significant figures).

Please see Response to Comment 3, which explains why the 5.5 lb/hr limit was added to the Final Permit and why the lb/MMBtu emission limit applies only at loads of 80% and higher.

The Proposed Permit limits the fuel that PPEC may combust to Public Utilities Commission (PUC)-pipeline quality natural gas with specified sulfur content limits (Condition IX.E.1). The applicant could use liquefied natural gas, provided that it meets the sulfur content requirements in Condition IX.E.1. Since PM emissions from combustion turbines vary depending on the sulfur content of the natural gas, the use of liquefied natural gas that meets the permit limits would not affect PM emissions at the PPEC or have any effect on our BACT determination.

[27] There is also no support in the record, or this comment, which demonstrates that 5.0 lb/hr is BACT or that any value with two significant figures less than 5.5 lb/hr is BACT.

With regard to consideration of dry low NO_x combustors to further limit PM emissions, the Commenter has not provided any specific information to show that PM emissions would be lower if this technology was used. Please see our Response to Comment 48 above.

51. **Comment:** Proposed BACT for the cooling tower is a drift rate of 0.0010% and a TDS level of less than 5,600 ppm TDS. The proposed permit should consider work practices and or water sources that would lower the 5,600 ppm TDS concentration or provide an analysis why less than 5,600 ppm cannot be achieved.

Applicant's comments: The water system is designed to minimize plant water use. Lowering the maximum allowable TDS level of the circulating cooling water will result in an increase in water consumption and wastewater production.

Response: Please see our Response to Comment 42. As explained in that response, the combination of a dry cooling system with a smaller wet cooling system meets BACT after consideration of the collateral environmental, energy and cost impacts of the controls. The application's consideration of collateral impacts ranked partial dry cooling as the top technology because, even though it has higher energy and cost impacts, as it minimizes water use and wastewater treatment requirements (see Table 1E.14 on page PSD-App-1.94). The resulting potential PM emissions from the system are very small at 1.4 tpy of PM, PM_{10}, and $PM_{2.5}$.

52. **Comment:** The commenter states that EPA is proposing to establish the initial heat rate limit at 9,196 btuhhv/kw-hr gross as BACT for GHG for the PPEC. According to the EPA analysis, this represents a 6% margin over the guaranteed heat rate for the variant of the LM-100 the applicant has chosen. There are other variants of the GE LMS-100 turbine which have better thermal efficiency than the proposed LM-100 variant. The LMS-100 DLE with low NOx combustors mentioned has a better heat rate of 7,509 btu/kWh and also reduces water consumption and particulate matter emissions. The LMS100 STIG has a thermal efficiency of 6,845 btu/kWh, much lower than the heat rate proposed for the turbine proposed for the project.

The commenter states that the Fact Sheet for the Project also dismisses combined cycle applications to reduce GHG emissions. The Fact Sheet cites excessive start up times of combined cycle units as much as three hours. While this statement may have been true several years ago, the new modern combined cycle projects have start times that are similar to "simple cycle peaker plants." For example, the Willow Pass Generating Station with its proposed Flex Plant 10 units has very short start times.[28] Based on vendor information, startup (i.e., the period from initial firing to compliance with emission limits) of the 275 MW FP10 units proposed for Willow Pass is expected to occur within 12 minutes.[29]

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[28] http://www.energy.ca.gov/sitingcases/willowpass/documents/intervenors/2008-08-21_LETTER_FROM_BAAQMD_REAGARDING_PRELIMINARY_REVIEW_OF_DETERMINATION_OF_COMPLIANCE_TN-47183.PDF

[29] http://www.energy.ca.gov/sitingcases/willowpass/documents/applicant/afc/Volume_01/7.1%20Air%20Quality.pdf, see page 7.1-9 Willow Pass AFC. Also, http://www.energy.siemens.com/co/pool/hq/energytopics/

The commenter asserts that the advent of these faster starting combined cycle turbines has permitting implications. Because "simple-cycle turbines are inherently less efficient than combined-cycle turbines," they emit much higher GHG emissions per megawatt and also have much higher criteria air pollutant emissions per megawatt and consume much more natural gas per megawatt. It is no longer necessary to sacrifice efficiency for shorter start up times. The final permit needs to address these factors in the permitting analysis.

Applicant's comments: Achieving compliance with the emission limits is not the same as achieving full load. The Willow Pass facility is expected to reach 150 MW within 10 minutes (full load for the gas turbine, but only 55% of the facility's full capacity of 275 MW), and compliance with emission limits within 12 minutes. The facility will not achieve full load until the steam turbine achieves full load. The startup time for the steam turbine is considerably longer (at least 40 minutes for a "hot" start, and longer for a "cold" start; see response to Sierra Club comment) because the HRSG and steam must be heated to operating temperature. By contrast, the PPEC LMS100 units will reach full load (300 MW) from a cold start within 10 minutes.

Response: EPA disagrees with the commenter's suggestions that the heat rate limit should be modified based on information provided by the commenter or that a combined cycle unit should be required, and we find no reason to revise the permit based on these comments. It is especially important to note that the manufacturer's stated heat rate is at ISO conditions, which are standard reference conditions for temperature and pressure. As discussed in our Fact Sheet, turbine efficiency is highly dependent upon actual ambient operating conditions, which are not necessarily the same as ISO reference conditions. It is precisely for this reason that it is necessary to adjust the heat rate limit in our permit to account for the actual operating conditions at the plant location. This is also why it is inappropriate and uninformative to compare the heat rate limit in the Proposed Permit for the PPEC with values observed elsewhere without accounting for such factors, which the commenter did not do. For additional reasons, we also find fault with the commenter's comparison between the heat rate limit in the Proposed Permit with the heat rate that can allegedly be achieved by an LMS100 STIG unit (which is the steam injection for power augmentation model of the LMS100). Notably, STIG systems utilize large volumes of steam to increase power and improve efficiency. However, the necessary steam is typically produced in a heat recovery steam generator and injected into the gas turbine. Also, please see Response to Comment 48 regarding the use of dry low NO_x combustion (which is used by the LMS100 DLE option) versus water injection. For reasons we thoroughly explained in our Fact Sheet and in Response to Comments 40-42 above, we do not believe a heat recovery steam generator is technically compatible with the operation of this facility.

The information shared by the commenter regarding the Willow Pass Generating Station is similarly unpersuasive. A permit for this facility was never proposed or finalized, and we were recently notified by the Bay Area AQMD that the application for this facility has been cancelled. In addition, the FP10 unit in question has a net generating capacity of 275 MW and it can operate down to a minimum load of 60 percent, or approximately 165 MW. In

pdfs/en/combined-cycle-power-plants/PowerGen2007PaperFinal_.pdf, see Page 15.

comparison, the LMS100 units used in this case have a practical operating range down to 50 MW. As we discussed in our Fact Sheet, it is a necessary element of the Project to operate over a wide range of loads and the unit suggested by the commenter is not capable of satisfying that objective.

53. **Comment:** The commenter states that to establish background concentrations for the Federal 1-Hour NO_2 standard, the Chula Vista Monitoring Station located 9 KM from the project site was utilized. According to the PSD Application, the closest air quality monitoring station to the Project is located in Otay Mesa at the Otay Mesa-Paseo International Border crossing 1.2 miles south of the Project. The applicant fails to use the monitoring data from the Otay Mesa International border because, "the pollutant concentrations recorded at this station are heavily influenced by the emissions from the hundreds of Mexican vehicles waiting each hour at the border entry."

The commenter further asserts that EPA's guidance for the 1-hour NO_2 analysis requires that monitors are placed near major roads as well as in other locations where maximum concentrations are expected. This would indicate that the International Border Crossing would be the ideal place to use as background for the 1-hour NO_2 analysis.

The commenter argues that the Otay Mesa Paseo International Border monitoring station should have been utilized to determine background for NO_2 impacts, not the Chula Vista Monitoring Station. "In general, the representativeness of the meteorological data used in an air quality modeling analysis is dependent on the proximity of the meteorological monitoring site to the "area-of-interest".

The commenter goes on to state that the final PSD permit should require a full-blown analysis of NO_2 impacts utilizing all receptors in the US and Mexico to determine if this project complies with the Federal 1 hour NO_2 standard.

Response: EPA believes that the background concentrations used in the 1-hour NO_2 cumulative impacts analysis for PPEC are consistent with EPA's Appendix W and relevant guidance and are appropriately representative, and that further analysis of 1-hour NO_2 impacts is not warranted; please refer to Response to Comment 45. With respect to the commenter's arguments recommending the use of data from the Otay Mesa monitoring station rather than the Chula Vista monitoring station, please refer to Response to Comment 45 above.

With respect to the commenter's statement that in general, the representativeness of the meteorological data used in an air quality modeling analysis is dependent on the proximity of the meteorological monitoring site to the area-of-interest, the applicant used five years of meteorology from the Otay Mesa meteorological monitoring site, which is only 1.9 miles from the PPEC site. See Section 8.3.2 (pages 30 and 31) of the Fact Sheet. EPA concluded that the meteorological data from this site is adequately representative based on proximity and other factors such as currentness and completeness.

In response to the commenter's argument that the PPEC cumulative impacts analysis demonstrating compliance with the 1-hour NO_2 standard should utilize all receptors in the U.S. and Mexico, we disagree. As discussed in Response to Comment 45 above, the applicant considered appropriate receptors as part of its 1-hour NO_2 NAAQS analysis. The PSD NAAQS analysis appropriately considers only receptors within the United States, as the NAAQS apply only within the geographic boundaries of the United States. The commenter has not identified any CAA provision that requires analysis of impacts in Mexico in this PSD permitting process, and we are aware of no such provision.[30] Nevertheless, we note that the data we have considered does not indicate that the PPEC's NO_2 emissions would cause impacts of concern at Mexican receptors. As discussed above, to add further conservatism to the 1-hour NO_2 modeling results, EPA requested the use of, and the applicant used, Otay Mesa data to evaluate cumulative impacts at receptors close to the Otay Mesa monitor to address the impacts of roadway emissions, and the impacts in that area demonstrated compliance with the 1-hour NO_2 NAAQS. Given the wind rose data discussed in Response 45 above, the PPEC's area of impact, and the magnitude of the PPEC impact near the Otay Mesa monitor, which is located near the Mexican border, we have no reason to believe that the PPEC's NO2 emissions would cause impacts of concern at Mexican receptors.

54. **Comment:** The commenter states that in 1994, President Clinton issued Executive Order 12898 calling on federal agencies to identify and address "Disproportionately high and adverse human health and environmental effects on minority populations and low income populations in the United States." The EPA led an interagency effort to carry out the executive order. In 1998, the EPA issued guidance for conducting analyses under the National Environmental Policy Act (NEPA) entitled "Final Guidance for incorporating Environmental Justice Concerns in USEPA's National Environmental Policy ACT Compliance Analysis." This document followed and was explicitly designed to supplement the Council on Environmental Quality's Environmental Justice Guidance under NEPA.

The commenter further states that the first requirement of any environmental justice analysis is to perform a screening analysis to determine whether an environmental justice community exists around the site. For the PPEC project, the 2010 Census shows the total population within the six-mile radius of the proposed site is 67,796 persons, with a minority population of 54,375 persons, or about 80% of the total population (US Census 2010a). The project area includes several detention centers in close proximity to the PPEC, the Richard J. Donovan Correctional Facility, the East Mesa Detention Complex home to four San Diego County-run detention centers and one privately run federal detention center. The prisoners at the detention center are also primarily minority and they reside in close proximity to the power plant 24 hours a day. The project is located next to a 500 MW power plant, the Otay Mesa Generating Station. There are also several other small peaking facilities near the proposed project. The commenter states that essentially this is the definition of an impacted minority community.

[30] We also note that section 115 of the Clean Air Act, which addresses international air pollution, does not apply to this permit and in no way indicates that international impacts must be considered in this PSD permitting process.

The commenter goes on to assert that the second step is to determine the unique circumstances of the population. Low income communities and communities of color suffer from substantially worse health outcomes and die earlier. Prisoners will be exposed to the air impacts of the two power plants, Otay Mesa and the PPEC, for 24 hours a day sometimes for many years. Environmental Justice Guidelines require outreach to the minority community. This includes a multi step process. EPA should reach out to leaders in the minority community, and hold several meetings with the minority community to get their feedback on the proposed project. The fact sheet, PSD documents, and public notice requirements must be made conveniently available and in multiple languages so the minority community can understand the project. Third, the individual and cumulative health impacts of the project must be assessed on the minority population in conjunction with their enhanced sensitivities.

The commenter also states that the fourth step is to recommend the appropriate mitigation. This is not possible without adequately examining the individual and cumulative impacts to the minority population in conjunction with their existing sensitivities. The mitigation for air impacts for this project are not real time emission reduction credits but worthless paper credits from past emission reductions which have no value in reducing the existing emissions from the multitude of point sources near the project.

Response: EPA believes that it has fulfilled its responsibilities under Executive Order 12898 (EO 12898 or EO) with respect to its PSD permitting action for the Project, as described in detail below. EPA also believes that the EJ Analysis that EPA prepared in conjunction with its proposed PSD permit for the PPEC was properly drafted and well-reasoned, and contained appropriate and adequate support for its conclusions.

Background

Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," was signed on February 11, 1994. The EO establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low-income populations. The EO is designed to focus the attention of federal agencies on the human health and environmental conditions in minority communities and low-income communities with the goal of achieving environmental justice.

EPA has determined that the EO applies to our PSD permitting decisions. *See, e.g., In re Shell Gulf of Mexico, Inc. & In Re Shell Offshore, Inc. (Frontier Discovery Drilling Unit)* 15 E.A.D.___, OCS Appeal Nos. 10-01 through 10-04, slip op. at 63-64 (EAB Dec. 30, 2010) (citing prior EPA Environmental Appeals Board (EAB) opinions). EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies. EPA has this goal for all communities and persons.

EPA defines meaningful involvement to mean that 1) potentially affected community residents have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment and/or health, 2) the public's contribution can influence our decision, 3) the concerns of all participants involved will be considered in our decision-making process and 4) the decision makers seek out and facilitate the involvement of those potentially affected.

EPA's Public Participation and Outreach Activities for the Proposed PSD Permit for the PPEC

With respect to public outreach and participation, EO 12898 affords EPA considerable discretion to determine appropriate outreach activities. In this case, EPA prepared the EJ Analysis and took numerous actions to facilitate input from the community regarding the Project, addressing the objectives described above. EPA's enhanced public participation process, described below, went beyond the specific regulatory requirements set forth in 40 CFR Part 124 for PSD permit proceedings, and clearly demonstrates a commitment on EPA's part to ensuring meaningful participation by affected communities in the decision making process.

In June 2012 and August 2012, EPA provided notice of its proposed PSD permit for the Project, as well as notice of a public hearing scheduled for July 24, 2012 (or the opportunity to request an additional public hearing), through a public notice issued in both English and Spanish. EPA distributed both the English-language and Spanish-language versions of the notice using a number of methods designed to reach the community in the area, including publishing the notices in the *San Diego Union-Tribune* (in English only) on June 20, 2012 and August 3, 2012, in *La Prensa San Diego* (in Spanish only), and on EPA Region 9's website. EPA also distributed the public notices by email or mail to the necessary parties in accordance with 40 CFR Part 124, as described above in Section I above. The public notice provided the public with a clear explanation of how to obtain additional information about EPA's action, including the fact that detailed materials relating to EPA's action were being made available at numerous locations in the communities near the Project site as well as on EPA Region 9's website and at EPA's office in San Francisco. The public notice also included the name, phone number, mailing address and email address of a contact person so that members of the public could contact EPA directly to ask questions or obtain additional information.

EPA sent a copy of its public notice, the Proposed Permit, and Fact Sheet to the SDAPCD in San Diego, CA, and, although not required by Part 124, EPA also distributed these documents to numerous locations in communities near the Project site to facilitate review by members of nearby communities: the San Ysidro Library in San Diego, CA; Otay Mesa Nestor Library in San Diego, CA; Civic Center Branch Library in Chula Vista, CA; National City Public Library in National City, CA; and Central Library in San Diego, CA.

EPA also posted key documents in the administrative record for its Proposed Permit on the Region 9 website, including the Proposed Permit, Fact Sheet, permit application and other key supporting information. Although Part 124 does not specifically require this approach, EPA determined that it would facilitate community involvement by making key information more immediately accessible to the public.

In addition, in order to facilitate community understanding, EPA prepared a Public Information Sheet, which included an overview of the proposed PSD permit, Project emissions, and air quality impacts. This document (in both English and Spanish) was also made available on EPA's online docket for review by the public on June 20, 2012.

Region 9 held a public hearing in San Diego on July 24, 2012. While Spanish translation is not required by Part 124, EPA determined that it would be appropriate to provide Spanish translation services at the hearing, and to translate the public notice and certain other documents relating to the Proposed Permit, in order to facilitate public involvement by Spanish-speaking members of nearby communities. EPA did not receive any oral public comments at the hearing. We received one set of written comments at the hearing, which was also transmitted to us via email.

EPA had previously determined that there may be minority or low-income populations potentially affected by its proposed action on the PPEC PSD permit application, and determined that it would be appropriate to prepare a separate EJ Analysis for this particular action. EPA prepared the analysis and made it available as part of the administrative record for the Proposed Permit at the time EPA issued its Proposed Permit for comment, so that the public could comment on the analysis if desired during the public comment period. The EJ Analysis was posted on EPA's on-line docket during the public comment period, and was briefly discussed in EPA's Fact Sheet and Public Information Sheet for the Project.

EPA believes that all of these efforts, which went beyond the required public notice and participation procedures in 40 CFR Part 124, were consistent with its public participation responsibilities under EO 12898, and served to ensure that the public documents, public notice, and public hearing relating to its proposed PSD permitting action for the Project were concise, understandable, and readily accessible to the public.

EPA's EJ Analysis and Consideration of Environmental Justice Public Comments for the PPEC

With respect to EPA's substantive consideration of environmental justice issues in the context of its PSD permitting action for the PPEC, EPA prepared a succinct, well-reasoned EJ Analysis to accompany its proposed PSD permit, in which EPA discussed potential impacts of its action on environmental justice communities. As noted previously, EPA made the EJ Analysis available for public review during the public comment period on the Proposed Permit. EPA's EJ Analysis described EPA's proposed PSD permitting action, included a brief description of the area near the Project and key demographic information regarding the surrounding communities, discussed the actions EPA was taking to provide enhanced public participation opportunities for its proposed PSD permit, and considered the impacts of EPA's permitting action on nearby communities, as described in more detail below.

The EJ Analysis noted that existing site and land uses in the vicinity of the proposed Project include the Otay Mesa Generating Project and two correctional facilities (the Richard J. Donovan Correctional Facility and the George F. Bailey County Correctional Facility). EJ Analysis at 4-5. The EJ Analysis' discussion of pertinent demographic information for the Project location and surrounding areas considered populations within 5, 10, 15, and 50 km of the proposed facility, and nearby communities, as well as San Diego County and State as a whole. EJ Analysis at 5-7.

With respect to potential impacts on environmental justice communities from EPA's proposed PSD permitting action, the EJ Analysis focused on the fact that the NAAQS are health-based standards, designed to protect public health with an adequate margin of safety, including sensitive populations such as children, the elderly, and asthmatics. The EJ analysis noted that as EPA's EAB recently observed, in the context of an environmental justice analysis, compliance with the NAAQS is emblematic of achieving a level of public health protection that, based on the level of protection afforded by the NAAQS, demonstrates that minority or low-income populations will not experience disproportionately high and adverse human health or environmental effects due to exposure to relevant criteria pollutants. EJ Analysis at 1.

EPA's EJ Analysis went on to explain that, in light of the health-based nature of the applicable NAAQS, EPA has determined that the modeled results from the NAAQS analysis for the Project indicate that proposed emissions of the pollutants regulated under EPA's PSD permit for the PPEC would not cause or contribute to a violation of the NAAQS, and therefore will not result in disproportionately high and adverse human health or environmental effects on minority populations and low-income populations. *Id*. at 8-9.

The EJ Analysis also discussed the fact that the Project will emit pollutants for which the area is not meeting the NAAQS (and precursors that lead to the formation of such pollutants), which are regulated by the SDAPCD, and noted that the District implements the Nonattainment New Source Review (NNSR) permitting program for this area as required under the Clean Air Act and 40 CFR 51.160 to 51.165. *Id.* at 3. The analysis noted that PPEC will not be a major source of any nonattainment pollutant, and therefore requirements of NNSR, including Lowest Achievable Emission Rate (LAER) and emission offsets, do not apply to the Project. Instead, the minor NSR permit issued by SDAPCD addresses both attainment and nonattainment pollutants. *Id.* The EJ Analysis later described health effects associated with ground-level ozone exposure and generally described the planning process that is being undertaken to address ozone nonattainment in the area. *Id.* at 8-9. In addition to preparing its EJ Analysis, EPA has carefully considered comments submitted during the public comment period raising environmental justice issues related to EPA's action and responded as appropriate.

In sum, EPA believes that its public participation process and substantive consideration of environmental justice issues with respect to its PSD permitting action for the Project were appropriate and consistent with the provisions of EO 12898 as well as its responsibilities under 40 CFR Part 124.

With respect to the commenter's reference to a 1998 National Environmental Policy Act (NEPA)/EJ guidance document issued by EPA, we note that EPA's PSD permitting action is not subject to NEPA, as actions taken under the Clean Air Act are specifically exempt from NEPA per section 7(c) of the Energy Supply and Environmental Coordination Act of 1974, 15 U.S.C. 793(c)(1). Therefore the NEPA/EJ guidance does not apply to EPA's issuance of the PSD permit to the PPEC, nor do the procedures discussed in that guidance to which the commenter refers.

The commenter raised concerns about outreach to and potential impacts from the Project on the populations at nearby correctional facilities. As mentioned above, EPA's EJ Analysis specifically mentioned two of these facilities, Richard J. Donovan Correctional Facility and the George F. Bailey County Correctional Facility, the latter of which is part of the larger correctional facility complex to which the commenter refers. EPA also sent its public notice for the Proposed Permit action directly to these two facilities. EPA believes that the public participation actions taken for the PPEC and described in detail above, including providing two public notices of the Proposed Permit in the newspaper, as well as sending copies of the public notice directly to the two facilities described above in June 2012 and August 2012, provided reasonable and appropriate means to provide nearby correctional facility populations with notice and the opportunity to raise any concerns that they might have about EPA's proposed permitting action. We note that inmates at the correctional facilities have access to the San Diego Union-Tribune, in which we published the public notices. Although inmates at the facilities presumably would not have been able to attend our public hearing, they had the opportunity to request information and submit written comments on our proposal by mail, as could members of the general public who may have had difficulty attending the public hearing. No inmate of the correctional facilities submitted comments on EPA's proposed permitting action for the Project.

We have considered the demographic and other information concerning the populations at correctional facilities provided by the commenter. We have also considered the unique conditions, such as overcrowding, social vulnerability and health related issues, impacting the prison communities located near the proposed Project site. See generally Comment and Response 55 and Response to Comment 56. As discussed above, EPA's EJ Analysis has determined that the modeled results of the NAAQS analysis indicate that proposed emissions of the pollutants regulated under EPA's PSD permit for the PPEC would not cause or contribute to a violation of the NAAQS. In light of the health-based nature of the applicable NAAQS, EPA concludes that the permitted emissions will not result in disproportionately high and adverse human health or environmental effects on minority populations and low-income populations. This conclusion would extend to potential human health or environmental effects to correctional facility populations as well as other populations. These modeled results consider emissions from the PPEC, and, for those pollutants where a cumulative impact analysis was conducted, also take into account background concentration levels of the pollutants at issue as well as emissions from relevant nearby sources, including the Otay Mesa Generating Project.

The commenter appears to suggest that mitigation may be required or should be further considered in the context of environmental justice impacts, but does not explain why he believes that is the case. EPA does not believe that mitigation for environmental justice impacts is necessary or appropriate in this case given that EPA's PSD permitting action will not result in disproportionately high and adverse human health or environmental effects on minority populations and low-income populations as explained above. We also note that the commenter's assertions about emission reduction credits focus on matters that are not regulated under the PSD permit. Nonattainment pollutants are addressed by the State and District approvals and comprehensive air quality planning processes, and thus are best addressed by the State/local air quality programs.

Additional Environmental Justice Comments Submitted by Bob Sarvey

55. **Comment:** The commenter states that the first requirement of any environmental justice analysis is to perform a demographic screening analysis to determine whether an environmental justice community exists around the site and where the EJ community is located. According to EPA's Environmental Justice Analysis, based on available information, there are a few residences within a five mile (8.0 km) radius of the proposed facility, with the closest being approximately 1.6 miles (2.6 km) away.

    The commenter asserts that EPA's EJ Analysis ignores two large inmate populations near the proposed PPEC. The commenter provides information concerning these populations, and notes that the California prison population under the California Department of Corrections is 25.6% white, 39% Hispanic, 29% black, and 6.1% other. The commenter states that the Richard J. Donovan Correctional Facility is located approximately 4,000 feet northwest of the Pio Pico Project, is designed for a prison population of 2,208 inmates, and currently houses 4,336 inmates, with a staff of 1,416. The commenter states that another prison complex with multiple detention centers is located 4,800 feet from the proposed project. The facility includes the George F. Bailey Detention Facility, the East Mesa Detention Facility, the Federal Immigration Detention Facility, and the County of San Diego Juvenile Detention Facility. The inmate population of these facilities numbers well over 5,000 inmates. Expansion of these facilities is foreseeable. The Corrections Corporation of America intervened in the CEC licensing as they are seeking an additional 2,100 bed facility near the proposed Pio Pico Facility.

    The commenter further states that the prisoners at the detention centers will reside in close proximity to the proposed power plant 24 hours a day, seven days a week. The project is proposing to locate next to a 510 MW power plant, the Otay Mesa Generating Station, that is already emitting substantial amounts of criteria pollutants and toxic air contaminants within a few thousand feet of thousands of inmates.

    Response: EPA disagrees that its EJ Analysis ignores the large inmate populations near the proposed PPEC. Although the EJ Analysis' discussion of nearby residences and residents did not specifically reference the inmate populations of nearby prison facilities, they were considered. Specifically, the description of the local area near the Project identified two nearby correctional facilities, see EJ Analysis at 4-5, and the data used for the demographic discussion in the EJ Analysis included the populations of the correctional facilities. We acknowledge and have also considered the information presented by the commenter on the demographics of these populations. Please see Responses to Comment 54 and 56 for additional discussion of the inmate populations. It is not clear whether the commenter is suggesting that the EJ Analysis' discussion of demographics consider the population makeup of potential expanded prison populations. We do not believe that consideration of future populations is required, nor would it be practicable given that information concerning the makeup of such population is unknown at this time. In any event, we believe that consideration of the demographics of the existing prison populations is adequate to inform our analysis concerning potential concerns regarding impacts on nearby prison populations. We note that the population within a six mile radius of the proposed source is 80% minority, which is actually slightly higher than the 75% minority percentage which the commenter cites for the prison population.

EPA believes that its public participation process and substantive consideration of environmental justice issues with respect to its PSD permitting action for the Project in its EJ Analysis and in these responses to comments is appropriate and consistent with our obligations under EO 12898 as well as our responsibilities under the CAA and its implementing regulations, as discussed in detail above in Response to Comment 54.

56. **Comment:** The commenter states that after analyzing the demographics and location of the affected minority and low income community, the environmental justice analysis next should identify factors that affect the health of the identified Environmental Justice community. Since the EPA analysis does not identify the two correctional facilities it does not analyze the demographic makeup of the inmate population. The EPA does not examine existing health sensitivities of the prison population. The EPA analysis does not examine the living conditions of the prisoners. The educational level of the prisoners. The EPA analysis does not consider the Linguistic isolation of the prison population.

Response: As stated in our Responses to Comments 54 and 55, EPA's EJ Analysis did identify and consider nearby correctional facilities and their populations, and EPA has further considered the information presented by the commenter concerning the populations of nearby correctional facilities. We also note that EPA has considered the unique conditions, such as overcrowding, social vulnerability and health related issues, impacting the prison communities located near the proposed Project site.

Our EJ Analysis considered demographic information at the 5km radius, which fully included the prison population as well as the surrounding population.[31] See Figure 1 below. Due to resolution limits of the census data used to generate the analysis, data from the 2010 census and 2000 census was derived assuming uniform population distribution with inclusion of the entire prison population. The percentages included in the demographics

[31] We note that the edges of the nearby prison complexes are approximately 1.4 and 1.5 km from the proposed Project site. When considering a 2 km radius, the prison facilities were bisected, leaving half of the buildings inside and half of the buildings excluded. In addition, due to resolution limits of the census data used to generate the analysis, data from the 2010 census and 2000 census was derived assuming uniform population distribution. Therefore, census data within the 2 km radius did not reflect the prison population in its entirety.

discussion in the EJ Analysis considered the percent minority, linguistically isolated and percentage of people with high school diplomas. We note that the commenter states that the minority population in the prisons is 75%, which is slightly lower than the 80% minority population within a six mile radius of the proposed source which the commenter cites.

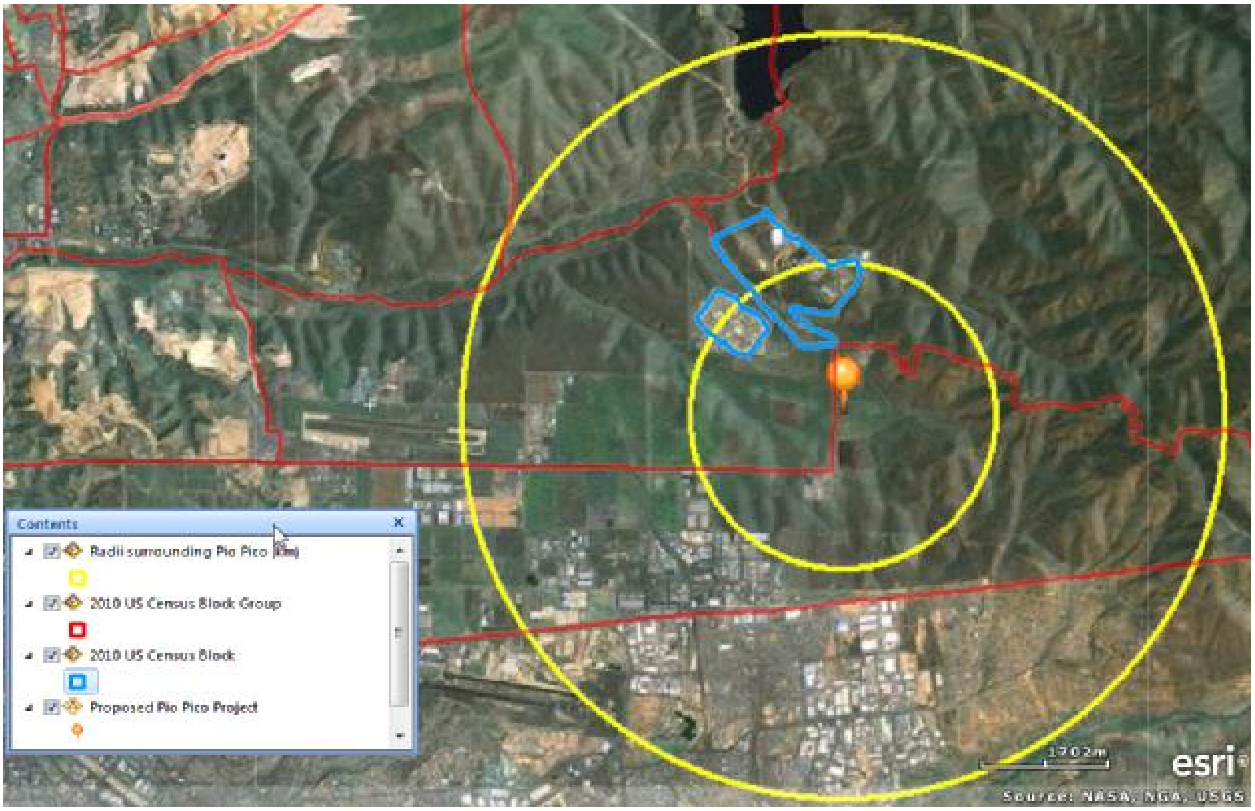
EPA has also considered the key health issues among inmates and understands that the most common health issues in the U.S. correctional system are HIV/AIDS, Hepatitis and Tuberculosis, Drug/Alcohol dependence, and mental health. The leading chronic medical conditions among California prisoners included hypertension, obesity, arthritis and asthma.

As stated in the conclusion of EPA's EJ Analysis,

> "…this Project will not cause or contribute to air quality levels in excess of health standards for the pollutants regulated under EPA's proposed PSD permit for the Project, and there will not be disproportionately high and adverse human health or environmental effects with respect to these air pollutants on minority or low-income populations residing near the proposed Project or the community as a whole.

This conclusion extends to EPA's consideration of the populations at the correctional facilities given that the NAAQS are health-based standards, designed to protect public health with an adequate margin of safety, including sensitive subpopulations. We are not aware of information, nor has the commenter presented any specific information, indicating that the environmental or health conditions faced by the prison population would call into question this conclusion.

Figure 1 - Location of correctional facilities with respect to the Project at the 2km and 5km radii.



57. **Comment:** The commenter states that the Otay Mesa Facility is permitted to emit up to 100 tons per year of NOx, 159 tons of PM_{10}, which is primarily $PM_{2.5}$, 235 tons per year of CO, 39 tons of SO_2, and 27 tons of VOC. The CEC decision provides the CEC's ambient air quality impact analysis for the Otay Mesa Project. The Otay Mesa project's 1 hour NO_2 impact is 130 ug/m^3 and the background concentration was 205 ug/m^3 for a one hour impact of 335 ug/m^3. The project's annual NO_2 impact was modeled as 0.8 ug/m^3 and background was 37.6 ug/m^3. The project's PM-10 24 hour impact was 4.8 ug/m^3 and the project's annual PM_{10} impact was modeled at 0.8 ug/m$_3$. The proposed Pio Pico Energy Center is permitted to add another 70.4 tons per year of NOx, 37.3 tons per year of PM_{10}/$PM_{2.5}$, 96.4 tons of CO, 19.4 tons of VOC, and 4.1 tons per year of SO_2.

Response: The commenter does not explain how the CEC analysis concerning the Otay Mesa Facility relates to EPA's PSD review for the Project. In its PSD cumulative impact analysis for the applicable pollutants, $PM_{2.5}$ and $NO_{2,}$ the applicant appropriately modeled the emissions from the Otay Mesa Power Plant, along with other surrounding nearby sources, as well as emissions from the Project and background data, and demonstrated compliance with those NAAQS in accordance with PSD requirements. We note that the NO_2 results for Pio Pico from the applicant's PSD cumulative impact analysis are different from the CEC data cited by the commenter. These results differ because the Otay Mesa Power Plant modeling done for the CEC used a form of the NO_2 standard that is different from the federal NO_2 standard, as well as different inputs and different models. We also note that the Otay Mesa project's PM_{10} emissions are not 159 tons per year; the source's emissions were lowered to 99.6 tons per year at Otay Mesa's request as part of its permitting process.[32]

58. **Comment:** The commenter states that to establish background concentrations for the Federal 1-Hour NO_2 standard, the Chula Vista Monitoring Station located 9 km from the Project site was utilized. According to the PSD Application, the closest air quality monitoring station to the project is located in Otay Mesa at the Otay Mesa-Paseo International Border crossing 1.2 miles south of the project. But instead the EPA allowed the use of the Chula Vista Station because the monitoring data from the Otay Mesa International border has "pollutant concentrations at the station that are heavily influenced by the emissions from the hundreds of Mexican vehicles waiting each hour at the border entry." Maximum hourly NO_2 concentrations are 40% higher at the border site than the Chula Vista Site and annual PM_{10} concentrations are 200% higher at the border site. The NO_2 and particulate matter concentrations at the project site are likely to be more similar to the border monitoring site than the Chula Vista site due to the presence of the Otay Mesa Power Plant. The Chula Vista monitoring site is not representative of the ambient air concentrations currently encountered near the project site because it does not capture the air quality impacts from the Otay Mesa Power plant and is located 9 km away.

    Response: We disagree with the commenter's suggestion that the Chula Vista monitoring site is not representative and that the Otay Mesa monitoring site generally should have been used in lieu of the Chula Vista site for purposes of background concentration data for the PPEC cumulative impact analysis. Please refer to Response to Comment 45 above for a detailed discussion of this issue. We specifically note that, as discussed above, the Otay Mesa Power Plant's emissions were modeled as emissions from an existing nearby source in the applicant's PSD cumulative impacts analyses that were required for $PM_{2.5}$ and NO_2 and therefore appropriately reflected in the results of the analyses. We further note that there is no $PM_{2.5}$ monitor at Otay Mesa. The closest $PM_{2.5}$ monitor is the Chula Vista monitor, which is located 9 miles from the Project site.

    It is not clear how the commenter's reference to PM_{10} concentrations relates to his arguments about the background monitor locations for the cumulative impact analyses, which were conducted for $PM_{2.5}$ and NO_2. As discussed in Response to Comment 45, emissions of PM_{10} were below the SIL and therefore a PM_{10} cumulative impact analysis was not required and background monitoring data for PM_{10} was not at issue in this case.

59. **Comment:** The commenter states that Environmental Justice considerations require onsite monitoring for a period of time to collect the data to provide proper background concentrations to assess the air quality impact of the Pio Pico Project and the Otay Mesa Project on the large inmate populations.

    Response: Please refer to Responses to Comments 45, 54, 57, and 58. The applicant's PSD cumulative impact analysis that was performed for $PM_{2.5}$ and NO_2 appropriately included

[32] See California Energy Commission, Otay Mesa Energy Center, Docket No.99-AFC-5C, Order No. 09-603-2, Order Approving Air Quality Conditions of Certification, AQ-43.

emissions from Otay Mesa Power Plant. The Project shows compliance with the applicable NAAQS.

60. **Comment:** The commenter states that the modeled 24-hour PM_{10} impact from the PPEC was estimated as 2.6 ug/m^3, which is below the SIL of 5 ug/m^3, but since the majority of particulate matter from natural gas fired power plants is $PM_{2.5}$ the 24-hour $PM_{2.5}$ impact of 2.6 ug/m^3 was higher than the SIL for $PM_{2.5}$ of 1.3 ug/m^3. What ambient air concentrations are at the project site is unknown. An annual $PM_{2.5}$ analysis was done and the predicted annual impact is 14.4 ug/m^3 very close to the NAAQS of 15 ug/m3 without accounting for the potential 159 tons per year of $PM_{2.5}$ from the Otay Mesa Plant right at the project site near the prisons. Utilization of the border site would have predicted annual $PM_{2.5}$ violations.

Response: As discussed in Responses to Comments 45 and 57-59, the applicant for the PPEC performed cumulative impact modeling for $PM_{2.5}$, both annual and 24-hour, which included modeling of the emissions from the Otay Mesa Power Plant, and demonstrated compliance with the $PM_{2.5}$ NAAQS. We note that the potential emissions of PM_{10} at the Otay Mesa Power Plant were lowered to 99.6 tons per year in the final permit (11.5 lb/hr per turbine), and the $PM_{2.5}$ emissions from the Otay Mesa Power Plant modeled in the PPEC cumulative impact analysis reflected this 11.5 lb/hr limit.[33] As discussed in detail in Response to Comment 45, we determined that the Chula Vista site was adequately representative for background ambient data for $PM_{2.5}$ and the fact that Otay Mesa Power Plant's emissions were modeled as a nearby source ensured that the plant's emissions were appropriately considered in the PPEC $PM_{2.5}$ NAAQS analysis. There is no $PM_{2.5}$ monitor at the Otay Mesa border site.

61. **Comment:** The commenter states that an additional uncertainty in EPA's NO_2 modeling is the applicant's proposed in-stack ratio of NO_2/NOx of 0.13 for normal operations and 0.24 for startup, when the SCR is not fully operational. Since available ratios specific for LMS turbine operations were not available, the SDAPCD recommended these two ratios based on source test results of gas turbines with operations considered similar to a LMS100 turbine. There are hundreds of LMS100 turbines in service in the United States. Surely there is available data from source testing to arrive at an accurate in-stack ratio for the LMS100 rather than rely on source data from other turbines.

Response: The commenter suggests that there is available source test data for LMS100 turbines for which NO_2/NO_x in-stack ratios (ISRs) are also available, but the commenter has not provided any such data. During our PSD permit application review, we were not aware of available information from source test results for LMS100 gas turbines that would provide us with the ability to determine NO_2/NO_x ISRs for such turbines. While source tests include reporting of oxides of nitrogen (NOx) emissions, the documentation concerning the conduct of these tests does not necessarily include a detailed speciation of the NO_x components, *i.e.*, NO, NO_2; therefore, more often than not, NO_2/NO_x ISRs cannot be determined from source test results.

[33] See California Energy Commission, Otay Mesa Energy Center, Docket No.99-AFC-5C, Order No. 09-603-2, Order Approving Air Quality Conditions of Certification, AQ-43.

In considering the appropriate ISRs for the Project, EPA consulted with the District and the CEC, both of which informed EPA that while considering ISRs for the proposed Project, they were unable to locate specific ISR data from source tests for the LMS100. In light of the lack of such data, the District instead used an alternative approach to determining the ISRs for the Project, identifying and considering available ISRs for similar equipment that has similar operating configurations. The air quality modeling for the PSD permit for the Project was completed based on information available at the time. We consider this an acceptable approach, and the commenter does not provide any reason to believe this approach would have underestimated NO_2 impacts.

In developing the ISRs for the Project, the District relied on ISR data for sources within its jurisdiction. As part of the District's NO_x source test requirements, NO_2 emissions must be measured. Furthermore, for all source tests, the District either conducts the source test itself or requires that the test be done by an independent contractor in accordance with a source test protocol approved by the District. If the source test is conducted by an independent contractor, the District witnesses the source test, reviews the contractor's source test report, and approves the source test results with corrections as necessary. The District also on occasion tests in parallel with an independent contractor. We reviewed the District's ISR information and discussed with the District its decision-making process, which involved its selection methodology and assumptions, such as equipment type, type of fuel fired, operating configuration, and control technologies. As summarized in the Fact Sheet (Section 8.4.3.3.A.1), the ISRs for normal and startup operations were based on the averages of source test results from four LM6000PC SPRINT gas turbines and eleven Frame 5 gas turbines, respectively. We agreed with the comparability of the two types of sources used as the basis for the NO_2/NO_x ISRs, and the commenter has not pointed to any particular reason to believe the equipment is not comparable. The District's close oversight of the source testing generating the data used to derive the ISRs provides assurance that the data are accurate and reliable.

62. **Comment:** The commenter states that environmental justice also requires consideration of reasonably foreseeable projects that could add additional cumulative pollution impacts to the minority community. An additional source, the Bull Moose Biomass plant, is being developed near the Pio Pico and Otay Mesa Power Plants. Construction is planned at the corner of Sanyo Road and Otay Mesa Boulevard, amongst the area's existing power plants and industrial warehouses. The Corrections Corporation of America also is in the process of siting a 2,100 bed facility right next the existing facility. The impacts of construction and operation of these projects is not captured EPA's EJ analysis.

Response: We disagree that environmental justice analyses for PSD permits must necessarily consider the impacts of projects that could be sited in the area at issue in the future. In this case, the commenter has not provided any specific information concerning the likelihood of any such projects, their likely impacts, or how they might be relevant to EPA's consideration of potential environmental justice impacts, so we cannot provide a further response on this issue. We note that future projects in the area will be subject to applicable permitting/approval requirements under Federal, State and/or local law, which should provide an opportunity in which to raise and address potential concerns about potential environmental justice impacts from these projects.

Regarding the air quality impacts of future sources, the air quality impacts of a future major stationary source would be considered at the time it seeks its own PSD permit, and it would have to account for sources existing at that time, including emission impacts from PPEC. We note that section 8.2.3.b of Appendix W provides that "nearby sources" should be explicitly modeled and explains that identification of nearby sources for modeling purposes is within the exercise of professional judgment by the reviewing authority. While it is EPA policy that the cumulative analysis may include nearby sources that have not yet been constructed, if they have been issued a PSD permit to construct or if they have submitted a complete PSD permit application at least 30 days prior to the proposed source's permit application,[34] we note that there are no such permits or pending applications in the PPEC area, so the PPEC analysis did not include any such future sources.

63. **Comment:** The commenter concludes that the EJ Analysis conducted by the EPA for the Proposed PSD permit fails. The EPA EJ analysis misses the first and most important step of any EJ analysis which is the proper identification of the location and demographics of the minority community. Thousands of inmates are located just several thousand feet from the proposed power plant and the Otay Mesa Power Plant. Those inmates will be exposed to the emissions from these two power plants 24 hours a day seven days a week. The localized impacts of these two power plants requires onsite monitoring at the prison sites to determine actual background pollutant concentrations to analyze the true impact of this power plant to these prisoners.

Response: EPA believes that its consideration of environmental justice issues in this case is appropriate and consistent with our obligations under EO 12898 as well as our responsibilities under the CAA and its implementing regulations. The commenter is directed to our Response to Comments 45 and 53-60 above.

Comments Submitted by Rob Simpson

64. **Comment:** The commenter states that this and the following emails from him constitute his opening comments and request for an extension of the public comment opportunity for the Pio Pico Proposed PSD permit. [35]

The commenter believes that an extension of the comment period is appropriate because there are live actions regarding this project, which may change its scope, at the state level in the California Public Utilities Commission (CPUC), the CEC and the District. Without germane information from those proceedings the public's ability to comment on PSD issues is unnecessarily restricted.

[34] 45 Fed. Reg. 52676 (August 7, 1980) "Requirements for Preparation, Adoption, and Submittal of Implementation Plans; Approval and Promulgation of Implementation Plans" (amendments to the regulations for Prevention of Significant Deterioration) at p. 52718.

[35] We also received a substantively identical comment as the one describe here from Mr. Simpson's attorney, Gretel Smith.

The commenter states that in its recent decision to license the Carlsbad Energy Center, despite a lack of a PSD determination, the CEC stated; “Power plant applicants at the Commission, when they are required to get a PSD permit, apply to EPA after they have obtained their state permit because it is EPA's preference that state and local permits be issued first. (12/12/2011 RT pp. 190-191.) In fact, EPA will typically wait until state permitting is finished before issuing its PSD. (Ibid.).” In this case the PSD comments are due one day after an evidentiary hearing at the CEC, and prior to evidentiary hearings at the CPUC, no state permitting is finished. The commenter states that, as an intervenor in the CEC and CPUC proceedings and having submitted comments to the air district, it is beyond his ability to participate in 4 disjointed proceedings regarding the same project at the same time. He requests that the EPA take Official Notice of all 3 proceedings. The air district proceeding may contain relevant air quality information, the CEC proceeding should contain relevant environmental information and the CPUC proceeding will demonstrate considerations of the need for the project.

The commenter further asserts that the EPA should include all notice lists from all 3 proceedings in its Notice of this proposed action, as they have demonstrated that they are interested parties for this proposed project. At this point there appears to be no notice issued by the EPA to the officials or interested parties from any other proceeding. The proposal should first be determined as necessary by the CPUC, next the CEC and Air District should do their combined proceeding and if the EPA declines to participate in the combined proceeding, their proceeding should follow the state determinations. This is how the system was designed and the only way to for the public to effectively participate. It is how the CEC describes the procedure. It would also preserve EPA resources.

The commenter also states that the District’s determination is not final and should not be relied on, at least, until the CEC issues a decision. He submitted comments to the air district on their preliminary determination. The Air district failed to respond to his comments and issued their decision. He submits the same comments regarding the Proposed PSD permit, in the following email, and requests that the EPA revoke the air districts authority for its failure. The EPA is not in a position to make a final decision on this project and so should not require that the public make one in the form of comments at this time.

The commenter contends that there is no need for this project. The commenter states that in response to his comments on the Palmdale proposed PSD permit, the EPA stated: “EPA has previously recognized that it may consider the need for a facility and a “no build” alternative within the context of CAA section 165(a)(2). In re Prairie State Generating Company, 13 E.A.D. 1, 32 (EAB 2006) (“Prairie State”). However, we have also observed that it is appropriate to refrain from analyzing whether a proposed facility is needed where the State has tasked another State agency with the authority to consider that issue. Id. Consistent with this precedent, EPA believes that mechanisms within the State of California provide the appropriate vehicles through which to address issues regarding the need for natural gas-fired power plants in the State, as these mechanisms involve the entities specifically authorized and best equipped to consider the State's short- and long-term energy needs in the context of State renewable requirements, among other factors.” In this case, as in Palmdale, the state has not finished addressing the issue. The response to comments further states, "In California, in order to conduct a reasoned analysis to determine the need for new natural gas-fired power plants in general, or a specific natural gas-fired power plant in particular, either within the State as a whole, or in a particular geographic location within the State, EPA would need to consider a myriad of extremely complex factors and detailed information that EPA has neither the resources nor the expertise to analyze." The commenter requests that the EPA take official notice of the Palmdale proceeding presently before the EAB.

The commenter states that there are at least 10,000 pages of documents of 4 different proceedings to review in order to effectively comment on this proposed action, and that he has made records requests to the air district and have not received the records yet. It is too much to review in such a short time period and without final determinations from the state agencies. It would require at least another 30 days to receive a response to his records requests and review documents.

The commenter asserts that the extension or delay of comment period deadlines may expedite a final permit. In Palmdale, the EPA denied his request for an extension of the comment period. He appealed that denial, and other issues, to the Environmental Appeals Board (EAB), eight months ago, on November 17, 2011. The EAB has still not made a decision. The EPA could preserve resources by cooperating with the public and considering state level decisions. Should the EPA have difficulty understanding the relevance of the above requests and following comments please inform me prior to the expiration of the comment opportunity so that he might clarify them.

Response: First, EPA notes that we extended the comment period for the Proposed Permit to September 5, 2012 (44 days after July 24, 2012, the date the comment period initially ended). EPA notified the commenter and his attorney, Gretel Smith, that the comment period would be extended in an email dated July 26, 2012. See generally our Response to Comment 46 above.

The commenter appears to suggest that EPA delay its public notice and comment process for the Proposed Permit, and/or its final PSD permit decision for the PPEC, until the conclusion of State and local agency proceedings for the Project. The commenter makes various arguments supporting this notion (described above), including an argument that extension or delay of comment period deadlines may expedite a final permit, and that delays associated with appeals of permit decisions to EPA's Environmental Appeals Board might be avoided by EPA's granting such an extended delay.

We believe that our extension of the public comment period for an additional 44 days, as mentioned above, should have served to minimize to some extent the commenter's concerns about overlapping proceedings in different for a relating to the Project. However, we do not believe that further delay in moving forward with processing the complete PSD permit application for the Project, whether in terms of issuing a proposed PSD permit decision, soliciting and considering public comment, or issuing a final PSD permit decision, would be appropriate in this case based on the status of the State and local agency proceedings. Most critically, the one-year deadline in section 165(c) of the Clean Air Act for EPA to grant or deny a PSD permit application compels us to act expeditiously on processing complete PSD applications. The proceedings of the CEC and other State and local agencies in California address matters of State law and are generally outside the scope of matters regulated under the PSD permit for the Project, and do not control EPA's action on PSD permit applications. The commenter does not identify specific issues germane to our PSD permit decision that are likely to be affected by the proceedings in or information or documents generated in these other for a nor does he identify specific deficiencies in EPA's record for this permit that allegedly arise from those proceedings, information, or documents. EPA's actions with regard to this permit are based on the specific administrative record that we have compiled, so commenters do not need to review all documents produced by other agencies in other proceedings related to the Project to comment effectively on EPA's Proposed Permit. We also note that the CEC approved the license for the PPEC on September 12, 2012, and SDAPCD's Final Determination of Compliance (FDOC) was issued on May 4, 2012.

We also note that many detailed, substantive comments on the Proposed Permit were submitted to EPA during the initial public comment period closing date of July 24, 2012. This supports EPA's conclusion that the public comment period provided in this case was sufficient, even before we decided to extend it. In fact, the only commenter who submitted any comments after the close of the initial public comment period on July 24, 2012 was a commenter who had requested an extension of time because he had not received individual notice of the permit although he had previously requested such notice (see Response to Comment 46).

Regarding the commenter's suggestion that EPA use public notice lists from the CEC, CPUC, and SDAPCD proceedings for the Project for EPA's public notice distribution for its PSD permit proceeding, the public notice procedures contained in 40 CFR Part 124, which govern EPA's PSD permitting, do not contain such a requirement. As described in detail in Section I above, EPA has complied with the relevant notification requirements in 40 CFR 124.10 – we provided robust public notification of our proposed permit and supporting analysis to the public and interested parties in both English and Spanish. Pursuant to the controlling regulations, we notified all parties that requested to be on EPA's mailing list for permit actions in Region 9, California, within the San Diego County Air Pollution Control District (SDAPCD or District), San Diego County, or specific to the PPEC. In addition, we notified appropriate federal, state and local agencies (including several organizations on CEC's mailing list for the Project), Indian tribes, and non-governmental organizations. We also sent notice of our proposed permit to more than 90 individuals on the email contact list of the San Diego-Tijuana Air Quality Task Force, which is composed of government and non-government stakeholders from both the U.S. and Mexico. Copies of the Proposed Permit and Fact Sheet were made available at five libraries and the SDAPCD. In addition, the notice was published in multiple newspapers, and posted on EPA's website in both English and Spanish. It is not required, nor do we believe it is warranted, that we issue a specific public notice of our proposed PSD permit action to every individual who may be on the mailing lists for State and local agency proceedings for the Project. In sum, we believe that our public notification process not only complied with Part 124, but went beyond the regulatory requirements by including additional parties that, to the best of our knowledge, might have an interest in EPA's Proposed Permit for the Project.

With respect to the commenter's request that we take official notice of the CEC, CPUC and SDAPCD proceedings with respect to the Project because these proceedings may contain relevant air quality information, environmental information, and information concerning the need for the project, Region 9 is familiar with and acknowledges the CEC and District proceedings. Region 9 is not familiar with the CPUC proceeding(s) concerning the PPEC and the commenter has not provided specific information to identify such proceedings(s). However, as noted above, any CEC, District and CPUC proceedings concerning the PPEC involve matters of State law and are generally outside the scope of matters regulated under the PSD permit for the Project, and the commenter has not provided enough specificity in the comment to indicate any specific details of those proceedings or the information developed therein that affect the Region's PSD permit decision. Our PSD permit decision must stand on its own record – EPA has developed a record for this permitting action – and so we decline to take "official notice" of these proceedings. Further, the commenter has not identified specific documents from those proceedings that should be included in our record, much less explained how those specific documents are relevant to this permitting action. Region 9 must address the facts before it, and public comments should focus on the record that Region 9 has created for this action.

In response to the commenter's argument that we should not rely on the FDOC issued by SDAPCD, at least until the CEC issues its decision, we note that our decision on the PPEC PSD application does not rely heavily on information from the SDAPCD's FDOC proceeding, and the commenter did not identify specific information in the FDOC proceeding that was likely to change in a manner that might affect EPA's PSD permit decision. In any event, the FDOC was issued on May 5, 2012 and the CEC approved the license for the PPEC on September 12, 2012. Thus, the FDOC is final at this time. We also note that the commenter's request that EPA revoke SDAPCD's authority is outside the scope of EPA's PSD permitting action for the PPEC.

The commenter contends that there is no need for the project, acknowledges previous statements by EPA in another EPA PSD permit proceeding for the City of Palmdale indicating the State of California's role in making determinations of need for such projects, requests that the EPA take official notice of that proceeding before the EAB,[36] and argues that the State has not fully addressed the need issue in this case. In so doing, the commenter appears to suggest that EPA should wait to proceed with its final PSD permit decision until

[36] Region 9 is well aware of the City of Palmdale PSD permit appeal. We note that the commenter's quotations of certain statements made by Region 9 in its Response to Comments document in that proceeding are accurate and we have considered them in our decision here. We note that the EAB recently issued a decision in the City of Palmdale proceeding upholding Region 9's decision not to conduct an independent analysis of the need for the facility at issue. See *In re City of Palmdale*, PSD Appeal No. 11-07, slip op. at 56-60 (EAB Sept. 17, 2012), 15 E.A.D. ___. However, Region 9 declines the commenter's request that we take "official notice" in this permitting action of the Palmdale EAB proceeding. As explained above, the PSD permit decision for the Project before us must stand on its own record. Further, the commenter has not identified specific documents from the proceeding of which we are requested to take "official notice" nor explained how any such documents are relevant to this action.

the State has determined the need for the Project. The commenter does not provide information or analysis supporting his assertion that there is no need for the Project.

The relevant portion of CAA section 165(a)(2) provides that PSD permitting authorities must provide the public with the opportunity to comment on "the air quality impact of[the proposed] source, *alternatives thereto,* control technology requirements, and other appropriate considerations[.]" CAA § 165(a)(2), 42 U.S.C. § 7475(a)(2) (emphasis added). The EAB interprets this language to allow, but not require, a permitting authority to consider a no-build alternative. *See In re Prairie State Generating Co.,* 13 E.A.D. 1, 32-33 (EAB 2006); *In re City of Palmdale*, PSD Appeal No. 11-07, slip op. at 57 (EAB Sept. 17, 2012), 15 E.A.D. ___. The EAB has made clear that the permit issuer does not have an obligation to independently investigate alternatives beyond those raised in public comments, including a no-build alternative. Further, the Board has observed the importance of this limitation on the permit issuer's obligation, particularly where the evaluation of need for additional electrical generation capacity would require a rigorous and robust analysis and would be time-consuming and burdensome for the permit issuer. In such circumstances, the permit issuer is granted considerable latitude in exercising its discretion to determine how best to apply scarce administrative resources.

As stated by the commenter, EPA has noted previously that in general, in California, in order to conduct a reasoned analysis to determine the need for new natural gas-fired power plants in general, or a specific natural gas-fired power plant in particular, either within the State as a whole, or in a particular geographic location within the State, EPA would need to consider a myriad of extremely complex factors and detailed information that EPA has neither the resources nor the expertise to analyze. This reasoning also applies in this case. The Region has the discretion, but is not required, to conduct an independent analysis of the need for the PPEC in the context of this PSD permit proceeding. *See In re City of Palmdale*, PSD Appeal No. 11-07, slip op. at 56-60 (EAB Sept. 17, 2012), 15 E.A.D. ___ (upholding Region 9's decision not to conduct an independent analysis of the need for the facility at issue). In this case, EPA does not believe that it is appropriate to conduct the type of rigorous and robust analysis that would be required to definitively determine the need for the Project. Even if EPA did have the expertise and resources to conduct such an analysis, the commenter has not provided any information on which to conduct such an analysis. We note, however, that while EPA has not conducted a detailed needs analysis for the PPEC, available information in the record for EPA's permit decision indicates that there is, in fact, need for the Project – see Section 7.13 of the Fact Sheet, page 16. The applicant has a 20-year Power Purchase Agreement with San Diego Gas & Electric (SDG&E). The purpose of this project is to meet the specific objectives of SDG&E's 2009 Request for Offers and the resulting contractual requirements contained in the PPA. See also Response to Comment 40.

Finally, to the extent the commenter is suggesting that EPA should wait for agencies within the State of California to conduct a detailed needs analysis before EPA proceeds with its final PSD permit decision, the commenter cites no authority for such a proposition nor is EPA aware of any. We are not deferring in this case to any agency's specific determination of need for the PPEC, and the commenter did not point to any specific information related to any such determination that we should consider. Rather, we have recognized that the

State agencies in California are better suited than EPA to assess California's energy needs in general.

The commenter also submitted a series of emails that contained miscellaneous attached documents. With the exception of one email that is the subject of this response, the body of those emails did not contain any actual comments on EPA's Proposed Permit or Fact Sheet. The attachments do not contain any actual comments on EPA's Proposed Permit or Fact Sheet for PPEC, nor has the commenter explained with any specificity the attachments' relevance to EPA's PSD permit decision. Therefore, EPA cannot provide a detailed response. EPA acknowledges the commenter's documents provided as attachments to his email transmittals and has included the attachments as part of the commenter's comments in the record for this action.

We also note that the commenter did not author any of the documents he submitted as attachments to those emails, with the exception of two letters, both dated January 18, 2012, which were submitted by the commenter and his attorney to SDACPD. These comment letters were issued long before EPA issued the Proposed Permit and Fact Sheet in this action, and constitute comments on SDAPCD's Preliminary Determination of Compliance for the project. However, the letters do not address or comment on the Proposed Permit and Fact Sheet, nor has the commenter explained with any specificity the letters' relevance to EPA's PSD permit decision**.** Accordingly, EPA cannot provide a detailed response to these letters.

In addition to the two letters, the commenter submitted a series of other documents:

- a document entitled "Standardized Planning Assumptions (Part 1) for System Resource Plans" that was submitted to the California Public Utilities Commission
- two scholarly articles by Jacobson ("On the causal link between carbon dioxide and air pollution mortality" and "Enhancement of Local Air Pollution by Urban CO2 Domes")
- a document entitled "Approved ARB-CEC Joint Policy Statement of Compliance with Air Quality Laws by New Power Plants"
- a document (presentation) prepared by a consultant entitled "San Diego Smart Energy 2020"
- a document (presentation) prepared by a consultant called "Energy Storage for Flexible Peaking Capacity"
- a CEC document entitled "Rebuttal Testimony of Bill Powers"

As with the letters commenting on SDAPCD's PDOC, the commenter has not explained with any specificity these documents' relevance to EPA's PSD permit decision, and therefore EPA cannot provide a detailed response.

Comments Submitted by Johannes Epke on behalf of Helping Hand Tools, Executive Director Rob Simpson

65. **Comment:** The comment asserts that PPEC is subject to PSD for CO because as currently permitted the facility has the potential to emit over 100 TPY of CO. The facility's PTE CO is underestimated because it is based on false assumptions and expectations. Specifically, the applicant claims that it expects maximum emissions of all criteria pollutants will occur at 100% load, which is not true for CO.

    The commenter states that the applicant claims in Table 1-1 on page 2 of the PSD application that the facility is not subject to PSD for CO because the PTE CO is 96.4 TPY, under the 100 TPY PSD threshold. Footnote C of this table directs the reader to AFC (Application for Certification) Table 5.2-31 for the source of this figure. The 96.4 TPY figure first appears in Table 5.2-20 on page 5.2-40 of the AFC, and the method of calculation is described as follows:

    Combustion turbine performance was evaluated for a number of operating scenarios with different turbine loads (ranging from 50% load to 100% load), and ambient temperatures ranging from a low of 30°F to a high of 110°F. The maximum hourly emissions for all criteria pollutants from the turbine during normal operations are expected to occur under the conditions with the highest firing rate: 100% load, use of evaporative cooling, and 72°F ambient temperature.

    The commenter asserts that the fatal flaw in the above-described method of calculating maximum CO emissions is that CO emissions are not at a maximum under conditions with the highest firing rate. CO emissions are the product of incomplete combustion and are emitted at higher rates when combustion turbines are operating at lower loads. According to EPA document AP-42 Chapter 3.1-4, "a gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide."

    The commenter states that the applicant provides detail of the facility's expected CO emissions in the AFC Appendix G, Table G-3.1 on page G-3-2. This table shows that the applicant expects the CO emission rate to be 0.0088 lb/MMBtu for all operating parameters, including both 100% load and 50% load. The applicant provides no further explanation of the source of this figure, or the rationale behind assuming that the emission rate will be the same for all operating parameters, contrary to conventional understanding of CO emission rates from this type of source.

    Response: EPA disagrees with the commenter's contention that the Facility's CO PTE has been underestimated and that the Project is subject to PSD review for CO. While EPA agrees that uncontrolled CO emissions from the engines will vary between 50% and 100% load, these engines will be equipped with oxidation catalysts. Regardless of load, the maximum CO emission rates from the Project (excluding startups and shutdowns, which are accounted for separately) are expected to be 4.0 ppmv @15%O_2, 0.0088 lb/MMBtu, and 7.97 lb/hr. (See PPEC PSD Application, pages PSD-4.32, and PSD App -1.51.) These rates were calculated from emission concentration rates and the exhaust flow rates from vendor performance data, and reflect the control efficiency expected to be achieved by the oxidation catalyst required by the permit issued to PPEC by the SDAPCD.

EPA concurs with the CO emission data presented by the applicant. The SDAPCD permit contains effective federally enforceable CO emission limits of 4.0 ppm, 8 lb/hr, and 96.4 tpy. PPEC does not have "significant" emissions of CO, as that term is defined in the PSD regulations at 40 CFR 52.21, and therefore is not subject to PSD review.

As noted in our Response to Comment 2 above, our review is based on the applicant's PSD application, not the Application for Certification submitted to the CEC.

66. **Comment:** The commenter states that EPA cannot rely on the District permit CO limit to avoid BACT analysis for CO. In addition to the above deficiencies regarding analysis of CO emissions from the facility, the EPA cannot rely on the air district's PSD analysis to conclude that the facility is not subject to BACT for CO. As the District acknowledges in its PDOC, "The District is currently not delegated to implement federal PSD by EPA nor does it have a PSD rule that has been approved by EPA. Hence, PSD permitting for federal PSD is solely the responsibility of EPA at the current time." Hence, EPA cannot rely on the District's faulty CO PSD conclusions and must perform an independent analysis.

    Response: EPA disagrees with the commenter that we cannot rely on the permit issued by the SDAPCD to determine that the Facility is not subject to PSD review for CO. As noted in our response to the previous comment, the SDAPCD permit contains effective federally enforceable CO emission limits of 4.0 ppm, 8 lb/hr, and 96.4 tpy. Since the CO PTE is less than the 100 tpy PSD significance threshold, the Facility is not subject to PSD for CO. The commenter has not provided any basis for the claim that SDAPCD arrived at "faulty CO PSD conclusions" beyond its argument that CO emissions have been underestimated, which is addressed in the response to the previous comment. We also note that EPA has the authority to enforce the permit issued by the SDAPCD to the Facility.

67. **Comment:** The commenter provides excerpts of comments submitted by Rob Simpson to Steven Moore of the SDAPCD on January 18, 2012 regarding the PDOC for proposed development of the PPEC (District Application No. APCD2010-APP-001251). The commenter requests that EPA consider the comments as they are applicable to the current proposed PSD permit, and states that any reference to the District as the permitting agency or the PDOC as the permit at issue should be construed as referring to the EPA and the proposed PSD permit respectively.

    Response: Commenter Rob Simpson has already submitted his comments on SDAPCD's draft PDOC to EPA as comments on our proposed PSD permit for PPEC. We noted in our Response to Comment 64 above that the commenter did not explain how these comments are relevant to EPA's PSD review for the PPEC, and therefore EPA cannot provide a detailed response. Here, the commenter states that the comments are relevant but, again, does not provide any specific information explaining why he believes that is the case. The commenter suggests that we should construe comments that Mr. Simpson previously submitted to the District concerning the PDOC, a document prepared in a separate permit proceeding by the District under State and local law, and on a different administrative record, such that the terms “District” and “PDOC” mean instead “EPA” and “Proposed Permit.” This suggestion is inappropriate and unreasonable, and does not provide a sufficient explanation of how these comments on the District’s PDOC, which were prepared long before EPA even issued its Proposed Permit and Fact Sheet, are relevant to EPA’s PSD permitting action. It is incumbent on the commenter to raise any concerns regarding the Proposed Permit with reasonable clarity and specificity. Nothing in the permitting procedures contained in 40 CFR part 124 requires EPA to effectively rewrite comments prepared many months before the issuance of EPA’s Proposed Permit, which concern a different permit in a different proceeding under State and local law, in order to tailor those comments to the proceeding before us, or to sift through those comments to determine which of them might be relevant to our PSD permit review and in what respects. Since the comments does not specifically address or comment on the Proposed Permit and Fact Sheet or explain their relevance to EPA’s PSD permit decision, EPA cannot provide to response.

Comments Submitted by the Rincon Band of Luiseño Indians

68. **Comment:** The commenter provided a letter written on behalf of the Rincon Band of Luiseño Indians. The commenter thanked EPA for inviting the Rincon Band to submit comments on the Pio Pico Energy Center Project, and stated that Rincon is submitting comments concerning the Project’s potential impact on Luiseño cultural resources. The Rincon Band has concerns for impacts to historic and cultural resources and findings of significant cultural value that could be disturbed or destroyed and are considered culturally significant to the Luiseño people. The commenter stated that the identified project location is not within the Luiseño Aboriginal Territory. The commenter recommended that EPA locate a Tribe within the project area to receive direction on how to handle any inadvertent findings according to their traditions and customs, and recommended that a Native American Monitor be present during any and all ground disturbances. The commenter recommended that EPA contact the Native American Heritage Commission or notify the Rincon Tribe if EPA needs further information on Tribes within the project area. The commenter also provided updated contact information for the Rincon Band.

    Response: EPA appreciates the Rincon Band’s suggestions and recommendations to ensure the protection of potential tribal cultural resources that might be affected by the PPEC and believe that appropriate action has been taken to ensure such protection. We note that EPA provided notice to a number of Tribes in the area near the Project of our Proposed Permit for the PPEC.

    The applicant and the CEC have conducted extensive analyses of cultural resources, including Tribal cultural resources, and the CEC has developed detailed and mandatory protocols to protect such resources, in the PPEC project area. As part of this effort, the applicant and CEC contacted the Native American Heritage Commission (NAHC) to request information regarding the presence of Native American cultural resources in the vicinity of the proposed PPEC, as well as a list of Native American representatives to whom inquiries could be made to identify any additional cultural resources and/or any concerns that Native Americans might have about the proposed project. The applicant contacted the Native American representatives on the list provided by the NAHC to obtain the representatives' input on the project and received two responses, although neither offered specific information regarding the existence or location of sacred sites for Native American cultural resources related to the PPEC project area. The CEC also sent letters contacting the Native American representatives and as of May 2012, had received limited responses from two local Native American representatives, which concerned tribal requests for Native American monitoring. The CEC has stated that its Cultural Resource Conditions, discussed below, would accommodate those tribal requests for monitoring.

The CEC license for the PPEC includes a number of specific Cultural Resources Conditions intended to protect cultural resources, including tribal resources, in the PPEC project area, and provides detailed protocols to protect such resources. Among other things, these conditions require the project owner to provide a qualified and CEC-approved Cultural Resources Specialist to generally manage cultural resources monitoring, mitigation, curation, and reporting activities, and pre-construction cultural resources activities. These conditions further provide that prior to the initiation of construction-related ground disturbance, the project owner must develop and obtain CEC approval of a Cultural Resources Monitoring and Mitigation Plan, which is to include a description of the manner in which Native American observers or monitors will be included, the procedures to be used to select them, and their role and responsibilities. In addition, these conditions provide that at least 30 days prior to the start of ground disturbance, the CEC will notify all Native Americans with whom the CEC communicated during the project review of the date on which the project's ground disturbance will begin, and generally provides that at the request of a Native American tribal representative with ancestral ties to the project area, the project owner is to obtain the services of one or more Native American representatives to monitor ground disturbance in the locations of all project linear facilities.

A detailed discussion of the applicant's and CEC's cultural resources analysis and related CEC licensing requirements is included in Section VII.C (pages 7.3-1 to 7.3-28, Cultural Resources) of the September 2012 Final Commission Decision (Decision) for the PPEC. The Cultural Resources Conditions included in the Decision were adopted by the CEC as licensing conditions as shown in the Commission Adoption Order signed September 12, 2012.

Finally, EPA has noted the Rincon Band's updated contact information and updated its records accordingly.

Comments Submitted by the Tijuana Agency for Environmental Protection

69. **Comment (original comment in Spanish):** Anteponiendo un cordial saludo, y en respuesta a la solicitud de comentarios públicos sobre la propuesta de Permiso de Prevención de Deterioros Significativos otorgado por la Agencia de Protección Ambiental (Environmental Protection Agency "EPA"), la Dirección de Protección al Ambiente propone se realice un análisis del efecto que las ondas electromagnéticas provenientes del Centro Energético Pio Pico pudieran tener sobre los Sistemas de Navegación Area de la Ciudad de Tijuana, Baja California, todo esto con el fin de evitar "ruido electromagnético"

en el Sistema de Aterrizaje por Instrumentos (ILS), debido a la potencial interferencia provocada por las radiaciones del Centro Energético Pio Pico.

Así mismo, solicito de la manera más atenta participar con ustedes en un recorrido por el sitio donde se instalará el Centro Energético Pio Pico con pretendida ubicación en No. 7363 Calzada de la Fuente en el Parque Empresarial Mesa de Otay.

ENGLISH TRANSLATION:
Greetings, and in response to your request for public comments regarding EPA's proposed Prevention of Significant Deterioration permit, the Agency for Environmental Protection proposes that an analysis of the effects that electromagnetic waves emanating from the Pio Pico Energy Center might have on the Tijuana City Area Navigation Systems (Baja California) be performed, all with the purpose of preventing "electromagnetic noise" in the Instrument Landing System (ILS), due to the potential interference caused by the Pio Pico Energy Center's radiations.

In addition, I politely request to join you in a tour of the site where the Pio Pico Energy Center will be constructed, with a proposed location at 7363 Calzada de la Fuente in the Otay Mesa Business Park.

Response: EPA and the City of Tijuana (Mexico) discussed these issues during a telephone conference on August 23, 2012. (This conversation is documented in a Memo to the File for the PPEC dated August 23, 2012, which is included in the administrative record for this PSD permit.) During this telephone conference, EPA provided additional information to the City of Tijuana, including the fact that PPEC would be adjacent to the existing Otay Mesa Energy Center, and the fact that the Brownfield Municipal Airport is within a 2-3 mile distance from the Otay Mesa power plant and the proposed PPEC site. Based on this information, the City of Tijuana stated that it no longer believed that electromagnetic frequencies from the PPEC electromagnetic waves would be a concern, and that no additional follow-up or action on EPA's part is necessary. (EPA also notes that concerns of this nature are generally outside the scope of PSD review.)

SPANISH TRANSLATION:
La Agencia de Protección Ambiental (Environmental Protection Agency "EPA") y la ciudad de Tijuana (México) discutieron estos asuntos durante una conferencia telefónica el 23 de agosto de 2012. (Esta conversación está documentada en un memorándum del archivo para el Centro Energético Pio Pico (PPEC) con fecha del 23 de agosto de 2012, el cual se incluye en el registro administrativo para este permiso de Prevención de Deterioro Significativo (PDS). Durante esta conferencia telefónica, la EPA proporcionó información adicional a la ciudad de Tijuana, incluyendo el dato de que el PPEC estaría adyacente al existente Centro Energético Otay Mesa y el dato de que el Aeropuerto Municipal Brownfield se encuentra a una distancia de 2-3 millas de la central eléctrica Otay Mesa y el sitio propuesto para el PPEC. Con base en esta información, la ciudad de Tijuana declaró que ya no creía que las frecuencias electromagnéticas de las ondas electromagnéticas del PPEC serían una preocupación y que ningún seguimiento adicional o acción de la Agencia

de la EPA fuera necesario. La EPA también notó que las preocupaciones de esta naturaleza están generalmente fuera del alcance de la revisión de la PDS.

Comments Submitted by the National Park Service

70. **Comment:** The commenter understands that EPA is accepting comments on the PPEC PSD permit application proposing to construct and operate three natural gas-fired simple-cycle combustion turbine generators totaling 300 MW capacity. The facility would be located 33 km SE of Cabrillo National Monument. In a March 22, 2012, email, the commenter stated that the National Park Service (NPS) agreed with PPEC's best available control technology (BACT) analysis for nitrogen oxides (NOx). The commenter no longer agrees that their proposal represents BACT because permits for combustion turbines with more stringent NOx limits have been issued, and this information should inform the PPEC BACT determination. For example, a permit application (attached) submitted to the State of Washington for the Gray's Harbor Energy project included Table 3 which contains three entries (Applied Energy, Chouteau Power and King Power) with a 2.0 ppm limit averaged over one hour, which is more stringent than PPEC's proposed 2.5 ppm limit (averaged over one hour). The commenter also attached a permit issued to Dominion Energy in Virginia which contains a 2.0 ppm limit averaged over one hour. While we understand that the examples cited are combined-cycle turbines, PPEC should show that it cannot achieve the same level of performance.

    Response: As noted in footnote 5 on page 11 of EPA's Fact Sheet, while a NO_x emission rate of 2.0 ppm has been demonstrated with combined cycle gas turbine configurations, SCR has not been able to achieve this emission rate on simple cycle turbines due to their higher exhaust gas temperatures and the variability in load as part of their normal operations. The combustion gases from the LMS-100 turbines at PPEC will exit the turbines at approximately 770ºF. The higher temperatures limit the selection of SCR technology available. EPA is not aware of any source that has proposed or achieved a 2.0 ppm NOx emission rate with SCR on a simple cycle gas turbine power plant.

III. Revisions in Final Permit

EPA revised several permit conditions in response to comments we received on the Proposed Permit. We have prepared an underline/strikeout version of the Final Permit to show these changes to assist interested parties in understanding the changes from the Proposed Permit to the Final Permit, and have included this document in the administrative record for this action. However, the signed, clean version of the Final Permit is the official permit, and it controls in the event of any unintended discrepancies between the underline/strikeout version of the Final Permit and the signed, clean version of the Final Permit. In addition, we added a cover sheet to the Final Permit titled “Prevention of Significant Deterioration Permit Issued Pursuant to the Requirements of 40 CFR 52.21”. This cover sheet does not result in changes to the specific terms and conditions that were included in the Proposed Permit.

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
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APPLICATION FOR CERTIFICATION FOR THE *PIO PICO ENERGY CENTER PROJECT*

Docket No. 11-AFC-01
PROOF OF SERVICE
(*Revised 8/16/2012)*

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*indicates change

<u>DECLARATION OF SERVICE</u>

I, Cenne Jackson, declare that on November 21, 2012, I served and filed a copy of the attached Workshop, dated November 19, 2012. This document is accompanied by the most recent Proof of Service list, located on the web page for this project at: www.energy.ca.gov/sitingcases/piopico/index.html.

The document has been sent to the other parties in this proceeding (as shown on the Proof of Service list) and to the Commission's Docket Unit or Chief Counsel, as appropriate, in the following manner:

(*Check all that Apply*)

For service to all other parties:

_x_ Served electronically to all e-mail addresses on the Proof of Service list;

_x_ Served by delivering on this date, either personally, or for mailing with the U.S. Postal Service with first-class postage thereon fully prepaid, to the name and address of the person served, for mailing that same day in the ordinary course of business; that the envelope was sealed and placed for collection and mailing on that date to those addresses NOT marked "e-mail service preferred."

AND

For filing with the Docket Unit at the Energy Commission:

_x_ by sending one electronic copy to the e-mail address below (preferred method); *OR*

___ by depositing an original and 12 paper copies in the mail with the U.S. Postal Service with first class postage thereon fully prepaid, as follows:

CALIFORNIA ENERGY COMMISSION – DOCKET UNIT
Attn: Docket No. 11-AFC-01
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512
docket@energy.ca.gov

OR, if filing a Petition for Reconsideration of Decision or Order pursuant to Title 20, § 1720:

__ Served by delivering on this date one electronic copy by e-mail, and an original paper copy to the Chief Counsel at the following address, either personally, or for mailing with the U.S. Postal Service with first class postage thereon fully prepaid:

California Energy Commission
Michael J. Levy, Chief Counsel
1516 Ninth Street MS-14
Sacramento, CA 95814
michael.levy@energy.ca.gov

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct, that I am employed in the county where this mailing occurred, and that I am over the age of 18 years and not a party to the proceeding.

<u>Originally Signed By Cenne Jackson</u>