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February 19, 2009

DOCKET	
07-AFC-6	
DATE	FEB 19 2009
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VIA HAND DELIVERY AND E-MAIL

Mike Monasmith, Siting Project Manager
California Energy Commission
1516 Ninth Street, MS-15
Sacramento, CA 95814

Re: Carlsbad Energy Center Project (07-AFC-6)
Applicant's Responses to Staff Data Requests, Set 4 (#142-158)

Dear Mr. Monasmith:

Please find enclosed for docketing Carlsbad Energy Center LLC's responses to Staff's Data Requests, Set 4 (#142-158). A copy of this submittal will be forwarded to all interested agencies and intervenors pursuant to the attached proof of service.

Should you have any questions regarding the enclosed material, please do not hesitate to contact John A. McKinsey or Robert Mason.

Respectfully submitted,

Kim Hellwig

Kimberly J. Hellwig
Senior Paralegal

Enclosure
cc: See Attached Proof of Service List

Portlnd3-1657204.1 0035434-00006

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA
1516 NINTH STREET, SACRAMENTO, CA 95814
1-800-822-6228 – WWW.ENERGY.CA.GOV

APPLICATION FOR CERTIFICATION FOR THE CARLSBAD ENERGY CENTER PROJECT

Docket No. 07-FAC-6
PROOF OF SERVICE
(Revised 2/18/2009)

Applicant's Responses to Staff Data Requests, Set 4 (#142-158)

CALIFORNIA ENERGY COMMISSION
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DECLARATION OF SERVICE

I, Elizabeth Hecox, declare that on February 19, 2009, I deposited copies of the aforementioned document in the United State mail at 980 Ninth Street, Suite 1900, Sacramento, California 95814, with first-class postage thereon fully prepaid and addressed to those identified on the Proof of Service list above.

OR

Transmission via electronic mail was consistent with the requirements of California Code of Regulations, Title 20, sections 1209, 1209.5, and 1210. All electronic copies were sent to all those identified on the Proof of Service list above.

I declare under penalty of perjury that the foregoing is true and correct.

Elizabeth Hecox

Elizabeth Hecox

Carlsbad Energy Center Project
(07-AFC-6)

Data Responses, Set 4
(Responses to Data Requests 142 though 158)

Submitted to
California Energy Commission

Submitted by
Carlsbad Energy Center LLC

February 2009

With Assistance from

2485 Natomas Park Drive
Suite 600
Sacramento, CA 95833

Shaw™ Stone & Webster, Inc.

Contents

Tables

Attachment

Introduction

Attached are Carlsbad Energy Center LLC's (Applicant) responses to the California Energy Commission (CEC) staff's Data Requests Set 4, numbered 142 through 158, for the Carlsbad Energy Center Project (CECP). The CEC staff served these data requests on January 22, 2009, as part of the discovery process for CECP's Application for Certification (AFC). Applicant's responses are presented in the same order as the CEC staff presented them and are keyed to the Data Request numbers (142 through 158). New or revised graphics or tables are numbered in reference to the Data Request number. For example, the first table used in response to Data Request 142 would be numbered Table DR142-1. The first figure used in response to Data Request 142 would be Figure DR142-1, and so on.

Air Quality (142–158)

Background: Initial Commissioning and Shakedown

In the AFC, Carlsbad Energy Center, LLC (applicant) described a Commissioning period of 49 days for each turbine, and amended that to approximately 60 days for each turbine in the PEAR document. Yet, the PDOC allows for a Commissioning period of 120 days per turbine. In addition, the PDOC includes an additional 60 day period after Commissioning and before commercial operation called Shakedown, which had previously not been addressed in the AFC. Staff needs clarification as to the changes to the Commissioning period for the project.

Data Request

142. Please describe whether the applicant requested the additional time for the Commissioning and Shakedown periods per new data/information from the turbine manufacturer (Siemens-Westinghouse), or if other relevant information resulted in the additional 60 days in the time period necessary for the Commissioning period for each turbine.

Response: The Applicant requested that the SDAPCD delay implementing the new annual emission limits on existing Units 1, 2, and 3 until 180 days following the first fire of each new gas turbine. The Applicant requested this length of time because these Siemens rapid response units are just being introduced into the market place and have not yet been operated in the U.S. The units employ a unique combination of components like a fast starting gas turbine and an HRSG that can receive hot combustion gases during a fast start. Consequently, these new units may require more evaluation and adjustment than is typical during commissioning which may extend the normal commissioning period. Therefore, the Applicant believes the 180 day period is needed to allow time to resolve these types of commissioning issues. As the Commission Staff is aware, other new technology units in California have required similar, extended startup periods.

Data Request

143. If the additional Shakedown period was requested by the applicant, then please provide a description of this Shakedown period and how it differs from Commissioning. Describe why it is necessary to have this additional period known as Shakedown before the project is deeming commercially operational.

Response: As discussed in Data Response Number 142, the Applicant requested a 180 day period following the first fire of each new gas turbine before implementing the new annual emission limits on existing Units 1, 2, and 3. Based on this request, the SDAPCD developed the concept of a separate Commissioning Period and a Shakedown Period during the writing of the Preliminary Determination of Compliance (PDOC). In the PDOC (see PDOC Condition Numbers 17, 83, and 84) the Shakedown Period delays the implementation of the new annual emission limits on existing Units 1, 2, and 3, until 180 days following the first fire of each new gas turbine.

The Commissioning Period differs from the Shakedown Period in two ways. First of all, the Commissioning Period is for a maximum of 120 days following first fire of a new gas turbine (see PDOC Condition Number 16) compared to a maximum of 180 days following first fire of a new gas turbine allowed for the Shakedown Period (see PDOC Condition Number 17). Second, because there will be elevated emissions during the Commissioning Period, the new gas turbine is exempt from the normal operation hourly NOx, CO, and VOC emission limits in the PDOC (see commissioning exemption in PDOC Condition Numbers 28, 29, and 30). However, there are no such emission limit exemptions allowed in the PDOC for the Shakedown Period. The Shakedown Period simply allows for an extra 60 days beyond the Commissioning Period to ensure that a new gas turbine is operating reliably before implementing the annual emission limits on existing Units 1, 2, and 3. Further, the Shakedown Period combined with the phase-in of the annual emission limits for existing Units 1, 2, and 3 are in place only for unexpected delays in the commercial operation of the new units, in order to allow Units 1, 2, and 3 to continue to provide power generation and reliable service until the new units become commercial.

Data Request

144. Please identify whether the applicant would be willing to stipulate to the Commissioning period, without the additional Shakedown period, as identified in the PEAR document, or some other period(s) for one or both that are shorter than currently allowed in the PDOC.

Response: The Applicant supports the Commissioning Period and Shakedown Period as written in the PDOC and would not be willing to stipulate to a shorter time for either period. While the shorter periods suggested by the Commission Staff are not unreasonable, the Applicant is mindful of the Staff's workload, and believes that it is prudent to anticipate that not everything would go smoothly during the commissioning of these new technology units. The Commissioning/Shakedown periods allowed in the PDOC are reasonable considering that a single failure or malfunction of a major component during the commissioning period could delay the commissioning by several weeks or months while replacement parts are procured. In addition, as shown in the following table a Commissioning/Shakedown period ranging from 120 to 180 days is consistent with commissioning periods allowed for other power plant projects approved by the CEC. Finally, the true limiting factor in the PDOC (see CECP PDOC Condition 16) with regards to minimizing elevated emissions during the commissioning period is the limit of 415 gas turbine operating hours rather then the number of calendar days during which these commissioning operating hours occur.

TABLE DR144-1
Commissioning Period Allowed in CEC Previously Approved Projects

AFC No	Project Name	Condition of Certification	Allowed Commissioning Period
99-AFC-8	Blythe Energy Project	AQ-C3	An initial commissioning period of no more than 120 days.
02-AFC-1	Blythe II Power Plant	AQ-19	An initial commissioning period of no more than 180 days.

TABLE DR144-1
Commissioning Period Allowed in CEC Previously Approved Projects

AFC No	Project Name	Condition of Certification	Allowed Commissioning Period
01-AFC-4	East Altamont Energy Center Power Plant Project	AQ Section - Definition of Commissioning	The commissioning period shall not exceed 180 days under any circumstances.
97-AFC-1	High Desert Power Plant	AQ-21	During an initial commissioning period of no more than one hundred twenty (120) days
01-AFC-17	Inland Empire Energy Center	AQ-18	The commissioning period shall not exceed 509 hours of operation for turbines during the first 180 calendar days from the date of initial operation.
03-AFC-2	Los Esteros 2 Power Plant	AQ Section - Definition of Commissioning	Commissioning Period shall not exceed 180 days
99-AFC-5	Otay Mesa Power Plant	AQ-24	Commissioning Period shall end 120 days after initial firing or immediately after written acceptance of clear custody
01-AFC-24	Palomar Energy Project	AQ-23	Commissioning Period shall end 120 days after initial startup or immediately after written acceptance of clear custody
01-AFC-21	Tesla Power Plant	AQ Section - Definition of Commissioning	The commissioning period shall not exceed 180 days under any circumstances
07-AFC-1	Victorville 2 Hybrid Power Project	AQT-19	Initial commissioning period of no more than 180 days

Background: Tuning

The PDOC defines tuning (Condition 13) as “adjustments to the combustion or emission control system that involves operating the combustion turbine or emission control system in a manner such that the emissions control equipment may not be fully effective or operational.” Staff needs clarifications as to what specific “adjustments to the combustion or emission control systems” will occur, why they will occur, and how often they will occur.

Data Request

145. Please describe why and what “adjustments” will be made to the combustor cans and/or the Selective Catalytic Reduction system.

Response: Following periodic maintenance on the gas turbine combustor cans, it will be necessary to re-adjust fuel and combustion air flows to the combustor cans to minimize NOx and CO at the turbine exhaust. These adjustments are standard in the industry for dry low-NOx combustors, and have been recognized in Commission approvals for the following projects:

- Delta Energy Center (98-AFC-3C); order approving amendment, 9/8/2004

- Metcalf Energy Center (99-AFC-3C); order approving amendment, 3/16/2005
- Moss Landing Power Project (99-AFC-4C); order approving amendment, January 2004
- Mountainview Power Project (00-AFC-2C); order approving amendment, 9/16/2004
- Inland Empire Energy Center (01-AFC-17C); order approving amendment, 5/14/2007
- Russell City Energy Center (01-AFC-7C), Condition AQ-19; order approving amendment, 10/3/2007
- Pastoria Energy Facility Expansion (05-AFC-1), Condition AQ-34; Commission Decision (December 2006)

Data Request

146. Please describe the frequency these adjustments will be made and whether they would occur at the time of the typical annual maintenance period.

Response: Based on the experiences at other plants, the Applicant expects that combustor tuning activities could occur as often as once or twice every calendar year.

Data Request

147. Please define the NOx and CO emission concentrations and hourly emission rate (lb/hr) that are necessary during a tuning event. Please describe the turbine loading and operation of emission control systems during a tuning event. Also quantify the number of hours annually that the Combustion Turbine Generator (CTG) would be undergoing tuning and be subject to the higher emission limits.

Response: As reflected in the SDACPD PDOC (see PDOC Condition 13), gas turbine tuning activities are not expected to occur for more than 12 hours per day or more than 40 hours per year. During these tuning activities, maximum hourly emissions are not expected to be higher than during an extended (six hour) gas turbine startup.

Background: Transient Load Change

Condition 15 of the PDOC defines a transient load change when the combustion turbine exceeds 50 MW per minute change. Subsequently, applicant's January 5, 2009 comment letter states that at load changes as low as 5 MW per minute the NOx BACT levels of 2.0 ppm cannot be met. This would imply that at only times when the project is not subject to load changes could the turbine meet the 2.0 ppm limit. The applicant is requesting (through its January 5, 2009 comment letter) for 15 hours per year per turbine cumulatively for all qualifying conditions to exclude the 2.0 ppm hourly emission concentration limit and replace it with a 12 ppm hourly concentration limit. Staff needs clarification of the various operational scenarios discussed in the applicant's January 5, 2009 comment letter to fully understand what those scenarios are, how they would be known to occur, and their justification.

Data Request

148. Please confirm that applicant's proposed condition XX from its January 5, 2009 PDOC comment letter (which describes four qualifying events/conditions for equipment operation), is meant to cover all transient load events where NOx emission exceptions are sought; and please revise the requested change so that it makes this point clear. In addition, please clarify that this qualifying event language is

only for NOx, and is not being requested for any other pollutant, such as CO and VOC

Response: In the Applicant's January 30, 2009 letter to the CEC commenting on the PSA, this emission excursion language (referred to above as proposed condition XX) was merged with the transient load condition (see PSA Condition AQ-15) for clarification purposes. While the pollutant of main concern during these transient conditions is NOx, the Applicant is also requesting that CO and VOC be included with this condition due to possible elevated emissions for these pollutants during transient operation.

Data Request

149. Please discuss why the applicant would bid their project to meet either California ISO or SDG&E resource needs, when the project appears incompatible with the ramp rates required by the bid specifications. Please include in this discussion if changes could be made to the project to allow it to meet all the bid specifications.

Response: The CECP project will be able to meet both California ISO (CAISO) operating requirements and the SDAPCD PDOC limits. With regards to ramp rates, the CAISO requirements were specific to operational capability during a singular short-term event lasting only a few minutes as opposed to maintaining this ramp rate during ongoing cyclic operation of the plant that could occur over a prolonged period. By providing suggested changes to the PDOC transient operating limits, the Applicant was attempting to address likely operating scenarios that could cause maximum ramp rates and possibly elevated emission levels.

Data Request

150. Should the project be excluded from bidding on certain resource bids, or should the project be bundled with other generation resources (such as a simple-cycle peaker) to ensure all bid specifications can be met within the permit limits?

Response: With regards to CAISO ramp rate requirements, the proposed project can meet, and exceed, the CAISO minimum required load change rate for Automatic Generation Control and meet SDAPCD PDOC limits. This CAISO requirement is defined as a change from minimum to maximum load within thirty minutes, which is less than 5 MW per minute, when considering the proposed project's minimum load to maximum load range. The transient operation ramp rate of 10 MW per minute requested in the Applicant's January 5, 2009 PDOC comment letter is twice this CAISO requirement.

Data Request

151. Please discuss when the California ISO would initiate the operation of the project under Automatic Generation Control. Include in this discussion how the California ISO would achieve control of the project and what is meant by Automatic Generation Control.

Response: The Applicant is not in a position to discuss the detailed operations of the California System Operator. However, as discussed in the Applicant's January 5, 2009 PDOC comment letter, the requested emission excursion language for specific transient operations was based on similar language previously approved by the CEC for other power plant projects. Similar emission excursion language can be found in the Final Commission Decisions for the following power plants:

- Cosumnes Power Plant (01-AFC-19, COC AQ-26);
- East Altamont Energy Center Power Plant (01-AFC-4, COC AQ-25i);
- Inland Empire Energy Center (01-AFC-17, COC AQ-22);
- Los Esteros 2 Power Plant (03-AFC-2, COC AQ-19g);
- Los Medanos District Energy Facility Project (98-AFC-1, COC AQ-22);
- Moss Landing Power Plant (99-AFC-4, COC AQ-18);
- Pastoria Energy Facility Expansion Project (05-AFC-01, COC AQ-33);
- San Joaquin Valley Energy Center (01-AFC-22, COC AQ-34);
- Donald Von Raesfeld Power Plant (02-AFC-3, COC AQ-20); and
- Walnut Energy Center Project (02-AFC-4, COC AQ-21).

Three of the above projects previously approved by the CEC (Inland Empire Energy, Los Esteros 2, and Donald Von Raesfeld) include emission exclusion language with a specific reference to CAISO Automatic Generation Control. CAISO Automatic Generation Control is a standard mode of operation that is an ongoing condition for power plants that provide the CAISO with this ancillary service. The proposed project will be providing this service to the CAISO. As such the CAISO (along with the service utility) will effectively be controlling the routine operation of the proposed project. The onsite operators will mainly be responsibility for monitoring equipment operation and will take over equipment operation if necessary to respond to system alarms and/or during gas turbine startups/shutdowns.

Data Request

152. Please provide historical circumstances within the last three years where the California ISO has initiated control of a power plant under Automatic Generation Control. Please provide the documentation from the California ISO that such Automatic Generation Control events occurred.

Response: Automatic Generation Control is not an "event", but an ongoing operational service provided to the CAISO by a power plant. While the CEC staff is in a better position to respond to this question on a system-wide basis, it is the Applicant's understanding that nearly every combined cycle and boiler power plant in California with a rating greater then 50 MW is currently operating under CAISO Automatic Generation Control.

Data Request

153. The January 5, 2009 letter requested that the 2 ppm NOx limit not apply during "[r]apid gas turbine load changes due to activation of a plant automatic safety or equipment protection system which rapidly decreases turbine load." Please discuss why it is not sufficient to rely on the District Rule 98 (Breakdown Conditions: Emergency Variance) instead of trying to formulate a permit condition that appears to cover a breakdown circumstance.

Response: While rapid gas turbine load changes that result in elevated emissions are only expected to occur infrequently, the Applicant does expect such events to occur. Consequently, the applicant does not believe that these events would qualify for relief under the SDAPCD Breakdown Regulation (SDACPD Rule 98), since such an event would have to be an unforeseeable failure or malfunction of air pollution control equipment, and must not be recurrent events. Even if the SDAPCD were to exercise enforcement discretion and grant relief for excursions due to these events, the Applicant believes it would be more prudent for these types of rapid gas turbine load changes to be addressed specifically in the SDAPCD permit and CEC Conditions of Certification. With this approach it will be clear to both the plant operators and regulatory agencies that these types of operating scenarios were considered and approved during the permitting process.

Data Request

154. Please discuss why the initiation and shutdown of the inlet air cooler would adversely affect complying with the 2 ppm NOx concentration. Please provide substantiation that a Siemens Rapid Response SCC6-5000F turbine unit with an evaporative inlet air cooler needs an exemption from the 2 ppm NOx concentration.

Response: As discussed in Data Response Number 151, the requested emission excursion language for specific transient operations was based on similar language previously approved by the CEC for other power plant projects. Nearly all of the previously approved projects listed in Data Response Number 151 included the initiation or shutdown of the gas turbine inlet air cooling system as a qualifying condition for emission excursions. Initiation or shutdown of the inlet air cooling system could result in significant changes in the inlet air temperature and relative humidity. This in turn could result in a rapid change in gas turbine load due to a change in the inlet air density which is affected by inlet air temperature/humidity.

The only information the Applicant has received from Siemens regarding NOx emission changes due to rapid load changes for a SGT6-5000F gas turbine was included in the Applicant's January 5, 2009 PDOC comment letter to the SDAPCD. As shown by this data the gas turbine outlet NOx levels can change rapidly from below 8 ppmvc[1] to as high as 13 ppmvc (prior to SCR) during transient gas turbine operations. Also included in this letter is a summary of NOx Continuous Emissions Monitoring (CEM) system data for four California power plants equipped with Siemens 501FD gas turbines (similar to those proposed for use for the CECP) and eight plants equipped with General Electric 7FA gas turbines. Excluding routine gas turbine startups and shutdowns, this CEM summary shows several instances for each power plant when NOx levels were higher then 2.0 ppmvc and were sometimes as high as nearly 30 ppmvc. The transient load NOx limit of 12 ppmvc requested in the Applicant's PDOC comment letter was based on this summary of CEM data.

Data Request

155. Please define the NOx and CO emission concentrations that are anticipated during the initiation and shutdown of the evaporative inlet air cooler. Also quantify the number of annual operation hours for this scenario.

Response: A discussion of the available NOx emissions data and maximum expected NOx level during rapid gas turbine load changes is discussed in Data Response Number 154. There is insufficient data available from Siemens to quantify the expected CO emission concentrations during these rapid gas turbine load changes. The Applicant would expect the CO excursion to be of the same order of magnitude as the NOx emissions change which

[1] ppmvc = ppmv at 15% O_2.

would be approximately six times the BACT limit (12 ppmvc for CO). As discussed in the Applicant's January 5, 2009 PDOC comment letter, the combined total number of qualified transient hours including excursions due to initiation/shutdown of the inlet air cooling system would be limited to 15 hours per 12-month period.

Data Request

156. The applicant requests in its January 5, 2009 PDOC comment letter the following language exempting the 2 ppm NOx concentration be added to the permit conditions: "Events as the result of technological limitation identified by the operator and approved in writing by the District." This language appears to be overly broad and open-ended. Please clarify the intent of this language and the technical reasons and "technological limitations" that could arise that would be included under this exemption.

Response: As discussed in the Applicant's January 5, 2009 PDOC comment letter, it is clear that all twelve F-Class power plants currently operating in California have exceeded their NOx hourly permit limits for a few hours over the past couple of years. While it would be an interesting case study to determine the exact cause for each of these excess emission events, is it beyond the Applicant's ability to perform such an analysis due to limitations on available detailed emissions/operating data from the power plants in question. It is likely that these excess emission events were caused by a range of operating issues including the ones described in the Applicant's emission excursion language (i.e., rapid gas turbine load changes due to the activation of safety systems or initiation of the CAISO Automatic Generation Control system, etc). The causes could also include other factors that affect the gas turbine combustion system such as changes in the natural gas supply temperature and/or natural gas heating value.

Because there are likely several possible causes for short-term emission excursions for F-Class power plants and because it is not possible at this time to know the precise reasons for all of these emission excursions, it is important for the emission exclusion language to include a general exemption clause. The "technological limitation" language serves as a general exemption clause to cover situations when there is a short term emissions excursion due to a legitimate unanticipated change in operating conditions. This language gives the power plant owner/operator an avenue to explain the situation to the SDAPCD and request an exemption. The SDAPCD can and will deny such a request if they are not convinced that the requested emission excursion is legitimate. It is also important to remember that the excursion language prohibits the power plant owner/operator from requesting an exemption due to operator neglect, improper equipment operation, improper equipment maintenance, and qualified equipment breakdowns under the SDAPCD regulations. The excursion language also limits the total number of excursions (regardless of justification) to 15 hours per 12-month period.

Data Request

157. Please estimate the maximum hourly NOx emissions associated with the 12 ppm concentration requested for the qualified transient load events and confirm that, assuming both turbines are concurrently operating under the 12 ppm limit, that these emissions do not result in the potential for impacts greater than those already modeled and analyzed for worst-case 1-hour NOx emission events.

Response: The maximum hourly NOx emissions at 2 ppmvc during full load operation are approximately 15.1 lbs/hr. Consequently, at 12 ppmvc the corresponding hourly NOx emission rate would be approximately 90.6 lbs/hr[2]. If both of the gas turbines associated with the proposed project experienced this emission excursion simultaneously, the combined NOx emissions would be approximately <u>181 lbs/hr</u>. The CECP AFC included a modeling analysis during the commissioning period when one gas turbine is undergoing commissioning and the second gas turbine is undergoing a routine startup. The combined NOx emission rate during this period is approximately <u>286 lbs/hr</u> which is 60% higher than the NOx emission level at 12 ppmvc. As shown in the PSA (CECP PSA, Table 25), the commissioning phase modeled impacts for the proposed project are below the most stringent NO_2 ambient air quality standard. Consequently, the Applicant expects the ambient NO_2 impacts when operating at 12 ppmvc to be significantly lower then the modeled impacts during commissioning and well below ambient air quality standards for NO_2.

Background: Permit Applicability Determination (PSD)

The San Diego County Air Pollution Control District's (District) Preliminary Determination of Compliance (PDOC) finding for PSD permit applicability was based on the District's interpretation of their own regulations rather than a strict interpretation of U.S.EPA PSD applicability emission calculation requirements. Since the District is not currently delegated PSD permitting authority from the U.S.EPA, and the applicant has not formally requested a PSD permit applicability finding from U.S.EPA, staff is concerned about the validity of the PSD permit applicability finding. Staff needs the applicant to provide a PSD applicability analysis, based on Federal PSD statute requirements, in order to accurately assess the PSD permit applicability and complete the Laws, Ordinances, Regulations, and Statutes (LORS) findings for this project.

It is staff's belief through conversations with U.S.EPA staff that the pertinent section in the PSD regulation is 40 CFR Part 52.21 (b)(48)(i), which specifies the requirements for determining baseline actual emissions from existing electric utility steam generating units, including requirements for non-compliant operations and multiple emission units. The specific issues most relevant to the assessment for the proposed project are the fact that the baseline must be based on the average annual emissions for a 24-month consecutive period that is the same for all of the multiple units, although not necessarily the same 24-month period for each pollutant, and that the 24-month period must be within 5 years immediately preceding the actual construction date. Since the project may not begin construction until sometime during 2009, it appears that would limit the period to the maximum 24-month emission period from no earlier than 2004 through the present.

Data Request

158. Please provide, according to federal PSD statute requirements for the actual emission baseline calculations for power plants, the applicant's PSD permit applicability assessment for both NO_2 and PM10 emissions. Please note that staff will likely request that U.S.EPA review this assessment for concurrence.

Response: The annual net emission increase associated with the shutdown of existing Units 1, 2, and 3 and operation of the proposed new units are shown in the SDAPCD PDOC (CECP PDOC, Table 5c). As shown by this analysis, the net emission changes for the

[2] Based on (12 ppmvc/2 ppmvc) x 15.1 lbs/hr.

proposed project are below the Federal PSD significance levels of 40 tons/year for NOx and 15 tons/year for PM_{10} (see 40 CFR 52.21.b.23). Consequently, the proposed project will not trigger PSD review. The emission decrease from the shutdown of existing Units 1, 2, and 3 shown in the PDOC is based on a 5-year baseline period from 2002 to 2006. This baseline period was agreed upon during the March 26, 2008 CEC CECP workshop and is reflected in both the PSA and PDOC.

While the Federal PSD regulations generally require that baseline emissions for existing electric utility steam generating units be based on a 2-year average of actual emissions during the 5 years preceding the initial construction of new units (see 40 CFR 52.21.b.48), the PSD regulations allow the use of a different look back period if requested by an applicant and approved by the EPA. This flexibility allowed in the PSD regulations is an important tool given the difficulty in accurately estimating the future operation of existing units during the period between when a permit is processed/issued for a new unit and when construction begins on a new unit. An example of this flexibility in the allowed baseline period is a decision that EPA Region IX made for the Morro Bay Plant Modernization Project where the EPA allowed a 10-year look back period to establish the baseline emissions for existing units (see Attachment DR158-1 for copy of this EPA decision).

Given the uncertainty of future operations of existing Units 1, 2, and 3 and the corresponding future emissions, the Applicant continues to believe that it is appropriate for PSD applicability purposes to use actual emissions during the period from 2002 to 2006 to determine the emission decrease associated with the shutdown of Units 1, 2, and 3. As shown in the PSA (CECP PSA, page 4.1-28) and the PDOC (CECP PDOC, Table 5a), the maximum 2-year average NOx and PM_{10} emissions for Units 1, 2, and 3 occurred during the period from 2004 to 2005. As shown in the following table, using this baseline period the net emission increase for the proposed project is below PSD significance levels. Therefore, the proposed project does not trigger PSD review.

TABLE DR158-1
PSD Applicability for CECP

Pollutant	Potential to Emit for New Units[3] (tons/year)	Emission Reductions for Shutdown of Units 1, 2, and 3 Based 2004-2005 Average (tons/year)	Net Emission Change (tons/year)	PSD Significance Levels (tons/year
NOx	72.8	-38.9	33.9	40
PM_{10}	39.0	-37.6	1.4	15

[3] See CECP PSA, Table 19 and SDAPCD PDOC, Table 5c for potential to emit for new units.

ATTACHMENT DR 158-1

EPA Region IX Decision on the Morro Bay Plant Modernization Project Assessment

Morro Bay Power Plant Modernization Project
US EPA Response to Comments
Proposed Prevention of Significant Deterioration Air Permit

Introduction

On May 17, 2006, the Region 9 office of the United States Environmental Protection Agency (EPA) requested public comment on a proposed permit for the Prevention of Significant Deterioration (PSD) of air quality, issued in accordance with 40 CFR § 52.21 and Part 124, to LSP Morro Bay, LLC, for the construction and operation of the Morro Bay Power Plant Modernization Project (Modernization Project).

The proposed Modernization Project will consist of two combined cycle gas turbine block units. Each block unit will be capable of producing 600 MW of electrical power, and will consist of two 180 MW natural gas-fired turbines, two heat recovery steam generators with duct burners, one 240 MW steam turbine, and associated air pollution control equipment. The Modernization Project is subject to federal PSD regulations for particulate matter (PM) and particulate matter less than 10 microns in aerodynamic diameter (PM_{10}). Other air emissions from the proposed project, including PM_{10}, are regulated by the San Luis Obispo Air Pollution Control District (District), and are subject to District air permits. A timeline of the Morro Bay PSD Permit Issuance process is shown in Table 1.

During the 30-day public comment period, we received forty-six (46) comments by fax, electronic and U.S. postal mail, thirty-nine (39) of which requested a public hearing for the proposed permit. A public hearing was scheduled for October 24, 2006 in Morro Bay, California. Notice for the hearing was provided to all individuals who submitted comments on the proposed permit, the District, and representatives of the applicant. Additionally, a notice was published in three local newspapers on September 20, 2006: The Tribune (San Luis Obispo, California), the Central Coast Sun Bulletin (Morro Bay, California), and The Bay News (Morro Bay, California). The public hearing was held at the Veterans Memorial Hall at 209 Surf Street in Morro Bay, California, from 6:00 – 8:15 PM on Tuesday, October 24, 2006. A transcript and audio tape recording of the hearing was prepared by Merit Reporting and Video (San Luis Obispo, California), and a video tape is available through AGP Video (Morro Bay, California)[1].

The public comment period closed on October 30, 2006. Any documents upon which EPA relied in reaching a final permit decision, and as referenced in this response to comments, such as the Ambient Air Quality Impact Report (AAQIR) and PSD application, are contained in the Administrative Record. An index of the Administrative Record, many documents in it, and the public hearing transcript, will be made available at www.regulations.gov, linked from the EPA Region 9 website[2].

This document represents the official U.S. EPA response to comments received during the public comment period. Each comment is referenced in this response by number (Table 2). Table 2 includes only substantive comments related to the PSD permit, and does not include

[1] http://www.slo-span.org/cgi-bin/media.pl?folder=SM
[2] http://www.epa.gov/region9/air/permit/r9-permits-issued.html

correspondence that we received which only requested a public hearing. Two comments were generally in favor of the Modernization Project (*# 17, 37*), and the remaining comments raised various concerns regarding the PSD permit and the health impacts of PM_{10}. Because many of these comments contain common themes, they are paraphrased and grouped by issue in this response.

Table 1: Timeline of Significant Events in the Morro Bay Modernization Project Application

Event	Date
Duke Energy Submits Application for Certification (AFC) to the California Energy Commission (CEC)	October 23, 2000
EPA Receives New PSD Permit Application	November 1, 2000
San Luis Obispo Air Pollution Control District Issues Final Determination of Compliance for District Application #3083	August 30, 2001
CEC Issues Part 1 of Final Staff Assessment	November 15, 2001
EPA Requests Concurrence from U.S. Fish and Wildlife Service (FWS) that Modernization Project Not Likely to Adversely Affect Any Federally Listed Species	November 27, 2001
EPA Requests Concurrence from National Marine Fisheries Service (NMFS) that Modernization Project Not Likely to Adversely Affect Any Federally Listed Species	November 30, 2001
CEC Issues Part 2 of Final Staff Assessment	December 19, 2001
CEC Issues Part 3 of Final Staff Assessment	April 25, 2002
NMFS Concludes Informal Consultation with EPA	May 17, 2002
EPA Requests ESA Consultation with FWS	April 10, 2003
CEC Approves Morro Bay Modernization Project	August 2, 2004
FWS Issues Biological Opinion to EPA	May 23, 2005
Duke Energy Submits Addendum to EPA to Implement Conditions of FWS Biological Opinion	June 23, 2005
Ownership of Morro Bay Power Plant changed from Duke Energy Morro Bay, LLC to LSP Morro Bay, LLC	May 4, 2006
EPA Proposes PSD Permit for Modernization Project and Opens Public Comment Period	May 17, 2006
EPA holds Public Hearing in Morro Bay, California	October 24, 2006
Public Comment Period for Proposed PSD Permit Closes	October 30, 2006

Table 2: Reference Numbers for Comments on the Morro Bay Power Plant (MBPP)

No.	Commenter	Format[3]	Date
1	Tacker, Julie	A	June 14, 2006
2	Dorfman, Barry	A; B	June 14; October 24, 2006
3	McCurdy, Jack	A	June 14, 2006
4	Beebe, Curt	A	June 15, 2006
5	Massa-Gooch, Shelley	A	June 15, 2006
6	Perlstein, Abe	A	June 15, 2006
7	Wiley, Susan	A	June 15, 2006
8	Watson, Elaine	A	June 17, 2006
9	Smith, Marie	A	June 20; Sept. 23; Oct. 19, 2006
10	Fram, Joe	A	July 11, 2006
11	Heinemann, Susan	A; C	July 23; October 24, 2006
12	Coastal Alliance on Plant Expansion (CAPE)	D; A	September 28; October 30, 2006
13	Savage, Arline	A	October 24, 2006
14	Ewing, Roger	B	October 24, 2006
15	Johnson, Colleen	B	October 24, 2006
16	Sullivan, Nelson	B	October 24, 2006
17	Johnson, Garry	B	October 24, 2006
18	Carter, Joan	B	October 24, 2006
19	Hill, Phil	B	October 24, 2006
20	LaPlante, Pauline	B	October 24, 2006
21	Crotzer, Shoosh	B	October 24, 2006
22	Crotzer, Colby	B	October 24, 2006
23	Churney, Bonita	B	October 24, 2006
24	Lucas, Michael	B	October 24, 2006
25	Cole, Robin	B	October 24, 2006
26	Risley, Peter	B	October 24, 2006
27	Davis, Mandy	B	October 24, 2006
28	Sadowski, Richard	B	October 24, 2006
29	Nelson, David	B	October 24, 2006
30	Groot, Henriette	B	October 24, 2006
31	Nelson, Monique	B	October 24, 2006
32	Racano, Joey	B	October 24, 2006
33	Beetham, Margaret	B	October 24, 2006
34	Bruton, Marla Jo	B	October 24, 2006
35	Martony, Bill	B	October 24, 2006
36	Dorfman, Barry	B	October 24, 2006
37	Cinowalt, Roy	B; C	October 24, 2006
38	DeMeritt, Melody	B; C; A	Oct. 24; Oct. 24; Oct. 29, 2006
39	Merrill, Lynda	C	October 24, 2006
40	Nelson, David	C	October 24, 2006
41	Taylor, Keith	C	October 24, 2006
42	Winter, H. Leabah	C	October 24, 2006
43	Purcell-McWilliams, Catherine	A	October 30, 2006
44	San Luis Bay Chapter of the Surfrider Foundation	A	October 30, 2006
45	Santa Lucia Chapter of the Sierra Club	A	October 30, 2006
46	CAPE	A	October 30, 2006

[3] A = electronic mail, B = Oral Comments at Hearing, C = Written Comments at Hearing, D = U.S. Mail

Section A: Pre- and post-project emission rate estimates

1. *PM_{10} emission rates of 11 and 13.3 lb/hr estimated by Sierra Research are too low because they were determined using inappropriate EPA test methods. Emission rates of condensable particulate were underestimated by Sierra Research because they were based on EPA Method 8, which is not approved for the measurement of condensable fraction of PM_{10}. (# 12, 23, 29, 31, 43-46)*

    Response to A-1:

    Because EPA Method 8 is an approved test method for sulfuric acid mist, but not for the measurement of condensable particulates, commenters were concerned that emission limits, and thus air quality impacts, are underestimated by the applicant. However, it is noted on page14 of the February 6, 2002 transcript from the CEC Evidentiary Hearing[4] that PM_{10} emission limits proposed by Sierra Research were not based on actual source tests using EPA Method 8. Rather, the PM_{10} emission rates estimated by Sierra Research were based on engineering experience and judgment.

    The proposed PSD permit requires performance tests pursuant to 40 CFR §60.8 (60 days after achieving maximum load but no later than 180 days after initial startup, and annually thereafter) for PM_{10} from the turbine exhaust stacks. The PSD permit does not allow the use of EPA Method 8 for condensable particulates; rather, the permit requires EPA Method 5 for filterable particulate matter (front-half) and EPA Method 202 for condensable particulates (back-half). Specifically, Method 202 test methodology must include a) one hour nitrogen purge b) the alternative procedure described in paragraph 8.1 to neutralize the sulfuric acid c) evaporation of the last 1 ml of the inorganic fraction by air drying following evaporation of the bulk of the impinger water in a 105 °C oven as described in the first sentence of section 5.3.2.3 of Method 202. The conditional test methods CTM-039 or 040, listed on the EPA Emission Measurement Center website: http://www.epa.gov/ttn/emc/ctm.html may be used in lieu of Method 202. The proposed PSD permit has been modified to include these test method specifications in the final permit. Additionally, EPA is currently assessing and improving available test methods for condensable particulate matter.

    The proposed emission rates of 11 and 13.3 lb/hr are consistent with emission limits for similar facilities listed in the EPA RACT/BACT/LAER Clearinghouse (See Response to B-1 and Table 3). Additionally, the proposed PM_{10} emission rates for each turbine block unit, converted into PM_{10} emission factors, i.e., PM_{10} production per unit energy (0.0054 and 0.0065 lb/MMBtu), are comparable to emission factors for

[4] http://www.energy.ca.gov/sitingcases/morrobay/documents/index.html

total PM (sum of filterable and condensable PM) from natural gas fired turbines (0.0066 lb/MMBtu), reported in Chapter 3-1 of AP 42, the EPA compilation of emission factors.

PM_{10} emission limits on the basis of lb/hr and ton per year (tpy) are separately enforceable conditions in the PSD permit (Permit Condition IX.B). Therefore, if the facility exceeds the PSD permit limits of 11 and 13.3 lb/hr without and with duct burner firing, or 203.2 tpy PM_{10}, the facility would be out of compliance and subject to enforcement action.

2. *The calculation of the change in emissions resulting from the project uses a baseline period (1998 – 2000) that is not representative of normal operating conditions. The baseline period includes a period of high energy production, fueled by the California Energy Crisis, and thus improperly inflates the actual emissions used to calculate the net emissions increase for the purpose of PSD applicability. The MBPP has most recently operated at reduced capacity. This recent period is the appropriate baseline period to use for the PSD analysis. (# 12, 29, 31, 34, 43-46)*

Response to A-2:

The PSD permit application submitted by Sierra Research, Inc. in November 2000 uses a 24-month baseline period from August 1998 – July 2000. Sierra Research additionally provided emissions data from January 1997 – July 2000. These data (Appendix 6.2-1.1) show a general pattern of higher criteria pollutant emissions during the late summer to early fall months. The competitive electric market in the State of California began on March 31, 1998, and was operated by the California Independent Systems Operator (ISO) and the Power Exchange (now bankrupt). According to the ISO, the competitive market began smoothly with electricity prices seemingly just and reasonable, until May 2000, when the first signs of a market crisis emerged[5]. The ISO reports that the California energy crisis continued until about May 2001. The baseline period used for the PSD applicability emissions calculations was August 1998 – July 2000, thus, the end of the 24-month baseline coincides with roughly 3 months at the beginning of the energy crisis in California.

Reform rules to the New Source Review (NSR) program, which includes the PSD regulations, promulgated on December 31, 2002 (67 Federal Register 80,186), and implemented March 3, 2003, codified existing policy for calculating "baseline actual emissions" (40 CFR §52.21(b)(48)(i)):

"For any electric utility steam generating unit, baseline actual emission means the average rate, in tons per year, at which the unit actually emitted

[5] http://www.caiso.com/docs/09003a6080/14/c5/09003a608014c508.pdf

the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation."

Based on the NSR Reform regulations, in determining the appropriate baseline period for an electric utility steam generating unit, the source must consider a consecutive 24-month period within the 5-year period immediately preceding actual construction. The source may select and EPA may allow the use of a different time period if such period is determined to be more representative of normal source operation.

The MBPP submitted their Application for Certification (AFC) to the California Energy Commission (CEC), and their PSD permit application to EPA, in November 2000 (see Table 1), using a consecutive 24-month baseline period of August 1988 – July 2000, which was within the 5-year period preceding the scheduled construction date. Although the baseline period chosen by MBPP was appropriate at the time the application was submitted in 2000, because the PSD permitting process has, to date, spanned 7 years, the baseline period must be re-examined, taking into account the 2002 NSR Reform regulations. Assuming actual construction on the project begins in 2007, the five year period, within which to choose the 24-month baseline, incorporates 2002 – 2006.

Beginning in September 2002 – December 2006, MBPP operated at significantly reduced capacity, with a corresponding significant reduction in emissions. During this time, MBPP typically operated only two of the four boilers. Because the boilers are old (circa 1950's -1960's), and MBPP had applied in 2000 to replace them with new combined cycle gas turbines, the reduced operation of the old boilers from 2002 - 2006 is not representative of "normal source operation", as normal operation would not occur at such significantly reduced capacity (in anticipation of boiler replacement), for such an extended period of time. By September 2002, when reduced operation of the boilers first began, the CEC had already issued their final approval of the Modernization Project in their three part Final Staff Assessments (April 2002, see Table 1). At that time MBPP did not expect that the EPA PSD permitting process, and the associated Section 7 ESA Consultation with the U.S. Fish and Wildlife Service, would require an additional 4 – 5 years. Therefore, MBPP determined that reduced operation of the boilers, in anticipation of their pending replacement, from September 2002 – December 2006, is not representative of normal source operation and hence indicated their desire to select a baseline period outside of the 2002 – 2006 period.

Because EPA shall allow use of a different time period upon a determination that it is more representative of normal source operation, we examined emissions of CO and NO_x from the MBPP over January 1997 – December 2006, a 10-year period preceding the revised construction date of 2007. Although we did not have VOC and PM_{10} data for August 2000 – December 2006, NO_x is an appropriate indicator for VOC and PM_{10} trends because emissions of VOC and PM_{10} correlated well with NO_x ($R^2 = 0.93$) over the period that we had data for all pollutants (January 1997 – July 2000). To determine a representative 24-month baseline within the 10-year look-back period, we calculated the average annual emissions based on a 24-month rolling average over the entire 10-year period from January 1997 – December 2006. We then selected the 24-month baseline period where actual annual emissions data most closely match the 10-year average. It is important to note that the average determined from this methodology still accounts for the "highs and lows" of operation during the 10-year period, encompassing both the energy crisis from mid-2000 to mid-2001, and the recent extended period of reduced operation from mid-2002 to late-2006. From this analysis, we determined that the period from June 1998 – May 2000 is the most representative period of normal operation over the 10-year period. This represents a two month shift backwards in time compared to the baseline period used by the facility in their original application (August 1988 – July 2000).

Using this most representative baseline period, while the proposed emissions increase from the project (baseline actual emissions to potential to emit) is higher, it has the same result, relative to PSD applicability, as the baseline period selected by MBPP. In other words, using the 24-month baseline period EPA has determined to be most representative of the previous 10-years, the Modernization Project still triggers PSD only for PM_{10} emissions, and does not trigger PSD for SO_2, CO, NO_x, and VOC. Therefore, although a different baseline period is more appropriate than the one used by MBPP (since the 5-year pre-construction window has shifted), it does not impact the PSD applicability determination. Additionally, if ambient air quality models used the lower baseline emission rate from the more representative 24-month baseline period (June 1998 – May 2000), the results would show that the Modernization Project has a lower impact on air quality than projected in the original Ambient Air Quality Impact Analysis (See Response to Comment C-4).

3. *The PSD analysis fails to consider Emission Reduction Credits, or "offsets" that were used to show compliance with state and local air quality standards, despite the fact that emissions would still increase. These offsets hide the real amount of emissions that the public would be exposed to. (# 44, 46)*

Response to A-3:

The Prevention of Significant Deterioration (PSD) program is the arm of the New Source Review (NSR) Program that regulates emissions of air pollutants for which the area is designated attainment or unclassifiable, from new major stationary sources or major modifications at existing major sources. The PSD regulations require the application of Best Available Control Technology (BACT), analyses of the impacts of the project on 1) PSD increments, 2) ambient air quality, 3) visibility and air quality in Class I areas, and 4) soils and vegetation. See 42 U.S.C. 7475. Offsets are not required by PSD; rather they are a component of the Nonattainment New Source Review (NNSR) Program, the arm of the NSR program that regulates emissions of air pollutants for which the area is designated nonattainment. See 42 U.S.C. 7503(a)(1)(A).

San Luis Obispo Air Pollution Control District Rule 204(B) is a local regulation that requires MBPP to mitigate emissions of any pollutant emitted above certain thresholds. Based on that regulation, the SLOAPCD will require offsets for the Modernization Project for emissions of NO_x, PM_{10}, SO_2, VOC, and CO.

In summary, for PSD purposes, offsets are not required for the Modernization Project because the project will be located in a Federal Attainment area for PM_{10}. The emission increase considered in the PSD analysis is based on the difference between the pre- and post-project emission rates. It would be improper for the PSD analysis to account for PM_{10} offsets because the purpose of offsets is yield a null net emission increase from the project. In this case, if the PSD analysis considered full offsets for PM_{10}, the net emissions increase would be zero. EPA also notes that the purpose of offsets is not to hide the real amount of emissions, as stated in the above comment, but to mitigate the effects of emissions increases in nonattainment areas to allow for new construction without affecting plans for nonattainment areas to achieve attainment. Offsets are not used to circumvent PSD or nonattainment NSR review; rather, offsets are required *as a result* of nonattainment NSR review or district review of project applications.

Section B: Best Available Control Technology (BACT)

1. *The BACT determination from 2000 is too old, and should be updated. (# 10, 12, 21, 24, 29-31, 44, 46)*

Response to B-1:

EPA agrees that the BACT determination made in 2000 should be reviewed to ensure that it is consistent with a 2007 BACT Determination.

The BACT determination was reviewed in 2006 prior to the proposal of the PSD permit, and has been reviewed again in 2007. According to 40 CFR §52.21(j)(4), BACT determinations must be reviewed and modified as appropriate at the latest reasonable time which occurs no more than 18 months prior to commencement of construction. Although §52.21(j)(4) applies to phased construction projects, the 18 month time period provides a guideline for how often BACT determinations must be revisited, given the possibility for improvements in technology, and when construction must be commenced after PSD permit issuance. Because PM_{10} is the only criteria pollutant subject to federal PSD requirements, PM_{10} is the only pollutant requiring a BACT determination.

BACT determinations may be an emission limitation, a design, equipment, work practice, operational standard, or combination thereof (40 CFR §52.21(b)(12)). From gas turbines, PM_{10} is emitted in part from sulfur in the natural gas, inert trace contaminants, and incomplete combustion of hydrocarbons. The final PSD permit for MBPP only allows the use of pipeline quality natural gas with a sulfur content of no more than 0.25 grains per 100 scf, and requires monthly analysis of the sulfur content of the natural gas combusted.

The EPA RACT/BACT/LAER Clearinghouse (RBLC)[6] provides a central online database of air pollution control technology determinations made to satisfy requirements for Reasonably Achievable Control Technology (RACT), Best Available Control Technology (BACT), and Lowest Achievable Emission Rate (LAER). We conducted recent searches (March 20, 2007) of the RBLC database for BACT determinations for natural gas-fired combined cycle turbines prior to the PSD permit proposal in May 2006 and recently as a result of public comments. The top BACT option for controlling PM_{10} from gas turbines is considered to be a combination of low or zero ash fuel (i.e., natural gas) and good combustion practices (See Table 3).

Recent BACT determinations for PM_{10} emissions from natural gas-fired turbines, reported by the EPA RBLC (Table 3) show that the proposed emissions limits of 11 and 13.3 lb/hr are comparable to facilities using similar natural gas turbines. A January 22, 2007 search of the California Air Resources Board (ARB) Statewide BACT Clearinghouse[7] reports three determinations for PM_{10} from ≥50 MW combined cycle natural gas-fired turbines. These emission limits range from 9 lb/hr (Sacramento Metropolitan Air Quality Management District (AQMD)), to 11.5 lb/hr (Feather River AQMD), to 17.2 lb/hr (San Joaquin Valley Air Pollution Control District), where the gas turbines from the power plant in

[6] http://www.epa.gov/ttn/catc/rblc/htm/welcome_eg.html
[7] http://www.arb.ca.gov/bact/bact.htm

the Feather River AQMD were most similar to the turbines proposed for use in the Modernization Project.

Facility	State	Date RBLC Determination last updated	PM_{10} without duct firing (lb/hr)	PM_{10} with duct firing (lb/hr)	Control Method Description
Rocky Mountain Energy Center, LLC	CO	5/8/06	7.6		Natural Gas Quality Fuel only and Good Combustion Practices
Crescent City Power [8]	LA	8/30/06	14.7	20.7	Clean Burning Fuel and Good Combustion Practices
Tracy Substation	CA	8/31/06		11.5	Best Combustion Practices
Forsythe Energy Plant [9]	NV	8/30/06	11.7	12.9	Clean Burning Low Sulfur Fuel and Good Combustion Practices
Berrien Energy, LLC	MI	1/4/06		19	Natural Gas and State of the Art Combustion Techniques
Duke Energy Hanging Rock Facility	OH	7/5/05	15	23.3	Low Sulfur Natural Gas

Table 3: Recent BACT Determinations from RBLC Database

The BAAQMD BACT workbook shows that the achieved in practice BACT for PM_{10} from large ($\geq$ 40MW) combined cycle gas turbines is natural gas fuel with a sulfur content not to exceed 1.0 grain/100 scf, achieved through the exclusive use of PUC-regulated grade natural gas. The proposed PSD permit for the Modernization Project restricts the facility to the use of pipeline-quality natural gas with a sulfur content of no more than 0.25 grain/100 scf. Thus, the BACT determination made in 2000, which EPA updated for the proposed PSD permit in 2006, is still consistent with the most recent determinations.

2. *Duct burner firing increases emissions of PM_{10}, and should not be considered BACT. (# 12, 44, 46)*

[8] Emission limits from the RBLC report were inferred to be the total for 2 turbines. The 14.7 and 20.7 lb/hr emission limits represent limits per individual turbine.
[9] The RBLC database reports the emission limit as the total for 3 turbines. The 11.7 and 12.9 lb/hr emission limits represent limits per individual turbine.

Response to B-2:

The purpose of duct burner firing in the heat recovery steam generator (HRSG) is to elevate the turbine exhaust temperature, allowing production of additional power and higher steam cycle efficiency. As such, duct burners are components of the HRSG used to increase power generation from the steam turbines, and by definition, are not control technology to reduce air pollutant emissions. As a component of the combined cycle system, the gas turbines block units, associated with the Modernization Project, are subject to BACT emission limits with and without supplemental firing of the duct burners (11 lb/hr and 13.3 lb/hr, respectively). A survey of the EPA RBLC shows that two different emission limits are typically imposed on turbines based on the whether or not the duct burners are fired.

3. *The BACT analysis should require updated information by the owner/operator (given the extended delay since submission of the application) to address current BACT generally for CO, NOx, VOC, PM_{10}, and specifically as to the duct burning component of the project. In recent statements by Mr. Gary Willey of the APCD, Mr. Willey suggested that current BACT for greenhouse gases* would prevent duct burning because other turbines would not produce these greenhouse gases, as well as the excess PM_{10} emissions from duct burning, are commercially available, albeit at an increase up-front capital cost to the owner/operator.*

* *Mr. Willey has indicated that the APCD will consider any then applicable APCD required emissions limitations on greenhouse gases in connection with the APCD's final BACT review, as well as BACT for excessive PM_{10} emissions resulting from duct burning. (# 12)*

Response to B-3:

For a discussion of the BACT determination for PM_{10}, the only criteria pollutant subject to PSD review, please see our response to comment B-1. For a general discussion on duct burning, PM_{10}, and BACT, please see our response to comment B-2.

To the extent the comment raises issues relating to EPA's general permitting authority for CO_2 and other greenhouse gases ("GHGs"), EPA recognizes the importance of addressing the global challenge of climate change, and in light of the Supreme Court's decision in *Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), the Agency is working diligently to develop an overall strategy for addressing the emissions of CO_2 and other GHGs under the Clean Air Act. See 73 Fed. Reg. 44354, "Regulating Greenhouse Gas Emissions Under the Clean Air Act" (Advance Notice of Proposed Rulemaking) (July 30, 2008). However, EPA does not currently have the authority to address the challenge of global climate change by imposing limitations on emissions of CO_2 and other greenhouse gases in PSD permits.

While EPA has been implementing voluntary programs aimed at reducing greenhouse gases for several years, since the Supreme Court decision, EPA has been exploring the additional tools provided by the Clean Air Act to help us expand on the solid foundation we have built to achieve the global goal of reduced greenhouse gas emissions. In fact, EPA has recently issued an advanced notice of proposed rulemaking (ANPR) seeking public input regarding issues relating to "the specific effects of climate change and potential regulation of greenhouse gas emissions from stationary and mobile sources under the Clean Air Act." 73 Fed. Reg. 44354. While the ANPR is the first step in developing a regulatory strategy for addressing CO_2 and other GHG emissions under the CAA, the Agency has not yet proposed rules to regulate these emissions under the Act.

It is well established that "EPA lacks the authority to impose [PSD permit] limitations or other restrictions directly on the emission of unregulated pollutants." *North County Resource Recovery Assoc.*, 2 E.A.D. 229, 230 (Adm'r 1986). The Clean Air Act and EPA's regulations require PSD permits to contain emissions limitations for "each pollutant subject to regulation" under the Act. CAA § 165(a) (4); 40 CFR § 52.21(b) (12). In defining those PSD permit requirements, EPA has historically interpreted the term "subject to regulation under the Act" to describe pollutants that are presently subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant. *See* 43 Fed. Reg. 26388, 26397 (June 19, 1978) (describing pollutants subject to BACT requirements); 61 Fed. Reg. 38250, 38309-10 (July 23, 1996) (listing pollutants subject to PSD review); *In Re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 132 (EAB 1997); *Inter-power of New York*, 5 E.A.D. 130, 151 (EAB 1994); Memorandum from Jonathan Z. Cannon, General Counsel to Carol M. Browner, Administrator, entitled *EPA's Authority to Regulate Pollutants Emitted by Electric Power Generation Sources* (April 10, 1998); Memorandum from Lydia N. Wegman, Deputy Director, Office of Air Quality Planning and Standards, entitled *Definition of Regulated Air Pollutant for Purposes of Title V*, at 5 (April 26, 1993). In 2002, EPA codified this approach for implementing PSD by defining the term "regulated NSR pollutant" and clarifying that Best Available Control Technology is required "for each regulated NSR pollutant that [a major source] would have the potential to emit in significant amounts." 40 CFR § 52.21(j) (2); 40 CFR 52.21(b) (50).

In defining a "regulated NSR pollutant," EPA identified such pollutants by referencing pollutants regulated in three principal program areas -- NAAQS pollutants, pollutants subject to a section 111 NSPS, and class I or II substance under title VI of the Act-- as well as any pollutant "that otherwise is subject to regulation under the Act." 40 CFR 52.21(b)(50)(i)-(iv). As used in this provision, EPA continues to interpret the phrase "subject to regulation under the Act" to refer to pollutants that are presently subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant. Because EPA has not established a NAAQS or NSPS for CO_2, classified CO_2

as a title VI substance, or otherwise regulated CO_2 under any other provision of the Act, CO_2 is not currently a "regulated NSR pollutant" as defined by EPA regulations.

Although the Supreme Court decided the case cited by the commenter and held that CO_2 and other GHGs are air pollutants under the CAA, *see Massachusetts v. EPA*, 127 S. Ct. 1438 (2007), that decision does not require the Agency to set emission limits for CO_2 and other GHGs in the Colusa Generating Station PSD permit. Notably, the Court did not hold that EPA was required to regulate CO_2 and other GHG emissions under Section 202, or any other section, of the Clean Air Act. Rather, the Court concluded that these emissions were "air pollutants" under the Act, and, therefore, EPA could regulate them under Section 202 (the provision at issue in the *Massachusetts* case), subject to certain Agency determinations pertaining to mobile sources.

EPA is currently exploring options for addressing GHG emissions in response to the Supreme Court decision. 73 Fed. Reg. 44354 (July 30, 2008). However, EPA has not yet issued regulations requiring control of CO_2 and other GHG emissions under the Act generally or the PSD program specifically. Accordingly, because CO_2 is not currently a pollutant regulated under the CAA, EPA cannot include emissions limitations for CO_2 (or other GHGs that are not otherwise regulated NSR pollutants) in the PSD permit for CGS. At this time, we believe that any action EPA might consider taking with respect to regulation of CO_2 or other GHGs in PSD permits or other contexts should be addressed through notice and comment rulemaking, as we have recently initiated by publishing the ANPR, allowing for a process which is public and transparent and based on the best available science. 73 Fed. Reg. 44354 (July 30, 2008).

4. *The BACT analysis should consider PM_{10} emissions from the potential use of cooling towers as an alternative to once-through sea water cooling. (# 12, 32, 34)*

Response to B-4:

Since the PSD permit application specifies the use of once-through seawater cooling with no resultant emissions of PM_{10}, a BACT determination for cooling tower options is not triggered. It is our understanding that the Central Coast Regional Water Quality Control Board ("Water Board") has postponed the issuance of a renewal permit under the National Pollutant Discharge Elimination System ("NPDES"). Although the public comment period for the proposed renewal NPDES permit for MBPP ended on January 26, 2007, the Water Board has placed the NPDES permit on an administrative extension, pending Water Board review of the recent EPA action on July 9, 2007 (72 FR 37107) to suspend the Phase II rule under section 316(b) of the Clean Water Act, regulating cooling water intake structures for existing large power plants. The suspension of the rule by EPA implements the decision from the 2nd Circuit U.S. Court of Appeals in Riverkeeper, Inc. v. EPA, issued January 25, 2007, remanding several provisions in the rule, including Best Technology Available determinations, restoration provisions, and performance standard ranges.

The EPA action retains a provision (40 CFR 125.90(b)) of the Phase II rule that requires permitting authorities to develop "Best Professional Judgment" controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. If the Water Board determines that once-through cooling by MBPP will not be allowed, and a different cooling method, such as dry cooling or cooling towers, is required, MBPP must apply for a revised PSD permit to include analyses of PM_{10} emissions from the cooling system, ensure that the new cooling system complies with all PSD requirements, including BACT, and specify revised PM_{10} emission limits in the new PSD permit.

Section C: Modeling and Ambient Air Quality Impact Analysis (AAQIR)

1. *The use of upper air data from Vandenberg Air Force Base is not appropriate. (# 12, 29-30, 44, 46)*

Response to C-1:

The upper air meteorological data from Vandenberg Air Force Base (VAFB) was used in the modeling analyses to determine atmospheric mixing heights, which impact the dispersion of pollutants (page 6.2-11). Vandenberg Air Force Base (VAFB) was the closest upper air meteorological station to Morro Bay (45 miles southeast). Given that marine climates influence mixing depths, the proximity of VAFB to the Pacific Ocean and to the project site makes the upper air data from Vandenberg appropriate for estimating mixing heights in Morro Bay.

The surface meteorological measurements were collected at the Morro Bay Power plant, and therefore are representative of the meteorological conditions at the proposed modification.

2. *Modeling scenarios examining a six-mile radius from the MBPP does not represent actual regional impacts of PM_{10} emissions. (# 12, 15, 44, 46)*

Response to C-2:

We agree that the PM_{10} emissions may have regional as well as local-scale impacts. Local-scale impacts typically result from primary emissions of PM_{10}, or PM_{10} emitted directly into the atmosphere. Regional impacts typically result from secondary PM_{10}, or PM_{10} formed in the atmosphere from chemical reactions. The MBBP's analyses considered both types of impacts. As required, the MBBP's source impact analysis predicted, through modeling, the local-scale ambient air quality impacts of the direct emissions of PM_{10} from the MBPP within the source's area of significant impact, as a result of the proposed modification. The analyses demonstrate that the proposed emissions increase from the modification will not cause or contribute to a violation of the NAAQS or PSD Class II increments for PM_{10}.

The MBBP's analysis of impacts beyond the local-scale impacts involved modeling the impacts of the source's emissions on the San Rafael Wilderness Class I area. The visibility analysis evaluates the visibility degradation that is caused by secondary particulate matter formed from NO_x and SO_x, as well as primary PM_{10}. The maximum impact on visibility in the San Rafael Wilderness Class I area meets the Federal Land Manager's criteria for the level of acceptable change. The air quality analysis demonstrates that the proposed modification will not cause or contribute to a violation of the NAAQS or PSD Class I increments for PM_{10} in the San Rafael Wilderness Class I.

3. *Meteorological conditions from 1994 – 1996 do not adequately address meteorological variability, including fog events, winter time inversions, and El Niño / La Niña phenomena. (# 9, 11-13, 27, 29, 35, 43-44, 46)*

<u>Response to C-3</u>:

The applicant reported in the Air Quality Analysis (page 6.2-49) that the meteorological conditions used in the modeling were obtained from data collected by PG&E at the MBPP site from 1994 – 1996. From the 1994 dataset, MBPP reported that the meteorological conditions expected to produce fog (relative humidity greater than 91.7%) were identified in 29% of all hours, representing roughly 51% of all days in 1994 experiencing at least one hour of fog, which is consistent with the long-term fog statistics from the National Weather Service Point Mugu station (page 6.2-58). The three years of real meteorological data were collected during actual conditions from 1994 – 1996, including foggy and non-foggy conditions and winter time inversions.

The three year data period from 1994 – 1996 was selected by the District to provide a variety of meteorological conditions (page 6.2-49). The District recommended use of data from 1994 – 1996 because they judged 1997 and 1998 to be highly unusual El Niño and La Niña years, and thus inappropriate to assure normal seasonal and short-term variations in meteorology (November 28, 2000 letter from Paul H. Allen III, SLOAPCD Supervising Air Quality Specialist to Kae Lewis, CEC Project Manager). Additionally, the Pacific Marine Laboratory (PMEL) of the National Oceanic and Atmospheric Administration (NOAA), part of the U.S. Department of Commerce, reported that weaker El Niño and La Niña years occurred in 1994 and 1995 – 1996, respectively[10]. Thus, data from 1994 – 1996 incorporated an El Niño year as well as two La Niña years. Therefore, because the meteorological data collected from 1994 – 1996 did incorporate fog events, and winter inversions, and El Niño Southern Oscillation (ENSO) events that were not as unusual as those experienced in 1997 – 1998, we determined that the data was representative of natural variability for Morro Bay.

4. *Assuming that the baseline emissions are estimated to be too high (Section A.2), the changes in emissions resulting from the project are larger than estimated and thus, do not adequately represent the impact of the project on the PSD increment and visibility. (# 12, 29, 31, 44, 46)*

<u>Response to C-4</u>:

This comment is confusing. The commenter seems to be implying that by overestimating the baseline emissions, the emissions increase and hence the projected impacts have been underestimated. The change in emissions resulting from the Modernization Project was **only** used to determine applicability of the Modernization Project to the PSD permitting program. The modeling analyses for this project submitted by the applicant (page 6.2-8) accounted for emissions from the proposed new turbines as well as from the existing boilers. Because the existing boilers will be shutdown as a result of the Modernization Project, by including the emissions from the existing boilers in the model, the impacts of the facility are modeled conservatively. Therefore, even if the baseline emissions were estimated to be too high, the impact of the project would not be underestimated, because the baseline emissions were not subtracted in the analysis. Thus, the applicant's analysis adequately estimates potential impacts from the facility.

5. *The additional impacts analysis states that MBPP operated without incident in proximity to agricultural uses. This does not adequately reflect the history of complaints by neighbors (# 1, 12, 29, 44, 46). The existence of historical complaints regarding fallout from the MBPP was highlighted in an article from the Fall 1967 issue of* Cry California: The Journal of California Tomorrow *(See Comment #29). The article describes an incident that occurred on May 20, 1966, where an increase in energy demand and natural gas consumption resulted in the combustion of fuel oil, rather than natural gas, by MBPP. The May 26, 1966 issue of the Morro Bay Sun newspaper reported resident complaints of damage to cars, house paint,*

[10] http://www.pmel.noaa.gov/tao/elnino/el-nino-story.html

clothes out to dry, flowers, and vegetables. The Cry California article cites the combustion of fuel oil as the cause of the fallout experienced in 1966. The article further stated that fuel oil combustion at the MBPP should be discontinued to avoid future fallout incidents (# 40).

Response to C-5:

The current Modernization Project proposes to remove the existing fuel oil tanks and replace the old fossil fuel oil-fired steam generators with combined cycle natural gas-fired turbines. Implementation of the proposed project will result in reduced emissions of NO_x, CO, and VOC, and an emissions increase of SO_2 that does not exceed the PSD significance threshold. Emissions of PM_{10} exceed the PSD significance threshold and are subject to the PSD regulations, requiring application of BACT, and impact analyses on ambient air (including national ambient air quality standards (NAAQS), PSD increments, visibility, soil, and vegetation). The modeling analyses have shown that PM_{10} emissions from the MBPP will comply with the NAAQS, the allowable PSD increment, and the allowable PSD Class I increment. Additionally, modeling has shown that visibility will not be adversely impacted by the Modernization Project, and the discontinued use of fuel oil by the MBPP will eliminate potential adverse impacts on soils and vegetation.

6. *The central and uncontested fact is that ground-level concentrations of particulate matter would rise 60% in Morro Bay, partly because of increased operating capacity and the reduction in stack height. (# 44, 46)*

Response to C-6:

EPA disagrees with the statement that it is a central and uncontested fact that ground level concentrations of particulate matter will increase by 60%. The change in *emissions* of PM_{10} resulting from the Modernization Project, calculated as the difference between the potential to emit (PTE) of the new turbines (203.2 tpy PM_{10}) and the baseline actual emissions of the existing boilers (127.2, tpy PM_{10}), is 76 tpy of PM_{10}. This increase of 76 tpy represents a 60% increase in potential PM_{10} *emissions*. Although potential emissions of PM_{10} from the facility will increase by 60%, the maximum modeled impact of the facility, estimated as the worst-case ground level concentration over a 24-hour averaging period (the averaging time for the National Ambient Air Quality Standard, or NAAQS), will increase by 24.2 micrograms of PM_{10} per cubic meter of air ($\mu g/m^3$). This represents a 42% increase over the background PM_{10} concentration (57 $\mu g/m^3$). It is important to note that 1) this modeled impact represents the maximum worst-case ground level concentration under fumigation conditions, and 2) the impact of the Modernization Project combined with the background PM_{10} concentration results in a total impact (81.2 $\mu g/m^3$)

that is 46% lower than the PM_{10} NAAQS of 150 $\mu g/m^3$. Therefore, the 60% increase in potential *emissions* results in a modeled maximum worst-case scenario increase in *ground level concentration* of 42%, which does not result in any violations of the PM_{10} NAAQS.

7. *The current applicable National Ambient Air Quality Standard (NAAQS) for PM_{10} cited in the AAQIR is out of date compared to a new NAAQS for PM_{10} adopted September 16, 1997. The new NAAQS should be implemented immediately. (#44, 46)*

Response to C-7:

The 24-hour and annual National Ambient Air Quality Standards for PM_{10} cited in the AAQIR (150 $\mu g/m^3$) were, and are up-to-date with the PM NAAQS promulgated on July 18, 1997 (68 FR 38652) and effective September 16, 1997. The 1997 standard for PM_{10} was revised from the previous standard to be based on the 3-year average of the 99th percentile of 24-hour PM_{10} concentrations at each monitor within an area. The numerical level of the standard 150 $\mu g/m^3$ was not changed in the 1997 rule. The annual PM_{10} standard was retained in the 1997 rule to be based on the 3-year average of the annual arithmetic mean PM_{10} concentration at each monitor in an area.

The 1997 PM Rule also created NAAQS for $PM_{2.5}$. However, due to the technical limitations associated with the monitoring, emissions estimation, and modeling of $PM_{2.5}$, EPA issued a guidance memorandum from John S. Seitz, Director, Office of Air Quality Planning and Standards, to Regional Air Directors (October 13, 1997), regarding interim implementation of the New Source Review Requirements for $PM_{2.5}$. This guidance applies to the PSD program and recommends interim use of PM_{10} emissions as a surrogate for $PM_{2.5}$ until the PM2.5 final NSR implementation rule is promulgated. Thus, if emissions of PM_{10} are determined to be in compliance with BACT and the air quality impacts analyses, then the source can be considered to be in compliance for $PM_{2.5}$ emissions. This guidance was reaffirmed in an additional guidance memorandum from Stephen D. Page, Director, Office of Air Quality Planning and Standards to Regional Air Directors (April 5, 2005).

The modeled impacts of the Modernization Project on the 24-hour and annual average NAAQS are in compliance with the appropriate air quality standards for PM_{10}, promulgated July 18, 1997 and effective September 16, 1997. Therefore, the Modernization Project is in compliance with respect to both PM_{10} and $PM_{2.5}$ NAAQS.

Section D: PSD Permit Conditions

1. *Limits placed on PM_{10} emission rates are ineffective and unenforceable due to the lack of continuous in-stack monitoring of PM_{10}. (# 12, 23, 44, 46)*

<u>Response to D-1</u>:

Performance tests for PM_{10} emissions from the turbine exhaust stacks are required within 60 days after achieving maximum load, but no later than 180 days after initial startup, and annually thereafter. The PSD permit specifies that these tests must use the EPA-approved methods, Methods 5 and 202, for measuring PM_{10} emissions. Monthly samples of the natural gas combusted will monitor the sulfur content of the fuel, which is limited by the PSD permit to 0.25 gr/100 scf. Noncombustible trace constituents of fuel and the sulfur content of the fuel contribute to PM_{10} emissions from the natural gas-fired turbines. The use of low sulfur, pipeline quality natural gas fuel limits PM_{10} emissions to negligible amounts, as reported in AP 42, Chapter 3-1 (Stationary Gas Turbines) .

The reporting and record-keeping requirements regarding date, time, and total duration of startups and shutdowns of each turbine, and firing hours and fuel flow rates from each turbine and duct burner, will provide the necessary information to determine compliance with the annual PM_{10} emission limit based on the measured PM_{10} emission rate from the performance tests. PM_{10} continuous emission monitoring systems (CEMS) are typically used at coal-fired power plants to monitor primary PM_{10}. Emissions of PM_{10} from natural gas-fired power plants are dominated by condensable particulates (secondary PM_{10}), and the concentration of primary PM_{10} emissions from natural gas fired power plants are too low to be reliably measured with CEMS. Thus, annual performance testing using EPA Methods 5 and 202, and monthly testing of the fuel sulfur content, are the most reliable methods for ensuring compliance with PM_{10} emission limits.

Section E: Human and Ecosystem Health

1. *The Modernization Project, particularly the proposal to shorten the stack height, will pose a health threat to the local community as well as to bird populations that use the Morro Bay Estuary. (# 2-8, 14-16, 18-20, 22, 24-28, 32, 33, 35-36, 38-39, 42, 44-46)*

<u>Response to E-1</u>:

New stack heights of 145 feet (reduced from previous heights of 450 feet) were proposed by the applicant as a balance between engineering, public health, and aesthetic considerations. The new stack heights are in compliance with Good Engineering Practice (GEP) stack height, as defined in 40 CFR § 51.100 (ii), and the GEP provisions of 40 CFR § 51.118.

The change in air quality resulting from the increase in emissions at the facility was modeled with the shorter stack height of 145 feet. The maximum modeled impact of the facility, estimated as the worst-case ground level concentration over a 24-hour averaging period (the averaging time for the National Ambient Air Quality Standard, or NAAQS), will increase by 24.2 micrograms of PM_{10} per cubic meter of air ($\mu g/m^3$), which is lower than the PM_{10} increment of $30 \mu g/m^3$. The impact of the Modernization Project combined with the background PM_{10} concentration results in a total impact of 81.2 $\mu g/m^3$, which is lower than the PM_{10} NAAQS of 150 $\mu g/m^3$.

Because the ambient air quality analyses, based on worst-case ground level conditions using the new (lower) stack heights of 145 feet, showed that the Modernization Project would not result in concentrations that exceed the NAAQS or PSD increments, EPA finds the proposed stack height acceptable because public health and welfare remain protected.

2. *What will the impact of PM_{10} be on endangered species? (# 31)*

Response to E-2:

Pursuant to Section 7 of the Endangered Species Act ("ESA"), 16 USC §1536 and 50 CFR Part 402, EPA consulted with the National Marine Fisheries Service ("NMFS") and the Fish and Wildlife Service ("FWS"). In a letter dated May 17, 2002 from Rodney R. McInnis, Acting Regional Administrator for the NMFW Southwest Region, to Gerardo C. Rios, Chief of the EPA Region IX Air Permits Office, NMFS concluded that the Modernization Project is not likely to adversely affect federally threatened steelhead (*Oncorhynchus mykiss*).

The FWS issued a Biological Opinion ("BO") on the proposed project on May 23, 2003. The BO concluded that the Modernization Project is not likely to jeopardize the continued existence of the federally threatened California red-legged frog (*Rana aurora draytonii*), the endangered Morro shoulderband snail (*Helminthoglypta walkeriana*), or the tidewater goby (*Eucyclogobius newberryi*). The BO included reasonable and prudent measures ("RPMs") that are necessary to minimize impacts of the Modernization Project on these listed species. In a letter dated June 23, 2005, and submitted as an addendum to the PSD permit application, Duke Energy Morro Bay, LLC, from Randall J. Hickok, Vice President of California Assets, to Gerardo C. Rios, stated that the Modernization Project will implement the RPMs, terms, conditions, and reporting requirements contained in the BO into the project description. The Morro Bay Power Plant changed names in 2006 to LSP Morro Bay, LLC, and in 2007 to Dynegy Morro Bay, LLC. In letters submitted to Gerardo C. Rios on May 8, 2006 and May 30, 2007, LSP and Dynegy notified EPA of the name change, and reaffirmed the facility's previous commitments related to compliance with the PSD permit, including the requirements of the Biological Opinion.

Section F: Changes to the proposed PSD permit unrelated to comments received

1. The proposed PSD permit did not include an averaging time associated with the PM_{10} emission limit of 11 and 13.3 lb/hr. The final PSD permit states that each turbine is subject to the pound per hour PM_{10} emission limits on a six-hour rolling average basis.

2. The proposed PSD permit was modified to specify a required test method for the monthly fuel sulfur analyses. The permit will require use of ASTM D5504, one of the fuel sulfur test methods acceptable under NSPS Subpart KKKK. EPA or District approved alternative test methods for fuel sulfur content may be used in lieu of ASTM D5504 upon EPA approval.

3. Emissions of particulate matter (PM) are subject to PSD review when emitted at rates exceeding the significance level of 25 tons per year (tpy). Emissions of particulate matter less than 10 microns in aerodynamic diameter (PM_{10}) are regulated by PSD when emitted at rates exceeding the significance threshold of 15 tpy. Because a natural gas-fired power plant is not expected to emit course particulate matter (PM greater than 10 microns in aerodynamic diameter), emissions of PM are expected to be equivalent to emissions of PM_{10}. The PSD permit proposed in May 2006 addressed only PM_{10}, and did not address PM; however, PM is subject to PSD review because emissions will exceed 25 tpy. Since no distinct air quality standard exists for PM, and since emissions of PM and PM_{10} will be equivalent, PSD review for PM_{10} satisfies requirements for PSD review for PM. The final PSD permit was modified to replace references to "PM_{10}" with "PM/PM_{10}".