EARTHJUSTICE

ALASKA CALIFORNIA FLORIDA MID-PACIFIC NORTHEAST NORTHERN ROCKIES
NORTHWEST ROCKY MOUNTAIN WASHINGTON, DC INTERNATIONAL

December 10, 2009

DOCKET 08-AFC-1	
DATE	DEC 10 2009
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VIA US MAIL
California Energy Commission
Attn: Docket No. 08-AFC-1
1516 Ninth Street, MS-4
Sacramento, CA 95814

RE: Presiding Member's Proposed Decision on Avenal Energy Project, Docket No. 08-AFC-1

To Whom It May Concern:

We submit the attached comments to the Energy Commission in the above-referenced matter. These comments were originally submitted to the U.S. Environmental Protection Agency on the proposed Prevention of Significant Deterioration permit for the Avenal Energy Plant. The issues identified in our comments are relevant to the Commission's consideration of this proposed project.

The Notice of Availability of the Presiding Member's Proposed Decision states that public comments may be submitted "<u>either</u> by mailing to the Commission Docket Unit . . . <u>or</u> e-mail" (emphasis added). Upon submittal of these comments by e-mail on December 4, 2009, however, we were informed by the Dockets Staff that a hardcopy of the comments must also be submitted. Please accept this as the hardcopy version of our December 4, 2009 electronic submittal.

Please feel free to contact me with any questions regarding this submittal.

Sincerely,

Paul Cort

Paul Cort
Staff Attorney

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EARTHJUSTICE

ALASKA CALIFORNIA FLORIDA MID PACIFIC NORTHEAST NORTHERN ROCKIES NORTHWEST ROCKY MOUNTAIN WASHINGTON, DC INTERNATIONAL

October 15, 2009

VIA ELECTRONIC MAIL

Ms. Shirley Rivera (AIR-3)
U.S. Environmental Protection Agency, Region 9
75 Hawthorne Street
San Francisco, CA 94105-3901

Re: Proposed Prevention of Significant Deterioration Permit for the Avenal Energy Project (PSD Permit No. SJ 08-01)

Dear Ms. Rivera:

These comments are submitted on behalf of the Tehipite Chapter of the Sierra Club to oppose issuance of the prevention of significant deterioration ("PSD") permit proposed by EPA for the Avenal Energy Project in Kings County, California. The proposed permit fails to impose emission limits representing the best available control technology ("BACT") for all pollutants subject to regulation, and fails to demonstrate that this massive new pollution source will not cause or contribute to violations of any national ambient air quality standards in one of the worst-polluted regions in the country.

I. The Proposed Permit Fails to Address BACT for Carbon Dioxide ("CO2")

Commenters find it stunning that the proposed permit does not even mention CO2 emissions or controls. EPA is well aware that the Environmental Appeals Board ("EAB") has returned multiple PSD permits for failing to consider whether CO2 is a pollutant "subject to regulation" under the Clean Air Act. *See In re Deseret Power Elec. Coop.*, PSD Appeal No. 07-03 (EAB Nov. 13, 2008); *In re Northern Mich. University Ripley Heating Plant*, PSD Appeal No. 08-02 (EAB Feb. 18, 2009). In light of these decisions, EPA Region 9 also withdrew portions of the PSD Permit issued to Desert Rock Energy Company in order to reconsider the issue of whether CO2 is a pollutant subject to regulation. Yet EPA proposes a PSD permit for another power plant that will emit over 1.7 million tons of CO2 each year[1] without any discussion of these contentious issues whatsoever. EPA must revise the proposed permit to explain EPA's position on BACT for CO2 so that the public can comment on the control levels selected or EPA's rationale for refusing to impose such controls.[2]

[1] *See* "Avenal Energy Application for Certification," at 6.2-85 (reporting annual CO2 emissions of 1.71 million metric tons per year).

[2] For example, commenters should be informed if EPA's decision not to address controls for CO2 is based on the memo from former EPA Administrator Stephen Johnson entitled "EPA's Interpretation of

While commenters believe EPA should be well informed of the legal and technical issues surrounding the control of CO2, commenters nonetheless provide the following summary.

1. The Clean Air Act Requires BACT for all Pollutants Subject to Regulation Under the Act.

The Clean Air Act defines BACT as an emission limitation based on the maximum degree of reduction of *each pollutant subject to regulation under this Act*." CAA § 169(3) (emphasis added). Thus, a BACT analysis for carbon dioxide must be completed if: (1) carbon dioxide is a "pollutant"; and (2) if it is "subject to regulation" under the Act.

a. Carbon Dioxide is a Clean Air Act "Pollutant"

The Supreme Court of the United States has held unequivocally that carbon dioxide is a "pollutant" as that term is used in the Act. *See Massachusetts v. EPA*, 549 U.S. 497, 528-29 (2007). In *Massachusetts*, "a group of States, local governments, and private organizations," including the Sierra Club, challenged EPA's contention that it lacked authority under the Clean Air Act to regulate greenhouse gas pollution, including carbon dioxide emissions, from motor vehicles. *Id.* at 504. The Court sided with challengers, ruling that "greenhouse gases fit well within the Clean Air Act's capacious definition of 'air pollutant.'" *Id.* at 532.

b. Carbon Dioxide is "Subject to Regulation"

Congress first enacted the PSD program (and the BACT requirements) as part of the 1977 Clean Air Act Amendments. One year later, EPA finalized its first regulations governing the PSD permitting process. In the preamble to those regulations, EPA stated:

Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program" (Dec. 18, 2008). This memo was issued in violation of the procedural requirements of the Administrative Procedure Act and conflicts with the plain language of the Clean Air Act. As a result, Administrator Jackson granted a petition for reconsideration on February 17, 2009 noting that the Johnson memo does not represent the "final word on the appropriate interpretation of Clean Air Act requirements." *See* Letter from Administrator Jackson, EPA, to David Bookbinder, Sierra Club (Feb. 17, 2009). EPA is in the process of formal rulemaking to resolve the meaning of the phrase "subject to regulation." *See* 74 Fed. Reg. 51535 (Oct. 7, 2009). If EPA Region 9 now contends that the Johnson memo does represent the "final word" without further discussion, commenters need to be made aware of this claim so that the appropriate record of responses can be prepared.

> Some questions have been raised regarding what "subject to regulation under this Act" means relative to BACT determinations. . . . "[S]ubject to regulation under this Act" means any pollutant regulated in Subchapter C of Title 40 of the Code of Federal Regulations for any source type.

43 Fed. Reg. 16388, 16397 (June 19, 1978) (*hereinafter* the "1978 Preamble").

As EPA is aware, there are multiple examples of regulations in 40 CFR Subchapter C that specifically apply to CO_2. Attachment A hereto includes a list of the hundreds of federal regulations that address CO_2 in one way or another. This section highlights two of these.

Section 821(a) of the 1990 Clean Air Act Amendments provides:

> Monitoring. – [EPA] . . . shall promulgate regulations within 18 months after the enactment of the Clean Air Act Amendments of 1990 to require that all affected sources subject to Title [IV] of the Clean Air Act shall also monitor carbon dioxide emissions . . . . The regulations shall require that such data be reported to the Administrator.

See 42 U.S.C. § 7651k note; Pub. L. 101-549; 104 Stat. 2699. In 1993, when EPA promulgated the regulations implementing this carbon dioxide monitoring and reporting program, it did so by amending Subchapter C of Title 40 of the Code of Federal Regulations. *See* 40 C.F.R. §§ 75.1(b), 75.10(a)(3), 75.33, 75.57, 75.60-64. The EAB recently confirmed that, based on this example, "the 1978 Federal Register Notice augers in favor of a finding that" CO_2 *is* subject to regulation under the Act. *Deseret*, PSD Appeal No. 07-03, slip op. at 41.

As EPA is also aware, on April 29, 2008, the Agency approved a state implementation plan revision for Delaware establishing federally enforceable emission limits for CO_2. *See* 73 Fed. Reg. 23101. EPA's approval notice stated that EPA was approving the CO_2 emission limits for new and existing generators "in accordance with" and "under" the Clean Air Act. *See id.*; 73 Fed. Reg. 11845 (Mar. 5, 2008). EPA's approval made these CO_2 control requirements enforceable under the Act. *See* CAA §§ 113, 304(a)(1) and (f)(3). These revisions to the state implementation plan appear in the regulations codified in Subchapter C of Title 40 of the Code of Regulations. *See* 40 CFR § 52.420

(2009). Accordingly, these regulations are also within the scope of the 1978 Preamble interpretation of "subject to regulation."

EPA in *Deseret* argued that "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." *Deseret*, PSD Appeal No. 07-03, slip op. at 16 (internal quotation marks omitted). The EAB rejected this rationale as "clearly erroneous." *Id.* at 9. It then rejected EPA's BACT decision and remanded the permit to EPA. *Id.* at 63. The EAB recently reaffirmed this decision. *See Northern Mich. U.*, PSD Appeal No. 08-02, slip op. at 31 (instructing the state agency on remand to be "guided by our findings in *Deseret*, to undertake the same consideration whether the CAA's 'pollutant subject to regulation' language requires application of a BACT limit to CO_2 emissions").

While the EAB in *Deseret* found that the Clean Air Act is ambiguous and allows room for agency interpretation, it was careful to warn that the agency's discretion was not unbounded. It advised that construing the Act to require BACT for CO_2 is not only plausible, but is also supported by the only regulatory history that speaks directly to the meaning of "subject to regulation." *Deseret*, PSD Appeal No. 07-03, slip op. at 38-42.

EPA's silence on the issue in the proposed Statement of Basis provides nothing to support its apparent decision to ignore CO_2 controls. This approach is inconsistent with the EAB's directives following remand of the Deseret and Northern Michigan University permits. It also denies commenters the ability to meaningfully review and comment on the proposed permitting decisions. The failure to address the legal status of CO_2 control is consequential for approval of this permit because the proposed permit does not otherwise ensure that CO_2 will be subject to BACT.

2. The Proposed Avenal Project Is Not Subject to BACT for CO_2

EPA's BACT analysis makes no mention of CO_2. The proposed PSD permit for Avenal includes no conditions that limit or otherwise control CO_2 emissions. If EPA had conducted any analysis, it could not have approved this project as meeting the BACT requirement for CO_2.

A proper BACT analysis should have explored the full range of alternatives available to reduce CO_2 emissions from the proposed project. These should have included energy production alternatives that do not rely on fossil fuel combustion, hybrid technologies that combine energy sources to improve the overall carbon efficiency of the power plant,[3] requiring co-generation with the project, and changes to the project design that would lower total carbon emissions (e.g., elimination of supplemental duct burners for the heat recovery steam generators, or replacement of those burners with a more efficient microturbine or solar energy collection system[4]). At a minimum, the analysis should have explored opportunities for improved turbine efficiency. For an example of what this analysis should look like, commenters have attached the Additional Statement of Basis for the Russell City Energy Center prepared by the Bay Area Air Quality Management District, which is the delegated federal PSD permitting agency for the San Francisco Bay Area. BAAQMD, "Additional Statement of Basis -- Russell City Energy Center," at 21 (Aug. 3, 2009) (Attachment B, hereto).[5]

The California Energy Commission has reported that the proposed Avenal project will have an overall project fuel efficiency of 50.5 percent lower heating value. CEC, "Final Staff Assessment," at 5.3-1 (June 2009). This is a terribly inefficient combined-cycle facility that comes nowhere close to utilizing the best available technology to limit the emissions of CO2. In the early Russell City Energy Center review, the Bay Area Air Quality Management District noted an old 2002 analysis prepared by the CEC that looked at three turbines and found efficiencies between 55.8 and 56.5 percent. *See* BAAQMD, "Statement of Basis for Russell City Energy Center," at 64 n.66 (Dec. 8, 2008). Upon further review, the Bay Area Air Quality Management District found that a gross efficiency of 56.45 percent lower heating value was achievable and required for the Russell City Energy Center. BAAQMD, "Additional Statement of Basis for Russell City Energy Center," at 21.

EPA's analysis should also consider emerging technology that promises efficiencies of between 58 and 60 percent. Of particular note is General Electric's H system turbines, which can reportedly achieve greater than 60 percent efficiency. *See* www.gepower.

[3] *See, e.g.*, http://www.energy.ca.gov/sitingcases/victorville2/index.html (Victorville 2); http://www.reuters.com/article/environmentNews/idUSN1139875020080612 (PG&E Coalinga project); http://my.epri.com/portal/server.pt/gateway/PTARGS_0_237_317_205_776_43/http;/uspalecp604;7087/publishedcontent/publish/epri_to_evaluate_adding_solar_thermal_energy_to_fossil_power_plants_da_609034.html (EPRI projects).

[4] *See, e.g.*, http://appft1.uspto.gov/netacgi/nph-Parser?Sect1=PTO1&Sect2=HITOFF&d=PG01&p=1&u=/netahtml/PTO/srchnum.html&r=1&f=G&l=50&s1='20080127647'.PGNR.&OS=DN/20080127647&RS=DN/20080127647 (application for patent on solar energy system to supplement thermal energy for heat recovery steam generators).

[5] By referencing the Russell City analysis, commenters do not mean to suggest that the analysis is without fault. But the analysis should serve as a useful starting point for EPA.

com/prod_serv/products/gas_turbines_cc/h_system/index.htm. These turbines have been in operation in Balgan Bay, Wales since 2003 and at the Tokyo Electric Power Company's Futtsu Thermal Power Station in Japan since 2007. *See* Attachment C, hereto. These turbines have also been proposed for use at the Inland Empire Energy Center here in California. *Id.*[6]

Once EPA determines the efficiency that represents best available control technology, EPA must translate that performance into enforceable limits on CO2 emissions. Again, the Russell City Energy Center analysis provides a useful example of how this can be accomplished. *See* BAAQMD, "Additional Statement of Basis for Russell City Energy Center," at 24-26 (using heat input per kilowatt-hour). The BACT determination for Russell City Energy Center equates to CO2 emissions of roughly 900 pounds of CO2 per megawatt-hour of energy produced.[7] A review of permitting decisions for other sources suggests that even lower levels are achievable. For example, the Carlsbad Energy Project, which is a retrofit of a peaking power plant (i.e., presumably less efficient than a new baseload plant), will emit 891 pounds of CO2 per megawatt-hour (.405 mt CO2/MW-hr). *See* Preliminary Staff Assessment, Carlsbad Energy Center Project (07-AFC-6) (CEC-700-2008-014-PSA) at 4.1-102 (Dec. 11, 2008).

EPA must revise the statement of basis to include an analysis of CO2 emissions and controls. The proposed project comes nowhere close to achieving the emission levels of CO2 that could be achieved using BACT.

II. The Proposed Permit Fails to Fully Analyze BACT for Oxides of Nitrogen ("NOx"), Carbon Monoxide ("CO") or Coarse Particulate Matter ("PM10")

The Clean Air Act requires that the proposed facility be subject to the best available control technology for each pollutant subject to regulation that results from the facility. CAA § 165(a)(4). The Act defines "best available control technology" as "the maximum degree of reduction of each pollutant . . . which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility . . . ." *Id.* § 169(3). EPA's guidance provided in the New Source Review Workshop Manual (draft Oct. 1990) outlines the

[6] Westinghouse has also introduced its advanced turbine system (ATS) program with preliminary results demonstrating efficiencies over 60 percent. *See* Attachment D.

[7] Emissions will depend on the carbon content of the natural gas fuel. *See* BAAQMD, "Additional Statement of Basis for Russell City Energy Center," at 29 n.49 (reporting varying emission factors).

analytical steps typically followed to make this case-by-case determination. *See Northern Mich. U.*, PSD Appeal No. 08-02, slip op. at 12.

Nowhere in the Statement of Basis for the proposed Avenal project does EPA provide anything resembling a top-down analysis. Instead EPA appears to apply a cookie-cutter review of old permit levels to justify limits proposed with no analysis by the source or the San Joaquin Valley Unified Air Pollution Control District. This approach is particularly troubling for CO.

The proposed permit concludes that BACT for CO is met by a limit of 2.0 parts per million by volume on a dry basis (ppmvd) over a 1-hour averaging period. Avenal Statement of Basis, at 18. This conclusion is based on a review of permitting levels for other sources using similar oxidation catalyst control technology. *Id.*

The first problem with EPA's analysis is that it is incomplete. At least two facilities have recently been permitted with CO emission levels below 2.0 ppmvd: Kleen Energy Systems in Connecticut (0.9 to 1.7 ppmvd)[8] and CPV Warren in Virginia (1.3 and 1.8 ppmvd without duct burning).[9] At a minimum, EPA's analysis should have started with these levels as the top level of control for the analysis. *See* NSR Manual at B.24 ("[W]hen reviewing a control technology with a wide range of emission performance levels, it is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates that there are source-specific factors or other relevant information that provide a technical, economic, energy or environmental justification to do otherwise.").

Based on these lower permit levels, the Bay Area Air Quality Management District analyzed the costs and emission reduction benefits of installing a larger oxidation catalyst capable of consistently maintaining CO emissions below 1.5 ppmvd for the Russell City Energy Center. *See* BAAQMD, "Additional Statement of Basis for Russell City Energy Center," at 48. The District found that such levels could be achieved at a cost-effectiveness of $4500 per ton of CO reduced. *Id.* This level of CO cost-effectiveness is consistent with the BACT cost-effectiveness levels found in a 2002 survey prepared for the Air and Waste Management Associations. *See* Hydari, N., et al., "Comparison of the Most Recent BACT/LAER Determinations for Combustion Turbines

[8] Connecticut Dept. of Env'tl Protection, Bureau of Air Mgmt, "New Source Review Permit to Construct and Operate a Stationary Source, issued to Kleen Energy Systems, LLC" (Feb. 25, 2008).
[9] Virginia Dept. Env'tl Quality, "Prevention of Significant Deterioration Permit – CPV Warren, LLC,"(July 30, 2004) (Attachment E hereto).

for State Air Pollution Control Agencies," Table 7 (2002) (Attachment F, hereto). That analysis found that the *average* (i.e., some of the permits had higher cost-effectiveness numbers and some had lower) cost-effectiveness of CO controls required in Arkansas was $3,373 per ton and in Michigan was $4,944 per ton. *See id.; see also* Letter from Steven Riva, Chief, Permitting Section, Region 2, EPA, to Robert Ewing, Project Manager, NYDEC, at 2-3 (Sept. 27, 2000) (concluding for the Sithe Heritage Station Generating Facility, in Scriba, New York that $3,412 per ton would be an acceptable cost for CO controls but that an option that would result in costs "well over $6,000 per ton" would not be BACT) (available at: http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/sithe.pdf).

EPA cannot simply rule out CO limits below 2.0 ppmvd without providing an analysis on the record of the feasibility and cost-effectiveness of improved performance. EPA must provide the missing top-down analysis for each of the pollutants subject to BACT.

The more fundamental problem with EPA's analysis, *which infects the analysis of each of the pollutants analyzed in the Statement of Basis*, is that a simple review of permitted levels is not a substitute for a BACT analysis. EPA's analysis fails to consider the range of control options available for the proposed source. As noted above, higher efficiency turbine options are available but have never been considered. Improved efficiency coupled with proposed controls would lower overall emissions, including CO. Moreover, alternatives to the supplemental duct-firing to produce peak power should also have been explored as this duct firing is extremely inefficient and significantly increases CO and NOx emission rates. *See* "Avenal Energy Application for Certification," at 6.2-43, Table 6.2-20.

By relying only on permit limits without exploring the effectiveness of the required controls themselves, EPA's analysis fails to provide a ranking of the control methods used to achieve these reported permit limits. *See* NSR Manual at B.6-7. EPA should have considered the inlet concentrations at these sources to determine (and rank) the removal effectiveness at the various sources. In addition, EPA should have reviewed not just permit limits, but actual emissions data from sources. *See* NSR Manual at B.23 (noting "the applicant should use the most recent regulatory decisions *and performance data* for identifying the emission performance level(s) to be evaluated in all cases.") (emphasis added). Using this data, EPA should have then applied the top-ranked control effectiveness (e.g., 98 percent pollutant removal) to the best achievable turbine efficiency performance level (as noted above) to determine the top-ranked BACT level of control.

Without a proper top-down BACT analysis, there is no basis for concluding that the Avenal project cannot achieve lower emissions. At a minimum, for CO, other sources have received lower permit limits and a rough analysis prepared by the Bay Area Air Quality Management District for a similar source suggests that such limits may be within an acceptable cost-effectiveness range. EPA must prepare the missing analysis and explain why those results are or are not reasonable as BACT.

III. The Proposed Permit Fails to Demonstrate that the Avenal Project Will Not Cause or Contribute to Violations of National Ambient Air Quality Standards for Ozone and Fine Particulate Matter.

Clean Air Act section 165(a)(3) provides that a PSD permit may not be issued unless the facility proponent "*demonstrates* . . . that emissions from the construction or operation of such facility will not cause, or contribute to, air pollution in excess of *any* . . . national ambient air quality standard in any air quality control region . . . ." (emphasis added); *see also* 40 CFR § 52.21(k)(1). The federal regulations require that the application for a PSD permit contain an analysis of ambient air quality in the area that the major source would affect for each pollutant emitted from the source in significant amounts. *Id.* § 52.21(m)(1)(a). The thresholds for determining whether emissions will be "significant" are provided in section 52.21(b)(23)(i) of the federal regulations. The threshold for PM2.5 emissions is 10 tons per year and for NOx, as a precursor to both PM2.5 and ozone, is 40 tons per year. *Id.* § 52.21(b)(23)(i).

The proposed Avenal project will result in emissions of 80.7 tons per year of PM2.5 and 144.3 tons per year of NOx. *See* "Avenal Energy Application for Certification," at 6.2-45, Table 6.2-24. Yet nowhere in the proposed PSD permit nor the facility's air quality analysis of its Application for Certification, is there any analysis of the impact the facility will have on ambient concentrations of ozone or PM2.5.

Commenters are aware of the exemption provided in 40 CFR 52.21(i)(2), which waives regulatory source impact analysis and air quality analysis requirements with respect to pollutants for which the area is designated nonattainment. This exemption, however, does not excuse the failures here. While the regulatory requirements as to how to make the required demonstration may be waived, this exemption cannot waive the statutory requirement to make the demonstration at all. Such an application of this regulatory requirement would be a clear violation of the statute. Thus, even if, as a result of this exemption, EPA's rules are silent as to how this demonstration must be made, the Act

still requires a demonstration that the source will not cause or contribute to a violation of "any" NAAQS. Moreover, with respect to the regulatory requirements, EPA has only just designated the San Joaquin Valley with respect to the 24-hour 35 $\mu g/m^3$ standard for PM2.5 and has not yet designated the Valley for the 75 parts per billion ("ppb") standard for ozone. Thus to the extent there is any rationale behind the regulatory exemption, it is not present here because the area does not have plans for meeting these new standards that will assure that any growth in emissions is consistent with attainment. Nor, as will be discussed in more detail below, can EPA rely on the San Joaquin Valley Unified Air Pollution Control District's dysfunctional nonattainment new source review program to fully offset these emissions. EPA cannot ignore the air pollution disaster in the San Joaquin Valley and approve this major new source without ensuring that it will not exacerbate the problems in the area.

A. The Applicant's Air Quality Analysis is Defective

In its Application for Certification, the project proponents report the results of their air quality analysis claiming "[t]hese analyses are designed to confirm that the proposed project's design features lead to less-than-significant impacts" even under conservative assumptions regarding emissions and other conditions. "Avenal Energy Application for Certification," at 6.2-40. The analysis, however, fails to meet this stated objective.

At the outset, there is no discussion of ambient ozone impacts whatsoever. The air quality analysis reports that 3-year average 8-hour ozone concentrations measured at the nearby Hanford monitoring site consistently exceed the 75 ppb standard. *See* "Avenal Energy Application for Certification" at 6.2-8 (reporting average concentrations of 95 ppb for 2004, 88 ppb for 2005 and 86 ppb for 2006). The analysis states that "ambient air quality measurements recorded at the monitoring stations are believed to represent area-wide ambient conditions rather than the localized impacts of any particular facility." *Id.* at 6.2-7. The analysis includes no other relevant discussion as to how the significant NOx emissions from the Avenal plant will or will not contribute to the ozone problem in the area. EPA's proposed Statement of Basis offers nothing more. The analysis does not claim that the impact will be insignificant or completely offset; the analysis is simply silent with respect to ozone impacts. Commenters cannot meaningfully comment on how this proposed project fulfills the requirement of section 165(a)(3) when there is no demonstration to review.

Avenal's analysis does purport to address PM2.5[10] but is fatally flawed. The analysis notes that emissions from the project will contribute to violations of state and national standards for PM10 and PM2.5 but adds that "[f]or these pollutants, existing concentrations already exceed the state and federal standards." "Avenal Energy Application for Certification," at 6.2-65. The project proponent appears to conclude that this is not a problem for permitting because "the project contribution of PM10 is less than the significant impact levels" provided in 40 CFR § 51.165(b). *Id.* at 6.2-72.

Section 51.165(b)(2) provides: "A major source or major modification will be considered to cause or contribute to a violation of a national ambient air quality standard when such source or modification would, at a minimum, exceed the following significance levels at any locality that does not or would not meet the applicable national standard." The section then defines the significant impact levels ("SILs") for PM10 as 1 $\mu g/m^3$ for the impact on annual concentrations and 5 $\mu g/m^3$ for the impact on 24-hour concentrations.

Avenal's conclusion that the impacts will not be significant is based on its modeling conclusions that maximum particulate matter impacts will be 0.8 $\mu g/m^3$ annually and 2.9 $\mu g/m^3$ for 24-hour concentrations. *See* "Avenal Energy Application for Certification," at 6.2-68, Table 6.2-34. These levels are below the significant impact levels promulgated for PM10.

The first problem with this conclusion is that the significant impact levels used are not relevant to, or appropriate for, PM2.5. To date, EPA has not promulgated similar *de minimis* thresholds for PM2.5. Avenal's comparison of modeled PM2.5 concentrations[11] to the PM10 levels is irrelevant for purposes of demonstrating that the source will not cause or contribute to a violation of the PM2.5 standards. Avenal appears to be operating under the mistaken belief that PM10 can be used as a surrogate for determining compliance with section 165(a)(3). *See* "Avenal Energy Application for

[10] The "Air Dispersion and Modeling Health Risk Assessment Protocol" prepared by Sierra Research stated that the analysis of PM2.5 ambient impacts would be conducted "for non-PSD purposes." Sierra Research, "Air Dispersion and Modeling Health Risk Assessment Protocol – Avenal Energy Project," at 3, Table 1 n. c, and 6 (Aug. 2007) (included in "Avenal Energy Application for Certification" Appendix 6.2). This qualification is not repeated in the air quality section of the Application for Certification, so commenters will assume Avenal believes it did attempt to address the requirements of Clean Air Act section 165(a)(3) with respect to the national standards for PM2.5.

[11] Avenal's reported particulate matter concentrations are assumed to be PM2.5 concentrations because all particulate matter emissions are assumed to be PM2.5 emissions. *See* "Avenal Energy Center Application for Certification," at 6.2-43, Table 6.2-19 n. b, Table 6.2-20 n. a, and Table 6.2-21 n. a.

Certification," at 6.2-34, Table 6.2-14 n. c (noting EPA guidance "provides that compliance with the federal PM2.5 NAAQS should be evaluated using the PM10 NAAQS and not modeled directly."). The use of the PM10 surrogate policy, to which Avenal seems to be referring, was available to PSD permit applications submitted before July 15, 2008. *See* 40 CFR § 52.21(b)(50)(xi). This illegal grandfathering exemption, however, is no longer available and has been stayed pending EPA rulemaking to revoke this exemption. *See* 74 Fed. Reg. 48153 (Sept. 22, 2009).

In the absence of a promulgated significant impact level that affords a *de minimis* exemption for purposes of evaluating the ambient PM2.5 contribution of sources, EPA has been clear that there is no *de minimis* exemption. *See* EPA, "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers in Diameter (PM2.5): Response to Comments" at 82 (Mar. 2008). Should a permitting agency wish to establish its own *de minimis* contribution thresholds, EPA has advised that they "are not precluded from developing and applying their own SILs for PM2.5 in the interim and demonstrating that a cumulative analysis would yield trivial gain." *Id.* Notwithstanding this direction, neither EPA nor Avenal has proposed any such PM2.5 SIL, let alone made any demonstration that such contributions would be trivial. Avenal used the PM10 SIL thinking that it could rely on the surrogate policy. It did not try to suggest that the same SIL was a reasonable *de minimis* threshold for the lower PM2.5 standards.

The concept of a SIL is grounded in the *de minimis* principles described by the court in *Alabama Power Co. v. Costle*, 636 F.2d 323, 360 (D.C. Cir. 1980). That court held that, "[u]nless Congress has been extraordinarily rigid, there is likely a basis for an implication of *de minimis* authority to provide exemption when the burdens of regulation yield a gain of trivial or no value." *Id.* at 360-61. The court emphasized that this is not a determination of whether the costs of control are justified by the benefits, but purely a determination that there will be no real benefit from control. *Id.* at 361. The court added that "when matters are truly *de minimis* naturally will turn on the assessment of particular circumstances, and the agency will bear the burden of making the required showing." *Id.* at 360. Neither EPA nor Avenal made any attempt to make the required demonstration let alone to meet the heavy burden required to do so.

Commenters note that EPA proposed SILs for PM2.5 in 2007. *See* 72 Fed. Reg. 54112 (Sept. 21, 2007). Under two of the three options EPA proposed, the modeled levels of Avenal's PM2.5 impacts would be considered significant. *See id.* at 54140. Commenters hasten to add, however, that even these proposed SILs are arbitrary numbers based on ratios that have no demonstrated or rational relationship to compliance with the NAAQS, and are not based on any demonstration of *de minimis* impacts. The numbers have no connection to what a *de minimis* source might look like or contribute to nonattainment. EPA has offered no evidence that the gain from regulating sources with impacts below the proposed SILs will in fact be trivial. For example, the most protective proposed "option 3" Class II 24-hour SIL of 1.2 μg/m3 is fully 13 percent of the entire 24-hour increment EPA proposes for these areas. It is absurd to claim that a source consuming over 10 percent of the allowable increment (*i.e.*, the maximum deterioration allowed in clean areas) has only a "trivial" impact in an area that is already violating the standard.

If EPA and Avenal propose to demonstrate compliance with section 165(a)(3) by claiming that the contribution to violations of the ozone or PM2.5 NAAQS will be *de minimis*, EPA and Avenal need to offer for public comment the rationale for applying a given threshold. The proposed PSD permit includes nothing of the sort.

Even if one were to accept the use of the PM10 thresholds, Avenal's modeling analysis would still be inadequate to demonstrate compliance with section 165(a)(3) because the modeling results do not account for the contribution of secondary PM2.5 (or ozone) formation as a result of the significant NOx emissions from the source. There is no basis for refusing to include secondarily formed PM2.5 in the assessment of ambient impacts. As EPA explained in its rulemaking proposing the increments of deterioration that it will allow, the Agency compared "the marginal pollutant concentration increases allowed by the safe harbor increment levels against the pollutant concentrations at which various environmental responses occur." 72 Fed. Reg. at 54133. In determining the scope of environmental effects, EPA "evaluated the health and welfare effects of both direct PM2.5 and secondarily-formed PM2.5 that may result from the transformation of other pollutants such as SO2 and NOx." *Id.* at 54127. It would be irrational to suggest that notwithstanding the fact that the increments are based on an assessment of the impacts of both direct and secondary PM2.5, the modeling to determine if such increments are violated or significantly impacted need only consider the direct fraction of these emissions.

This approach would be especially irrational here, where the District has already acknowledged that secondary PM2.5 in the form of ammonium nitrate is a major component of ambient PM2.5 concentrations in the San Joaquin Valley. *See* San Joaquin Valley Unified Air Pollution Control District, "2008 PM2.5 Plan," at 3-7 (April 30, 2008) (adding that "ammonium nitrate formation is limited by the availability of nitric acid"); *see also id.* at 6-6 (noting District's strategy is to "giv[e] priority to NOx controls."). The analysis of Avenal's impact on ambient PM2.5 concentrations simply cannot ignore the addition of 144 tons per year of NOx emissions in assessing whether the contribution to PM2.5 nonattainment in the Valley will be significant.

Models are available to conduct this required analysis. Section 5.2.2.1.a of Appendix W to 40 CFR Part 51 ("Guideline on Air Quality Models") advises that in choosing models for analyzing the impacts of multiple sources (which would be the exercise required for Avenal if it chooses to claim the ambient air quality benefits of the emission reduction credits it has acquired), "[c]ontrol agencies with jurisdiction over areas with secondary PM-2.5 problems . . . [should] use models which integrate chemical and physical processes important in the formation, decay and transport of these species (e.g., Models-3, CMAQ or REMSAD)." While the guidelines note that "generally regional models are not designed for the evaluation of individual sources," they also provide that "[i]f it is determined that regional transport of secondary particulates, such as sulfates or nitrates, is likely to contribute significantly to the problem, use of a regional model may be the preferred approach." *See* 40 CFR Part 51, App. W, §§ 5.1.f and 7.2.6.b.

In addition to considering secondary pollutant formation, the analysis should analyze the effect of adding 1.7 million tons per year of CO2 to the area. Recent studies have shown that emissions of CO2, can create localized increases in ambient concentrations (so called CO2 "domes") that in turn alter local atmospheric chemistry, increasing the formation of ozone and fine particulate matter concentrations. *See* Jacobson, M., "On the casual link between carbon dioxide and air pollution mortality," 35 Geophys. Res. Letters L03809 (Feb. 2008) (Attachment G, hereto). Of particular concern is the effect on particulate matter formation. As Dr. Jacobson explains in a recent paper, "While higher temperatures slightly decrease[] PM2.5, higher water vapor due to [anthropogenic CO2 emissions] increased PM2.5 by increasing aerosol water content, increasing nitric acid and ammonia gas dissolution, forming more particle nitrate and ammonium." Jacobson, M., "The enhancement of local air pollution by urban CO2 domes," at 3 (April 3, 2009) (Attachment H, hereto). The result, according to Dr. Jacobson's modeling, was a net increase in PM2.5 concentrations with increases in CO2 emissions. *Id.*

As noted above, it is no excuse to hide behind the claim that these atmospheric chemistry issues are difficult to model. Dr. Jacobson has outlined an approach to quantifying the local impact of increasing CO2 emissions. *See* Attachment G. There are several options for modeling these impacts EPA could explore. EPA could use the PM2.5 impacts predicted without increased CO2 and then apply Dr. Jacobson's approach to adjust these results. Alternatively, EPA could use Dr. Jacobson's approach to look at how CO_2 emissions increases will affect temperature and aerosol water content, and then use these numbers as inputs in the underlying PM2.5 modeling.

In the end, the analysis conducted to date on the ambient impacts of the Avenal plant is insufficient to "demonstrate[]" that emissions will not cause or contribute to air pollution in excess of the PM2.5 NAAQS. *See* CAA § 165(a)(3). Should EPA and Avenal persist in trying to claim that this new major source of pollution will contribute only insignificantly to ongoing violations of the ozone and PM2.5 NAAQS, EPA must work with Avenal to prepare an adequate analysis and circulate that analysis for public review and comment.

It is important to note that a *de minimis* demonstration is not the only option available to Avenal. As EPA has explained, "where emissions from a proposed PSD source or modification would have an ambient impact in a non-attainment area that would exceed the [significant impact levels], the source is considered to cause or contribute to a violation of the NAAQS and may not be issued a permit without obtaining emission reductions to compensate for its impact." 72 Fed. Reg. 54112, 54138 (Sept. 21, 2007). In other words, a facility can still be permitted even if the impact on ambient concentrations in a nonattainment area would be significant as long as the source can demonstrate that it has obtained emission reductions from other sources to compensate for its impact. This alternative is discussed in more detail below.

B. The District's Defective Offset Requirements Will Not Prevent the Project from Contributing to Violations of the National Standards

Neither EPA nor Avenal has suggested that the impacts on ambient concentrations of PM2.5 and ozone will be offset, nor could they based on the current record. As noted above, the impacts on ambient ozone have never been assessed and the analysis of the impacts on ambient PM2.5 concentrations is defective. More importantly, neither EPA nor Avenal has provided any record for showing how the offsets obtained for this project will compensate for the impacts of this source. To the contrary, based on the record to date, it is clear that the emission reduction credits described by Avenal will provide no compensating benefit whatsoever to offset the new ambient impacts the Avenal plant will create.

The first problem with relying of the District's nonattainment new source review program to satisfy the requirement of section 165(a)(3) is that the nonattainment new

source review program and the PSD program are fundamentally different when it comes to offsets. The nonattainment new source review program looks at the balancing of emissions increases and decreases as a kind of accounting problem based on tons of emissions. *See* CAA § 173(a) (focusing on "total tonnage" of emissions). This is particularly true for the District's new source review program. EPA has recognized that the District's program fails to comply with the requirements of the Clean Air Act by, among other things, allowing sources to offset only to preset thresholds rather than down to zero, failing to apply the ratios specified in the Act, and refusing to ensure that emission reductions are surplus at the time of use. *See* 66 Fed. Reg. 37587 (July 19, 2001). EPA has waived these statutory violations by allowing the District to demonstrate overall equivalency of the District's offset requirements to the requirements of the Clean Air Act. *See* 69 Fed. Reg. 27837 (May 17. 2004). This accounting approach has no relation to what is actually happening in the ambient air. Moreover, while the equivalency approach relied upon in the District might have been theoretically viable at the time EPA approved it, the approach has become bankrupt with the District's bump up to extreme nonattainment for ozone in 2004. Since then, the federal rules should have been requiring offsets for sources with NOx or VOC emissions over 10 tons per year, but the District has not been applying these lower thresholds in its annual equivalency demonstration. At this point, there is no rational basis for believing that the District is achieving all of the emission reductions needed even to meet the accounting requirement of Clean Air Act section 173(a).

The requirements in section 165(a)(3) and 51.165(b)(3), by contrast, focus on "air pollution" and the "impact" on "air quality" as opposed to merely the tons of emissions. This difference is often used to the advantage of sources seeking a PSD permit by allowing them to claim that their significant impacts can be mitigated through less than complete offset of their emissions. Here, however, because the District allows sources to use offsets that are worthless in their benefit to air quality, the requirements of section 165(a)(3) cannot be met through the bankrupt accounting games approved for the nonattainment new source review program in the San Joaquin Valley.

In its Final Determination of Compliance ("FDOC") document, the District calculated what it asserts are acceptable offset targets for the project's NOx, VOC, and PM10 emissions. The District established these offset targets as the project's total emissions, minus any emissions from exempt equipment, minus an 'offset threshold' for each pollutant, times a distance offset ratio of 1.5:1 (because the reductions used as offsets took place more than 15 miles from the Avenal project). Additionally, the District allowed the substitution of SOx emission reduction credits to offset PM-10 emissions at a 1:1 ratio.

As noted above, this calculation of the emission reduction credits ("ERCs") needed to offset the tons of emission increases that will be generated by Avenal includes no analysis of the actual impact the proposed project will have on air quality or the mitigation of that impact that will be provided by the ERCs. As explained by the CEC in a letter dated August 12, 2008, (Attachment I, hereto), the applicant's proposed mitigation includes the use of ERCs issued between 1991 and 2002. While the District may allow the use of these very old ERCs to satisfy the accounting requirements of its defective nonattainment new source review program, for PSD purposes, the reductions represented by these ERCs are already reflected in the current ambient air quality concentrations used to assess Avenal's projected impact. Neither EPA nor the District has demonstrated how emissions reductions that are already reflected in current air quality levels, which continue to violate the national standards, can be used to show that the new emissions from the proposed project will not cause or contribute to a violation of any NAAQS in the project impact area.

In addition, as the District has pointed out, the reductions being used as offsets took place well outside the proposed project site. In fact, as far as commenters can tell[12], a majority of the reductions took place more than 75 miles away from the proposed project location. Without performing modeling or other technical analysis to show how these distant reductions can possibly offset the impact of the new emissions on the project impact area, EPA cannot conclude that the ERCs identified by the applicant adequately prevent the project from causing or contributing to a violation of any NAAQS.

Finally, even if the temporal and spatial defects of these offsets could be ignored, the emission reductions suffer from the further defect that the District relies on inter-pollutant trading that has no rational basis. The District has allowed Avenal to comply with the nonattainment new source review requirements for PM2.5 offsets by substituting SOx emission reductions on a 1 to 1 basis (this ratio becomes 1.5 to 1 when factoring in the distance offset ratio). This ratio is entirely unsupported by the record. EPA, in its implementation of the new source review program for PM2.5, determined a

[12] Despite an August 12, 2008 request by the CEC, a full description of the original emission reduction site and date, and the method of reduction for the ERCs was never provided by the applicant or the District. In fact, a number of the ERCs listed in the FDOC do not even appear on the District's Emission Reduction Credits Registry.

nationwide preferred ratio of 40 to 1 for trading SOx emission reductions for PM2.5 emission reductions, unless a demonstration can be made, substantiated "by modeling and/or other technical demonstrations of the net air quality benefit for PM2.5 ambient concentrations," that another ratio is locally appropriate. 73 Fed. Reg. 28321, 28339 (May 16, 2008). According to EPA, these local determinations must address a number of local factors, including but not limited to: 1) the relative magnitude of emissions of direct PM2.5 and precursor gases within the geographic area, 2) the relative contribution to local PM2.5 nonattainment of directly emitted PM2.5 and individual precursors from the various sources or source categories under consideration as part of a potential inter-pollutant trade, and 3) the meteorological conditions and topography of the area, which result in different source-receptor relationships across pollutants within the local area. *Id.* The District has never made any such demonstration to justify the lower ratio applied here.[13] Given the total absence of analysis supporting a 1 to 1 benefit ratio for SOx emission reductions, EPA simply cannot reasonably rely on the SOx ERCs required by the District to meet the requirements 165(a)(3) for PM2.5.

While EPA could grant Avenal a PSD permit with a showing that the contributions to ongoing ozone and PM2.5 nonattainment concentrations will be offset, no such demonstration has been made to date. The emission reduction credits allowed to be used under the defective San Joaquin Valley Unified Air Pollution Control District nonattainment new source review program are insufficient to satisfy this demonstration. Should EPA wish to rely on an argument that emission reductions have been required to compensate for the ambient impacts of the Avenal project, EPA must make that demonstration on the record and circulate it for public review and comment.

IV. CONCLUSION

There is still considerable work to be done on this proposed PSD permit. Many critical issues have not been analyzed and a revised proposal is necessary. Commenters look forward to working with EPA to ensure the completion of a full and open analysis of the air quality issues surrounding this proposed project.

[13] As EPA pointed out in comments on another San Joaquin Valley power plant project, the District's "methodology" for determining appropriate inter-pollutant ratios has never been approved by EPA. *See* EPA's May 21, 2009 Comments on Project Number N-1083212 ("the underlying methodology to determine the appropriate ratios for inter-pollutant offsets has not been approved by EPA . . . It is important to note that modeling is a critical component of an inter-pollutant offset analysis . . . .") (See Attachment J, hereto)

Sincerely,

Paul Cort
Staff Attorney

ATTACHMENT A

IN THE SUPERIOR COURT OF FULTON COUNTY
STATE OF GEORGIA

FRIENDS OF THE CHATTAHOOCHEE, INC. and SIERRA CLUB,

Petitioners,

v.

DR. CAROL COUCH, DIRECTOR, ENVIRONMENTAL PROTECTION DIVISION, GEORGIA DEPARTMENT OF NATURAL RESOURCES

Respondent,

and

LONGLEAF ENERGY ASSOCIATES, LLC,

Respondent-Intervenor.

Docket No. 2008CV146398

CLEAN AIR ACT REGULATIONS THAT ADDRESS CARBON DIOXIDE

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CLEAN AIR ACT REGULATIONS THAT ADDRESS CARBON DIOXIDE

Following are regulations under the Clean Air Act regarding carbon dioxide that have been issued by the United States Environmental Protection Agency. The following compendium of such regulations is not inclusive of all of the EPA's CO_2 regulations, nor does it include the full text for each regulation that addresses CO_2. Instead, only a Westlaw printout of the citation of the regulation, the title of the regulation, and the specific portion mentioning carbon dioxide/CO_2 is included for illustrative purposes.

This listing alone runs 128 pages. Had the entire body of the regulations been included, the magnitude of this volume would, of course, have been many times greater.

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184 C 40 C.F.R. § 51.351 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 51--REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS SUBPART S--INSPECTION/MAINTENANCE PROGRAM REQUIREMENTS § 51.351 Enhanced I/M performance standard.

... in appendix B of this subpart S); and (viii) Maximum exhaust dilution measured as no less than 6% CO plus **carbon dioxide (CO2)** on vehicles subject to a steady-state test (as described in appendix B of this subpart S); and (ix) Maximum exhaust ...

... in appendix B of this subpart S); and (ix) Maximum exhaust dilution measured as no less than 6% CO plus **carbon dioxide (CO2)** on vehicles subject to a steady-state test (as described in appendix B of this subpart S). (8) Emission control device ...

185 40 C.F.R. § 51.357 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 51--REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS SUBPART S--INSPECTION/MAINTENANCE PROGRAM REQUIREMENTS § 51.357 Test procedures and standards.

...(b) Test standards-- (1) Emissions standards. HC, CO, and CO+**CO2** (or **CO2** alone) emission standards shall be applicable to all vehicles subject to the program with the exception of MY ...

... provided to the State under § 51.351(d). (ii) Transient test. Transient test emission standards shall be established for HC, CO, **CO2**, and NOX for subject vehicles based on model year and vehicle type. (2) Visual equipment inspection standards. (i) Vehicles shall ...

186 C 40 C.F.R. § 51.365 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 51--REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS SUBPART S--INSPECTION/MAINTENANCE PROGRAM REQUIREMENTS § 51.365 Data collection.

...(19) Carbon monoxide emission scores and standards for each applicable test mode; (20) **Carbon dioxide** emission scores (CO+**CO2**) and standards for each applicable test mode; (21) Nitrogen oxides emission scores and standards for each applicable ...

187 C 40 C.F.R. § 51.371 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 51--REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS SUBPART S--INSPECTION/MAINTENANCE PROGRAM REQUIREMENTS § 51.371 On-road testing.

...On-road testing is defined as testing of vehicles for conditions impacting the emission of HC, CO, NOx and/or **CO2** emissions on any road or roadside in the nonattainment area or the I/M program area. On-road testing is required in ...

188 40 C.F.R. Pt. 51, Subpt. S, App. A CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 51--REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS SUBPART S--INSPECTION/MAINTENANCE PROGRAM REQUIREMENTS Appendix A to Subpart S--Calibrations, Adjustments and Quality Control

... conduct an automatic zero and span check prior to each test. The span check shall include the HC, CO, and **CO2** channels, and the NO and O2 channels, if present. If zero and/or span drift cause the signal levels to move ...

... operating day in high-volume stations, analyzers shall automatically require and successfully pass a two-point gas calibration for HC, CO, and **CO2** and shall continually compensate for changes in barometric pressure. Calibration shall be checked within four hours before the test and ...

... changes in barometric pressure are compensated for automatically and statistical process (A) 300--ppm propane (HC) 1.0--% carbon monoxide (CO) 6.0--% **carbon dioxide (CO2)** 1000--ppm nitric oxide (if equipped with NO) 1200--ppm propane (HC) 4.0--% carbon monoxide (CO) ...

189. 40 C.F.R. Pt. 51, Subpt. S, App. B CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 51--REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS SUBPART S--INSPECTION/MAINTENANCE PROGRAM REQUIREMENTS Appendix B to Subpart S--Test Procedures

... The test shall immediately end and any exhaust gas measurements shall be voided if the measured concentration of CO plus **CO2** falls below six percent or the vehicle's engine stalls at any time during the test sequence. (4) Multiple exhaust pipes. ...

...(iv) The measured concentration of CO plus **CO2** shall be greater than or equal to six percent. (c) First-chance test. The test timer shall start (tt=0) when the ...

... The test shall immediately end and any exhaust gas measurements shall be voided if the measured concentration of CO plus **CO2** falls below six percent or the vehicle's engine stalls at any time during the test sequence. (4) Multiple exhaust pipes. ...

190. 40 C.F.R. Pt. 51, Subpt. S, App. D CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 51--REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS SUBPART S--INSPECTION/MAINTENANCE PROGRAM REQUIREMENTS Appendix D to Subpart S--Steady-State Short Test Equipment

... line, a water removal system, particulate trap, sample pump, flow control components, tachometer or dynamometer, analyzers for HC, CO, and **CO2**, and digital displays for exhaust concentrations of HC, CO, and **CO2**, and engine rpm. Materials that are in contact with ...

... and warm-up requirements. The instrument shall be considered "warmed up" when the zero and span readings for HC, CO, and **CO2** have stabilized, within +-3% of the full range of low scale, for five minutes without adjustment. (7) Electromagnetic isolation and ...

... 5.01-9.99 - 0.40 0.10 0.15 **CO2**, % .... 0-4.0 - 0.6 0.2 ...

191. **C** 40 C.F.R. Pt. 51, App. M CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 51--REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS Appendix M to Part 51--Recommended Test Methods for State Implementation Plans

... stack velocity (minimum, maximum, and average), atmospheric pressure, stack static pressure, meter box temperature, stack moisture, percent 02, and percent **CO2** in the stack gas, pitot coefficient (Csubp), orifice Delta H@, flow rate measurement calibration values [slope (m) and y-intercept (b) ...

195. **C** 40 C.F.R. § 52.120 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 52--APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS SUBPART D--ARIZONA § 52.120 Identification of plan.

...8-1-5.3 (Pumps and Compressors) 8-1-5.4 (Organic Solvents; Other Volatile Compounds) 8-1-6.1 (**CO2** Emissions--Industrial) 8-1-7.1 (NO2 Emissions--Fuel Burning Equipment) 8-1-7.2 (NO2 Emissions--Nitric Acid Plants) ...

...7-3-4.1 (**CO2** Emissions--Industrial) 7-3-5.1 (NO2 Emissions--Fuel Burning Equipment) 7-3-5.2 (NO2 Emissions--Nitric Acid Plants) ...

196. **C** 40 C.F.R. § 52.145 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 52--APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS SUBPART D--ARIZONA § 52.145 Visibility protection.

... of this section, the owner or operator: (i) Shall furnish the Administrator written notification of the SO2 , oxygen, and **carbon dioxide** emissions according to the procedures found in 40 CFR § 60.7 in effect on October 3, 1991. (ii) Shall furnish ...

197. C 40 C.F.R. § 52.246 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 52--APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS SUBPART F--CALIFORNIA § 52.246 Control of dry cleaning solvent vapor losses.

... a control technique, 90 percent or more of the carbon in the organic compounds being incinerated must be oxidized to **carbon dioxide.** [38 FR 31246, Nov. 12, 1973, as amended at 42 FR 41122, Aug. 15, 1977; 42 FR 42226, Aug. 22, ...

198. C 40 C.F.R. § 52.254 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 52--APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS SUBPART F--CALIFORNIA § 52.254 Organic solvent usage.

...(1) Incineration, provided that 90 percent or more of the carbon in the organic material being incinerated is oxidized to **carbon dioxide,** or (2) Adsorption, or (3) Processing in a manner determined by the Administrator to be not less effective than the ...

...(l) For the purpose of this section, organic materials are defined as chemical compounds of carbon excluding carbon monoxide, **carbon dioxide,** carbonic acid, metallic carbonates, and ammonium carbonate. (m) Architectural coatings and their use shall conform to the following requirements, on ...

200. C 40 C.F.R. § 52.1145 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 52--APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS SUBPART W--MASSACHUSETTS § 52.1145 Regulation on organic solvent use.

... the least allowable percentage of total volume of solvents. (3) "Organic materials" are chemical compounds of carbon excluding carbon monoxide, **carbon dioxide,** carbonic acid, metallic carbides, metallic carbonates, and ammonium carbonate. (b) This section is applicable throughout the Boston Intrastate Region. The ...

...(1) Incineration, provided that 90 percent or more of the carbon in the organic material being incinerated is converted to **carbon dioxide,** or (2) Adsorption, or (3) The use of other abatement control equipment determined by the Regional Administrator to be no ...

201. C 40 C.F.R. § 52.1605 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 52--APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS SUBPART FF--NEW JERSEY § 52.1605 EPA-approved New Jersey regulations.

... **carbon dioxide** and ...

202. C 40 C.F.R. § 53.22 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 53--AMBIENT AIR MONITORING REFERENCE AND EQUIVALENT METHODS SUBPART B--PROCEDURES FOR TESTING PERFORMANCE CHARACTERISTICS OF AUTOMATED METHODS FOR SO2, CO, O3, AND NO2 § 53.22 Generation of test atmospheres.

... references 1 and 2. **Carbon dioxide ......** Cylinder of zero air or Use NBS-certified standards ...

... nitrogen containing **CO2** whenever possible. If NBS ...

203. C 40 C.F.R. § 59.208 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 59--NATIONAL VOLATILE ORGANIC COMPOUND EMISSION STANDARDS FOR CONSUMER AND COMMERCIAL PRODUCTS SUBPART C--NATIONAL VOLATILE ORGANIC COMPOUND EMISSION STANDARDS FOR CONSUMER PRODUCTS § 59.208 Charcoal lighter material testing protocol.

... appendix A, Method 25, SCAQMD Method 25.1 (incorporated by reference--§ 59.213 of this subpart), or equivalent, for analysis. Carbon monoxide, **carbon dioxide,** methane, and non-methane organic carbon are analyzed by the TCA and TCA/Flame Ionization Detector (FID) methods. Oxygen content is determined ...

... a carrier for cleaning and purging. =1 C=Average concentration for each duplicate run of total gaseous nonmethane organic compounds as **CO2** (parts per million, from lab analysis sheet) D=Sampling duration =25 minutes d=Molar density of gas at standard conditions ...

204 C 40 C.F.R. § 60.3 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART A--GENERAL PROVISIONS § 60.3 Units and abbreviations.

...(c) Chemical nomenclature: CdS--cadmium sulfide CO carbon monoxide **CO2--carbon dioxide** HCl--hydrochloric acid Hg--mercury H2O--water H2S--hydrogen sulfide H2SO4--sulfuric acid ...

205 40 C.F.R. § 60.17 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART A--GENERAL PROVISIONS § 60.17 Incorporations by reference.

...(38) ASTM D2597-94 (Reapproved 1999), Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and **Carbon Dioxide** by Gas Chromatography, IBR approved for § 60.335(b)(9)(i). (39) ASTM D2622-87, 94, 98, Standard Test Method for Sulfur in Petroleum ...

...(1) Gas Processors Association Method 2377-86, Test for Hydrogen Sulfide and **Carbon Dioxide** in Natural Gas Using Length of Stain Tubes, IBR approved for §§ 60.334(h)(1), 60.4360, and 60.4415(a)(1)(ii). ...

207 C 40 C.F.R. § 60.46 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART D--STANDARDS OF PERFORMANCE FOR FOSSIL-FUEL-FIRED STEAM GENERATORS FOR WHICH CONSTRUCTION IS COMMENCED AFTER AUGUST 17, 1971 § 60.46 Test methods and procedures.

... = Emission rate of pollutant, ng/J (lb/MMBtu); C = Concentration of pollutant, ng/dscm (lb/dscf); **%cO2** = **CO2** concentration, percent dry basis; and Fc = Factor as determined in appropriate sections of Method 19 of appendix A of ...

... then three runs of Method 3B of appendix A of this part shall be used to determine the O2 and **CO2** concentration according to the procedures in paragraph (b)(2)(ii), (4)(ii), or (5)(ii) of this section. Then if Fo (average of three ...

QUERY - "CARBON DIOXIDE" CO2 DATABASE(S) - CFR

211 C 40 C.F.R. § 60.41b CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART DB--STANDARDS OF PERFORMANCE FOR INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS § 60.41b Definitions.

... oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with **carbon dioxide (CO2)** levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of ...

212 C 40 C.F.R. § 60.52 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART E--STANDARDS OF PERFORMANCE FOR INCINERATORS § 60.52 Standard for particulate matter.

... any affected facility any gases which contain particulate matter in excess of 0.18 g/dscm (0.08 gr/dscf) corrected to 12 percent **CO2**. [39 FR 20792, June 14, 1974; 65 FR 61753, Oct. 17, 2000] SOURCE: 36 FR 24877, Dec. 23, 1971; 50 ...

220 C 40 C.F.R. § 60.54 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART E--STANDARDS OF PERFORMANCE FOR INCINERATORS § 60.54 Test methods and procedures.

... the particulate matter standard in § 60.52 as follows: (1) The concentration (c12) of particulate matter, corrected to 12 percent **CO2**, shall be computed for each run using the following equation: c12 = cs (12/%cO2) where: c12 =concentration of particulate matter, ...

... each run using the following equation: c12 = cs (12/**%cO2**) where: c12 =concentration of particulate matter, corrected to 12 percent **CO2**, g/dscm (gr/dscf). cs=concentration of particulate matter, g/dscm (gr/dscf). **%cO2** =**CO2** concentration, percent dry basis. (2) Method 5 shall be used ...

... The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine **CO2** concentration (%cO2. (i) The **CO2** sample shall be obtained simultaneously with, and at the same traverse points as, the particulate ...

223 **C** 40 C.F.R. § 60.84 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART H--STANDARDS OF PERFORMANCE FOR SULFURIC ACID PLANTS § 60.84 Emission monitoring.

... problems encountered in the measurement of gas velocities or production rate. Continuous emission monitoring systems for measuring SO2, O2, and **CO2** (if required) shall be installed, calibrated, maintained, and operated by the owner or operator and subjected to the certification procedures ...

... span value for the SO2 monitor shall be as specified in paragraph (b) of this section. The span value for **CO2** (if required) shall be 10 percent and for O2 shall be 20.9 percent (air). A conversion factor based on process ...

... factor based on process rate data is not necessary. Calculate the SO2 emission rate as follows: Es = (CsS)/[0.265-(0.126 2-(A %**cO2**] where: Es = emission rate of SO2, kg/metric ton (lb/ton) of 100 percent of H2 SO4 produced. ...

224 **C** 40 C.F.R. § 60.85 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART H--STANDARDS OF PERFORMANCE FOR SULFURIC ACID PLANTS § 60.85 Test methods and procedures.

...(i) The integrated technique of Method 3 is used to determine the O2 concentration and, if required, **CO2** concentration. (ii) The SO2 or acid mist emission rate is calculated as described in § 60.84(d), substituting the acid mist ...

QUERY - "CARBON DIOXIDE" CO2 DATABASE(S) - CFR

225 **C** 40 C.F.R. § 60.106 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART J--STANDARDS OF PERFORMANCE FOR PETROLEUM REFINERIES § 60.106 Test methods and procedures.

... The coke burn-off rate (Rc) shall be computed for each run using the following equation: Rc = K1 Qr (% **CO2** + % CO) + K2 Qa - K3 Qr (% CO/2 + % **CO2** + 2) Where: Rc = Coke ...

...%**cO2** = **Carbon dioxide** concentration, percent by volume (dry basis). %cO = Carbon monoxide concentration, percent by volume (dry basis). % O2 = Oxygen ...

...(ii) The emission correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine **CO2**, CO, and O2 concentrations. (4) Method 9 and the procedures of § 60.11 shall be used to determine opacity. ...

227 **C** 40 C.F.R. § 60.641 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART LLL--STANDARDS OF PERFORMANCE FOR ONSHORE NATURAL GAS PROCESSING; SO2 EMISSIONS § 60.641 Definitions.

... the Act and in Subpart A of this part. Acid gas means a gas stream of hydrogen sulfide (H2S) and **carbon dioxide (CO2)** that has been separated from sour natural gas by a sweetening unit. Natural gas means a naturally occurring mixture of ...

...Sweetening unit means a process device that separates the H2S and **CO2** contents from the sour natural gas stream. Total SO2 equivalents means the sum of volumetric or mass concentrations of the ...

237. **C** 40 C.F.R. § 60.1460 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART AAAA--STANDARDS OF PERFORMANCE FOR SMALL MUNICIPAL WASTE COMBUSTION UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER AUGUST 30, 1999 OR FOR WHICH MODIFICATION OR RECONSTRUCTION IS COMMENCED AFTER JUNE 6, 2001 § 60.1460 What equations must I use?

...C7% = concentration corrected to 7 percent oxygen. Cunc = uncorrected pollutant concentration. **CO2** = concentration of oxygen (percent). (b) Percent reduction in potential mercury emissions. Calculate the percent reduction in potential mercury emissions ...

238. 40 C.F.R. Pt. 60, Subpt. AAAA, Tbl. 3 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART AAAA--STANDARDS OF PERFORMANCE FOR SMALL MUNICIPAL WASTE COMBUSTION UNITS FOR WHICH CONSTRUCTION IS COMMENCED AFTER AUGUST 30, 1999 OR FOR WHICH MODIFICATION OR RECONSTRUCTION IS COMMENCED AFTER JUNE 6, 2001 Table 3 of Subpart AAAA of Part 60--Requirements for Validating Continuous Emission Monitoring Systems (CEMS)

... **carbon dioxide)** -- 1. Nitrogen Oxides (Class I units only) [FNa] .... Method 7, 7A, 7B, 7C, 7D, ...

250. **C** 40 C.F.R. § 60.1935 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART BBBB--EMISSION GUIDELINES AND COMPLIANCE TIMES FOR SMALL MUNICIPAL WASTE COMBUSTION UNITS CONSTRUCTED ON OR BEFORE AUGUST 30, 1999 § 60.1935 What equations must I use?

...C7% = concentration corrected to 7 percent oxygen. Cunc = uncorrected pollutant concentration. **CO2** = concentration of oxygen (percent). (b) Percent reduction in potential mercury emissions. Calculate the percent reduction in potential mercury emissions ...

251. 40 C.F.R. Pt. 60, Subpt. BBBB, Tbl. 6 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART BBBB--EMISSION GUIDELINES AND COMPLIANCE TIMES FOR SMALL MUNICIPAL WASTE COMBUSTION UNITS CONSTRUCTED ON OR BEFORE AUGUST 30, 1999 Table 6 of Subpart BBBB of Part 60--Model Rule--Requirements for Validating Continuous Emission Monitoring Systems (CEMS)

... **carbon dioxide)** -- 1. Nitrogen Oxides (Class I units only) [FNa] .... Method 7, 7A, 7B,7C, 7D, or ...

253. 40 C.F.R. Pt. 60, Subpt. BBBB, Tbl. 8 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART BBBB--EMISSION GUIDELINES AND COMPLIANCE TIMES FOR SMALL MUNICIPAL WASTE COMBUSTION UNITS CONSTRUCTED ON OR BEFORE AUGUST 30, 1999 Table 8 of Subpart BBBB of Part 60--Model Rule--Requirements for Stack Tests

... containers or trucks. -- [FNa] Must simultaneously measure oxygen (or **carbon dioxide**) using Method 3A or 3B in appendix A of this part. [FNb] Use CEMS to test sulfur dioxide, nitrogen oxide, ...

254. C 40 C.F.R. § 60.4102 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART HHHH--EMISSION GUIDELINES AND COMPLIANCE TIMES FOR COAL-FIRED ELECTRIC STEAM GENERATING UNITS § 60.4102 Definitions.

... system (DAHS)), a permanent record of Hg emissions, stack gas volumetric flow rate, stack gas moisture content, and oxygen or **carbon dioxide** concentration (as applicable), in a manner consistent with part 75 of this chapter. The following systems are the principal types ...

... of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H2O. (4) A **carbon dioxide** monitoring system, consisting of a **CO2** concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the **CO2** ...

... the **CO2** concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of **CO2** emissions, in percent **CO2**; and (5) An oxygen monitoring system, consisting of an O2 concentration monitor and an automated data ...

255. C 40 C.F.R. § 60.4103 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART HHHH--EMISSION GUIDELINES AND COMPLIANCE TIMES FOR COAL-FIRED ELECTRIC STEAM GENERATING UNITS § 60.4103 Measurements, abbreviations, and acronyms.

...Measurements, abbreviations, and acronyms used in this part are defined as follows: Btu--British thermal unit. **CO2--carbon dioxide.** H2O--water. Hg--mercury. hr--hour. kW--kilowatt electrical. kWh--kilowatt hour. lb--pound. ...

259. 40 C.F.R. § 60.4248 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES SUBPART JJJJ--STANDARDS OF PERFORMANCE FOR STATIONARY SPARK IGNITION INTERNAL COMBUSTION ENGINES § 60.4248 What definitions apply to this subpart?

... by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and **carbon dioxide (CO2)**. Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required ...

... land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and **CO2** . Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a ...

264. 40 C.F.R. Pt. 60, App. A-1 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES Appendix A-1 to Part 60--Test Methods 1 through 2F

...8.6 Determine the stack gas dry molecular weight. For combustion processes or processes that emit essentially **CO2**, O2, CO, and N2, use Method 3. For processes emitting essentially air, an analysis need not be conducted; use a ...

... rate are measured at the incinerator inlet using either Method 25A or Method 25B and Method 2A, respectively. Organic carbon, **carbon dioxide (CO2)**, and carbon monoxide (CO) concentrations are measured at the outlet using either Method 25A or Method 25B and Method 10, ...

... must meet the specifications set forth in Section 6.1.2 of Method 10, except that the span shall be 15 percent **CO2** by volume. 7.0 Reagents and Standards Same as Section 7.0 of Method 10 and Method 25A, with the following addition ...

265. 40 C.F.R. Pt. 60, App. A-2 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES Appendix A-2 to Part 60--Test Methods 2G through 3C

...Method 3--Gas analysis for the determination of dry molecular weight Method 3A--Determination of oxygen and **carbon dioxide** concentrations in emissions from stationary sources (instrumental analyzer procedure) Method 3B--Gas analysis for the determination of emission rate correction factor ...

...Method 3C--Determination of **carbon dioxide**, methane, nitrogen, and oxygen from stationary sources The test methods in this appendix are referred to in § 60.8 (Performance ...

...8.13 Molecular Weight. Determine the stack or duct gas dry molecular weight. For combustion processes or processes that emit essentially **CO2**, O2, CO, and N2, use Method 3 or 3A. For processes emitting essentially air, an analysis need not be conducted; ...

267. 40 C.F.R. Pt. 60, App. A-4 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES Appendix A-4 to Part 60--Test Methods 6 through 10B

...Method 6--Determination of sulfur dioxide emissions from stationary sources Method 6A--Determination of sulfur dioxide, moisture, and **carbon dioxide** emissions from fossil fuel combustion sources Method 6B--Determination of sulfur dioxide and **carbon dioxide** daily average emissions from fossil fuel ...

...Method 6A--Determination of Sulfur Dioxide, Moisture, and **Carbon Dioxide** From Fossil Fuel Combustion Sources Note: This method does not include all of the specifications (e.g., equipment and supplies) and ...

... (2.12×10^{-7} lb/ft^3) **CO2** .... 124-38-9 N/A H2O .... 7732-18-5 N/A -- 1.2 Applicability. This method is applicable for the determination of sulfur dioxide ...

268. 40 C.F.R. Pt. 60, App. A-5 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES Appendix A-5 to Part 60--Test Methods 11 through 15A

... its dew point below the operating temperature of the GC/FPD analytical system prior to analysis. 4.2 Carbon Monoxide (CO) and **Carbon Dioxide (CO2)**. CO and **CO2** have substantial desensitizing effects on the FPD even after 9:1 dilution. (Acceptable systems must demonstrate that they ...

... 9:1 dilution. (Acceptable systems must demonstrate that they have eliminated this interference by some procedure such as eluting CO and **CO2** before any of the sulfur compounds to be measured.) Compliance with this requirement can be demonstrated by submitting chromatograms of ...

... compounds to be measured.) Compliance with this requirement can be demonstrated by submitting chromatograms of calibration gases with and without **CO2** in the diluent gas. The **CO2** level should be approximately 10 percent for the case with **CO2** present. The two ...

269. 40 C.F.R. Pt. 60, App. A-6 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES Appendix A-6 to Part 60--Test Methods 16 through 18

... its dew point below the operating temperature of the GC/FPD analytical system prior to analysis. 4.2 Carbon Monoxide (CO) and **Carbon Dioxide (CO2)**. CO and **CO2** have a substantial desensitizing effect on the flame photometric detector even after dilution. Acceptable systems must demonstrate ...

... compounds to be measured. Compliance with this requirement can be demonstrated by submitting chromatograms of calibration gases with and without **CO2** in the diluent gas. The **CO2** level should be approximately 10 percent for the case with **CO2** present. The two ...

... of the particulate filter, described in Section 6.1.3 of Method 16A, will eliminate this interference. 4.3 Carbon monoxide (CO) and **carbon dioxide (CO2)** have substantial desensitizing effects on the FPD even after dilution. Acceptable systems must demonstrate that they have eliminated this interference ...

271. 40 C.F.R. Pt. 60, App. A-8 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES Appendix A-8 to Part 60--Test Methods 26 through 30B

... a wood-fired appliance while the appliance is operating at a prescribed set of conditions. The gas sample is analyzed for **carbon dioxide (CO2)**, oxygen (O2), and carbon monoxide (CO). These stack gas components are measured for determining the dry molecular weight of the ...

... air to the mass of dry fuel consumed. 6.3.2 Instrumental Analyzers. Same as Method 5H, Sections 6.1.3.4 and 6.1.3.5, for **CO2** and CO analyzers, except use a CO analyzer with a range of 0 to 5 percent and use a **CO2** ...

... Equation 28A-1 in Section 12.2. 9.1.2 If CO is present in quantities measurable by this method, adjust the O2 and **CO2** values before performing the calculation for Fo as shown in Section 12.3 and 12.4. 9.1.3 Compare the calculated Fo factor ...

273. **C** 40 C.F.R. Pt. 60, App. F CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 60--STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES Appendix F to Part 60--Quality Assurance Procedures

...2.2 Diluent Gas. A major gaseous constituent in a gaseous pollutant mixture. For combustion sources, **CO2** and O2 are the major gaseous constituents of interest. 2.3 Span Value. The upper limit of a gas concentration measurement ...

... **CO2** ...

275. 40 C.F.R. Pt. 61, App. B CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 61--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS Appendix B to Part 61--Test Methods

... Radionuclides of these elements are measured directly using an in-line or off-line monitor. Radionuclides of carbon in the form of **carbon dioxide** may be collected by dissolution in caustic solutions. 2.3 Definition of Terms In-line monitor means a continuous measurement system in ...

285. **C** 40 C.F.R. § 62.15390 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 62--APPROVAL AND PROMULGATION OF STATE PLANS FOR DESIGNATED FACILITIES AND POLLUTANTS SUBPART JJJ--FEDERAL PLAN REQUIREMENTS FOR SMALL MUNICIPAL WASTE COMBUSTION UNITS CONSTRUCTED ON OR BEFORE AUGUST 30, 1999 § 62.15390 What equations must I use?

...Where: C7% = concentration corrected to 7 percent oxygen. Cunc = uncorrected pollutant concentration. CO2 = concentration of oxygen (%). (b) Percent reduction in potential mercury emissions. Calculate the percent reduction in potential mercury emissions ...

286. **C** 40 C.F.R. § 63.309 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART L--NATIONAL EMISSION STANDARDS FOR COKE OVEN BATTERIES § 63.309 Performance tests and procedures.

... the stack gas. You may also use as an alternative to Method 3B, the manual method for measuring the oxygen, **carbon dioxide**, and carbon monoxide content of exhaust gas, ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses" (incorporated by reference, see § ...

288. **C** 40 C.F.R. § 63.547 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART X--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FROM SECONDARY LEAD SMELTING § 63.547 Test methods.

...(2) The Single Point Integrated Sampling and Analytical Procedure of Method 3B shall be used to measure the **carbon dioxide** content of the stack gases to determine compliance under § 63.543(c), (d), and (e). (3) Method 4 shall be used ...

... determining compliance under § 63.543(c), (d), and (e) shall be expressed as propane and shall be corrected to 4 percent **carbon dioxide**, as described in paragraph (c) of this section. (c) For the purposes of determining compliance with the emission limits under ...

...concentrations shall be corrected to 4 percent **carbon dioxide** as listed in paragraphs (c)(1) through (c)(2) of this section in the following manner: (1) If the measured percent ...

289. 40 C.F.R. § 63.641 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART CC--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FROM PETROLEUM REFINERIES § 63.641 Definitions.

... including, but not limited to, wastewater drains, sewer vents, and sump drains; and (14) Hydrogen production plant vents through which **carbon dioxide** is removed from process streams or through which steam condensate produced or treated within the hydrogen plant is degassed or ...

... definition) managing wastewater. Refinery fuel gas means a gaseous mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species (nitrogen, **carbon dioxide,** hydrogen sulfide, etc.) that is produced in the refining of crude oil and/or petrochemical processes and that is separated for ...

290. C 40 C.F.R. § 63.801 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART JJ--NATIONAL EMISSION STANDARDS FOR WOOD FURNITURE MANUFACTURING OPERATIONS § 63.801 Definitions.

... means, for the purposes of this industry, an enclosed combustion device that thermally oxidizes volatile organic compounds to CO and **CO2**. This term does not include devices that burn municipal or hazardous waste material. Janitorial maintenance means the upkeep of equipment ...

291. C 40 C.F.R. § 63.1189 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART DDD--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR MINERAL WOOL PRODUCTION § 63.1189 What test methods do I use?

...(c) Method 3 or 3A in appendix A to part 60 of this chapter for oxygen and **carbon dioxide** for diluent measurements needed to correct the concentration measurements to a standard basis. (d) Method 4 in appendix A to ...

293. C 40 C.F.R. § 63.1564 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART UUU--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR PETROLEUM REFINERIES: CATALYTIC CRACKING UNITS, CATALYTIC REFORMING UNITS, AND SULFUR RECOVERY UNITS § 63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?

... air to catalytic cracking unit catalyst regenerator, as determined from instruments in the catalytic cracking unit control room, dscm/min (dscf/min); **%cO2 = Carbon dioxide** concentration in regenerator exhaust, percent by volume (dry basis); %cO = Carbon monoxide concentration in regenerator exhaust, percent by volume ...

294. C 40 C.F.R. § 63.1573 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART UUU--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR PETROLEUM REFINERIES: CATALYTIC CRACKING UNITS, CATALYTIC REFORMING UNITS, AND SULFUR RECOVERY UNITS § 63.1573 What are my monitoring alternatives?

...(ii) Install and operate a continuous gas analyzer to measure and record the concentration of **carbon dioxide,** carbon monoxide, and oxygen of the catalytic cracking regenerator exhaust. (iii) Calculate and record the hourly average flow rate using ...

...**%cO2 = Carbon dioxide** concentration in regenerator exhaust, percent by volume (dry basis); CO = Carbon monoxide concentration in regenerator exhaust, percent by volume ...

295. C 40 C.F.R. § 63.2292 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART DDDD--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: PLYWOOD AND COMPOSITE WOOD PRODUCTS § 63.2292 What definitions apply to this subpart?

... as bark) and use microbiological activity to transform organic pollutants in a process exhaust stream to innocuous compounds such as **carbon dioxide,** water, and inorganic salts. Wastewater treatment systems such as aeration lagoons or activated sludge systems are not considered to be ...

296. 40 C.F.R. Pt. 63, Subpt. EEEE, Tbl. 5 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART EEEE--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: ORGANIC LIQUIDS DISTRIBUTION (NON-GASOLINE) Table 5 to Subpart EEEE of Part 63.--Requirements for Performance Tests and Design Evaluations

... and (ii) of flow rate this table. (A) Concen- See the tration requirements of **CO2** in items 1.a.- and O2 i.(1)(A)(i) and dry and (ii) of molecular this table. weight of the stack gas (A) ...

... (A) Concen- See the tration requirements of **CO2** in items 1.a.- and O2 i.(1)(A)(i) and dry and (ii) of molecular this table. weight of the stack ...

306. **C** 40 C.F.R. § 63.6175 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART YYYY--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR STATIONARY COMBUSTION TURBINES § 63.6175 What definitions apply to this subpart?

... by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and **CO2**. Distillate oil means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 ...

... land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and **CO2**. Lean premix gas-fired stationary combustion turbine means: (1)(i) Each stationary combustion turbine which is equipped only to fire gas using ...

309. **C** 40 C.F.R. § 63.6675 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART ZZZZ--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES § 63.6675 What definitions apply to this subpart?

... by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and **CO2**. Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and ...

... land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and **CO2**. Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich ...

... engines that, in a two-step reaction, promotes the conversion of excess oxygen, NOX, CO, and volatile organic compounds (VOC) into **CO2**, nitrogen, and water. Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon ...

311. 40 C.F.R. Pt. 63, Subpt. DDDDD, Tbl. 5 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART DDDDD--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR INDUSTRIAL, COMMERCIAL, AND INSTITUTIONAL BOILERS AND PROCESS HEATERS Table 5 to Subpart DDDDD of Part 63.--Performance Testing Requirements

... **carbon dioxide** ...

... **carbon dioxide** ...

... **carbon dioxide** ...

313 C 40 C.F.R. § 63.8687 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART LLLLL--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: ASPHALT PROCESSING AND ASPHALT ROOFING MANUFACTURING § 63.8687 What performance tests, design evaluations, and other procedures must I use?

... outlet, parts per million by volume (dry), as measured by the test method specified in Table 3 to this subpart. **CO2 = Carbon dioxide** concentration at the combustion device outlet, parts per million by volume (dry), as measured by the test method specified in ...

... outlet, parts per million by volume (dry), as measured by the test method specified in Table 3 to this subpart. **CO2 = Carbon dioxide** concentration at the combustion device outlet, parts per million by volume (dry), as measured by the test method specified in ...

314 40 C.F.R. Pt. 63, Subpt. LLLLL, Tbl. 3 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART LLLLL--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: ASPHALT PROCESSING AND ASPHALT ROOFING MANUFACTURING Table 3 to Subpart LLLLL of Part 63.--Requirements for Performance Tests [FNa] [FNb]

... requirements-- ------------------------------------ 1. All particulate matter, total hydrocarbon, carbon monoxide, and **carbon dioxide** emission tests . a. Select ...

... this chapter 4. All particulate matter, total hydrocarbon, carbon monoxide, and **carbon dioxide** emission tests . Measure ...

315 40 C.F.R. Pt. 63, Subpt. LLLLL, Tbl. 4 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART LLLLL--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS: ASPHALT PROCESSING AND ASPHALT ROOFING MANUFACTURING Table 4 to Subpart LLLLL to Part 63.--Initial Compliance With Emission Limitations

... and carbon monoxide, **carbon dioxide,** ...

... and carbon monoxide, **carbon dioxide,** ...

316 C 40 C.F.R. § 63.9800 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART SSSSS--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR REFRACTORY PRODUCTS MANUFACTURING § 63.9800 How do I conduct performance tests and establish operating limits?

... THC-C=THC concentration, corrected to 18 percent oxygen, parts per million by volume, dry basis (ppmvd) C THC=THC concentration (uncorrected), ppmvd **CO2**=oxygen concentration, percent. (2) To determine compliance with any of the emission limits based on percentage reduction across an emissions control ...

317 40 C.F.R. Pt. 63, Subpt. ZZZZZ, Tbl. 1 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES SUBPART ZZZZZ--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR IRON AND STEEL FOUNDRIES AREA SOURCES Table 1 to Subpart ZZZZZ of Part 63.--Performance Test Requirements for New and Existing Affected Sources Classified as Large Foundries

... as an alternative to EPA Method 3B (40 CFR part 60, appendix A), the manual method for measuring the oxygen, **carbon dioxide,** and carbon monoxide content of exhaust gas, ANSI/ASME PTC 19.10-1981, "Flue and Exhaust Gas Analyses" (incorporated by reference--see § 63.14). ...

319. **C** 40 C.F.R. Pt. 63, App. A CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 63--NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES Appendix A to Part 63--Test Methods

... Methane. Phenol .... 1231.32-1131.47 .... Water, Ammonia, Methane. Methanol .... 1041.56-1019.95 .... Water, Ammonia. COS [FNa] .... 2028.4-2091.9 .... Water, **CO2**, CO. CO [FNa] .... 2092.1-2191.8 .... Water, **CO2**, COS. -- [FNa] Suggested analytical regions assume about 15 percent moisture and ...

... CO. CO [FNa] .... 2092.1-2191.8 .... Water, **CO2**, COS. -- [FNa] Suggested analytical regions assume about 15 percent moisture and **CO2**, and that COS and CO have about the same absorbance (in the range of 10 to 50 ppm). If CO ...

... absorbance (in the range of 10 to 50 ppm). If CO and COS are hundreds of ppm or higher, then **CO2** and moisture interference is reduced. If CO or COS is present at high concentration and the other at low concentration, ...

320. **C** 40 C.F.R. § 72.3 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 72--PERMITS REGULATION SUBPART A--ACID RAIN PROGRAM GENERAL PROVISIONS § 72.3 Measurements, abbreviations, and acronyms.

...scfh--cubic feet per hour at standard conditions. sec--second. std--at standard conditions. **CO2--carbon dioxide.** NOx--nitrogen oxides. O2--oxygen. THC--total hydrocarbon content. SO2--sulfur dioxide. [64 FR 28588, May 26, 1999] ...

321. **C** 40 C.F.R. § 74.14 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 74--SULFUR DIOXIDE OPT-INS SUBPART B--PERMITTING PROCEDURES § 74.14 Opt-in permit process.

... sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that all SO2 emissions, NOx emissions, **CO2** emissions, and opacity of the combustion or process source are monitored and reported in accordance with part 75 of this ...

322. **C** 40 C.F.R. § 75.1 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART A--GENERAL § 75.1 Purpose and scope.

... this part is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO2), nitrogen oxides (NOX), and **carbon dioxide (CO2)** emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to sections 412 and 821 ...

... continuous emission or opacity monitoring systems and specific requirements for the monitoring of SO2 emissions, volumetric flow, NOx emissions, opacity, **CO2** emissions and SO2 emissions removal by qualifying Phase I technologies. Specifications for the installation and performance of continuous emission monitoring ...

... into units of the standard are included in appendix F to this part. Procedures for the monitoring and calculation of **CO2** emissions are included in appendix G of this part. [58 FR 34126, June 23, 1993; 58 FR 40747, July 30, ...

323. **C** 40 C.F.R. § 75.4 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART A--GENERAL § 75.4 Compliance dates.

... operator of each existing affected unit shall ensure that all monitoring systems required by this part for monitoring SO2, NOX, **CO2**, opacity, moisture and volumetric flow are installed and that all certification tests are completed no later than the following dates ...

... Phase II unit, January 1, 1995, except that installation and certification tests for continuous emission monitoring systems for NOX and **CO2** or excepted monitoring systems for NOX under appendix E or **CO2** estimation under appendix G of this part shall be ...

... of each new affected unit shall ensure that all monitoring systems required under this part for monitoring of SO2, NOX, **CO2**, opacity, and volumetric flow are installed and all certification tests are completed on or before the later of the following ...

324. **C** 40 C.F.R. § 75.5 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART A--GENERAL § 75.5 Prohibitions.

... affected unit shall operate the unit so as to discharge, or allow to be discharged, emissions of SO2, NOX or **CO2** to the atmosphere without accounting for all such emissions in accordance with the provisions of §§ 75.10 through 75.19. (e) ...

... system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO2, NOX, or **CO2** emissions discharged to the atmosphere, except for periods of recertification, or periods when calibration, quality assurance, or maintenance is performed ...

325. **C** 40 C.F.R. § 75.10 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART B--MONITORING PROVISIONS § 75.10 General operating requirements.

... (a) Primary Measurement Requirement. The owner or operator shall measure opacity, and all SO2, NOx, and **CO2** emissions for each affected unit as follows: (1) To determine SO2 emissions, the owner or operator shall install, certify, operate, ...

...pollutant concentration monitor and an O2 or **CO2** diluent gas monitor) with an automated data acquisition and handling system for measuring and recording NOX concentration (in ppm), O2 ...

... gas monitor) with an automated data acquisition and handling system for measuring and recording NOX concentration (in ppm), O2 or **CO2** concentration (in percent O2 or **CO2**) and NOX emission rate (in lb/mmBtu) discharged to the atmosphere, except as provided in ...

326. **C** 40 C.F.R. § 75.11 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART B--MONITORING PROVISIONS § 75.11 Specific provisions for monitoring SO2 emissions.

... 75.19(a) and (b). If this option is selected for SO2, the LME methodology must also be used for NOX and **CO2** when these parameters are required to be monitored by applicable program(s). (c) Special considerations during the combustion of gaseous fuels. ...

... owner or operator of an affected unit that uses a certified flow monitor and a certified diluent gas (O2 or **CO2**) monitor to measure the unit heat input rate shall, during any hours in which the unit combusts only gaseous fuel, ...

328. **C** 40 C.F.R. § 75.13 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART B--MONITORING PROVISIONS § 75.13 Specific provisions for monitoring CO2 emissions.

...§ 75.13 Specific provisions for monitoring **CO2** emissions. (a) **CO2** continuous emission monitoring system. If the owner or operator chooses to use the continuous emission monitoring method, ...

... continuous emission monitoring method, then the owner or operator shall meet the general operating requirements in § 75.10 for a **CO2** continuous emission monitoring system and flow monitoring system for each affected unit. The owner or operator shall comply with the ...

... operator shall comply with the applicable provisions specified in § 75.11(a) through (e) or § 75.16, except that the phrase "**CO2** continuous emission monitoring system" shall apply rather than "SO2 continuous emission monitoring system," the phrase "**CO2** concentration" shall apply rather ...

332 C 40 C.F.R. § 75.22 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART C--OPERATION AND MAINTENANCE REQUIREMENTS § 75.22 Reference test methods.

...(3) Methods 3, 3A, or 3B are the reference methods for the determination of the dry molecular weight O2 and **CO2** concentrations in the emissions. (4) Method 4 (either the standard procedure described in section 8.1 of the method or the ...

...(1) Method 3A for determining O2 or **CO2** concentration; (2) Method 6C for determining SO2 concentration; (3) Method 7E for determining total NOX concentration (both NO and NO2); ...

335 C 40 C.F.R. § 75.32 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART D--MISSING DATA SUBSTITUTION PROCEDURES § 75.32 Determination of monitor data availability for standard missing data procedures.

... (a) Following initial certification of the required SO2, **CO2**, O2, or Hg concentration, or moisture monitoring system(s) at a particular unit or stack location (i.e., the date and time ...

337 C 40 C.F.R. § 75.35 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART D--MISSING DATA SUBSTITUTION PROCEDURES § 75.35 Missing data procedures for CO2.

...§ 75.35 Missing data procedures for **CO2**. (a) The owner or operator of a unit with a **CO2** continuous emission monitoring system for determining **CO2** mass emissions ...

... system for determining **CO2** mass emissions in accordance with § 75.10 (or an O2 monitor that is used to determine **CO2** concentration in accordance with appendix F to this part) shall substitute for missing **CO2** pollutant concentration data using the procedures ...

... data begins to be recorded by a CEMS at that location), or (when implementing these procedures for a previously certified **CO2** monitoring system) during the 720 quality-assured monitor operating hours preceding implementation of the standard missing data procedures in paragraph (d) ...

339 C 40 C.F.R. § 75.37 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART D--MISSING DATA SUBSTITUTION PROCEDURES § 75.37 Missing data procedures for moisture.

...(i) Provided that none of the following equations is used to determine SO2 emissions, **CO2** emissions or heat input: Equation F-2, F-14b, F-16, F-17, or F-18 in appendix F to this part, or Equation 19-5 ...

... rather than "maximum potential SO2 concentration;" or (ii) If any of the following equations is used to determine SO2 emissions, **CO2** emissions or heat input: Equation F-2, F-14b, F-16, F-17, or F-18 in appendix F to this part, or Equation 19-5 ...

340 C 40 C.F.R. § 75.53 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART F--RECORDKEEPING REQUIREMENTS § 75.53 Monitoring plan.

... this part and the use of data derived from these systems to demonstrate that all unit SO2 emissions, NOX emissions, **CO2** emissions, and opacity are monitored and reported. (b) Whenever the owner or operator makes a replacement, modification, or change in ...

... span, and flow rate span value and full scale value (in scfh) for each unit or stack using SO2, NOX, **CO2**, O2, Hg, or flow component monitors. (xi) If the monitoring system or excepted methodology provides for the use of a ...

341 C 40 C.F.R. § 75.57 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART F--RECORDKEEPING REQUIREMENTS § 75.57 General recordkeeping provisions.

... **CO2** or O2: Method 3A. 5 ..... For units with add-on SO2 and/or NOX emission controls: SO2 ...

... parametric monitoring method. 6 ..... Average of the hourly SO2 concentrations, **CO2** concentrations, O2 ...

... hourly SO2 concentration, **CO2** concentration, O2 concentration, ...

342 **C** 40 C.F.R. § 75.58 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART F--RECORDKEEPING REQUIREMENTS § 75.58 General recordkeeping provisions for specific situations.

...(f) Specific SO2, NOX, and **CO2** record provisions for gas-fired or oil-fired units using the optional low mass emissions excepted methodology in § 75.19. In lieu ...

... 75.19(c): (B) Indicate the fuel type resulting in the highest emission factor for each parameter (SO2, NOX emission rate, and **CO2**) separately (this option is required on and after January 1, 2009); (iv) Average hourly NOX emission rate (lb/mmBtu, rounded to ...

...(vii) Hourly **CO2** mass emissions (tons, rounded to the nearest tenth); (viii) Hourly calculated unit heat input in mmBtu; (ix) Hourly unit output ...

343 **C** 40 C.F.R. § 75.59 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART F--RECORDKEEPING REQUIREMENTS § 75.59 Certification, quality assurance, and quality control record provisions.

... and recording emissions or flow from an affected unit. (1) For each SO2 or NOX pollutant concentration monitor, flow monitor, **CO2** emissions concentration monitor (including O2monitors used to determine CO2emissions), Hg monitor, or diluent gas monitor (including wet- and dry-basis O2 ...

... corrective action: to a passed test or following a failed test. (3) For each SO2 or NOX pollutant concentration monitor, **CO2** emissions concentration monitor (including O2 monitors used to determine **CO2** emissions), Hg concentration monitor, or diluent gas monitor (including wet-and ...

... For each SO2 pollutant concentration monitor, flow monitor, each CO2emissions concentration monitor (including any O2 concentration monitor used to determine **CO2** mass emissions or heat input), each NOX-diluent continuous emission monitoring system, each NOX concentration monitoring system, each diluent gas (O2 ...

344 **C** 40 C.F.R. § 75.64 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART G--REPORTING REQUIREMENTS § 75.64 Quarterly reports.

... rounded to the nearest thousandth) during the quarter and cumulative NOX emission rate for the calendar year. (10) Tons of **CO2** emitted during quarter and cumulative **CO2** emissions for calendar year. (11) Total heat input (mmBtu) for quarter and cumulative heat ...

345 **C** 40 C.F.R. § 75.66 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING SUBPART G--REPORTING REQUIREMENTS § 75.66 Petitions to the Administrator.

... to account for emissions of the following parameters, as applicable: SO2 mass emissions (in lbs), NOX emission rate (in lbs/mmBtu), **CO2** mass emissions (in lbs) and, if the unit is subject to the requirements of subpart H of this part, NOX ...

353 **C** 40 C.F.R. Pt. 75, App. A CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING Appendix A to Part 75--Specifications and Test Procedures

... or path for the monitor probe(s) (or for the path from the transmitter to the receiver) such that the SO2, **CO2**, O2, and NOX concentration monitoring system or NOX -diluent CEMS (NOX pollutant concentration monitor and diluent gas monitor), Hg concentration ...

... this appendix). In implementing sections 2.1.1 through 2.1.6 of this appendix, set the measurement range for each parameter (SO2, NOX, **CO2**, O2, or flow rate) high enough to prevent full-scale exceedances from occurring, yet low enough to ensure good measurement accuracy ...

... PARAGRAPH (C) OF SECTION 2.1.1.1. 2w = Minimum oxygen concentration, percent wet basis, under typical operating conditions. %cO2w = Maximum **carbon dioxide** concentration, percent wet basis, under typical operating conditions. GCV = Minimum gross calorific value of the fuel or blend to ...

355 C 40 C.F.R. Pt. 75, App. D CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING Appendix D to Part 75--Optional SO2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units

... The designated representative may also petition the Administrator under § 75.66 to use this apportionment procedure to calculate SO2 and **CO2** mass emissions. (b) Determine total hourly fuel flow or flow rate through the fuel flowmeter supplying gas or oil fuel ...

357 40 C.F.R. Pt. 75, App. G CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING Appendix G to Part 75--Determination of CO2 Emissions

...Appendix G to Part 75--Determination of **CO2** Emissions 1. Applicability The procedures in this appendix may be used to estimate **CO2** mass emissions discharged to the atmosphere ...

... this appendix may be used to estimate **CO2** mass emissions discharged to the atmosphere (in tons/day) as the sum of **CO2** emissions from combustion and, if applicable, **CO2** emissions from sorbent used in a wet flue gas desulfurization control system, fluidized ...

... used in a wet flue gas desulfurization control system, fluidized bed boiler, or other emission controls. 2. Procedures for Estimating **CO2** Emissions From Combustion Use the following procedures to estimate daily **CO2** mass emissions from the combustion of fossil fuels. The ...

358 C 40 C.F.R. Pt. 75, App. K CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 75--CONTINUOUS EMISSION MONITORING Appendix K to Part 75--Quality Assurance and Operating Procedures for Sorbent Trap Monitoring Systems

... the manufacturer, equipment supplier, or end user may calibrate the meter using a bottled gas mixture containing 12 +- 0.5% **CO2**, 7 +- 0.5% O2, and balance N2, or these same gases in proportions more representative of the expected stack gas ...

359 C 40 C.F.R. § 76.2 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 76--ACID RAIN NITROGEN OXIDES EMISSION REDUCTION PROGRAM § 76.2 Definitions.

... of the combustion zone that converts NOX to molecular nitrogen, water, and when urea or cyanuric acid are used, to **carbon dioxide (CO2)**. Stoker boiler means a boiler that burns solid fuel in a bed, on a stationary or moving grate, that is ...

360 C 40 C.F.R. § 79.52 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 79--REGISTRATION OF FUELS AND FUEL ADDITIVES SUBPART F--TESTING REQUIREMENTS FOR REGISTRATION § 79.52 Tier 1.

... are those identified pursuant to the emission characterization procedures specified in paragraph (b) of this section, other than carbon monoxide, **carbon dioxide**, nitrogen oxides, benzene, 1,3-butadiene, acetaldehyde, and formaldehyde. (3) In the case of the individual emission products of non-baseline or atypical ...

361 C 40 C.F.R. § 79.55 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 79--REGISTRATION OF FUELS AND FUEL ADDITIVES SUBPART F--TESTING REQUIREMENTS FOR REGISTRATION § 79.55 Base fuel specifications.

... max .... 0.2 Oxygen, mole%, max .... 0.6 Sulfur (including odorant additive) ppmv, max .... 16 Inert gases: Sum of **CO2** and N2, mole%, max .... 4.0 -- (g) Propane Base Fuel. (1) The propane base fuel is a gaseous motor ...

362. C 40 C.F.R. § 79.57 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 79--REGISTRATION OF FUELS AND FUEL ADDITIVES SUBPART F--TESTING REQUIREMENTS FOR REGISTRATION § 79.57 Emission generation.

... 10 percent of the target concentration for the single species being controlled. (3) For all species, daily monitoring of CO, **CO2**, NOX, SOX, and total hydrocarbons in the exposure chamber shall be required. Analysis of the particle size distribution shall also ...

... 10 percent of the target concentration for the single species being controlled. (3) For all species, daily monitoring of CO, **CO2**, NOX, SOX, and total hydrocarbons in the exposure chamber shall be required. Analysis of the particle size distribution shall also ...

363. C 40 C.F.R. § 79.61 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 79--REGISTRATION OF FUELS AND FUEL ADDITIVES SUBPART F--TESTING REQUIREMENTS FOR REGISTRATION § 79.61 Vehicle emissions inhalation exposure guideline.

... emissions concentration delivered to the exposure system, serving the function of diluting the associated combustion gases, such as carbon monoxide, **carbon dioxide**, nitrogen oxides, sulfur dioxide and other noxious gases and vapors, to levels that will ensure that there are no significant ...

... samples shall be taken daily to determine concentrations (ppm) of the major vapor components of the test atmosphere including CO, **CO2**, NOX, SO2, and total hydrocarbons. (B) To ensure that animals in different locations of the chamber receive a similar exposure ...

364. C 40 C.F.R. § 80.50 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 80--REGULATION OF FUELS AND FUEL ADDITIVES SUBPART D--REFORMULATED GASOLINE § 80.50 General test procedure requirements for augmentation of the emission models.

... must be followed when testing to augment the complex emission model described at § 80.45. (1) VOC, NOX, CO, and **CO2** emissions must be measured for all fuel-vehicle combinations tested. (2) Toxics emissions must be measured when testing the extension fuels ...

365. 40 C.F.R. Pt. 82, Subpt. A, App. I CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 82--PROTECTION OF STRATOSPHERIC OZONE SUBPART A--PRODUCTION AND CONSUMPTION CONTROLS Appendix I to Subpart A of Part 82--Global Warming Potentials (mass basis), referenced to the Absolute GWP for the adopted carbon cycle model CO2 decay response and future CO2 atmospheric concentrations held constant at current levels. (Only direct effects are considered.)

... Subpart A of Part 82--Global Warming Potentials (mass basis), referenced to the Absolute GWP for the adopted carbon cycle model **CO2** decay response and future **CO2** atmospheric concentrations held constant at current levels. (Only direct effects are considered.) --- Species ...

366. C 40 C.F.R. § 82.154 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 82--PROTECTION OF STRATOSPHERIC OZONE SUBPART F--RECYCLING AND EMISSIONS REDUCTION § 82.154 Prohibitions.

...(iii) Chlorine in industrial process refrigeration (processing of chlorine and chlorine compounds); (iv) **Carbon dioxide** in any application; (v) Nitrogen in any application; or (vi) Water in any application. (2) The knowing release of a ...

367. 40 C.F.R. Pt. 82, Subpt. G, App. A CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 82--PROTECTION OF STRATOSPHERIC OZONE SUBPART G--SIGNIFICANT NEW ALTERNATIVES POLICY PROGRAM Appendix A to Subpart G of Part 82--Substitutes Subject to Use Restrictions and Unacceptable Substitutes

... **CO2**. ...

368. C 40 C.F.R. § 85.2122 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 85--CONTROL OF AIR POLLUTION FROM MOBILE SOURCES SUBPART V--EMISSIONS CONTROL SYSTEM PERFORMANCE WARRANTY REGULATIONS AND VOLUNTARY AFTERMARKET PART CERTIFICATION PROGRAM § 85.2122 Emission-Critical Parameters.

... system of an internal combustion engine that utilizes catalytic action to oxidize hydrocarbon (HC) and carbon monoxide (CO) emissions to **carbon dioxide** (CO_2)and water (H_2O). (B) "Conversion Efficiency" means the measure of the catalytic converter's ability to oxidize HC/CO to **CO2**/H2O under ...

...50% of the incoming HC and CO to **CO2** and H2O. (D) "Peak Air Flow" means the maximum engine intake mass air flow rate measure during the 195 second ...

369. C 40 C.F.R. § 85.2213 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 85--CONTROL OF AIR POLLUTION FROM MOBILE SOURCES SUBPART W--EMISSION CONTROL SYSTEM PERFORMANCE WARRANTY SHORT TESTS § 85.2213 Idle test--EPA 91.

... test conditions. The test immediately terminates and any exhaust gas measurements are voided if the measured concentration of CO plus **CO2** falls below six percent or the vehicle's engine stalls at any time during the test sequence. (4) Multiple exhaust pipes. ...

...(iv) The measured concentration of CO plus **CO2** must be greater than or equal to six percent. (c) First-chance test. The test timer starts (tt=0) when the conditions ...

370. C 40 C.F.R. § 85.2215 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 85--CONTROL OF AIR POLLUTION FROM MOBILE SOURCES SUBPART W--EMISSION CONTROL SYSTEM PERFORMANCE WARRANTY SHORT TESTS § 85.2215 Two speed idle test--EPA 91.

... test conditions. The test immediately terminates and any exhaust gas measurements are voided if the measured concentration of CO plus **CO^2** falls below six percent or the vehicle's engine stalls at any time during the test sequence. (4) Multiple exhaust pipes. ...

...(iv) The measured concentration of CO plus **CO^2** must be greater than or equal to six percent. (c) First-chance test and second-chance high-speed mode. The test timer starts ...

371. C 40 C.F.R. § 85.2217 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 85--CONTROL OF AIR POLLUTION FROM MOBILE SOURCES SUBPART W--EMISSION CONTROL SYSTEM PERFORMANCE WARRANTY SHORT TESTS § 85.2217 Loaded test--EPA 91.

... test conditions. The test immediately terminates and any exhaust gas measurements are voided if the measured concentration of CO plus **CO2** falls below six percent or the vehicle's engine stalls at any time during the test sequence. (4) Multiple exhaust pipes. ...

...(v) The measured concentration of CO plus **CO2** must be greater than or equal to six percent. (c) Overall test procedure. The test timer starts (tt=0) when the ...

372. C 40 C.F.R. § 85.2218 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 85--CONTROL OF AIR POLLUTION FROM MOBILE SOURCES SUBPART W--EMISSION CONTROL SYSTEM PERFORMANCE WARRANTY SHORT TESTS § 85.2218 Preconditioned idle test--EPA 91.

... test conditions. The test immediately terminates and any exhaust gas measurements are voided if the measured concentration of CO plus **CO2** falls below six percent or the vehicle's engine stalls at any time during the test sequence. (4) Multiple exhaust pipes. ...

...(iv) The measured concentration of CO plus **CO2** must be greater than or equal to six percent. (c) First-chance test. The test timer starts (tt=0) when the conditions ...

373. **C** 40 C.F.R. § 85.2219 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 85--CONTROL OF AIR POLLUTION FROM MOBILE SOURCES SUBPART W--EMISSION CONTROL SYSTEM PERFORMANCE WARRANTY SHORT TESTS § 85.2219 Idle test with loaded preconditioning--EPA 91.

... test conditions. The test immediately terminates and any exhaust gas measurements are voided if the measured concentration of CO plus **CO2** falls below 6 percent or the vehicle's engine stalls at any time during the test sequence. (4) Multiple exhaust pipes. ...

...(v) The measured concentration of CO plus **CO2** must be greater than or equal to 6 percent. (c) First-chance test. The test timer starts (tt=0) when the conditions ...

374. **C** 40 C.F.R. § 85.2220 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 85--CONTROL OF AIR POLLUTION FROM MOBILE SOURCES SUBPART W--EMISSION CONTROL SYSTEM PERFORMANCE WARRANTY SHORT TESTS § 85.2220 Preconditioned two speed idle test--EPA 91.

... test conditions. The test immediately terminates and any exhaust gas measurements are voided if the measured concentration of CO plus **CO2** falls below six percent or the vehicle's engine stalls at any time during the test sequence. (4) Multiple exhaust pipes. ...

...(iv) The measured concentration of CO plus **CO2** must be greater than or equal to six percent. (c) First-chance test. The test timer starts (tt=0) when the conditions ...

375. **C** 40 C.F.R. § 85.2225 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 85--CONTROL OF AIR POLLUTION FROM MOBILE SOURCES SUBPART W--EMISSION CONTROL SYSTEM PERFORMANCE WARRANTY SHORT TESTS § 85.2225 Steady state test exhaust analysis system--EPA 91.

... line; a water removal system; particulate trap; sample pump; flow control components; tachometer or dynamometer; analyzers for HC, CO, and **CO2**; and digital displays for exhaust concentrations of HC, CO, and **CO2**; and for engine rpm. Materials that are in contact ...

... stability and warmup requirements. The instrument is considered "warmed up" when the zero and span readings for HC, CO, and **CO2** have stabilized, within 3 percent of the full range of low scale, for five minutes without adjustment. (7) Electromagnetic isolation ...

... .15 **CO2**, **%** .... 0-4.0+-0.6 .... .2 ...

376. **C** 40 C.F.R. § 85.2233 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 85--CONTROL OF AIR POLLUTION FROM MOBILE SOURCES SUBPART W--EMISSION CONTROL SYSTEM PERFORMANCE WARRANTY SHORT TESTS § 85.2233 Steady state test equipment calibrations, adjustments, and quality control--EPA 91.

... conducts an automatic zero and span check prior to each test. The span check must include the HC, CO, and **CO2** channels and, if present, the NO channel. If zero and/or span drift cause the signal levels to move beyond the ...

... operating day in high-volume stations, analyzers must automatically require and successfully pass a two-point gas calibration for HC, CO, and **CO2** and must continually compensate for changes in barometric pressure. Calibration must be checked within four hours before the test and ...

... are compensated for automatically and statistical process control demonstrates (B) 1.0% and 4.0% carbon monoxide (CO). (C) 6.0% and 12.0% **carbon dioxide (CO2)**. (D) (if equipped for nitric oxide) 1000 ppm and 3000 ppm nitric oxide (NO). (ii)(A) 0 ppm and 600 ppm ...

377 C 40 C.F.R. § 86.007-21 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART A--GENERAL PROVISIONS FOR EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES, LIGHT-DUTY TRUCKS AND HEAVY-DUTY ENGINES, AND FOR 1985 AND LATER MODEL YEAR NEW GASOLINE FUELED, NATURAL GAS-FUELED, LIQUEFIED PETROLEUM GAS-FUELED AND METHANOL-FUELED HEAVY-DUTY VEHICLES § 86.007-21 Application for certification.

... For engines subject to the MAEL (see § 86.007-11(a)(3)(ii)), concentrations and mass flow rates of all regulated gaseous emissions plus **carbon dioxide**; (4) Values of all emission-related engine control variables at each test point; (5) A statement that the test results correspond ...

378. C 40 C.F.R. § 86.078-3 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART A--GENERAL PROVISIONS FOR EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES, LIGHT-DUTY TRUCKS AND HEAVY-DUTY ENGINES, AND FOR 1985 AND LATER MODEL YEAR NEW GASOLINE FUELED, NATURAL GAS-FUELED, LIQUEFIED PETROLEUM GAS-FUELED AND METHANOL-FUELED HEAVY-DUTY VEHICLES § 86.078-3 Abbreviations.

...CFV--Critical flow venturi. CFV-CVS--Critical flow venturi--constant volume sampler. CL--Chemiluminescence. **CO2--carbon dioxide.** CO--Carbon monoxide. conc.--concentration. cfm--cubic feet per minute. CT--Closed throttle. cu. in.--cubic inch(es). ...

379 C 40 C.F.R. § 86.111-90 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.111-90 Exhaust gas analytical system.

... gas analytical system for analysis of hydrocarbons (HC) (hydrocarbons plus methanol in the case of methanol-fueled vehicles), carbon monoxide (CO), **carbon dioxide** (CO sub2), and oxides of nitrogen (NO subx). The schematic diagram of the hydrocarbon analysis train for diesel vehicles (and ...

... C) for methanol-fueled vehicles) for the determination of hydrocarbons, non-dispersive infrared analyzers (NDIR) for the determination of carbon monoxide and **carbon dioxide** and a chemiluminescence analyzer (CL) for the determination of oxides of nitrogen. A heated flame ionization detector (HFID) is used ...

... sample conditioning column containing CaSO sub4 , or indicating silica gel to remove water vapor and containing ascarite to remove **carbon dioxide** from the CO analysis stream. (i) If CO instruments which are essentially free of CO sub2 and water vapor interference ...

380 C 40 C.F.R. § 86.111-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.111-94 Exhaust gas analytical system.

... in the case of methanol-fueled vehicles), methane (CH4) (for vehicles subject to the NMHC and NMHCE standards), carbon monoxide (CO), **carbon dioxide (CO2)**, and oxides of nitrogen (NO subx). The schematic diagram of the continuous THC analysis train (and for THC plus methanol ...

... a sample conditioning column containing CaSO sub4, or indicating silica gel to remove water vapor, and containing ascarite to remove **carbon dioxide** from the CO analysis stream. (i) If CO instruments which are essentially free of CO sub2 and water vapor interference ...

381. C 40 C.F.R. § 86.113-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.113-94 Fuel specifications.

... 0.6 Inert gases: Sum of **CO2** and N2 max. mole pct. ...

382. C 40 C.F.R. § 86.114-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.114-94 Analytical gases.

... or nitrogen) impurity concentrations shall not exceed 1 ppm equivalent carbon response, 1 ppm carbon monoxide, 0.04 percent (400 ppm) **carbon dioxide**, and 0.1 ppm nitric oxide. (7) "Zero grade air" includes artificial "air" consisting of a blend of nitrogen and oxygen ...

383. C 40 C.F.R. § 86.116-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.116-94 Calibrations, frequency and overview.

... the following calibrations and checks shall be performed: (1) Calibrate the THC analyzers (both evaporative and exhaust instruments), methane analyzer, **carbon dioxide** analyzer, carbon monoxide analyzer, and oxides of nitrogen analyzer (certain analyzers may require more frequent calibration depending on particular equipment ...

384. 40 C.F.R. § 86.124-78 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.124-78 Carbon dioxide analyzer calibration.

...§ 86.124-78 **Carbon dioxide** analyzer calibration. Prior to its introduction into service and monthly thereafter the NDIR **carbon dioxide** analyzer shall be calibrated: (a) ...

...(b) Zero the **carbon dioxide** analyzer with either zero-grade air or zero-grade nitrogen. (c) Calibrate on each normally used operating range with **carbon dioxide** in ...

385. C 40 C.F.R. § 86.127-00 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.127-00 Test procedures; overview.

... operating test conditions. Vehicles are tested for any or all of the following emissions: (1) Gaseous exhaust THC, CO, NOx, **CO2** (for petroleum-fueled and gaseous-fueled vehicles), plus CH3OH and HCHO for methanol-fueled vehicles, plus CH4 (for vehicles subject to the NMHC ...

... to the NMHC and NMHCE standards). (b) The FTP Otto-cycle exhaust emission test is designed to determine gaseous THC, CO, **CO2**, CH4, NOx, and particulate mass emissions from gasoline-fueled, methanol-fueled and gaseous-fueled Otto-cycle vehicles as well as methanol and formaldehyde from ...

... element of the SFTP for exhaust emissions related to aggressive driving (US06) is designed to determine gaseous THC, NMHC, CO, **CO2**, CH4, and NOx emissions from gasoline-fueled or diesel-fueled vehicles (see § 86.158-00 Supplemental test procedures; overview, and § 86.159-00 Exhaust ...

386. C 40 C.F.R. § 86.127-96 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.127-96 Test procedures; overview.

... and operating conditions. Vehicles are tested for any or all of the following emissions: (1) Gaseous exhaust THC, CO, NOX, **CO2** (for petroleum-fueled and gaseous-fueled vehicles), plus CH3OH and HCHO for methanol-fueled vehicles, plus CH4 (for vehicles subject to the NMHC ...

... subject to the NMHC and NMHCE standards). (b) The Otto-cycle exhaust emission test is designed to determine gaseous THC, CO, **CO2**, CH4, NOX, and particulate mass emissions from gasoline-fueled, methanol-fueled and gaseous-fueled Otto-cycle vehicles as well as methanol and formaldehyde from ...

... diluted exhaust is continuously analyzed for THC using a heated sample line and analyzer; the other gaseous emissions (CH4, CO, **CO2**, and NOX) are collected continuously for analysis as in § 86.127(b). For methanol-fueled vehicles, THC, methanol, formaldehyde, CO, **CO2**, CH4, ...

387. C 40 C.F.R. § 86.135-90 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.135-90 Dynamometer procedure.

... sample is collected for analysis during each phase. The composite samples collected in bags are analyzed for hydrocarbon, carbon monoxide, **carbon dioxide,** and oxides of nitrogen. A parallel sample of the dilution air is similarly analyzed for hydrocarbon, carbon monoxide, **carbon dioxide,** ...

... for analysis during each test phase. For petroleum-fueled vehicles, the composite samples collected in bags are analyzed for carbon monoxide, **carbon dioxide,** and oxides of nitrogen. Hydrocarbons from petroleum-fueled vehicles are sampled and analyzed continuously according to the provisions of § 86.110. ...

... according to the provisions of § 86.110. Parallel samples of the dilution air are similarly analyzed for hydrocarbon, carbon monoxide, **carbon dioxide,** and oxides of nitrogen. For methanol-fueled vehicles, bag samples are collected and analyzed for hydrocarbons, carbon monoxide, **carbon dioxide,** and ...

388. C 40 C.F.R. § 86.135-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.135-94 Dynamometer procedure.

... gasoline-fueled, natural gas-fueled and liquefied petroleum gas-fueled Otto-cycle vehicles, the composite samples collected in bags are analyzed for THC, CO, **CO2**, CH4 and NOX. For petroleum-fueled diesel-cycle vehicles (optional for natural gas-fueled, liquefied petroleum gas-fueled and methanol-fueled diesel-cycle vehicles), THC is ...

... continuously according to the provisions of § 86.110. Parallel samples of the dilution air are similarly analyzed for THC, CO, **CO2**, CH4 and NOX. For natural gas- fueled, liquefied petroleum gas-fueled and methanol-fueled vehicles, bag samples are collected and analyzed for ...

... fueled, liquefied petroleum gas-fueled and methanol-fueled vehicles, bag samples are collected and analyzed for THC (if not sampled continuously), CO, **CO2**, CH4 and NOX. For methanol-fueled vehicles, methanol and formaldehyde samples are taken for both exhaust emissions and dilution air (a ...

389. C 40 C.F.R. § 86.140-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.140-94 Exhaust sample analysis.

...(a) For CO, **CO2**, CH4, NOX, and for Otto-cycle and methanol-fueled, natural gas-fueled and liquefied petroleum gas-fueled (if non-heated FID option is used) diesel ...

390. C 40 C.F.R. § 86.142-90 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.142-90 Records required.

...(q) Additional required records for natural gas-fueled vehicles. Composition, including all carbon containing compounds; e.g. **CO2**, of the natural gas-fuel used during the test. C1 and C2 compounds shall be individually reported. C3 and heavier hydrocarbons. ...

391. C 40 C.F.R. § 86.144-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.144-94 Calculations; exhaust emissions.

...(1) YWM = Weighted mass emissions of each pollutant, i.e., THC, CO, THCE, NMHC, NMHCE, CH4, NOX, or **CO2**, in grams per vehicle mile. (2) Yct=Mass emissions as calculated from the "transient" phase of the cold start test, in ...

...(4) **Carbon dioxide** mass: CO2mass=Vmix x DensityCO2 x (CO2conc/100) (5) Methanol mass: CH3OHmass=Vmix x DensityCH3OH x (CH3OHconc/1,000,000) ...

...(iii)(A) COconc=Carbon monoxide concentration of the dilute exhaust sample corrected for background, water vapor, and **CO2** extraction, in ppm. (B) COconc=COe - COd(1-(1/DF)). Where: (iv)(A) COe=Carbon monoxide concentration of the dilute exhaust volume corrected for water ...

392. C 40 C.F.R. § 86.158-00 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.158-00 Supplemental Federal Test Procedures; overview.

...(a) Vehicles are tested for the exhaust emissions of THC, CO, NOX, CH4, and **CO2**. For diesel-cycle vehicles, THC is sampled and analyzed continuously according to the provisions of § 86.110. (b) Each test procedure ...

393. C 40 C.F.R. § 86.158-08 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.158-08 Supplemental Federal Test Procedures; overview.

...(a) Vehicles are tested for the exhaust emissions of THC, CO, NOX, CH4, and **CO2** . For diesel-cycle vehicles, THC is sampled and analyzed continuously according to the provisions of § 86.110. (b) Each test ...

394. C 40 C.F.R. § 86.159-00 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.159-00 Exhaust emission test procedures for US06 emissions.

... 86.136-90 (engine starting and restarting). For gasoline-fueled Otto-cycle vehicles, the composite samples collected in bags are analyzed for THC, CO, **CO2**, CH4, and NOX. For petroleum-fueled diesel-cycle vehicles, THC is sampled and analyzed continuously according to the provisions of § 86.110. ...

... analyzed continuously according to the provisions of § 86.110. Parallel bag samples of dilution air are analyzed for THC, CO, **CO2**, CH4, and NOX. (b) Dynamometer activities. (1) All official US06 tests shall be run on a large single roll electric ...

395. C 40 C.F.R. § 86.159-08 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.159-08 Exhaust emission test procedures for US06 emissions.

... 86.136-90 (engine starting and restarting). For gasoline-fueled Otto-cycle vehicles, the composite samples collected in bags are analyzed for THC, CO, **CO2**, CH4, and NOX . For petroleum-fueled diesel-cycle vehicles, THC is sampled and analyzed continuously according to the provisions of § ...

... analyzed continuously according to the provisions of § 86.110. Parallel bag samples of dilution air are analyzed for THC, CO, **CO2**, CH4, and NOX (b) Dynamometer activities. (1) All official US06 tests shall be run on a large single roll ...

396. **C** 40 C.F.R. § 86.160-00 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART B--EMISSION REGULATIONS FOR 1977 AND LATER MODEL YEAR NEW LIGHT-DUTY VEHICLES AND NEW LIGHT-DUTY TRUCKS AND NEW OTTO-CYCLE COMPLETE HEAVY-DUTY VEHICLES; TEST PROCEDURES § 86.160-00 Exhaust emission test procedure for SC03 emissions.

... minute soak), including the preconditioning. For gasoline-fueled Otto-cycle vehicles, the composite samples collected in bags are analyzed for THC, CO, **CO2**, CH4, and NOX. For petroleum-fueled diesel-cycle vehicles, THC is sampled and analyzed continuously according to the provisions of § 86.110. ...

... analyzed continuously according to the provisions of § 86.110. Parallel bag samples of dilution air are analyzed for THC, CO, **CO2**, CH4, and NOX. (b) Dynamometer activities. (1) All official air conditioning tests shall be run on a large single roll ...

397. **C** 40 C.F.R. § 86.211-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART C--EMISSION REGULATIONS FOR 1994 AND LATER MODEL YEAR GASOLINE-FUELED NEW LIGHT-DUTY VEHICLES, NEW LIGHT-DUTY TRUCKS AND NEW MEDIUM-DUTY PASSENGER VEHICLES; COLD TEMPERATURE TEST PROCEDURES § 86.211-94 Exhaust gas analytical system.

... that the NOX analyzer is optional. The exhaust gas analytical system must contain components necessary to determine hydrocarbons, carbon monoxide, **carbon dioxide**, methane, and formaldehyde. The exhaust gas analytical system is not required to contain components necessary for determining oxides of nitrogen. ...

398. **C** 40 C.F.R. § 86.224-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART C--EMISSION REGULATIONS FOR 1994 AND LATER MODEL YEAR GASOLINE-FUELED NEW LIGHT-DUTY VEHICLES, NEW LIGHT-DUTY TRUCKS AND NEW MEDIUM-DUTY PASSENGER VEHICLES; COLD TEMPERATURE TEST PROCEDURES § 86.224-94 Carbon dioxide analyzer calibration.

...§ 86.224-94 **Carbon dioxide** analyzer calibration. The provisions of § 86.124-78 apply to this subpart. SOURCE: 50 FR 35386, Aug. 30, 1985; 53 FR ...

399. **C** 40 C.F.R. § 86.235-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART C--EMISSION REGULATIONS FOR 1994 AND LATER MODEL YEAR GASOLINE-FUELED NEW LIGHT-DUTY VEHICLES, NEW LIGHT-DUTY TRUCKS AND NEW MEDIUM-DUTY PASSENGER VEHICLES; COLD TEMPERATURE TEST PROCEDURES § 86.235-94 Dynamometer procedure.

... sample is collected for analysis during each phase. The composite samples collected in bags are analyzed for hydrocarbons, carbon monoxide, **carbon dioxide**, and, optionally, other pollutants. A parallel sample of the dilution air is similarly analyzed for carbon monoxide and, optionally, hydrocarbons, ...

... and, optionally, other pollutants. A parallel sample of the dilution air is similarly analyzed for carbon monoxide and, optionally, hydrocarbons, **carbon dioxide**, and oxides of nitrogen. (b) As long as an emission sample is not taken, practice runs over the prescribed driving ...

400. **C** 40 C.F.R. § 86.244-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART C--EMISSION REGULATIONS FOR 1994 AND LATER MODEL YEAR GASOLINE-FUELED NEW LIGHT-DUTY VEHICLES, NEW LIGHT-DUTY TRUCKS AND NEW MEDIUM-DUTY PASSENGER VEHICLES; COLD TEMPERATURE TEST PROCEDURES § 86.244-94 Calculations; exhaust emissions.

... must calculate and report the weighted mass of each relevant pollutant, i.e., THC, CO, THCE, NMHC, NMHCE, CH4, NOX, and **CO2** in grams per vehicle mile. [71 FR 77926, Dec. 27, 2006; 72 FR 7921, Feb. 21, 2007] SOURCE: 50 FR ...

401. 40 C.F.R. § 86.308-79 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART D--EMISSION REGULATIONS FOR NEW GASOLINE-FUELED AND DIESEL-FUELED HEAVY-DUTY ENGINES; GASEOUS EXHAUST TEST PROCEDURES § 86.308-79 Gas specifications.

... (a) Analyzer gases. (1) Calibration gases for the CO and **CO2** analyzers shall have zero grade nitrogen as a diluent. Combined CO and **CO2** span gases are permitted. Zero grade nitrogen ...

... a diluent. Combined CO and **CO2** span gases are permitted. Zero grade nitrogen shall be the diluent for CO and **CO2** span gases. (2) Calibration or span gases for the hydrocarbon analyzer shall be propane with zero-grade nitrogen as a diluent ...

...(5) Zero-grade gases for the carbon monoxide, **carbon dioxide** and oxides of nitrogen analyzers shall be either zero-grade air or zero-grade nitrogen. (6) The allowable zero grade gas (air ...

402. 40 C.F.R. § 86.309-79 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART D--EMISSION REGULATIONS FOR NEW GASOLINE-FUELED AND DIESEL-FUELED HEAVY-DUTY ENGINES; GASEOUS EXHAUST TEST PROCEDURES § 86.309-79 Sampling and analytical system; schematic drawing.

... the HC analyzer and the NOx analyzer must be heated as is indicated in Figure D79-1. (iii) Carbon monoxide and **carbon dioxide** measurements must be made on a dry basis. Specific requirements for the means of drying the sample can be found ...

403. 40 C.F.R. § 86.316-79 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART D--EMISSION REGULATIONS FOR NEW GASOLINE-FUELED AND DIESEL-FUELED HEAVY-DUTY ENGINES; GASEOUS EXHAUST TEST PROCEDURES § 86.316-79 Carbon monoxide and carbon dioxide analyzer specifications.

...§ 86.316-79 Carbon monoxide and **carbon dioxide** analyzer specifications. (a) Carbon monoxide and **carbon dioxide** measurements are to be made with nondispersive infrared (NDIR) analyzers. (b) The ...

...(c) The minimum water rejection ratio (maximum **CO2** interference) as measured by § 86.321 shall be: (1) For CO analyzers, 1000:1. (2) For **CO2** analyzers, 100:1. (d) The ...

... as measured by § 86.321 shall be: (1) For CO analyzers, 1000:1. (2) For **CO2** analyzers, 100:1. (d) The minimum **CO2** rejection ratio (maximum **CO2** interference) as measured by § 86.322 for CO analyzers shall be 5000:1. (e) Zero suppression. Various ...

404. 40 C.F.R. § 86.320-79 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART D--EMISSION REGULATIONS FOR NEW GASOLINE-FUELED AND DIESEL-FUELED HEAVY-DUTY ENGINES; GASEOUS EXHAUST TEST PROCEDURES § 86.320-79 Analyzer bench check.

...(6) Water rejection ratio, NDIR analyzers only (see §§ 86.316(c) and 86.318 (b)(5)). (7) **CO2** rejection ratio, NDIR analyzers only (see §§ 86.316(d) and 86.318(b)(6)). (8) Quench check, CL analyzers only (see § 86.327). ...

405. 40 C.F.R. § 86.322-79 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART D--EMISSION REGULATIONS FOR NEW GASOLINE-FUELED AND DIESEL-FUELED HEAVY-DUTY ENGINES; GASEOUS EXHAUST TEST PROCEDURES § 86.322-79 NDIR CO2 rejection ratio check.

...§ 86.322-79 NDIR **CO2** rejection ratio check. (a) Zero and span the analyzer on the lowest range that will be used. (b) Introduce a ...

... rejection ratio check. (a) Zero and span the analyzer on the lowest range that will be used. (b) Introduce a **CO2** calibration gas of at least 10 percent **CO2** or greater to the analyzer. (c) Record the **CO2** calibration gas concentration ...

... analyzer. (c) Record the **CO2** calibration gas concentration in ppm. (d) Record the analyzers' response (AR) in ppm to the **CO2** calibration gas. (e) Calculate the **CO2** rejection ratio (CO2RR) from: CO2RR=(ppm **CO2**)/AR SOURCE: 42 FR 45154, Sept. 8, 1977; 50 ...

406. 40 C.F.R. § 86.327-79 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART D--EMISSION REGULATIONS FOR NEW GASOLINE-FUELED AND DIESEL-FUELED HEAVY-DUTY ENGINES; GASEOUS EXHAUST TEST PROCEDURES § 86.327-79 Quench checks; NOx analyzer.

...(1) Calibrate the NOx analyzer on the lowest range that will be used for testing. (2) Introduce a mixture of **CO2** calibration gas and NO2 calibration gas to the CL analyzer. Dynamic blending may be used to provide this mixture. Dynamic ...

... value due to blending may then be used to determine the true concentration of the NOx in the mixture. The **CO2** concentration of the mixture shall be approximately equal to the highest concentration experienced during testing. Record the response. (3) Recheck ...

...(4) Prior to testing, the difference between the calculated NOx response and the response of NOx in the presence of **CO2** (step 2) must not be greater than 3.0 percent of full-scale. The calculated NOx response is based on the calibration ...

407. 40 C.F.R. § 86.329-79 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART D--EMISSION REGULATIONS FOR NEW GASOLINE-FUELED AND DIESEL-FUELED HEAVY-DUTY ENGINES; GASEOUS EXHAUST TEST PROCEDURES § 86.329-79 System response time; check procedure.

...(4) If the elapsed time is more than 20.0 seconds, make necessary adjustments. (5) Repeat with the CO, **CO2**, and NOx instruments and span gases. (b) Option. If the following parameters are determined, the initial system response time may ...

408. 40 C.F.R. § 86.340-79 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART D--EMISSION REGULATIONS FOR NEW GASOLINE-FUELED AND DIESEL-FUELED HEAVY-DUTY ENGINES; GASEOUS EXHAUST TEST PROCEDURES § 86.340-79 Gasoline-fueled engine dynamometer test run.

...(c) Exhaust gas measurements. (1) Measure HC, CO, **CO2**, and NOx volume concentration in the exhaust sample. Should the analyzer response exceed 100 percent of full scale or respond ...

409. 40 C.F.R. § 86.341-79 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART D--EMISSION REGULATIONS FOR NEW GASOLINE-FUELED AND DIESEL-FUELED HEAVY-DUTY ENGINES; GASEOUS EXHAUST TEST PROCEDURES § 86.341-79 Diesel engine dynamometer test run.

...(c) Exhaust gas measurements. (1) Measure HC, CO, **CO2**, and NOx volume concentration in the exhaust sample. Should the analyzer response exceed 100 percent of full scale or respond ...

410 40 C.F.R. § 86.343-79 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART D--EMISSION REGULATIONS FOR NEW GASOLINE-FUELED AND DIESEL-FUELED HEAVY-DUTY ENGINES; GASEOUS EXHAUST TEST PROCEDURES § 86.343-79 Chart reading.

... whichever is applicable, into a minimum of 10 equally spaced increments. Determine the chart deflection of each increment for the **CO2**, CO, HC, and NOx analyzers. (ii) Option for Diesel engine modes. If the deviation from a straight line (other than ...

411 40 C.F.R. § 86.403-78 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART E--EMISSION REGULATIONS FOR 1978 AND LATER NEW MOTORCYCLES, GENERAL PROVISIONS § 86.403-78 Abbreviations.

...cfm--Cubic feet per minute. cm--Centimetre(s). CO--Carbon monoxide. **CO2--Carbon dioxide.** Conc--Concentration. cu.--Cubic. CVS--Constant volume sampler. EGR--Exhaust gas recirculation. EP--End point. ...

412 **C** 40 C.F.R. § 86.511-90 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART F--EMISSION REGULATIONS FOR 1978 AND LATER NEW MOTORCYCLES; TEST PROCEDURES § 86.511-90 Exhaust gas analytical system.

... gas analytical system for analysis of hydrocarbons (HC) (hydrocarbons plus methanol in the case of methanol-fueled motorcycles), carbon monoxide (CO), **carbon dioxide (CO2)**, and oxides of nitrogen (NOsubx). Since various configurations can produce accurate results, exact conformance with the drawing is not required. ...

... coordinate the functions of the component systems."(b) Major component description. The exhaust gas analytical system for HC, CO and **CO2**, Figure F90-3, consists of a flame ionization detector (FID) (heated (235°+-15 ° C (113°+-8 ° C)) for methanol-fueled vehicles) for ...

... C)) for methanol-fueled vehicles) for the determination of hydrocarbons, nondispersive infrared analyzers (NDIR) for the determination of carbon monoxide and **carbon dioxide** and, if oxides of nitrogen are measured, a chemiluminescence analyzer (CL) for the determination of oxides of nitrogen. The analytical ...

413 **C** 40 C.F.R. § 86.513-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART F--EMISSION REGULATIONS FOR 1978 AND LATER NEW MOTORCYCLES; TEST PROCEDURES § 86.513-94 Fuel and engine lubricant specifications.

... 0.6 Inert gases: Sum of **CO2** and N2 max. mole pct............. D1945 ...

414 **C** 40 C.F.R. § 86.514-78 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART F--EMISSION REGULATIONS FOR 1978 AND LATER NEW MOTORCYCLES; TEST PROCEDURES § 86.514-78 Analytical gases.

... or nitrogen) impurity concentrations shall not exceed 1 ppm equivalent carbon response, 1 ppm carbon monoxide, 0.04 percent (400 ppm) **carbon dioxide,** and 0.1 ppm nitric oxide. (6) "Zero grade air" includes artificial "air" consisting of a blend of nitrogen and oxygen ...

415. C 40 C.F.R. § 86.516-90 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART F--EMISSION REGULATIONS FOR 1978 AND LATER NEW MOTORCYCLES; TEST PROCEDURES § 86.516-90 Calibrations, frequency and overview.

... maintenance which could alter calibration, the following calibrations and checks shall be performed: (1) Calibrate the hydrocarbon analyzer, methane analyzer, **carbon dioxide** analyzer, carbon monoxide analyzer, and oxides of nitrogen analyzer (certain analyzers may require more frequent calibration depending on particular equipment ...

416. 40 C.F.R. § 86.522-78 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART F--EMISSION REGULATIONS FOR 1978 AND LATER NEW MOTORCYCLES; TEST PROCEDURES § 86.522-78 Carbon monoxide analyzer calibration.

... introduction into service and annually thereafter the NDIR carbon monoxide analyzer shall be checked for response to water vapor and **CO2**: (1) Follow the manufacturer's instructions for instrument startup and operation. Adjust the analyzer to optimize performance on the most sensitive ...

...(3) Bubble a mixture of 3 percent **CO2** in N2 through water at room temperature and record analyzer response. (4) An analyzer response of more than 1 percent ...

417. 40 C.F.R. § 86.524-78 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART F--EMISSION REGULATIONS FOR 1978 AND LATER NEW MOTORCYCLES; TEST PROCEDURES § 86.524-78 Carbon dioxide analyzer calibration.

...§ 86.524-78 **Carbon dioxide** analyzer calibration. (a) Prior to its introduction into service and monthly thereafter the NDIR **carbon dioxide** analyzer shall be calibrated: ...

...(2) Zero the **carbon dioxide** analyzer with either zero grade air or zero grade nitrogen. (3) Calibrate on each normally used operating range with ...

... dioxide analyzer with either zero grade air or zero grade nitrogen. (3) Calibrate on each normally used operating range with **carbon dioxide** in N T22 calibration gases with nominal concentrations of 15, 30, 45, 60, 75, and 90 percent of that range. ...

418. C 40 C.F.R. § 86.535-90 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART F--EMISSION REGULATIONS FOR 1978 AND LATER NEW MOTORCYCLES; TEST PROCEDURES § 86.535-90 Dynamometer procedure.

... sample is collected for analysis during each phase. The composite samples collected in bags are analyzed for hydrocarbons, carbon monoxide, **carbon dioxide**, and, optionally, for oxides of nitrogen. A parallel sample of the dilution air is similarly analyzed for hydrocarbon, carbon monoxide, ...

... and, optionally, for oxides of nitrogen. A parallel sample of the dilution air is similarly analyzed for hydrocarbon, carbon monoxide, **carbon dioxide**, and, optionally, for oxides of nitrogen. Methanol and formaldehyde samples (exhaust and dilution air) are collected and analyzed for methanol- ...

419. **C** 40 C.F.R. § 86.540-90 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART F--EMISSION REGULATIONS FOR 1978 AND LATER NEW MOTORCYCLES; TEST PROCEDURES § 86.540-90 Exhaust sample analysis.

...The following sequence of operations shall be performed in conjunction with each series of measurements: (a) For CO, **CO2**, gasoline-fueled, natural gas-fueled, liquefied petroleum gas-fueled and methanol-fueled motorcycle HC and, if appropriate, NOX: (1) Zero the analyzers and obtain ...

...(5) Measure HC, CO, **CO2**, and, if appropriate, NOX, concentrations of samples. (6) Check zero and span points. If difference is greater than 2 percent ...

420. **C** 40 C.F.R. § 86.542-90 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART F--EMISSION REGULATIONS FOR 1978 AND LATER NEW MOTORCYCLES; TEST PROCEDURES § 86.542-90 Records required.

...(q) Additional required records for natural gas-fueled vehicles. Composition, including all carbon containing compounds: e.g. **CO2**, of the natural gas-fuel used during the test. C1 and C2 compounds shall be individually reported. C3 and heavier hydrocarbons ...

421. **C** 40 C.F.R. § 86.544-90 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART F--EMISSION REGULATIONS FOR 1978 AND LATER NEW MOTORCYCLES; TEST PROCEDURES § 86.544-90 Calculations; exhaust emissions.

...(3) Carbon monoxide mass: COmass = Vmix x DensityCO x (COconc/1,000,000) (4) **Carbon dioxide** mass: CO2mass = Vmix x DensityCO2 x (CO2conc/100) (5) Methanol mass: CH3OHmass = Vmix x DensityCH3OH x (CH3OHconc/1,000,000) ...

...corrected for background, water vapor, and **CO2** extraction, ppm. (B) COconc = COe - COd(1 - (1/DF)) Where: (iv)(A) COe = Carbon monoxide concentration of the dilute ...

... - (1/DF)) Where: (iv)(A) COe = Carbon monoxide concentration of the dilute exhaust sample volume corrected for water vapor and **carbon dioxide** extraction, in ppm. (B) COe = (1 - 0.01925CO2e - 0.000323R)COem for gasoline-fueled vehicles with hydrogen to carbon ratio of ...

422. **C** 40 C.F.R. § 86.608-98 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART G--SELECTIVE ENFORCEMENT AUDITING OF NEW LIGHT-DUTY VEHICLES § 86.608-98 Test procedures.

... 20 minutes warm-up for the HC analyzer, and for diesel vehicles, a minimum of two hours warm-up for the CO, **CO2**, and NOX analyzers. (Power is normally left on infrared and chemiluminescent analyzers. When not in use, the chopper motors of ...

423. **C** 40 C.F.R. § 86.609-98 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART G--SELECTIVE ENFORCEMENT AUDITING OF NEW LIGHT-DUTY VEHICLES § 86.609-98 Calculation and reporting of test results.

...(B) Will not be performed on all other production vehicles. (v) **Carbon dioxide** emission values for all valid and invalid exhaust emission tests. (vi) Where a vehicle was deleted from the test sequence ...

424. **C** 40 C.F.R. § 86.1008-2001 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART K--SELECTIVE ENFORCEMENT AUDITING OF NEW HEAVY-DUTY ENGINES, HEAVY-DUTY VEHICLES, AND LIGHT-DUTY TRUCKS § 86.1008-2001 Test procedures.

... 20 minutes warm-up for the HC analyzer, and for diesel vehicles, a minimum of two hours warm-up for the CO, **CO2**, and NOx analyzers. (Power is normally left on infrared and chemiluminescent analyzers. When not in use, the chopper motors of ...

425. **C** 40 C.F.R. § 86.1009-2001 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART K--SELECTIVE ENFORCEMENT AUDITING OF NEW HEAVY-DUTY ENGINES, HEAVY-DUTY VEHICLES, AND LIGHT-DUTY TRUCKS § 86.1009-2001 Calculation and reporting of test results.

... sequence by authorization of the Administrator, the reason for the deletion. (vi) For all valid and invalid exhaust emission tests, **carbon dioxide** emission values for LDTs and brake-specific fuel consumption values for HDEs. (vii) Any other information the Administrator may request relevant ...

426. **C** 40 C.F.R. § 86.1111-87 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART L--NONCONFORMANCE PENALTIES FOR GASOLINE-FUELED AND DIESEL HEAVY-DUTY ENGINES AND HEAVY-DUTY VEHICLES, INCLUDING LIGHT-DUTY TRUCKS § 86.1111-87 Test procedures for PCA testing.

... a minimum of 20 minutes warm-up for the HC analyzer, and a minimum of 2 hours warm-up for the CO, **CO2** and NOX analyzers. [Power is normally left on for infrared and chemiluminescent analyzers. When not in use, the chopper motors ...

427. **C** 40 C.F.R. § 86.1242-90 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART M--EVAPORATIVE EMISSION TEST PROCEDURES FOR NEW GASOLINE-FUELED, NATURAL GAS-FUELED, LIQUEFIED PETROLEUM GAS-FUELED AND METHANOL-FUELED HEAVY-DUTY VEHICLES § 86.1242-90 Records required.

...(m) For natural gas-fueled vehicles. Composition, including all carbon containing compounds; e.g. **CO2**, of the natural gas-fuel used during the test. C1 and C2 compounds shall be individually reported. C3 and heavier hydrocarbons, ...

429. **C** 40 C.F.R. § 86.1310-90 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1310-90 Exhaust gas sampling and analytical system; diesel engines.

... (described in § 86.1309) of measuring the combined mass emissions of HC, CH3OH and HCHO from methanol-fueled engines and CO, **CO2** and particulate from all fuel types. A continuously integrated system is required for THC (petroleum-fueled, natural gas-fueled, and liquefied petroleum ...

... (petroleum-fueled, natural gas-fueled, and liquefied petroleum gas-fueled engines) and NOX (all engines) measurement, and is allowed for all CO and **CO2** measurements plus the combined emissions of CH3OH, HCHO, and HC from methanol-fueled engines. Where applicable, separate sampling systems are required ...

... an option, the measurement of total fuel mass consumed over a cycle may be substituted for the exhaust measurement of **CO2**. General requirements are as follows: (1) This sampling system requires the use of a PDP-CVS and a heat exchanger, a ...

430. **C** 40 C.F.R. § 86.1310-2007 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1310-2007 Exhaust gas sampling and analytical system for gaseous emissions from heavy-duty diesel-fueled engines and particulate emissions from all engines.

... the CVS concept (described in § 86.1309) of measuring the combined mass emissions of THC, NOX, CH4 (if applicable) CO, **CO2** and particulate matter. For all emission measurement systems described in this section, multiple or redundant systems may be used during ...

... from the arithmetic mean of the results. A continuously integrated system may be used for THC, NOX , CO and **CO2** measurement. The use of proportional bag sampling for sample integration is allowed for THC, NOX, CO, and **CO2** measurement, but ...

... an option, the measurement of total fuel mass consumed over a cycle may be substituted for the exhaust measurement of **CO2**. General requirements are as follows: (1) This sampling system requires the use of a CVS The CVS system may use ...

431. **C** 40 C.F.R. § 86.1311-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1311-94 Exhaust gas analytical system; CVS bag sample.

... CH4 (for engines subject to NMHC standards, where applicable), nondispersive infrared analyzers (NDIR) for the measurement of carbon monoxide and **carbon dioxide**, and a chemiluminescence analyzer (CL) for the measurement of oxides of nitrogen. The analytical system for methanol consists of a ...

... require a sample conditioning column containing CaSO4, or desiccating silica gel to remove water vapor, and containing ascarite to remove **carbon dioxide** from the CO analysis stream. (i) If CO instruments are used which are essentially free of **CO2** and water vapor ...

... may be deleted (see §§ 86.1322 and 86.1342). (ii) A CO instrument will be considered to be essentially free of **CO2** and water vapor interference if its response to a mixture of three percent **CO2** in N2, which has been bubbled ...

432. **C** 40 C.F.R. § 86.1313-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1313-94 Fuel specifications.

... 0.6 Inert gases: Sum of **CO2** and N2 max. mole pct. ...

433. **C** 40 C.F.R. § 86.1314-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1314-94 Analytical gases.

... (a) Gases for the CO and **CO2** analyzers shall be single blends of CO and **CO2**, respectively, using nitrogen as the diluent. (b) Gases for the hydrocarbon ...

... or nitrogen) impurity concentrations shall not exceed 1 ppm equivalent carbon response, 1 ppm carbon monoxide, 0.04 percent (400 ppm) **carbon dioxide** and 0.1 ppm nitric oxide. (g)(1) "Zero-grade air" includes artificial "air" consisting of a blend of nitrogen and oxygen with ...

434. **C** 40 C.F.R. § 86.1316-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1316-94 Calibrations; frequency and overview.

... after any maintenance which could alter calibration, the following calibrations and checks shall be performed: (1) Calibrate the hydrocarbon analyzer, **carbon dioxide** analyzer, carbon monoxide analyzer, and oxides of nitrogen analyzer (certain analyzers may require more frequent calibration depending on the equipment ...

435. **C** 40 C.F.R. § 86.1322-84 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1322-84 Carbon monoxide analyzer calibration.

... introduction into service and annually thereafter, the NDIR carbon monoxide analyzer shall be checked for response to water vapor and **CO2**: (1) Follow good engineering practices for instrument start-up and operation. Adjust the analyzer to optimize performance on the most sensitive ...

...(3) Bubble a mixture of 3 percent **CO2** in N2 through water at room temperature and record analyzer response. (4) An analyzer response of more than 1 percent ...

436. **C** 40 C.F.R. § 86.1323-2007 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1323-2007 Oxides of nitrogen analyzer calibration.

... at least once per year thereafter, the quench check described in this section shall be performed on CLD NOX analyzers. **CO2** and water vapor interfere with the response of a CLD by collisional quenching. The combined quench effect at their highest ...

... a CLD by collisional quenching. The combined quench effect at their highest expected concentrations shall not exceed 2 percent. (1) **CO2** quench check procedure: (i) For the procedure described in this paragraph, variations are acceptable provided that they produce equivalent %cO2quench ...

... For the procedure described in this paragraph, variations are acceptable provided that they produce equivalent %cO2quench results. Connect a pressure-regulated **CO2** span gas to one of the inlets of a three-way valve. Its **CO2** concentration should be approximately twice the maximum ...

437. **C** 40 C.F.R. § 86.1324-84 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1324-84 Carbon dioxide analyzer calibration.

...§ 86.1324-84 **Carbon dioxide** analyzer calibration. Prior to its introduction into service and monthly thereafter, the NDIR **carbon dioxide** analyzer shall be calibrated as ...

...(b) Zero the **carbon dioxide** analyzer with either zero-grade air or zero-grade nitrogen. (c) Calibrate on each used operating range with a minimum of 6, ...

... zero-grade air or zero-grade nitrogen. (c) Calibrate on each used operating range with a minimum of 6, approximately equally spaced, **carbon dioxide**-in-N2 calibration or span gases (e.g., 15, 30, 45, 60, 75, and 90 percent of that range). For each range calibrated, ...

438. **C** 40 C.F.R. § 86.1327-96 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1327-96 Engine dynamometer test procedures; overview.

... tests. The composite samples collected are analyzed either in bags or continuously for hydrocarbons (HC), methane (CH4) carbon monoxide (CO), **carbon dioxide (CO2)**, and oxides of nitrogen (NOX), or in sample collection impingers for methanol (CH3OH) and sample collection impingers (or cartridges) for ...

... used. A bag or continuous sample of the dilution air is similarly analyzed for background levels of hydrocarbon, carbon monoxide, **carbon dioxide,** and oxides of nitrogen and, if appropriate, methane and/or methanol and/or formaldehyde. In addition, for diesel-cycle engines, particulates are collected ...

439. C 40 C.F.R. § 86.1337-96 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1337-96 Engine dynamometer test run.

... (and natural gas-fueled, liquified petroleum gas-fueled or methanol-fueled diesels, if used) turn on the hydrocarbon and NOX (and CO and **CO2**, if continuous) analyzer system integrators (if used), and turn on the particulate sample pumps and indicate the start of the ...

... engine and begin exhaust and dilution air sampling. For diesel engines, turn on the hydrocarbon and NOx (and CO and **CO2**, if continuous) analyzer system integrator (if used), indicate the start of the test on the data collection medium, and turn ...

440. C 40 C.F.R. § 86.1337-2007 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1337-2007 Engine dynamometer test run.

... (and natural gas-fueled, liquified petroleum gas-fueled or methanol-fueled diesels, if used) Turn on the hydrocarbon and NOX (and CO and **CO2**, if continuous) analyzer system integrators (if used), and turn on the particulate sample pumps and indicate the start of the ...

... engine and begin exhaust and dilution air sampling. For diesel engines, turn on the hydrocarbon and NOX (and CO and **CO2**, if continuous) analyzer system integrator (if used), indicate the start of the test on the data collection medium, and turn ...

441. C 40 C.F.R. § 86.1338-84 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1338-84 Emission measurement accuracy.

... calibrate the analyzer, input the value of a second calibration gas (a span gas may be used for calibrating a **CO2** analyzer) having a named concentration between 10 and 20 percent of full scale. This gas shall be included on the ...

442. C 40 C.F.R. § 86.1340-90 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1340-90 Exhaust sample analysis.

... used, electronically record the most recent zero and span response as the pre-analysis values. (7) Measure HC (except diesels), CO, **CO2**, and NOX sample and background concentrations in the sample bag(s) with approximately the same flow rates and pressures used in ...

... most recent zero and span response as the pre-analysis values. (9) Measure the emissions (HC required for diesels; NOX, CO, **CO2** optional) continuously during the cold start cycle. Indicate the start of the test, the range(s) used, and the end of ...

...(10) Collect background HC, CO, **CO2**, and NOX in a sample bag. (11) Perform a post-analysis zero and span check for each range used at the ...

443. C 40 C.F.R. § 86.1340-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1340-94 Exhaust sample analysis.

...(a) to (d)(6) [Reserved]. For guidance see § 86.1340-90. (d)(7) Measure HC (except diesels), CH4 (natural gas-fueled engines only), CO, **CO2**, and NOX sample bag(s) with approximately the same flow rates and pressures used in § 86.1340-90(d)(3). (Constituents measured continuously ...

444 **C** 40 C.F.R. § 86.1342-90 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1342-90 Calculations; exhaust emissions.

...CO mass=V mixxDensity COx(CO conc/10^6) (4) **Carbon dioxide** mass: CO 2mass=V mixxDensity CO 2x(CO 2conc/10^2) (5) Methanol mass: CH3OH mass=V mixxDensity ...

...(iv) CO e=Carbon monoxide concentration of the dilute exhaust bag sample volume corrected for water vapor and **carbon dioxide** extraction, in ppm. For flow compensated sample systems (CO e) i is the instantaneous concentration. (v)(A) CO e=(1-0.01925CO 2e-0.000323R)CO em ...

...(vii)(A) CO 2e=**Carbon dioxide** concentration of the dilute exhaust bag sample, in percent, if measured. For flow compensated sample systems, (CO 2e) i is ...

445 **C** 40 C.F.R. § 86.1342-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1342-94 Calculations; exhaust emissions.

...(a) introductory text [Reserved]. For guidance see § 86.1342-90. (a)(1) AWM=Weighted mass emission level (HC, CO, **CO2**, or NOX) in grams per brake horsepower-hour and, if appropriate, the weighted mass total hydrocarbon equivalent, formaldehyde, or non-methane hydrocarbon ...

446 **C** 40 C.F.R. § 86.1344-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART N--EMISSION REGULATIONS FOR NEW OTTO-CYCLE AND DIESEL HEAVY-DUTY ENGINES; GASEOUS AND PARTICULATE EXHAUST TEST PROCEDURES § 86.1344-94 Required information.

... temperature of the dilute exhaust mixture immediately ahead of the particulate filter. (17) Sample concentrations (background corrected) for HC, CO, **CO2** and NOX for each test phase (cold and hot). (18) For engines requiring methanol and/or formaldehyde measurement (as applicable): ...

...containing compounds; e.g., **CO2**, of the natural gas-fuel used during the test. C1 and C2 compounds shall be individually reported. C3 and heavier compounds, ...

447 **C** 40 C.F.R. § 86.1437 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART O--EMISSION REGULATIONS FOR NEW GASOLINE-FUELED OTTO-CYCLE LIGHT-DUTY VEHICLES AND NEW GASOLINE-FUELED OTTO-CYCLE LIGHT-DUTY TRUCKS; CERTIFICATION SHORT TEST PROCEDURES § 86.1437 Test run--manufacturer.

... test conditions. The test immediately terminates and any exhaust gas measurements are voided if the measured concentration of CO plus **CO2** falls below six percent or the vehicle's engine stalls at any time during the test sequence. (3) Multiple exhaust pipes. ...

...(iv) The measured concentration of CO plus **CO2** must be greater than or equal to six percent. (f) Idle mode. (1) The mode timer starts (mt=0) when the ...

448. **C** 40 C.F.R. § 86.1438 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART O--EMISSION REGULATIONS FOR NEW GASOLINE-FUELED OTTO-CYCLE LIGHT-DUTY VEHICLES AND NEW GASOLINE-FUELED OTTO-CYCLE LIGHT-DUTY TRUCKS; CERTIFICATION SHORT TEST PROCEDURES § 86.1438 Test run--EPA.

... test conditions. The test immediately terminates and any exhaust gas measurements are voided if the measured concentration of CO plus **CO2** falls below six percent or the vehicle's engine stalls at any time during the test sequence. (3) Multiple exhaust pipes. ...

...(4) The measured concentration of CO plus **CO2** must be greater than or equal to six percent. (f) When the requirements listed in paragraph (c) of this section ...

449. **C** 40 C.F.R. § 86.1442 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART O--EMISSION REGULATIONS FOR NEW GASOLINE-FUELED OTTO-CYCLE LIGHT-DUTY VEHICLES AND NEW GASOLINE-FUELED OTTO-CYCLE LIGHT-DUTY TRUCKS; CERTIFICATION SHORT TEST PROCEDURES § 86.1442 Information required.

...(2) The test time and mode time at which the reported exhaust concentrations are at a minimum. (3) Minimum CO+**CO2** concentration (if applicable). SOURCE: 58 FR 58426, Nov. 1, 1993, unless otherwise noted. 40 C. F. R. § 86.1442, 40 ...

450. **C** 40 C.F.R. § 86.1509-84 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART P--EMISSION REGULATIONS FOR OTTO-CYCLE HEAVY-DUTY ENGINES, NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE HEAVY-DUTY ENGINES, NEW OTTO-CYCLE LIGHT-DUTY TRUCKS, AND NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE LIGHT-DUTY TRUCKS; IDLE TEST PROCEDURES § 86.1509-84 Exhaust gas sampling system.

... or continuous analysis as specified in 40 CFR part 1065 is permitted as applicable. The inclusion of an additional raw **carbon dioxide (CO2)** analyzer as specified in 40 CFR part 1065 is required if the CVS system is used, in order to accurately ...

... The heated sample line specified in 40 CFR part 1065 for raw emission requirements is not required for the raw (**CO2**) measurement. (d) A raw exhaust sampling system as specified in 40 CFR part 1065 is permitted. [60 FR 34376, June ...

451. **C** 40 C.F.R. § 86.1511-84 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART P--EMISSION REGULATIONS FOR OTTO-CYCLE HEAVY-DUTY ENGINES, NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE HEAVY-DUTY ENGINES, NEW OTTO-CYCLE LIGHT-DUTY TRUCKS, AND NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE LIGHT-DUTY TRUCKS; IDLE TEST PROCEDURES § 86.1511-84 Exhaust gas analysis system.

... Applicable analyzer ———————————————— **CO2** .... 14 percent .... CO C3H8 .... 1 percent .... CO H2O .... Saturated vapor at 100° F .... CO ...

...(b) The inclusion of a raw **CO2** analyzer as specified in 40 CFR part 1065 is required in order to accurately determine the CVS dilution factor. [60 ...

452. C 40 C.F.R. § 86.1524-84 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART P--EMISSION REGULATIONS FOR OTTO-CYCLE HEAVY-DUTY ENGINES, NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE HEAVY-DUTY ENGINES, NEW OTTO-CYCLE LIGHT-DUTY TRUCKS, AND NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE LIGHT-DUTY TRUCKS; IDLE TEST PROCEDURES § 86.1524-84 Carbon dioxide analyzer calibration.

...§ 86.1524-84 **Carbon dioxide** analyzer calibration. (a) The calibration requirements for the dilute-sample **CO2** analyzer are specified in 40 CFR part 1065, subpart D, ...

... part 1065, subpart D, for heavy-duty engines and § 86.124-78 for light-duty trucks. (b) The calibration requirements for the raw **CO2** analyzer are specified in 40 CFR part 1065, subpart D. [70 FR 40441, July 13, 2005] <Text of part effective ...

453. C 40 C.F.R. § 86.1537-84 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART P--EMISSION REGULATIONS FOR OTTO-CYCLE HEAVY-DUTY ENGINES, NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE HEAVY-DUTY ENGINES, NEW OTTO-CYCLE LIGHT-DUTY TRUCKS, AND NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE LIGHT-DUTY TRUCKS; IDLE TEST PROCEDURES § 86.1537-84 Idle test run.

...(2) Start the CVS (if not already on), the sample pumps, integrators, and the raw **CO2** analyzer, as applicable. (The heat exchanger of the constant volume sampler, if used, shall be running at operating temperature before ...

... 6 minutes. Follow the sampling and exhaust measurements requirements of 40 CFR part 1065, subpart F, for conducting the raw **CO2** measurement. (7) As soon as possible, transfer the idle test exhaust and dilution air samples to the analytical system and ...

454. C 40 C.F.R. § 86.1540-84 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART P--EMISSION REGULATIONS FOR OTTO-CYCLE HEAVY-DUTY ENGINES, NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE HEAVY-DUTY ENGINES, NEW OTTO-CYCLE LIGHT-DUTY TRUCKS, AND NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE LIGHT-DUTY TRUCKS; IDLE TEST PROCEDURES § 86.1540-84 Idle exhaust sample analysis.

...(b) If the CVS sampling system is used, the analysis procedures for dilute CO and **CO2** specified in 40 CFR part 1065 apply. Follow the raw **CO2** analysis procedure specified in 40 CFR part 1065, subpart ...

... part 1065 apply. Follow the raw **CO2** analysis procedure specified in 40 CFR part 1065, subpart F, for the raw **CO2** analyzer. (c) If the continuous raw exhaust sampling technique specified in 40 CFR part 1065 is used, the analysis procedures ...

455. C 40 C.F.R. § 86.1542-84 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART P--EMISSION REGULATIONS FOR OTTO-CYCLE HEAVY-DUTY ENGINES, NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE HEAVY-DUTY ENGINES, NEW OTTO-CYCLE LIGHT-DUTY TRUCKS, AND NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE LIGHT-DUTY TRUCKS; IDLE TEST PROCEDURES § 86.1542-84 Information required.

...(7) Idle exhaust CO concentration (dry basis). (8) Idle exhaust raw **CO2** concentration (if applicable). (9) Dilute bag sample CO and **CO2** concentrations (if applicable). (10) Total CVS flow rate with calculated ...

...(14) Idle exhaust raw **CO2** concentration (if applicable). (15) Dilute bag sample CO and **CO2** concentrations (if applicable). (16) Total CVS flow rate with calculated ...

456 C 40 C.F.R. § 86.1544-84 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART P--EMISSION REGULATIONS FOR OTTO-CYCLE HEAVY-DUTY ENGINES, NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE HEAVY-DUTY ENGINES, NEW OTTO-CYCLE LIGHT-DUTY TRUCKS, AND NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE LIGHT-DUTY TRUCKS; IDLE TEST PROCEDURES § 86.1544-84 Calculation; idle exhaust emissions.

...(1) Use the procedures, as applicable, in 40 CFR 1065.650 to determine the dilute wet-basis CO and **CO2** in percent. (2) Use the procedure, as applicable, in 40 CFR 1065.650 to determine the raw dry-basis **CO2** in percent. ...

... procedure, as applicable, in 40 CFR 1065.650 to determine the raw dry-basis **CO2** in percent. (3) Convert the raw dry-basis **CO2** to raw wet-basis. An assumption that the percent of water by volume in the raw sample is equal to the ...

... assumption that the percent of water by volume in the raw sample is equal to the percent of raw dry-basis **CO2** minus 0.5 percent is acceptable. For example: 10.0% dry **CO2**-0.5%=9.5% water (1.00-0.095) (10.0% dry **CO2**)=9.05% wet **CO2** (4) Calculate the ...

457 40 C.F.R. § 86.1509 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART P--EMISSION REGULATIONS FOR OTTO-CYCLE HEAVY-DUTY ENGINES, NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE HEAVY-DUTY ENGINES, NEW OTTO-CYCLE LIGHT-DUTY TRUCKS, AND NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE LIGHT-DUTY TRUCKS; IDLE TEST PROCEDURES § 86.1509 Exhaust gas sampling system.

... or continuous analysis as specified in 40 CFR part 1065 is permitted as applicable. The inclusion of an additional raw **carbon dioxide (CO2)** analyzer as specified in 40 CFR part 1065 is required if the CVS system is used, in order to accurately ...

... The heated sample line specified in 40 CFR part 1065 for raw emission requirements is not required for the raw (**CO2**) measurement. (d) A raw exhaust sampling system as specified in 40 CFR part 1065 is permitted. [60 FR 34376, June ...

458 40 C.F.R. § 86.1511 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART P--EMISSION REGULATIONS FOR OTTO-CYCLE HEAVY-DUTY ENGINES, NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE HEAVY-DUTY ENGINES, NEW OTTO-CYCLE LIGHT-DUTY TRUCKS, AND NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE LIGHT-DUTY TRUCKS; IDLE TEST PROCEDURES § 86.1511 Exhaust gas analysis system.

... Applicable analyzer -- **CO2** .... 14 percent .... CO C3H8 .... 1 percent .... CO H2O .... Saturated vapor at 100° F .... CO ...

...(b) The inclusion of a raw **CO2** analyzer as specified in 40 CFR part 1065 is required in order to accurately determine the CVS dilution factor. [60 ...

459. 40 C.F.R. § 86.1524 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART P--EMISSION REGULATIONS FOR OTTO-CYCLE HEAVY-DUTY ENGINES, NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE HEAVY-DUTY ENGINES, NEW OTTO-CYCLE LIGHT-DUTY TRUCKS, AND NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE LIGHT-DUTY TRUCKS; IDLE TEST PROCEDURES § 86.1524 Carbon dioxide analyzer calibration.

...§ 86.1524 **Carbon dioxide** analyzer calibration. (a) The calibration requirements for the dilute-sample **CO2** analyzer are specified in 40 CFR part 1065, subpart D, ...

... part 1065, subpart D, for heavy-duty engines and § 86.124-78 for light-duty trucks. (b) The calibration requirements for the raw **CO2** analyzer are specified in 40 CFR part 1065, subpart D. [70 FR 40441, July 13, 2005] <Text of part effective ...

460. 40 C.F.R. § 86.1537 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART P--EMISSION REGULATIONS FOR OTTO-CYCLE HEAVY-DUTY ENGINES, NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE HEAVY-DUTY ENGINES, NEW OTTO-CYCLE LIGHT-DUTY TRUCKS, AND NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE LIGHT-DUTY TRUCKS; IDLE TEST PROCEDURES § 86.1537 Idle test run.

...(2) Start the CVS (if not already on), the sample pumps, integrators, and the raw **CO2** analyzer, as applicable. (The heat exchanger of the constant volume sampler, if used, shall be running at operating temperature before ...

... 6 minutes. Follow the sampling and exhaust measurements requirements of 40 CFR part 1065, subpart F, for conducting the raw **CO2** measurement. (7) As soon as possible, transfer the idle test exhaust and dilution air samples to the analytical system and ...

461. 40 C.F.R. § 86.1540 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART P--EMISSION REGULATIONS FOR OTTO-CYCLE HEAVY-DUTY ENGINES, NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE HEAVY-DUTY ENGINES, NEW OTTO-CYCLE LIGHT-DUTY TRUCKS, AND NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE LIGHT-DUTY TRUCKS; IDLE TEST PROCEDURES § 86.1540 Idle exhaust sample analysis.

...(b) If the CVS sampling system is used, the analysis procedures for dilute CO and **CO2** specified in 40 CFR part 1065 apply. Follow the raw **CO2** analysis procedure specified in 40 CFR part 1065, subpart ...

... part 1065 apply. Follow the raw **CO2** analysis procedure specified in 40 CFR part 1065, subpart F, for the raw **CO2** analyzer. (c) If the continuous raw exhaust sampling technique specified in 40 CFR part 1065 is used, the analysis procedures ...

462. 40 C.F.R. § 86.1542 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART P--EMISSION REGULATIONS FOR OTTO-CYCLE HEAVY-DUTY ENGINES, NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE HEAVY-DUTY ENGINES, NEW OTTO-CYCLE LIGHT-DUTY TRUCKS, AND NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE LIGHT-DUTY TRUCKS; IDLE TEST PROCEDURES § 86.1542 Information required.

...(7) Idle exhaust CO concentration (dry basis). (8) Idle exhaust raw **CO2** concentration (if applicable). (9) Dilute bag sample CO and **CO2** concentrations (if applicable). (10) Total CVS flow rate with calculated ...

...(14) Idle exhaust raw **CO2** concentration (if applicable). (15) Dilute bag sample CO and **CO2** concentrations (if applicable). (16) Total CVS flow rate with calculated ...

463. 40 C.F.R. § 86.1544 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART P--EMISSION REGULATIONS FOR OTTO-CYCLE HEAVY-DUTY ENGINES, NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE HEAVY-DUTY ENGINES, NEW OTTO-CYCLE LIGHT-DUTY TRUCKS, AND NEW METHANOL-FUELED NATURAL GAS-FUELED, AND LIQUEFIED PETROLEUM GAS-FUELED DIESEL-CYCLE LIGHT-DUTY TRUCKS; IDLE TEST PROCEDURES § 86.1544 Calculation; idle exhaust emissions.

...(1) Use the procedures, as applicable, in 40 CFR 1065.650 to determine the dilute wet-basis CO and **CO2** in percent. (2) Use the procedure, as applicable, in 40 CFR 1065.650 to determine the raw dry-basis **CO2** in percent. ...

... procedure, as applicable, in 40 CFR 1065.650 to determine the raw dry-basis **CO2** in percent. (3) Convert the raw dry-basis **CO2** to raw wet-basis. An assumption that the percent of water by volume in the raw sample is equal to the ...

... assumption that the percent of water by volume in the raw sample is equal to the percent of raw dry-basis **CO2** minus 0.5 percent is acceptable. For example: 10.0% dry **CO2**-0.5%=9.5% water (1.00-0.095) (10.0% dry **CO2**)=9.05% wet **CO2** (4) Calculate the ...

464. **C** 40 C.F.R. § 86.1804-01 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART S--GENERAL COMPLIANCE PROVISIONS FOR CONTROL OF AIR POLLUTION FROM NEW AND IN-USE LIGHT-DUTY VEHICLES, LIGHT-DUTY TRUCKS, AND COMPLETE OTTO-CYCLE HEAVY-DUTY VEHICLES § 86.1804-01 Acronyms and abbreviations.

...CID--Cubic inch displacement. Cl--Chemiluminescence. CO--Carbon monoxide. **CO2--Carbon dioxide.** conc.--Concentration. CST--Certification Short Test. cu. in.--Cubic inch(es). CVS--Constant volume sampler. ...

465. **C** 40 C.F.R. § 86.1847-01 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART S--GENERAL COMPLIANCE PROVISIONS FOR CONTROL OF AIR POLLUTION FROM NEW AND IN-USE LIGHT-DUTY VEHICLES, LIGHT-DUTY TRUCKS, AND COMPLETE OTTO-CYCLE HEAVY-DUTY VEHICLES § 86.1847-01 Manufacturer in-use verification and in-use confirmatory testing; submittal of information and maintenance of records.

... all emission tests performed, including tests results, the date of each test, and the phase mass values for fuel economy, **carbon dioxide** and each pollutant measured by the Federal Test Procedure and Supplemental Federal Test Procedure as prescribed by subpart B of ...

... all emission tests performed, including tests results, the date of each test, and the phase mass values for fuel economy, **carbon dioxide** and each pollutant measured by the Federal Test Procedure and Supplemental Federal Test Procedure as prescribed by subpart B of ...

466. **C** 40 C.F.R. § 86.1910 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART T--MANUFACTURER-RUN IN-USE TESTING PROGRAM FOR HEAVY-DUTY DIESEL ENGINES § 86.1910 How must I prepare and test my in-use engines?

... THC, NMHC (by any method specified in 40 CFR part 1065, subpart J), CO, NOX, PM (as appropriate), O2, and **CO2** (e) For Phase 1 testing, you must test the engine under conditions reasonably expected to be encountered during normal ...

467. **C** 40 C.F.R. § 86.1920 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES SUBPART T--MANUFACTURER-RUN IN-USE TESTING PROGRAM FOR HEAVY-DUTY DIESEL ENGINES § 86.1920 What in-use testing information must I report to EPA?

...(D) Altitude. (E) Emissions of THC, NMHC, CO, **CO2** or O2, NOX, and PM (as appropriate). Report results for CH4 if it was measured and used to determine NMHC. ...

468. 40 C.F.R. Pt. 86, App. XVI CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 86--CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES Appendix XVI to Part 86--Pollutant Mass Emissions Calculation Procedure for Gaseous-Fueled Vehicles and for Vehicles Equipped With Periodically Regenerating Trap Oxidizer Systems Certifying to the Provisions of Part 86, Subpart R

... Mol. Wt. -- C ....
12.01115 H .... 1.00797 0 .... 15.9994
CO .... 28.01055 **CO2** 44.00995
CH2.658 [FNa] 14.6903
-- [FNa] Average ratio of Hydrogen to carbon atoms in HD-5 fuel. (B) ...

...**CO2**=wt. of **CO2**x(12.01115/44.00995) wt **CO2**x(0.273) CH2.658=wt. of CH2.658x(12.01115/14.6903)=wt CH2.658x(0.818) ...

...**CO2**=CVS **CO2** in grams/mile For gasoline: =2421 / ((0.866)(HC)+(0.429)(CO)+(0.273)(CO2)) For Natural Gas: ...

469. **C** 40 C.F.R. § 87.60 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 87--CONTROL OF AIR POLLUTION FROM AIRCRAFT AND AIRCRAFT ENGINES SUBPART G--TEST PROCEDURES FOR ENGINE EXHAUST GASEOUS EMISSIONS (AIRCRAFT AND AIRCRAFT GAS TURBINE ENGINES) § 87.60 Introduction.

...(c) The exhaust emission test is designed to measure hydrocarbons, carbon monoxide, **carbon dioxide**, and oxides of nitrogen concentrations, and to determine mass emissions through calculations during a simulated aircraft landing-takeoff cycle (LTO). The ...

470. **C** 40 C.F.R. § 88.306-94 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 88--CLEAN-FUEL VEHICLES SUBPART C--CLEAN-FUEL FLEET PROGRAM § 88.306-94 Requirements for a converted vehicle to qualify as a clean-fuel fleet vehicle.

...(3) The void test criteria in 40 CFR 85.2215(a)(3) and (b)(2)(iv) associated with maintaining the measured concentration of CO plus **CO**[2] above six percent does not apply. However, the Administrator may reconsider requiring that the void test criteria in 40 CFR ...

471. **C** 40 C.F.R. § 89.3 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART A--GENERAL § 89.3 Acronyms and abbreviations.

... Carbon monoxide. **CO2** **Carbon dioxide.** EGR ...

472. **C** 40 C.F.R. § 89.304 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 89.304 Equipment required for gaseous emissions; overview.

...(c) Analyzers used are a non-dispersive infrared (NDIR) absorption type for carbon monoxide and **carbon dioxide** analysis; a heated flame ionization (HFID) type for hydrocarbon analysis; and a chemiluminescent detector (CLD) or heated chemiluminescent detector (HCLD) ...

473. **C** 40 C.F.R. § 89.309 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 89.309 Analyzers required for gaseous emissions.

...(ii) The use of linearizing circuits is permitted. (2) **Carbon Dioxide** (**CO2**) analysis. (i) The **carbon dioxide** analyzer must be of the non-dispersive infrared (NDIR) absorption type. (ii) The use of linearizing ...

...(1) Carbon monoxide and **carbon dioxide** measurements must be made on a dry basis (for raw exhaust measurement only). Specific requirements for the means of drying ...

474. **C** 40 C.F.R. § 89.310 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 89.310 Analyzer accuracy and specifications.

... to calibrate the analyzer, input the value of a second calibration gas (a span gas may be used for the **CO2** analyzer) having a named concentration between 10 and 20 percent of full scale. This gas shall be included on the ...

475. **C** 40 C.F.R. § 89.311 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 89.311 Analyzer calibration frequency.

...(d) Verify that all NDIR analyzers meet the water rejection ratio and the **CO2** rejection ratio as specified in § 89.318. (e) Verify that the dynamometer test stand and power output instrumentation meet the ...

476. **C** 40 C.F.R. § 89.312 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 89.312 Analytical gases.

... must be available for operation: (1) Purified nitrogen (Contamination <= 1 ppm C, <= 1 ppm CO, <= 400 ppm **CO2**, <= 0.1 ppm NO) (2) [Reserved] (3) Hydrogen-helium mixture (40 +- 2 percent hydrogen, balance helium) (Contamination <= 31 ppm ...

...(4) Purified synthetic air (Contamination <= 1 ppm C, < = 1 ppm CO, <= 400 ppm **CO2**, <= 0.1 ppm NO) (Oxygen content between 18-21 percent vol.) (c) Calibration and span gases. (1) Calibration gas values are ...

...(v) **CO2** and purified nitrogen. (3) The true concentration of a span gas must be within +-2 percent of the NIST gas ...

477. **C** 40 C.F.R. § 89.313 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 89.313 Initial calibration of analyzers.

...(c) Zero setting and calibration. (1) Using purified synthetic air (or nitrogen), the CO, **CO2**, NOX, and HC analyzers shall be set at zero. (2) Introduce the appropriate calibration gases to the analyzers and the ...

478. **C** 40 C.F.R. § 89.318 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 89.318 Analyzer interference checks.

... introduction into service and annually thereafter, the NDIR carbon monoxide analyzer shall be checked for response to water vapor and **CO2**: (1) Follow good engineering practices for instrument start-up and operation. Adjust the analyzer to optimize performance on the most sensitive ...

...(3) Bubble a mixture of 3 percent **CO2** in N2 through water at room temperature and record analyzer response. (4) An analyzer response of more than 1 percent ...

...(c) NOXanalyzer quench check. The two gases of concern for CLD (and HCLD) analyzers are **CO2** and water vapor. Quench responses to these two gases are proportional to their concentrations and, therefore, require test techniques to ...

479. **C** 40 C.F.R. § 89.320 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 89.320 Carbon monoxide analyzer calibration.

... introduction into service and annually thereafter, the NDIR carbon monoxide analyzer shall be checked for response to water vapor and **CO2** in accordance with § 318.96(b). (c) Initial and periodic calibration. Prior to its introduction into service, after any maintenance which ...

480. **C** 40 C.F.R. § 89.322 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 89.322 Carbon dioxide analyzer calibration.

...§ 89.322 **Carbon dioxide** analyzer calibration. (a) Prior to its introduction into service, after any maintenance which could alter calibration, and bi-monthly thereafter, the ...

... calibration. (a) Prior to its introduction into service, after any maintenance which could alter calibration, and bi-monthly thereafter, the NDIR **carbon dioxide** analyzer shall be calibrated on all normally used instrument ranges. New calibration curves need not be generated each month if ...

... follows: (1) Follow good engineering practices for instrument start-up and operation. Adjust the analyzer to optimize performance. (2) Zero the **carbon dioxide** analyzer with either zero-grade air or zero-grade nitrogen. (3) Calibrate on each normally used operating range with **carbon dioxide**-in-N2 calibration ...

481. 40 C.F.R. Pt. 89, Subpt. D, App. A CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS Appendix A to Subpart D--Tables

... Table 1.--Abbreviations Used in Subpart D -- CLD .... Chemiluminescent detector. CO ..... Carbon monoxide. **CO2 .. Carbon dioxide.** HC ..... Hydrocarbons. HCLD ... Heated chemiluminescent detector. HFID ... Heated flame ionization detector. GC ..... Gas chromatograph. NDIR ... ...

... check .... 90% Monthly. 21 ... **CO2** analyzer .... +- 2% .... Once per 60 days or ...

482. C 40 C.F.R. § 89.407 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART E--EXHAUST EMISSION TEST PROCEDURES § 89.407 Engine dynamometer test run.

...(d) Exhaust gas measurements. (1) Measure HC, CO, **CO2**, and NOX concentration in the exhaust sample. (2) Each analyzer range that may be used during a test mode must ...

483. C 40 C.F.R. § 89.409 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART E--EXHAUST EMISSION TEST PROCEDURES § 89.409 Data logging.

...(d) Determine the final value for **CO2**, CO, HC, and NOX concentrations by averaging the concentration of each point taken during the sample period for each mode. ...

484. C 40 C.F.R. § 89.411 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART E--EXHAUST EMISSION TEST PROCEDURES § 89.411 Exhaust sample procedure--gaseous components.

... equipment is used, electronically record the most recent zero and span response as the pre-analysis values. (7) Measure HC, CO, **CO2**, and NOX background concentrations in the sample bag(s) with approximately the same flow rates and pressures used in paragraph (c)(3) ...

... is used, electronically record the most recent zero and span response as the pre-analysis values. (9) Collect background HC, CO, **CO2**, and NOX in a sample bag (for dilute exhaust sampling only, see § 89.420). (10) Perform a post-analysis zero and ...

... and post-analysis checks on any range used may exceed 3 percent for HC, or 2 percent for NOX, CO, and **CO2**, of full scale chart deflection, or the test is void. (If the HC drift is greater than 3 percent of ...

485. C 40 C.F.R. § 89.413 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART E--EXHAUST EMISSION TEST PROCEDURES § 89.413 Raw sampling procedures.

... heated filter to extract solid particles from the flow of gas required for analysis. The sample line for CO and **CO2** analysis may be heated or unheated. [63 FR 56995, 57016, Oct. 23, 1998] SOURCE: 59 FR 31335, June 17, 1994; ...

486. C 40 C.F.R. § 89.417 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART E--EXHAUST EMISSION TEST PROCEDURES § 89.417 Data evaluation for gaseous emissions.

... the gaseous emission recording, the last 60 seconds of each mode are recorded, and the average values for HC, CO, **CO2**, and NOX during each mode are determined from the average concentration readings determined from the corresponding calibration data. [63 FR ...

487. C 40 C.F.R. § 89.418 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART E--EXHAUST EMISSION TEST PROCEDURES § 89.418 Raw emission sampling calculations.

... ppm. **CO2** .... 15.19 ...

... calculation of u, v, and w for NOX (as NO2), CO, HC (in paragraph (e) of this section as CH1.80), **CO2**, and O2: Where: $w = 4.4615.10^{-5} \times M$ if conc. in ppm $w = 4.4615.10^{-1} \times M$ if conc. in ...

488. C 40 C.F.R. § 89.419 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART E--EXHAUST EMISSION TEST PROCEDURES § 89.419 Dilute gaseous exhaust sampling and analytical system description.

... CVS concept (described in 40 CFR part 1065, subparts A and B) of measuring mass emissions of HC, CO, and **CO2**. A continuously integrated system is required for HC and NOX measurement and is allowed for all CO and **CO2** measurements. ...

... an option, the measurement of total fuel mass consumed over a cycle may be substituted for the exhaust measurement of **CO2**. General requirements are as follows: (1) This sampling system requires the use of a PDP-CVS and a heat exchanger or ...

...(3) The CO and **CO2** analytical system requires: (i) Bag sampling (see 40 CFR part 1065) and analytical capabilities (see 40 CFR part 1065), as ...

489. C 40 C.F.R. § 89.420 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART E--EXHAUST EMISSION TEST PROCEDURES § 89.420 Background sample.

...(c) Measure HC, CO, **CO2**, and NOX exhaust and background concentrations in the sample bag(s) with approximately the same flow rates and pressures used during ...

490. C 40 C.F.R. § 89.421 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART E--EXHAUST EMISSION TEST PROCEDURES § 89.421 Exhaust gas analytical system; CVS bag sample.

... C +-6 ° C) for the measurement of hydrocarbons, nondispersive infrared analyzers (NDIR) for the measurement of carbon monoxide and **carbon dioxide**, and a chemiluminescence detector (CLD) (or HCLD) for the measurement of oxides of nitrogen. The exhaust gas analytical system shall ...

... results and if approved in advance by the Administrator. (2) If CO instruments are used which are essentially free of **CO2** and water vapor interference, the use of the conditioning column may be deleted. (See 40 CFR part 1065, subpart D.) ...

...(3) A CO instrument will be considered to be essentially free of **CO2** and water vapor interference if its response to a mixture of 3 percent **CO2** in N2, which has been bubbled ...

491. C 40 C.F.R. § 89.424 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 89--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION-IGNITION ENGINES SUBPART E--EXHAUST EMISSION TEST PROCEDURES § 89.424 Dilute emission sampling calculations.

...Where: Awm = Weighted mass emission level (HC, CO, **CO2**, PM, or NOX) in g/kW-hr. gi = Mass flow in grams per hour, = grams measured during the mode divided ...

...(4) **Carbon dioxide** mass: CO2mass = Vmix x DensityCO2 x (CO2conc/102) (c) The mass of each pollutant for the mode for flow compensated ...

...COconc=Carbon monoxide concentration of the dilute exhaust sample corrected for background, water vapor, and **CO2** extraction, ppm. Where: COe=Carbon monoxide concentration of the dilute exhaust bag sample volume corrected for water vapor and **carbon dioxide** ...

492 C 40 C.F.R. § 90.5 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART A--GENERAL § 90.5 Acronyms and abbreviations.

...CAAA--Clean Air Act Amendments of 1990 CLD--chemiluminescent detector CO--Carbon monoxide **CO2--Carbon dioxide** EPA--Environmental Protection Agency FTP--Federal Test Procedure g/kW-hr--grams per kilowatt hour ...

493 C 40 C.F.R. § 90.304 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 90.304 Test equipment overview.

...(c) Analyzers used are a non-dispersive infrared (NDIR) absorption type for carbon monoxide and **carbon dioxide** analysis; paramagnetic (PMD), zirconia (ZRDO), or electrochemical type (ECS) for oxygen analysis; a flame ionization (FID) or heated flame ionization ...

494 C 40 C.F.R. § 90.312 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 90.312 Analytical gases.

...(1) Purified nitrogen, also refered to as "zero-grade nitrogen" (Contamination <=1 ppm C, <=1 ppm CO, <=400 ppm **CO2**, <=0.1 ppm NO); (2) Purified oxygen (Purity 99.5 percent vol O2); (3) Hydrogen-helium mixture (40+-2 percent hydrogen, balance helium) (Contamination ...

... synthetic air, also refered to as "zero air" or "zero gas" (Contamination <=1 ppm C, <=1 ppm CO, <=400 ppm **CO2**, <=0.1 ppm NO) (Oxygen content between 18-21 percent vol.). (c) Calibration and span gases. (1) Calibration gas values are to ...

...**CO2** and purified nitrogen. Note: For the HFID or FID the manufacturer may choose to use as a diluent span gas ...

495 C 40 C.F.R. § 90.313 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 90.313 Analyzers required.

...(ii) The use of linearizing circuits is permitted. (2) **Carbon dioxide (CO2)** analysis. (i) The **carbon dioxide** analyzer shall be of the non-dispersive infrared (NDIR) absorption type. (ii) The use of linearizing ...

...(1) Carbon monoxide and **carbon dioxide** measurements must be made on a dry basis (for raw exhaust measurement only). Specific requirements for the means of drying ...

496 C 40 C.F.R. § 90.314 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 90.314 Analyzer accuracy and specifications.

...(iii) Select a calibration gas (a span gas may be used for calibrating the **CO2** analyzer) with a concentration between the two lowest non-zero gas divider increments. This gas must be "named" to an accuracy ...

... in paragraph (c)(2)(iii) of this section. The concentration derived from the curve must be within +-2.3 percent (+-2.8 percent for **CO2** span gas) of the gas's original named concentration. (v) Provided the requirements of paragraph (c)(2)(iv) of this section are met, ...

497 C 40 C.F.R. § 90.315 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 90.315 Analyzer initial calibration.

...(c) Zero setting and calibration. Using purified synthetic air (or nitrogen), set the CO, **CO2**, NOX, and HC analyzers at zero. Connect the appropriate calibrating gases to the analyzers and record the values. Use the ...

498. C 40 C.F.R. § 90.317 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 90.317 Carbon monoxide analyzer calibration.

... Prior to its initial use and annually thereafter, check the NDIR carbon monoxide analyzer for response to water vapor and **CO2**: (1) Follow good engineering practices for instrument start-up and operation. Adjust the analyzer to optimize performance on the most sensitive ...

...(3) Bubble a mixture of three percent **CO2** in N2 through water at room temperature and record analyzer response. (4) An analyzer response of more than one percent ...

499. C 40 C.F.R. § 90.320 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 90.320 Carbon dioxide analyzer calibration.

...§ 90.320 **Carbon dioxide** analyzer calibration. (a) Prior to its initial use and monthly thereafter, or within one month prior to the certification test, ...

... Prior to its initial use and monthly thereafter, or within one month prior to the certification test, calibrate the NDIR **carbon dioxide** analyzer as follows: (1) Follow good engineering practices for instrument start-up and operation. Adjust the analyzer to optimize performance. ...

...(2) Zero the **carbon dioxide** analyzer with either purified synthetic air or zero-grade nitrogen. (3) Calibrate on each normally used operating range with **carbon dioxide**-in-N2 ...

500. C 40 C.F.R. § 90.325 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 90.325 Analyzer interference checks.

...(b) CO analyzer water and CO2interference checks. Bubble through water at room temperature a **CO2** span gas having a concentration of between 80 percent and 100 percent inclusive of full scale of the maximum operating ...

... ranges below 300 ppm. (c) NOX analyzer quench check. The two gases of concern for CLD (and HCLD) analyzers are **CO2** and water vapor. Quench responses to these two gases are proportional to their concentrations and, therefore, require test techniques to ...

... test techniques to determine quench at the highest expected concentrations experienced during testing. (1) NOXanalyzer CO2quench check. (i) Pass a **CO2** span gas having a concentration of 80 percent to 100 percent of full scale of the maximum operating range used ...

501. C 40 C.F.R. § 90.328 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 90.328 Measurement equipment accuracy/calibration frequency table.

...(f) Verify that all NDIR analyzers meet the water rejection ratio and the **CO2** rejection ratio as specified in § 90.325. (g) Verify that the dynamometer test stand and power output instrumentation meet the ...

502. C 40 C.F.R. § 90.329 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 90.329 Catalyst thermal stress test.

... Volume percent Parts per million -- Carbon Monoxide .... 1 .... Oxygen .... 1.3 .... **Carbon Dioxide** .... 3.8 .... Water Vapor .... 10 .... Sulfur dioxide ....

504. **C** 40 C.F.R. § 90.404 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 90.404 Test procedure overview.

...(b) The test is designed to determine the brake-specific emissions of hydrocarbons, carbon monoxide, **carbon dioxide**, and oxides of nitrogen and fuel consumption. For Phase 2 Class I-B, Class I, and Class II natural gas fueled ...

505. **C** 40 C.F.R. § 90.409 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 90.409 Engine dynamometer test run.

...(c) Exhaust gas measurements. (1) Measure HC, CO, **CO2**, and NOX concentration in the exhaust sample. (2) Each analyzer range that may be used during a test mode must ...

506. **C** 40 C.F.R. § 90.412 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 90.412 Data logging.

...(e) Determine the final value for **CO2**, CO, HC, and NOX concentrations by averaging the concentration of each point taken during the sample period for each mode. ...

QUERY - "CARBON DIOXIDE" CO2 DATABASE(S) - CFR

507. **C** 40 C.F.R. § 90.413 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 90.413 Exhaust sample procedure--gaseous components.

...(2) Record the most recent zero and span response as the pre-analysis values. (3) Measure and record HC, CO, **CO2**, and NOX concentrations in the exhaust sample bag(s) and background sample bag(s) using the same flow rates and pressures. (6) ...

... and pressures. (6) Record the most recent zero and span response as the pre-analysis values. (7) Collect background HC, CO, **CO2**, and NOX in a sample bag (for dilute exhaust sampling only, see § 90.422). (8) Perform a post-analysis zero and ...

... and post-analysis checks on any range used may exceed three percent for HC, or two percent for NOX, CO, and **CO2**, of full-scale chart deflection, or the test is void. (If the HC drift is greater than three percent of full-scale ...

508. **C** 40 C.F.R. § 90.415 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 90.415 Raw gaseous sampling procedures.

... flow of gas required for analysis. The sample line for HC measurement must be heated. The sample line for CO, **CO2** and NOX analysis may be heated or unheated. SOURCE: 60 FR 34598, July 3, 1995; 65 FR 24305, April 25, ...

509. **C** 40 C.F.R. § 90.418 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 90.418 Data evaluation for gaseous emissions.

... the gaseous emissions recording, record the last two minutes of each mode and determine the average values for HC, CO, **CO2** and NOX during each mode from the average concentration readings determined from the corresponding calibration data. Longer averaging times are ...

510. **C** 40 C.F.R. § 90.419 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 90.419 Raw emission sampling calculations--gasoline fueled engines.

...WCO=CO percent concentration in the exhaust, wet DCO=CO percent concentration in the exhaust, dry WCO2=**CO2** percent concentration in the exhaust, wet DCO2=**CO2** percent concentration in the exhaust, dry WNOX=NO volume concentration in exhaust, ppm wet ...

...WCO2=**CO2** percent concentration in the exhaust, wet DCO=CO percent concentration in the exhaust, dry DCO2=**CO2** percent concentration in the exhaust, dry ...

511. **C** 40 C.F.R. § 90.421 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 90.421 Dilute gaseous exhaust sampling and analytical system description.

... utilizes the Constant Volume Sampling (CVS) concept (described in § 90.420) of measuring mass emissions of HC, NOX, CO, and **CO2**. Grab sampling for individual modes is an acceptable method of dilute testing for all constituents, HC, NOX, CO, and **CO2**. ...

... an option, the measurement of total fuel mass consumed over a cycle may be substituted for the exhaust measurement of **CO2**. General requirements are as follows: (1) This sampling system requires the use of a Positive Displacement Pump-- Constant Volume Sampler ...

...(3) The CO and **CO2** analytical system requires: (i) Grab sampling (see § 90.420, and Figure 2 or Figure 3 in Appendix B of this ...

512. **C** 40 C.F.R. § 90.422 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 90.422 Background sample.

...(c) Measure HC, CO, **CO2**, and NOX exhaust and background concentrations in the sample bag(s) with approximately the same flow rates and pressures used during ...

514. **C** 40 C.F.R. § 90.426 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 90--CONTROL OF EMISSIONS FROM NONROAD SPARK-IGNITION ENGINES AT OR BELOW 19 KILOWATTS SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 90.426 Dilute emission sampling calculations--gasoline fueled engines.

...Where: AWM=Final weighted brake-specific mass emission rate for an emission (HC, CO, **CO2**, or NOX) [g/kW-hr] Wi=Average mass flow rate of an emission (HC, CO, **CO2**, NOX) from a test engine during mode ...

...CD **CO2**=Concentration of **CO2** in the dilute sample [ppm] (e) The humidity correction factor KH is an adjustment made to measured NOX ...

...CO2mass=mass of **carbon dioxide** emissions for the mode sampling period [grams] alpha=The atomic hydrogen to carbon ratio of the fuel [70 FR 40450, July ...

515. **C** 40 C.F.R. § 91.4 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART A--GENERAL § 91.4 Acronyms and abbreviations.

...CAAA--Clean Air Act Amendments of 1990 CLD--chemiluminescent detector CO--Carbon monoxide **CO2--Carbon dioxide** EPA--Environmental Protection Agency FEL--Family Emission Limit g/kw-hr--grams per kilowatt hour ...

516. **C** 40 C.F.R. § 91.304 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 91.304 Test equipment overview.

...(c) Analyzers used are a non-dispersive infrared detector (NDIR) absorption type for carbon monoxide and **carbon dioxide** analysis; paramagnetic detector (PMD), zirconia (ZRDO), or electrochemical type (ECS) for oxygen analysis; a flame ionization detector (FID) or heated ...

517. **C** 40 C.F.R. § 91.312 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 91.312 Analytical gases.

...(1) Purified nitrogen, also referred to as "zero-grade nitrogen" (Contamination<=1 ppm C, <=1 ppm CO, <=400 ppm **CO2**, <=0.1 ppm NO) (2) Purified oxygen (Purity 99.5 percent vol O2) (3) Hydrogen-helium mixture (40+-2 percent hydrogen, balance helium) (Contamination<=1 ...

...(4) Purified synthetic air, also referred to as "zero gas" (Contamination<=1 ppm C, <=1 ppm CO, <=400 ppm **CO2**, <=0.1 ppm NO) (Oxygen content between 18-21 percent vol.) (c) Calibration and span gases. (1) Calibration gas values are to ...

...**CO2** and purified nitrogen. Note: For the HFID or FID, the manufacturer may choose to use as a diluent span gas ...

518. **C** 40 C.F.R. § 91.313 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 91.313 Analyzers required.

...(ii) The use of linearizing circuits is permitted. (2) **Carbon dioxide (CO2)** analysis. (i) The **carbon dioxide** analyzer must be of the non-dispersive infrared (NDIR) absorption type. (ii) The use of linearizing ...

...(1) Carbon monoxide and **carbon dioxide** measurements must be made on a dry basis (for raw exhaust measurement only). Specific requirements for the means of drying ...

519. **C** 40 C.F.R. § 91.314 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 91.314 Analyzer accuracy and specifications.

...(iii) Select a calibration gas (a span gas may be used for calibrating the **CO2** analyzer) with a concentration between the two lowest non-zero gas divider increments. This gas must be "named" to an accuracy ...

... (c)(2)(iii) of this section. The concentration derived from the curve must be within +- 2.3 percent (+- 2.8 percent for **CO2** span gas) of the gas' original named concentration. (v) Provided the requirements of paragraph (c)(2)(iv) of this section are met, ...

520. **C** 40 C.F.R. § 91.315 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 91.315 Analyzer initial calibration.

...(c) Zero setting and calibration. Using purified synthetic air (or nitrogen), set the CO, **CO2**, NOX and HC analyzers at zero. Connect the appropriate calibrating gases to the analyzers and record the values. The same ...

523. C 40 C.F.R. § 91.325 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 91.325 Analyzer interference checks.

...(b) CO analyzer water and **CO_2** interference checks. Bubble through water at room temperature a **CO_2** span gas having a concentration of between 80 percent and ...

... ranges below 300 ppm. (c) NOX analyzer quench check. The two gases of concern for CLD (and HCLD) analyzers are **CO_2** and water vapor. Quench responses to these two gases are proportional to their concentrations and, therefore, require test techniques to ...

... concentrations and, therefore, require test techniques to determine quench at the highest expected concentrations experienced during testing. (1) NOX analyzer **CO_2** quench check. (i) Pass a **CO_2** span gas having a concentration of 80 percent to 100 percent of full scale ...

524. C 40 C.F.R. § 91.328 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART D--EMISSION TEST EQUIPMENT PROVISIONS § 91.328 Measurement equipment accuracy/calibration frequency table.

...(f) Verify that all NDIR analyzers meet the water rejection ratio and the **CO_2** rejection ratio as specified in § 91.325. (g) Verify that the dynamometer test stand and power output instrumentation meet the ...

527. C 40 C.F.R. § 91.409 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 91.409 Engine dynamometer test run.

...(c) Exhaust gas measurements. (1) Measure HC, CO, **CO_2**, and NOX concentration in the exhaust sample. (2) Each analyzer range that may be used during a test segment must ...

528. C 40 C.F.R. § 91.412 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 91.412 Data logging.

...(e) Determine the final value for **CO_2**, CO, HC, and NOX concentrations by averaging the concentration of each point taken during the sample period for each mode. ...

529. C 40 C.F.R. § 91.413 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 91.413 Exhaust sample procedure--gaseous components.

...(2) Record the most recent zero and span response as the pre-analysis value. (3) Measure HC, CO, **CO_2**, and NOX background concentrations in the sample bag(s) and background sample bag(s) using the same flow rates and pressures. (6) ...

... and pressures: (6) Record the most recent zero and span response as the pre-analysis values. (7) Collect background HC, CO, **CO_2**, and NOX in a sample bag (for dilute exhaust sampling only, see § 91.422). (8) Perform a post-analysis zero and ...

...percent for NOX, CO, and **CO_2**, of full scale chart deflection, or the test is void. (If the HC drift is greater than three percent of ...

530. C 40 C.F.R. § 91.415 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 91.415 Raw gaseous sampling procedures.

... flow of gas required for analysis. The sample line for HC measurement must be heated. The sample line for CO, **CO_2**, and NOX may be heated or unheated. SOURCE: 61 FR 52102, Oct. 4, 1996; 65 FR 24314, April 25, 2000, ...

531. **C** 40 C.F.R. § 91.418 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 91.418 Data evaluation for gaseous emissions.

... the gaseous emissions recording, record the last two minutes of each mode and determine the average values for HC, CO, **CO2**, and NOX during each mode from the average concentration readings determined from the corresponding calibration data. SOURCE: 61 FR 52102, ...

532. **C** 40 C.F.R. § 91.419 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 91.419 Raw emission sampling calculations.

...WCO = CO percent concentration in the exhaust, wet DCO = CO percent concentration in the exhaust, dry WCO2 = **CO2** percent concentration in the exhaust, wet DCO2 = **CO2** percent concentration in the exhaust, dry WNOX = NO volume concentration ...

...WCO2 = **CO2** percent concentration in the exhaust, wet DCO2 = **CO2** percent concentration in the exhaust, dry WNOx = NO volume concentration ...

533. **C** 40 C.F.R. § 91.421 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 91.421 Dilute gaseous exhaust sampling and analytical system description.

... CO2. Grab sampling for individual modes is an acceptable method of dilute testing for all constituents, HC, NOx, CO, and **CO2**. Continuous dilute sampling is not required for any of the exhaust constituents, but is allowable for all. Heated sampling is ...

... an option, the measurement of total fuel mass consumed over a cycle may be substituted for the exhaust measurement of **CO2**. General requirements are as follows: (1) This sampling system requires the use of a Positive Displacement Pump-- Constant Volume Sampler ...

...(3) The CO and **CO2** analytical system requires: (i) Grab sampling (see § 91.420, and Figure 2 or Figure 3 in appendix B of this ...

534. **C** 40 C.F.R. § 91.423 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 91.423 Exhaust gas analytical system; CVS grab sample.

... flame ionization detector (HFID) for the measurement of hydrocarbons, nondispersive infrared analyzers (NDIR) for the measurement of carbon monoxide and **carbon dioxide,** and a chemiluminescence detector (CLD) (or heated CLD (HCLD)) for the measurement of oxides of nitrogen. The exhaust gas analytical ...

... results and if approved in advance by the Administrator. (2) If CO instruments are used which are essentially free of **CO2** and water vapor interference, the use of the conditioning column may be deleted. (See §§ 91.317 and 91.320.) ...

...(3) A CO instrument will be considered to be essentially free of **CO2** and water vapor interference if its response to a mixture of three percent **CO2** in N2, which has been bubbled ...

535. **C** 40 C.F.R. § 91.426 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 91--CONTROL OF EMISSIONS FROM MARINE SPARK-IGNITION ENGINES SUBPART E--GASEOUS EXHAUST TEST PROCEDURES § 91.426 Dilute emission sampling calculations.

...Where: Awm=Weighted mass emission level (HC, CO, **CO2**, or NOX) for a test [g/kW-hr]. Wi=Average mass flow rate of an emission from a test engine during mode i ...

...CD **CO2** = Concentration of **CO2** in the dilute sample [ppm]. (e) The humidity correction factor KH is an adjustment made to ...

...**CO2** mass = mass of **carbon dioxide** emissions for the mode sampling period [g]. alpha = The atomic hydrogen to carbon ...

536. C 40 C.F.R. § 92.3 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 92--CONTROL OF AIR POLLUTION FROM LOCOMOTIVES AND LOCOMOTIVE ENGINES SUBPART A--GENERAL PROVISIONS FOR EMISSION REGULATIONS FOR LOCOMOTIVES AND LOCOMOTIVE ENGINES § 92.3 Abbreviations.

...CFV--Critical flow venturi CL--Chemiluminescence CO--Carbon monoxide **CO2--Carbon dioxide** cu in--cubic inch(es) CVS--Constant volume sampler EP--End point EPA--Environmental Protection Agency ...

537. C 40 C.F.R. § 92.103 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 92--CONTROL OF AIR POLLUTION FROM LOCOMOTIVES AND LOCOMOTIVE ENGINES SUBPART B--TEST PROCEDURES § 92.103 Test procedures; overview.

... measure brake-specific mass emissions of organic compounds (hydrocarbons for locomotives using petroleum diesel fuel), oxides of nitrogen, particulates, carbon monoxide, **carbon dioxide**, and smoke in a manner representative of a typical operating cycle. (b)(1) The sampling systems specified in this subpart are ...

538. C 40 C.F.R. § 92.109 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 92--CONTROL OF AIR POLLUTION FROM LOCOMOTIVES AND LOCOMOTIVE ENGINES SUBPART B--TEST PROCEDURES § 92.109 Analyzer specifications.

... (a) General analyzer specifications.-- (1) Analyzer response time. Analyzers for THC, **CO2**, CO, and NOX must respond to an instantaneous step change at the entrance to the analyzer with a response equal ...

... associated plumbing need not be included in the analyzer response time. (2) Precision. The precision of the analyzers for THC, **CO2**, CO, and NOX must be no greater than +-1 percent of full-scale concentration for each range used above 155 ppm ...

... 10-second period shall not exceed 2 percent of full/scale chart deflection on all ranges used: (4) Zero drift. For THC, **CO2**, CO, and NOX analyzers, the zero-response drift during a 1-hour period shall be less than 2 percent of full-scale chart ...

539. C 40 C.F.R. § 92.112 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 92--CONTROL OF AIR POLLUTION FROM LOCOMOTIVES AND LOCOMOTIVE ENGINES SUBPART B--TEST PROCEDURES § 92.112 Analytical gases.

... (a) Gases for the CO and **CO2** analyzers shall be single blends of CO and **CO2**, respectively, using zero grade nitrogen as the diluent. (b) Gases for ...

... or nitrogen) impurity concentrations shall not exceed 1 ppm equivalent carbon response, 1 ppm carbon monoxide, 0.04 percent (400 ppm) **carbon dioxide** and 0.1 ppm nitric oxide. (h)(1) "Zero-grade air" includes artificial "air" consisting of a blend of nitrogen and oxygen with ...

541. C 40 C.F.R. § 92.114 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 92--CONTROL OF AIR POLLUTION FROM LOCOMOTIVES AND LOCOMOTIVE ENGINES SUBPART B--TEST PROCEDURES § 92.114 Exhaust gas and particulate sampling and analytical system.

... stacks, proportional samples may be collected from each exhaust outlet instead of ducting the exhaust stacks together, provided that the **CO2** concentrations in each exhaust stream are shown (either prior to testing or during testing) to be within 5 percent of ...

... of each other at notch 8. (B) Flowmeters. Flowmeters FL1 and FL2 indicate sample flow rates through the CO and **CO2** analyzers. Flowmeters FL3, FL4, FL5, and FL6 indicate bypass flow rates. (C) Gauges. Downstream gauges are required for any system ...

... Upstream gauges may be required under this subpart. Upstream gauges G1 and G2 measure the input to the CO and **CO2** analyzers. Downstream gauges G3 and G4 measure the exit pressure of the CO and **CO2** analyzers. If the normal operating ...

542. C 40 C.F.R. § 92.115 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 92--CONTROL OF AIR POLLUTION FROM LOCOMOTIVES AND LOCOMOTIVE ENGINES SUBPART B--TEST PROCEDURES § 92.115 Calibrations; frequency and overview.

... (certain analyzers may require more frequent calibration depending on the equipment and use). Exception: the water rejection ratio and the **CO2** rejection ratio on all NDIR analyzers is only required to be performed quarterly. (c) At least monthly or after any ...

543. **C** 40 C.F.R. § 92.118 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 92--CONTROL OF AIR POLLUTION FROM LOCOMOTIVES AND LOCOMOTIVE ENGINES SUBPART B--TEST PROCEDURES § 92.118 Analyzer checks and calibrations.

...(iv) If the elapsed time is more than 20.0 seconds, make necessary adjustments. (v) Repeat with the CO, **CO2**, and NOX instruments and span gases. (2) Option. If the following parameters are determined, the initial system response time may ...

544. **C** 40 C.F.R. § 92.120 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 92--CONTROL OF AIR POLLUTION FROM LOCOMOTIVES AND LOCOMOTIVE ENGINES SUBPART B--TEST PROCEDURES § 92.120 NDIR analyzer calibration and checks.

...(1) Zero and span the analyzer on the lowest range that will be used. (2) Introduce a **CO2** calibration gas of at least 10 percent **CO2** or greater to the analyzer. (3) Record the **CO2** calibration gas concentration ...

... analyzer. (3) Record the **CO2** calibration gas concentration in ppm. (4) Record the analyzers' response (AR) in ppm to the **CO2** calibration gas. (5) Calculate the **CO2** rejection ratio (CO2RR) from: CO2RR=(ppm **CO2**)/AR (c) NDIR analyzer calibration. (1) Detector optimization. If ...

545. **C** 40 C.F.R. § 92.121 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 92--CONTROL OF AIR POLLUTION FROM LOCOMOTIVES AND LOCOMOTIVE ENGINES SUBPART B--TEST PROCEDURES § 92.121 Oxides of nitrogen analyzer calibration and check.

...(i) Calibrate the NOX analyzer on the lowest range that will be used for testing. (ii) Introduce a mixture of **CO2** calibration gas and NOX calibration gas to the CL analyzer. Dynamic blending may be used to provide this mixture. Dynamic ...

... the CL analyzer. Dynamic blending may be used to provide this mixture. Dynamic blending may be accomplished by analyzing the **CO2** in the mixture. The change in the **CO2** value due to blending may then be used to determine the true ...

... value due to blending may then be used to determine the true concentration of the NOX in the mixture. The **CO2** concentration of the mixture shall be approximately equal to the highest concentration experienced during testing. Record the response. (iii) Recheck ...

546. **C** 40 C.F.R. § 92.126 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 92--CONTROL OF AIR POLLUTION FROM LOCOMOTIVES AND LOCOMOTIVE ENGINES SUBPART B--TEST PROCEDURES § 92.126 Test run.

... beginning of each test mode, and shall end six minutes after the beginning of each test mode. (iii) Sampling of **CO2** in the dilution air and diluted exhaust does not need to be continuous, but the measurements used for the calculations ...

547. **C** 40 C.F.R. § 92.127 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 92--CONTROL OF AIR POLLUTION FROM LOCOMOTIVES AND LOCOMOTIVE ENGINES SUBPART B--TEST PROCEDURES § 92.127 Emission measurement accuracy.

...(iii) Select a calibration gas (a span gas may be used for calibrating the **CO2** analyzer) with a concentration between the two lowest non-zero gas divider increments. This gas must be "named" to an accuracy ...

... two lowest non-zero gas divider increments. This gas must be "named" to an accuracy of +-1.0 percent (+-2.0 percent for **CO2** span gas) of NIST gas standards, or other standards approved by the Administrator. (iv) Using the calibration curve fitted to ...

... in paragraph (b)(2)(iii) of this section. The concentration derived from the curve shall be within +-2.3 percent (+-2.8 percent for **CO2** span gas) of the gas' original named concentration. (v) Provided the requirements of paragraph (b)(2)(iv) of this section are met, ...

548. **C** 40 C.F.R. § 92.129 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 92--CONTROL OF AIR POLLUTION FROM LOCOMOTIVES AND LOCOMOTIVE ENGINES SUBPART B--TEST PROCEDURES § 92.129 Exhaust sample analysis.

... approximately the same flow rates and system pressures used in paragraph (d)(5) of this section. (10)(i) Collect background HC, CO, **CO2**, and NOX in a sample bag (optional). (ii) Measure the concentration of **CO2** in the dilution air and the diluted ...

... and post-analysis checks on any range used may exceed 3 percent for HC, or 2 percent for NOX, CO, and **CO2**, of full scale chart deflection, or the test is void. (If the HC drift is greater than 3 percent of ...

... (if necessary) by introducing the background sample into the overflow sample system. (14) Determine background levels of NOX, CO, or **CO2** (if necessary). (e) HC hang-up. If HC hang-up is indicated, the following sequence may be performed: ...

549. **C** 40 C.F.R. § 92.130 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 92--CONTROL OF AIR POLLUTION FROM LOCOMOTIVES AND LOCOMOTIVE ENGINES SUBPART B--TEST PROCEDURES § 92.130 Determination of steady-state concentrations.

... criteria of paragraph (b) of this section and the criterion of paragraph (c) of this section. (2) For CO and **CO2** emissions, a steady-state concentration measurement, measured after 300 seconds (or 840 seconds for notch 8) of testing shall be used. ...

... testing shall be used. The provisions of paragraphs (b) through (f) of this section do not apply for CO and **CO2** emissions. (b)(1) The steady-state concentration is considered representative of the entire measurement period if the time-weighted concentration is not more ...

551. **C** 40 C.F.R. § 92.133 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 92--CONTROL OF AIR POLLUTION FROM LOCOMOTIVES AND LOCOMOTIVE ENGINES SUBPART B--TEST PROCEDURES § 92.133 Required information.

... the dilute exhaust mixture immediately ahead of the particulate filter. (14) Sample concentrations (background corrected as applicable) for HC, CO, **CO2**, and NOX (and methane, NMHC, alcohols and aldehydes, as applicable) for each test mode. This includes the continuous trace and ...

552. **C** 40 C.F.R. § 94.3 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 94--CONTROL OF EMISSIONS FROM MARINE COMPRESSION-IGNITION ENGINES SUBPART A--GENERAL PROVISIONS FOR EMISSION REGULATIONS FOR COMPRESSION-IGNITION MARINE ENGINES § 94.3 Abbreviations.

...degreesC--Degrees Celsius. CI--Compression ignition. CO--Carbon monoxide. **CO2--Carbon dioxide.** disp.--volumetric displacement of an engine cylinder. EGR--Exhaust gas recirculation. EP--End point. EPA--Environmental Protection Agency. ...

553. C 40 C.F.R. § 96.2 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 96--NOX BUDGET TRADING PROGRAM AND CAIR NOX AND SO2 TRADING PROGRAMS FOR STATE IMPLEMENTATION PLANS SUBPART A--NOX BUDGET TRADING PROGRAM GENERAL PROVISIONS § 96.2 Definitions.

...(1) Flow monitor, (2) Nitrogen oxides pollutant concentration monitors; (3) Diluent gas monitor (oxygen or **carbon dioxide**) when such monitoring is required by subpart H of this part; (4) A continuous moisture monitor when such monitoring is ...

... should be reported, in accordance with part 75 of this chapter, using the maximum potential flowrate and either the maximum **carbon dioxide** concentration (in percent **CO2**) or the minimum oxygen concentration (in percent O2). Maximum potential NOX emission rate means the emission ...

... appendix A of part 75 of this chapter, and either the maximum oxygen concentration (in percent O2) or the minimum **carbon dioxide** concentration (in percent **CO2**), under all operating conditions of the unit except for unit start up, shutdown, and upsets. ...

554. C 40 C.F.R. § 96.3 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 96--NOX BUDGET TRADING PROGRAM AND CAIR NOX AND SO2 TRADING PROGRAMS FOR STATE IMPLEMENTATION PLANS SUBPART A--NOX BUDGET TRADING PROGRAM GENERAL PROVISIONS § 96.3 Measurements, abbreviations, and acronyms.

...mmBtu--million Btu. MWe--megawatt electrical. ton--2000 pounds. **CO2--carbon dioxide.** NOX--nitrogen oxides. O2--oxygen. SOURCE: 63 FR 57514, Oct. 27, 1998; 70 FR 25339, May 12, 2005; 71 FR 25380, April ...

556. C 40 C.F.R. § 96.103 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 96--NOX BUDGET TRADING PROGRAM AND CAIR NOX AND SO2 TRADING PROGRAMS FOR STATE IMPLEMENTATION PLANS SUBPART AA--CAIR NOX ANNUAL TRADING PROGRAM GENERAL PROVISIONS § 96.103 Measurements, abbreviations, and acroynyms.

...Measurements, abbreviations, and acronyms used in this subpart and subparts BB through II are defined as follows: Btu--British thermal unit. **CO2--carbon dioxide** H2O--water Hg--mercury hr--hour kW--kilowatt electrical kWh--kilowatt hour lb--pound ...

560. C 40 C.F.R. § 96.203 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 96--NOX BUDGET TRADING PROGRAM AND CAIR NOX AND SO2 TRADING PROGRAMS FOR STATE IMPLEMENTATION PLANS SUBPART AAA--CAIR SO2 TRADING PROGRAM GENERAL PROVISIONS § 96.203 Measurements, abbreviations, and acronyms.

...Measurements, abbreviations, and acronyms used in this subpart and subparts BBB through III are defined as follows: Btu--British thermal unit **CO2--carbon dioxide** H2O--water Hg--mercury hr--hour kW--kilowatt electrical kWh--kilowatt hour lb--pound ...

564. C 40 C.F.R. § 96.303 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 96--NOX BUDGET TRADING PROGRAM AND CAIR NOX AND SO2 TRADING PROGRAMS FOR STATE IMPLEMENTATION PLANS SUBPART AAAA--CAIR NOX OZONE SEASON TRADING PROGRAM GENERAL PROVISIONS § 96.303 Measurements, abbreviations, and acronyms.

...Measurements, abbreviations, and acronyms used in this subpart and subparts BBBB through IIII are defined as follows: Btu--British thermal unit **CO2--carbon dioxide** H2O--water Hg--mercury hr--hour kW--kilowatt electrical kWh--kilowatt hour lb--pound ...

568. C 40 C.F.R. § 97.3 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 97--FEDERAL NOX BUDGET TRADING PROGRAM AND CAIR NOX AND SO2 TRADING PROGRAMS SUBPART A--NOX BUDGET TRADING PROGRAM GENERAL PROVISIONS § 97.3 Measurements, abbreviations, and acronyms.

...Measurements, abbreviations, and acronyms used in this part are defined as follows: Btu-British thermal unit. **CO2-carbon dioxide.** hr-hour. kW-kilowatt electrical. kWh-kilowatt hour. lb-pounds. mmBtu-million Btu. ...

570. C 40 C.F.R. § 97.103 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 97--FEDERAL NOX BUDGET TRADING PROGRAM AND CAIR NOX AND SO2 TRADING PROGRAMS SUBPART AA--CAIR NOX ANNUAL TRADING PROGRAM GENERAL PROVISIONS § 97.103 Measurements, abbreviations, and acronyms.

...Measurements, abbreviations, and acronyms used in this subpart and subparts BB through II are defined as follows: Btu--British thermal unit **CO2--carbon dioxide** H2O--water Hg--mercury hr--hour kW--kilowatt electrical kWh--kilowatt hour lb--pound ...

574. 40 C.F.R. § 97.203 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 97--FEDERAL NOX BUDGET TRADING PROGRAM AND CAIR NOX AND SO2 TRADING PROGRAMS SUBPART AAA--CAIR SO2 TRADING PROGRAM GENERAL PROVISIONS § 97.203 Measurements, abbreviations, and acronyms.

...Measurements, abbreviations, and acronyms used in this subpart and subparts BBB through III are defined as follows: Btu--British thermal unit. **CO2--carbon dioxide.** H2O--water. Hg--mercury. hr--hour. kW--kilowatt electrical. kWh--kilowatt hour. lb--pound. ...

578. C 40 C.F.R. § 97.303 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER C--AIR PROGRAMS PART 97--FEDERAL NOX BUDGET TRADING PROGRAM AND CAIR NOX AND SO2 TRADING PROGRAMS SUBPART AAAA--CAIR NOX OZONE SEASON TRADING PROGRAM GENERAL PROVISIONS § 97.303 Measurements, abbreviations, and acronyms.

...Measurements, abbreviations, and acronyms used in this subpart and subparts BBBB through IIII are defined as follows: Btu--British thermal unit. **CO2--carbon dioxide.** H2O--water. Hg--mercury. hr--hour. kW--kilowatt electrical. kWh--kilowatt hour. lb--pound. ...

619. 40 C.F.R. § 1033.205 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1033--CONTROL OF EMISSIONS FROM LOCOMOTIVES SUBPART C--CERTIFYING ENGINE FAMILIES § 1033.205 Applying for a certificate of conformity.

... on results from previous emission tests, development tests, or other testing information. Include data for NOX, PM, HC, CO, and **CO**². (9) The intended deterioration factors for the engine family, in accordance with § 1033.245. If the deterioration factors for the ...

620. 40 C.F.R. § 1033.501 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1033--CONTROL OF EMISSIONS FROM LOCOMOTIVES SUBPART F--TEST PROCEDURES § 1033.501 General provisions.

... the applicable duty cycles specified in this subpart. Measure emissions of all the pollutants we regulate in § 1033.101 plus **CO2**. The general test procedure is the procedure specified in 40 CFR part 1065 for steady-state discrete-mode cycles. However, if you ...

621. 40 C.F.R. § 1033.905 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1033--CONTROL OF EMISSIONS FROM LOCOMOTIVES SUBPART J--DEFINITIONS AND OTHER REFERENCE INFORMATION § 1033.905 Symbols, acronyms, and abbreviations.

...AESS automatic engine stop/start CFR Code of Federal Regulations. CO carbon monoxide. **CO2 carbon dioxide.** EPA Environmental Protection Agency. FEL Family Emission Limit. g/bhp-hr grams per brake horsepower-hour. ...

623. C 40 C.F.R. § 1039.805 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1039--CONTROL OF EMISSIONS FROM NEW AND IN-USE NONROAD COMPRESSION- IGNITION ENGINES SUBPART I--DEFINITIONS AND OTHER REFERENCE INFORMATION § 1039.805 What symbols, acronyms, and abbreviations does this part use?

...The following symbols, acronyms, and abbreviations apply to this part: CFR Code of Federal Regulations. CO carbon monoxide. **CO2 carbon dioxide.** EPA Environmental Protection Agency. FEL Family Emission Limit. g/kW-hr grams per kilowatt-hour. ...

626. 40 C.F.R. § 1042.905 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1042--CONTROL OF EMISSIONS FROM NEW AND IN-USE MARINE COMPRESSION-IGNITION ENGINES AND VESSELS SUBPART J--DEFINITIONS AND OTHER REFERENCE INFORMATION § 1042.905 Symbols, acronyms, and abbreviations.

...AECD auxiliary-emission control device. CFR Code of Federal Regulations. CO carbon monoxide. **CO2 carbon dioxide.** cyl cylinder. disp. displacement. EPA Environmental Protection Agency. FEL Family Emission Limit. g grams. ...

628. C 40 C.F.R. § 1048.805 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1048--CONTROL OF EMISSIONS FROM NEW, LARGE NONROAD SPARK-IGNITION ENGINES SUBPART I--DEFINITIONS AND OTHER REFERENCE INFORMATION § 1048.805 What symbols, acronyms, and abbreviations does this part use?

...CFR Code of Federal Regulations. cm centimeter. CO carbon monoxide. **CO2 carbon dioxide.** EPA Environmental Protection Agency. g/kW-hr grams per kilowatt-hour. HC hydrocarbon. ISO International Organization for Standardization. ...

630. C 40 C.F.R. § 1051.805 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1051--CONTROL OF EMISSIONS FROM RECREATIONAL ENGINES AND VEHICLES SUBPART I--DEFINITIONS AND OTHER REFERENCE INFORMATION § 1051.805 What symbols, acronyms, and abbreviations does this part use?

...CFR--Code of Federal Regulations. cm--centimeter. C--Celsius. CO--carbon monoxide. **CO2--carbon dioxide.** EPA--Environmental Protection Agency. F--Fahrenheit. g--grams. g/gal/day--grams per gallon per test day. ...

631. C 40 C.F.R. § 1065.170 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART B--EQUIPMENT SPECIFICATIONS § 1065.170 Batch sampling for gaseous and PM constituents.

... kW -- CO, **CO2**, O2, CH4, C2H6, C3H8, NO, NO2 [FN1] ... TedlarTM, [FN2] KynarTM, ...

632. C 40 C.F.R. § 1065.250 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART C--MEASUREMENT INSTRUMENTS § 1065.250 Nondispersive infra-red analyzer.

... Part 1065. Engine-Testing Procedures (Refs & Annos) Subpart C. Measurement Instruments Co and **Co2** Measurements § 1065.250 Nondispersive infra-red analyzer. (a) Application. Use a nondispersive infra-red (NDIR) analyzer to measure CO and **CO2** concentrations ...

634. C 40 C.F.R. § 1065.303 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART D--CALIBRATIONS AND VERIFICATIONS § 1065.303 Summary of required calibration and verifications.

... part. § 1065.350: **CO2** NDIR H2O interference .... Upon initial installation and after major ...

... maintenance. § 1065.355: CO NDIR **CO2** and H2O interference .... Upon initial installation and after major ...

... maintenance. § 1065.370: CLD **CO2** and H2O quench .... Upon initial installation and after major ...

635. 40 C.F.R. § 1065.303 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART D--CALIBRATIONS AND VERIFICATIONS § 1065.303 Summary of required calibration and verifications.

... of this part. § 1065.350: **CO2** NDIR H2O interference .....Upon initial installation and after major maintenance. § 1065.355: CO NDIR **CO2** and H2O interference ....

... and after major maintenance. § 1065.370: CLD **CO2** and H2O quench .... Upon initial installation and after major maintenance. § 1065.372: NDUV HC and H2O interference ..... Upon ...

636. C 40 C.F.R. § 1065.308 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART D--CALIBRATIONS AND VERIFICATIONS § 1065.308 Continuous gas analyzer system-response and updating-recording verification.

.... source to one inlet of a fast-acting 3-way valve (2 inlets, 1 outlet). Using a gas divider, equally blend an NO-CO-**CO2**-C3 H8-CH4 (balance N2) span gas with a span gas of NO2. Connect the gas divider outlet to the other inlet ...

637. 40 C.F.R. § 1065.308 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART D--CALIBRATIONS AND VERIFICATIONS § 1065.308 Continuous gas analyzer system-response and updating-recording verification--general.

... and blended span gases to the analyzers. You may use a gas mixing or blending device to equally blend an NO-CO-**CO2**-C3H8-CH4, balance N2 span gas with a span gas of NO2, balance purified synthetic air. Standard binary span gases may also ...

... of NO2, balance purified synthetic air. Standard binary span gases may also be used, where applicable, in place of blended NO-CO-**CO2**-C3H8-CH4, balance N2 span gas, but separate response tests must then be run for each analyzer. In designing your experimental setup, ...

638. C 40 C.F.R. § 1065.309 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART D--CALIBRATIONS AND VERIFICATIONS § 1065.309 Continuous gas analyzer uniform response verification.

... a 100 ° C heated fast-acting 3- way valve (2 inlets, 1 outlet). Using a gas divider, equally blend an NO-CO-**CO2**-C3 H8-CH4 (balance N2) span gas with a span gas of NO2 (balance N2). Connect the gas divider outlet to ...

639. 40 C.F.R. § 1065.309 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART D--CALIBRATIONS AND VERIFICATIONS § 1065.309 Continuous gas analyzer system-response and updating-recording verification--with humidified-response verification.

... gases to the analyzers. You may use a gas blending or mixing device to equally blend a span gas of NO-CO-**CO2**-C3H8-CH4, balance N2, with a span gas of NO2, balance purified synthetic air. Standard binary span gases may be used, where ...

... gas of NO2, balance purified synthetic air. Standard binary span gases may be used, where applicable, in place of blended NO-CO-**CO2**-C3H8-CH4, balance N2 span gas, but separate response tests must then be run for each analyzer. In designing your experimental setup, ...

... not humidify NO2 span gas by passing it through a sealed humidification vessel that contains water. We recommend humidifying your NO-CO-**CO2**-C3H8-CH4, balance N2 blended gas by flowing the gas mixture through a sealed vessel that humidifies the gas by bubbling it ...

641 **C** 40 C.F.R. § 1065.350 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART D--CALIBRATIONS AND VERIFICATIONS § 1065.350 H2 O interference verification for CO2 NDIR analyzers.

... Part 1065. Engine-Testing Procedures (Refs & Annos) Subpart D. Calibrations and Verifications Co and **Co2** Measurements § 1065.350 H2 O interference verification for **CO2** NDIR analyzers. (a) Scope and frequency. If you measure **CO2** using ...

... after initial analyzer installation and after major maintenance. (b) Measurement principles. H2O can interfere with an NDIR analyzer's response to **CO2**. If the NDIR analyzer uses compensation algorithms that utilize measurements of other gases to meet this interference verification, simultaneously conduct ...

...(c) System requirements. A **CO2** NDIR analyzer must have an H2O interference that is within +-2% of the flow-weighted mean **CO2** concentration expected at the ...

642 **C** 40 C.F.R. § 1065.355 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART D--CALIBRATIONS AND VERIFICATIONS § 1065.355 H2O and CO2 interference verification for CO NDIR analyzers.

... Part 1065. Engine-Testing Procedures (Refs & Annos) Subpart D. Calibrations and Verifications Co and **Co2** Measurements § 1065.355 H2O and **CO2** interference verification for CO NDIR analyzers. (a) Scope and frequency. If you measure CO ...

... NDIR analyzers. (a) Scope and frequency. If you measure CO using an NDIR analyzer, verify the amount of H2O and **CO2** interference after initial analyzer installation and after major maintenance. (b) Measurement principles. H2O and **CO2** can positively interfere with an ...

... interference verification, simultaneously conduct these other measurements to (c) System requirements. A CO NDIR analyzer must have combined H2O and **CO2** interference that is within +-2% of the flow-weighted mean concentration of CO expected at the standard, though we strongly recommend ...

643. **C** 40 C.F.R. § 1065.370 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART D--CALIBRATIONS AND VERIFICATIONS § 1065.370 CLD CO2 and H2O quench verification.

...§ 1065.370 CLD **CO2** and H2O quench verification. (a) Scope and frequency. If you use a CLD analyzer to measure NOX, verify the amount ...

... verification. (a) Scope and frequency. If you use a CLD analyzer to measure NOX, verify the amount of H2O and **CO2** quench after installing the CLD analyzer and after major maintenance. (b) Measurement principles. H2O and **CO2** can negatively interfere with ...

... vapor in humidified NO span gas. The procedure and the calculations scale the quench results to the water vapor and **CO2** concentrations expected during testing. If the CLD analyzer uses quench compensation algorithms that utilize H2O and/or **CO2** measurement instruments, use ...

644. 40 C.F.R. § 1065.545 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART F--PERFORMING AN EMISSION TEST OVER SPECIFIED DUTY CYCLES § 1065.545 Validation of proportional flow control for batch sampling and minimum dilution ratio for PM batch sampling.

...(d) Use measured or calculated flows and/or tracer gas concentrations (e.g., **CO2**) to determine the minimum dilution ratio for PM batch sampling over the test interval. [73 FR 25324, May 6, 2008] ...

645. **C** 40 C.F.R. § 1065.640 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART G--CALCULATIONS AND DATA REQUIREMENTS § 1065.640 Flow meter calibration calculations.

... <= 1800 **CO2** ...... $1.370 \cdot 10^{5}$ ...

646. **C** 40 C.F.R. § 1065.655 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART G--CALCULATIONS AND DATA REQUIREMENTS § 1065.655 Chemical balances of fuel, intake air, and exhaust.

... in your intake or dilution air. We recommend guessing an initial value of xCproddry as the sum of your measured **CO2**, CO, and THC values. If you measure diluted exhaust, we also recommend guessing an initial xdil between 0.75 and 0.95, ...

... values. xO2airdry = Amount of oxygen per dry mole of air. Use xO2airdry = 0.209445 mol/mol. xCO2airdry = Amount of **carbon dioxide** per dry mole of air. Use xCO2airdry = 375 mol/mol. <<alpha>> = Atomic hydrogen-to-carbon ratio in fuel. ...

647 **C** 40 C.F.R. § 1065.672 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART G--CALCULATIONS AND DATA REQUIREMENTS § 1065.672 Drift correction.

... However, in some cases you might you know that xrefzero has a non-zero concentration. For example, if you zero a **CO2** analyzer using ambient air, you may use the default ambient air concentration of **CO2**, which is 375 <<mu>>mol/mol. In this ...

648 **C** 40 C.F.R. § 1065.675 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART G--CALCULATIONS AND DATA REQUIREMENTS § 1065.675 CLD quench verification calculations.

...(b) Estimate the expected amount of water and **CO2** in the exhaust you sample, xH2Oexp and xCO2exp, respectively, by considering the maximum expected amounts of water in combustion air, ...

... applicable). xH2Omeas = measured amount of water entering the CLD sample port during the quench verification specified in § 1065.370. xNO,**CO2** = measured concentration of NO when NO span gas is blended with **CO2**%l span gas, according to § 1065.370.%l xNO,N2 ...

... when NO span gas is blended with N2 span gas, according to § 1065.370. xCO2exp = expected maximum amount of **CO2** entering the CLD sample port during emission testing. xCO2meas = measured amount of **CO2** entering the CLD sample port during ...

649. 40 C.F.R. § 1065.640 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART G--CALCULATIONS AND DATA REQUIREMENTS § 1065.640 Flow meter calibration calculations.

... <= 1800 **CO2** ...... $1.370 \cdot 10^{5}$ ...

650. 40 C.F.R. § 1065.655 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART G--CALCULATIONS AND DATA REQUIREMENTS § 1065.655 Chemical balances of fuel, intake air, and exhaust.

... in your intake or dilution air. We recommend guessing an initial value of xCcombdry as the sum of your measured **CO_2**, CO, and THC values. We also recommend guessing an initial xdil/exh between 0.75 and 0.95, such as 0.8. Iterate values ...

... calculated values. xO2int = Amount of intake air O2 per mole of intake air. xCO2intdry = Amount of intake air **CO_2** per mole of dry intake air. You may use xCO2intdry = 375 <<mu>>mol/mol, but we recommend measuring the actual concentration ...

... air. xH2Ointdry = Amount of intake air H_2O per mole of dry intake air. xCO2int = Amount of intake air **CO_2** per mole of intake air. xCO2dil = Amount of dilution gas **CO_2** per mole of dilution gas. xCO2dildry = Amount ...

651. 40 C.F.R. § 1065.672 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART G--CALCULATIONS AND DATA REQUIREMENTS § 1065.672 Drift correction.

... However, in some cases you might you know that xrefzero has a non-zero concentration. For example, if you zero a **CO_2** analyzer using ambient air, you may use the default ambient air concentration of **CO_2**, which is 375 <<mu>>mol/mol. In this ...

652. 40 C.F.R. § 1065.675 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART G--CALCULATIONS AND DATA REQUIREMENTS § 1065.675 CLD quench verification calculations.

...(b) Estimate the expected amount of water and **CO_2** in the exhaust you sample, xH2Oexp and xCO2exp, respectively, by considering the maximum expected amounts of water in combustion air, ...

... applicable). xH2Omeas = measured amount of water entering the CLD sample port during the quench verification specified in § 1065.370. xNO,**CO2** = measured concentration of NO when NO span gas is blended with **CO_2** span gas, according to § 1065.370. xNO,N2 ...

...xCO2exp = expected maximum amount of **CO_2** entering the CLD sample port during emission testing. xCO2meas = measured amount of **CO_2** entering the CLD sample port during ...

653. C 40 C.F.R. § 1065.715 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART H--ENGINE FLUIDS, TEST FUELS, ANALYTICAL GASES AND OTHER CALIBRATION STANDARDS § 1065.715 Natural gas.

... mol/mol. 6. C6 and higher .... Maximum, 0.001 mol/mol. 7. Oxygen .... Maximum, 0.001 mol/mol. 8. Inert gases (sum of **CO_2** and N_2) .... Maximum, 0.051 mol/mol. ———————————————— [FN1] All parameters are based on the reference procedures in ASTM D 1945-03 ...

654. 40 C.F.R. § 1065.715 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART H--ENGINE FLUIDS, TEST FUELS, ANALYTICAL GASES AND OTHER CALIBRATION STANDARDS § 1065.715 Natural gas.

... . Maximum, 0.0013 mol/mol. C6 and higher .... Maximum, 0.001 mol/mol. Oxygen .... Maximum, 0.001 mol/mol. Inert gases (sum of **CO_2** and N_2) Maximum, 0.051 mol/mol. ———————————————— [FN1] All parameters are based on the reference procedures in ASTM D1945-03 (incorporated by ...

655. **C** 40 C.F.R. § 1065.750 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART H--ENGINE FLUIDS, TEST FUELS, ANALYTICAL GASES AND OTHER CALIBRATION STANDARDS § 1065.750 Analytical gases.

... [FN1] ———————————————————— THC (C1 equivalent) .. <0.05 <<mu>>mol/mol.......... < 0.05 <<mu>>mol/mol CO .... <1 <<mu>>mol/mol .... < 1 <<mu>>mol/mol **CO2** .... < 10 <<mu>>mol/mol .... < 10 <<mu>>mol/mol O2 .... 0.205 to 0.215 mol/mol .. < 2 <<mu>>mol/mol NOX ....

... <<mu>>mol/mol FN1 We do not require these levels of purity to be NIST-traceable. ———————————————————— (iv) CO, balance purified N2. (v) **CO2**, balance purified N2. (vi) NO, balance purified N2. (vii) NO2, balance purified N2. (viii) O2, balance purified N2. ...

...(ix) C3 H8, CO, **CO2**, NO, balance purified N2. (x) C3 H8, CH4, CO, **CO2**, NO, balance purified N2. (4) You may use gases for ...

656. 40 C.F.R. § 1065.750 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART H--ENGINE FLUIDS, TEST FUELS, ANALYTICAL GASES AND OTHER CALIBRATION STANDARDS § 1065.750 Analytical gases.

... THC (C1 equivalent) .. < 0.05 <<mu>>mol/mol .... < 0.05 <<mu>>mol/mol. CO .... < 1 <<mu>>mol/mol .... < 1 <<mu>>mol/mol. **CO2** .... < 10 <<mu>>mol/mol .... < 10 <<mu>>mol/mol. O2 .... 0.205 to 0.215 mol/mol .... < 2 <<mu>>mol/mol. NOX ....

... <<mu>>mol/mol. ———————————————————— [FN1] We do not require these levels of purity to be NIST-traceable. (iv) CO, balance purified N2. (v) **CO2**, balance purified N2. (vi) NO, balance purified N2. (vii) NO2, balance purified synthetic air. (viii) O2, balance purified N2. ...

...(ix) C3H8, CO, **CO2**, NO, balance purified N2. (x) C3H8, CH4, CO, **CO2**, NO, balance purified N2. (4) You may use gases for species ...

657. **C** 40 C.F.R. § 1065.1005 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART K--DEFINITIONS AND OTHER REFERENCE INFORMATION § 1065.1005 Symbols, abbreviations, acronyms, and units of measure.

... carbon. CH4 ...... methane. C2H6 ... ethane. C3H8 ... propane. C4H10 .. butane C5H12 .. pentane. CO .... carbon monoxide. **CO2 ...... carbon dioxide.** H .... atomic hydrogen H2 .... molecular hydrogen. H2O ...... water. He .... helium. ^{85}Kr ..... krypton 85. N2 ....

... 0.00934 xCO2air .. amount of **carbon dioxide** in dry air 0.000375 xN2air ... amount of nitrogen in dry air ...

... 28.0101 MCO2 ...... molar mass of **carbon dioxide** 44.0095 MH .... molar mass of atomic hydrogen ...

658. 40 C.F.R. § 1065.1005 CODE OF FEDERAL REGULATIONS TITLE 40--PROTECTION OF ENVIRONMENT CHAPTER I--ENVIRONMENTAL PROTECTION AGENCY SUBCHAPTER U--AIR POLLUTION CONTROLS PART 1065--ENGINE-TESTING PROCEDURES SUBPART K--DEFINITIONS AND OTHER REFERENCE INFORMATION § 1065.1005 Symbols, abbreviations, acronyms, and units of measure.

... carbon. CH4 ...... methane. C2H6 ... ethane. C3H8 ... propane. C4H10 .. butane C5H12 .. pentane. CO .... carbon monoxide. **CO2 ...... carbon dioxide.** H .... atomic hydrogen H2 .... molecular hydrogen. H2O ...... water. He .... helium. ^{85}Kr ..... krypton 85. N2 ....

... 0.00934 xCO2air .. amount of **carbon dioxide** in dry air 0.000375 xN2air ... amount of nitrogen in dry air ...

... 28.0101 MCO2 ...... molar mass of **carbon dioxide** 44.0095 MH .... molar mass of atomic hydrogen ...

ATTACHMENT B

Additional Statement of Basis

Draft Federal "Prevention of Significant Deterioration" Permit

Russell City Energy Center

Bay Area Air Quality Management District
Application Number 15487

August 3, 2009

Draft Federal PSD Permit
Additional Statement of Basis and
Solicitation of Further Public Comment
For the Proposed Russell City Energy Center

August 3, 2009

The Bay Area Air Quality Management District ("Air District") is revising its draft Federal PSD Permit for the proposed Russell City Energy Center based on new information received since the initial draft was published in December of 2008. Pursuant to 40 C.F.R. section 124.14(b), the Air District is incorporating this new information into this Federal PSD permit proceeding by:

(1) Issuing a revised draft permit with certain modifications to address new information under 40 C.F.R. section 124.6;

(2) Issuing an additional "Statement of Basis" for the draft permit under 40 C.F.R. sections 124.7 and 124.8[1]; and

(3) Reopening the comment period under 40 C.F.R. section 124.10 to give interested persons an opportunity to comment on the new information and the District's proposed treatment of it; and to give interested persons an opportunity to submit any further comments that they could not reasonably have submitted during the initial comment period.

This document contains the revised draft Federal PSD Permit conditions and the District's Additional Statement of Basis supporting them. The purpose of this Additional Statement of Basis is to briefly set forth additional facts and further factual, legal, methodological and policy questions that the Air District has considered regarding the draft permit since the initial Statement of Basis was issued. The document briefly describes the derivation of the current revisions to the draft permit conditions and the reasons for them. The Additional Statement of Basis provides further documentation regarding the Air District's proposed decision to issue the Federal PSD Permit in order to provide the public a further opportunity to comment on it. The Air District has prepared this Additional Statement of Basis because it has undertaken additional analysis and consideration regarding this proposed project since the initial Statement of Basis was issued. This additional analysis and consideration was undertaken for several reasons, including recent changes in the Federal PSD regulatory environment, additional factual information that has become available since the initial Statement of Basis was prepared, insightful comments received from members of the public during the initial comment period, and further discussions with the project applicant. The Air District believes that this additional analysis and consideration, as well as the revised draft permit conditions that have come out of it, will result in an improved permit.

[1] As with the initial Statement of Basis, the Air District calls this document a "Statement of Basis", but has prepared it in accordance with all of the comprehensive requirements for documenting the agency's analysis contained in 40 C.F.R. Sections 124.7 (statement of basis) and 124.8 (fact sheet). *See* Statement of Basis, p. 3 fn. 1, for further discussion.

The Air District invites all interested members of the public to review the Revised Draft Federal PSD Permit and Additional Statement of Basis and submit comments on the issues raised in them. To assist the public in doing so, the Air District is making a number of materials available so that the public may review them and learn more about the proposed permit. This Additional Statement of Basis, the initial Statement of Basis published in December of 2008, the revised proposed permit conditions, the initial permit application and all subsequent data and information submitted by the applicant, and all other materials supporting the Air District's proposal to issue the Federal PSD Permit are available for public inspection at the Outreach and Incentives Division Office located on the 5th Floor of District Headquarters, 939 Ellis Street, San Francisco, CA, 94109. The Additional Statement of Basis and revised proposed permit conditions, as well as the initial Statement of Basis and initial proposed permit conditions, are also available on the District's website at www.baaqmd.gov. The public may also contact Weyman Lee, P.E., Senior Air Quality Engineer, Bay Area Air Quality Management District, 939 Ellis Street, San Francisco, CA, 94109, (415) 749-4796, weyman@baaqmd.gov, for further information. **Para obtener la información en español, comuníquese con Brenda Cabral en la sede del Distrito, (415) 749-4686, bcabral@baaqmd.gov.**

The Air District invites all interested members of the public to submit written and/or oral comment on any issues raised by this revised Draft Federal PSD Permit and Additional Statement of Basis. Written comment should be directed to Weyman Lee at the contact address provided above, and must be received by September 16, 2009. Oral comments may be submitted at the public hearing the Air District will be holding for this project. The public hearing will be held at Hayward City Hall, 777 B Street, Hayward, CA, 94541, on Wednesday, September 2, 2009, from 6:30 to 9:00 pm. Air District staff will be available from 6:00 to 6:30 to discuss the project informally and answer questions.

The Air District also invites all interested members of the public to submit written and/or oral comment on any issues regarding the initial draft permit and statement of basis that were published in December of 2008 that members of the public were not able to comment on during the initial comment period (which closed on February 6, 2009). To the extent that members of the public have comments regarding the initial draft permit and statement of basis that they could not reasonably have made during the initial comment period (for example, because of evidence or information that was not reasonably ascertainable during the initial comment period, because of changes in regulatory requirements since that time, *etc.*), the Air District invites them to be submitted during this additional comment period (either in writing addressed to Mr. Lee or orally at the public hearing) so that the Air District can consider them before making a final decision on the proposed permit.

Members of the public who submitted comments during the initial comment period on the initial draft permit and statement of basis **do not** need to re-submit their comments to the Air District. The Air District has taken all comments previously received during the comment period under consideration and will consider and respond to them before making a final decision on the proposed permit. Persons who submitted comments earlier may of course provide additional comments during the current comment period on any relevant issues.

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ADDITIONAL STATEMENT OF BASIS

The Air District's additional analysis and consideration of the Federal PSD requirements as they apply to the proposed Russell City Energy Center are described in this section. This additional analysis builds on and refines the analysis set forth in the initial Statement of Basis issued in December of 2008, which is incorporated herein by reference. The draft PSD Permit conditions based on this analysis are set forth at the end of this document.

I. PROPOSAL TO ISSUE FEDERAL PSD PERMIT FOR RUSSELL CITY ENERGY CENTER

At the outset, the Air District wishes to clarify that it is now proposing to issue a new Federal PSD Permit for the Russell City Energy Center, not an amendment to an existing Federal PSD Permit as the District originally proposed. The Air District has reviewed the permitting record since it issued its original proposal in light of comments received during the initial comment period. Based on this review, the District has concluded that when the facility was initially permitted in 2002, the District did not issue a final Federal PSD Permit along with its state-law Authority to Construct, as is the District's normal practice. The record indicates that the District did not finalize the Federal PSD Permit at the time it issued the Authority to Construct because EPA Region 9 had not completed its Endangered Species Act consultation with the US Fish & Wildlife Service. The project applicant subsequently withdrew its plans to build the facility at the original location, however, and so the consultation was never finalized and the Federal PSD Permit was never issued.

The Air District is therefore revising its initial proposal to issue an "Amended Federal PSD Permit". The Air District is now proposing to issue a new Federal PSD Permit for this facility, since no final PSD Permit has yet been issued. The Air District has reviewed its analysis in the initial Statement of Basis and has concluded that this analysis supports the issuance of all elements of the permit as a new permit, because the Air District treated the facility's permit application, in substance, as an application for a new permit rather than as an application for an amendment. In evaluating the project for compliance with Federal PSD requirements, the Air District did not rely in any way on the analysis prepared for the initial permit. To the contrary, the Air District made clear in the Statement of Basis that it was evaluating the entire project for compliance with the Federal PSD requirements, not just elements that were changing since the initial permitting. As the Air District explained in the Statement of Basis, it analyzed both the amendments to the proposed project as well as the elements that were not being changed, and concluded "[t]he analysis of the elements that are not being amended shows that the conditions from the initial permit that are not being changed meet current applicable legal standard for Federal PSD Permit, and that they would *comply with current PSD requirements even if they were being proposed anew at this time*." (Statement of Basis at p. 7 (emphasis added).) The detailed analyses provided in the Statement of Basis support this conclusion. The Air District evaluated all of the equipment at the project from scratch to ensure that it meets current BACT standards as is required for a new permit application. The District similarly conducted an Air Quality Impacts Analysis (and related analyses) from scratch for the entire project, using the most current information and modeling techniques, as is required for a new project. Those analyses, along with the additional review and analysis described in this document, fully support the issuance of a new Federal PSD Permit as the District is now proposing to do.

The Air District provides this discussion to clarify in the record at this point that it is proposing to issue a new permit, not an amendment to an existing PSD permit. To the extent that there were any issues involving the District's proposal that any members of the public refrained from commenting on during the initial comment period because they understood the proposed permit to be an amendment and not a new permit, the Air District invites the public to submit any such comments for the District's consideration at this time.

II. ISSUES REGARDING THE POWER GENERATION EQUIPMENT PROPOSED FOR THIS FACILITY

The Air District has conducted further analysis regarding the electrical generating equipment that the applicant proposes to use at the Russell City Energy Center and whether it is appropriate for this facility under the Federal PSD regulations. These issues are discussed below.

A. Currentness of Combustion Turbine Technology

The District received a number of comments regarding the type of electrical generating equipment the applicant intends to use at the Russell City Energy Center, and in particular whether it will be the cleanest and most efficient equipment consistent with the Best Available Control Technology requirements of the Federal PSD permitting program. Some of these comments stated that the Air District incorrectly based its BACT analysis for the combustion turbines/heat recovery boilers on the equipment that the applicant has already purchased and intends to use at the facility. Some comments questioned whether other equipment besides what the applicant intends to use for the project would be able to achieve lower emission rates. Although many of these comments were specific to emissions of individual PSD-regulated pollutants (or potentially PSD-regulated pollutants such as greenhouse gases), a number of them were directed at whether alternative equipment might be cleaner and more efficient in general. In response to these comments, the Air District explored whether there was more efficient generating equipment that the facility could use.

The Air District has identified "FD3" turbine technology as the current state-of-the-art electrical generating equipment for a facility of this type, as outlined in detail in Section III below. FD3 turbine technology would allow the facility to achieve an overall thermal efficiency of 56.4% (lower heating value), which is the highest efficiency of any similar plant that the Air District reviewed. This FD3 technology is slightly more efficient than the "FD2" technology that the applicant originally proposed. After further discussions with the project applicant, the applicant has agreed to upgrade its equipment to incorporate the more modern FD3 technology. These FD3 upgrades will result in an improvement in the thermal performance of the gas turbines, resulting in a slightly higher efficiency for the plant as a whole. That is, they will result in a reduction in the plant's "heat rate", which is the amount of fuel required to produce a megawatt (MW) of electricity, making the gas turbine's efficiency comparable to the best F-Class turbines available on the market today. The Air District is basing its BACT determinations on this state-of-the-art technology, not on the FD2 technology used in the turbines that the applicant originally proposed.

The FD3 upgrades will consist of decreasing the clearances in the compressor section of the turbine, adjusting the inlet guide vanes and optimizing the control system components. More specifically, the upgrades will include the following:

- The inlet guide vanes will be opened more to increase airflow.
- The existing compressor row 7-15 diaphragm inter-stage labyrinth seal holders will be replaced with honeycomb seals.

- The compressor row 16 blades will be replaced with a new design.
- The gas turbine row 1 blades will be replaced with a new design.
- The gas turbine row 1 ring segments and isolation rings will be replaced with a new improved design.
- The gas turbine row 2 seal housing will be replaced with a new rope seal.
- The gas turbine rows 2 and 3 vane sealing will be enhanced.
- The gas turbine row 4 blade ring assembly, consisting of blade rings, vanes, ring segments and inter-stage seal housing will be replaced with a new design.
- The gas turbine row 4 blades will be replaced with a new design.
- The existing exhaust cylinder will be replaced.

The Applicant will also implement operational and maintenance changes recommended by the original equipment manufacturer to improve performance, reliability and maintainability of the equipment. In addition, the Applicant will replace the control system with Siemens' latest control technology, known as the "T-3000" system.[2]

With these upgrades, the turbines the applicant has already purchased will, for all emissions performance purposes, be the equivalent of FD3 turbines commercially available today. These upgrades will increase the plant's overall efficiency, such that the rate of emissions per unit of energy produced will be reduced, which will allow the facility to meet a BACT standard set by the emissions rate achievable by FD3 turbines. Based on this FD3 technology, the facility will be able to achieve a thermal efficiency of 56.4%, which is the highest efficiency of any similar plant the Air District reviewed. This highly efficient technology will generate fewer emissions for a given amount of power generation than any other similar facility. The Air District is basing its proposed BACT permit conditions on this current technology.[3]

Furthermore, to clarify the record on this issue, Air District notes that it is basing its proposed BACT permit conditions on the emissions performance of this FD3-level technology, but is not proposing permit requirements specifying exactly what equipment must be used to satisfy the applicable BACT permit limits. BACT requires emission limits to be imposed based on the best emissions performance achievable by current state-of-the-art technology, but once the BACT limits are established based on this technology as the Air District is proposing, the specific

[2] *See* Email Memorandum re "RCEC: GHGs BACT Analysis Technical Documentation", from K. Poloncarz, Calpine Counsel, to A. Crockett, BAAQMD, April 2, 2009.

[3] The BACT analyses for certain specific pollutants and/or specific operating scenarios depend on other factors such as the availability of add-on controls, *etc.* But to the extent that emissions performance is linked to turbine efficiency, the emissions performance from these FD3-equivalent turbines will be the lowest achievable because FD3 turbines are the most efficient for this type of application. The gist of the comments the Air District received regarding turbine efficiency were primarily directed at greenhouse gases (to the extent that these are regulated NSR pollutants subject to BACT), but this same analysis holds true for the other pollutants, which are also dependent to some extent on turbine efficiency (*i.e.*, how much power can be generated for a given amount of fuel).

equipment the facility uses to achieve that limitation is irrelevant. As long as the facility keeps emissions within the BACT emission standards, it does not matter what particular choice of equipment the facility uses to do so. Certainly, from an environmental standpoint the choice is irrelevant because it is the emissions that impact air quality not the make or model of the equipment that generates them. If the applicant can meet current emission standards by upgrading existing equipment, there may be significant benefits to be gained, such as avoiding the costs of purchasing new equipment that would ultimately be borne by ratepayers and avoiding the waste inherent in junking serviceable equipment. But how the applicant meets current emission standards is up to the applicant. What matters from an air quality perspective – and what matters for purposes of the Federal PSD Permit requirements – is whether the limits established in the permit reflect the maximum emission reductions achievable for the source using current technology. As demonstrated in the Air District's BACT analyses (as set forth in more detail in the rest of this document), the limits the District is imposing on this facility are all based on current technology. Since the limits that the facility will be subject to are based on current technology, issues such as the date of manufacture or purchase of the specific equipment the applicant may choose to install are not relevant for purposes of the Federal PSD Permit.

B. Use of Duct Burners to Generate Additional Power

The District also received comments asserting that the proposed design of using duct burners to generate additional steam to power the steam turbine is not the most efficient method to generate additional power to meet peak demand. These comments asserted that duct burners are inefficient and reduce the fuel efficiency (and thus increase the air emissions) of the facility. They stated that the Air District should have considered alternatives to duct burners, such as simple-cycle turbines or solar alternatives, to meet peak load demand. In light of these comments, the Air District has considered further whether the use of duct burners satisfies the BACT requirement.

Upon further consideration, the District has concluded that there are no more efficient alternatives that would meet the power generation needs for which this facility was designed. The facility is designed to meet a maximum power demand of nominally 600 megawatts, but a 2x1 combined-cycle facility without duct burning can meet a nominal demand of only 550 megawatts.[4] Duct burning is an efficient way of generating additional power to meet peak demand from the combustion turbine exhaust. Duct burning involves burning additional natural gas in the ducts to the heat recovery boiler, which increases the temperature of the exhaust coming from the combustion turbines and thereby creates additional steam for the steam turbine.

[4] Combustion turbines come only in discrete size classes, and so it is not always possible to design a facility to meet the demand called for using turbines alone. Where it is not possible, some way of making up the additional capacity must be used. (Note that these are nominal capacities; actual power output from a specific facility at any given time depends on a large number of design and operational variables.) The facility's design capacity cannot be achieved here by use of a 2x1 turbine configuration alone without some additional peak power.

In response to these comments, the Air District evaluated whether the additional peak capacity could be more efficiently provided by other technologies besides duct burning.[5]

The Air District first evaluated the alternative of replacing the duct burners with simple-cycle generating technology (*i.e.*, "peaker" turbines) that could generate approximately the same amount of energy during peak demand periods. Simple-cycle turbines would not be more efficient than duct burning here, however. To the contrary, simple-cycle turbines of similar capacity would have a higher heat rate (i.e., take more fuel to produce a unit of power) than duct burning. The incremental additional heat rate using duct burning to generate peak capacity (rated at 46.3 MW) is 7,595 Btu/kWhr (LHV).[6] In comparison, a basic GE LM6000 gas turbine generator set, rated at 42.3 megawatts, would have a heat rate of 8,308 Btu/kWh (LHV); with additional features, a GE LM6000 Sprint ("Spray-Intercooled Turbine"), rated at 46.9 megawatts, would have a heat rate of 8,235 Btu/kWh (LHV).[7] Duct firing will therefore be a more efficient method of generating peak capacity than installation of the most efficient form of simple-cycle generation capacity the Air District is aware of. The Air District therefore concludes that the use of a simple-cycle turbine would not provide any advantage over duct burning.

Moreover, even if it were not for the superior performance of Russell City Energy Center's duct burners in comparison to an LM6000, replacement of duct burners with a separate simple-cycle unit would likely be eliminated from consideration as BACT based upon the significantly greater cost and ancillary environmental impacts. According to a report prepared by the California Energy Commission, the cost to replace the proposed Russell City Energy Center's peaking capacity with a simple cycle plant would be approximately $507.98 per MWhr for an investor-owned utility (IOU) plant or $647.28 per MWhr for a "merchant" plant.[8] In contrast, the total estimated cost for a 550-MW combined cycle plant with duct firing is approximately $95.59 or $103.52 per MWhr for an IOU or merchant plant, respectively;[9] whereas the cost for a combined cycle facility without duct firing is estimated for an IOU and merchant plant at $94.47 or $102.19 per MWhr, respectively.[10] In light of these estimates, the marginal cost associated with duct firing at a facility like the proposed Russell City Energy Center would appear substantially more favorable than the cost to replace its peak capacity with a separate simple-cycle unit. The Air District therefore concludes the cost of requiring simple-cycle peak power generation would be obviously excessive, and thus would not be required as BACT for this additional reason as well.

The Air District also examined the potential for using solar thermal technology as an alternative to using duct burners in response to this comment. The Air District reviewed the approach taken with the proposed Victorville 2 Hybrid Power Project, which utilizes solar technology to eliminate some of the need for duct burning to address peak demand. The Victorville Project will be a 570-MW facility located in the Mojave Desert and will consist of natural gas-fired, combined-cycle generating equipment integrated with solar thermal generating equipment. The solar thermal component of the Victorville "hybrid" Project will consist of a series of diurnal, single-axis-tracking parabolic trough solar collectors laid out in parallel rows aligned on a north-south horizontal axis. Each solar collector will track the sun from east to west to assure that it continuously reflects the greatest amount of sunlight possible onto a "linear receiver", which contains a heat transfer fluid that circulates through the receiver and returns to a series of heat exchangers, where it is used to generate high-pressure steam for two heat recovery steam generators (HRSGs). The solar thermal input is intended to provide approximately 10% of the power generated by the facility during peak periods. Use of solar thermal equipment is projected to increase the overall thermal efficiency of the combined-cycle plant from 52.7% to 59% (LHV) because it would allow the facility to reduce firing of the duct burners during peak periods and replace that peak capacity with the input from the solar thermal generating equipment.[11] In comparison to Victorville's 59% efficiency rating (LHV) during such periods, the Russell City Energy Center's efficiency rating would be 56.44% (LHV) during periods of duct burning.[12]

A solar alternative to duct burning would not be feasible for the Russell City facility, however, because there is far less available area at the project than in the Mojave Desert, and the compact site would not provide adequate space for installation of a solar collectors. To construct a solar thermal plant to replace some of the peak capacity from duct burning would need 275 acres of

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[5] It is not clear whether the BACT analysis requires a consideration of alternatives to duct firing to meet peak capacity demand. The BACT analysis is not intended to require the applicant to change its design from construction of a combined cycle to simple cycle facility or to eliminate and replace key elements of its design with different sources. (*See, e.g., In re Kendall New Century Development*, PSD Appeal No. 03-01, 11 E.A.D. 40, 51-52 (EAB 2003) (finding that, in identifying BACT for a proposed peaking generating facility, the permitting authority "does not have authority to require [the Applicant] to construct a facility with larger combustion units or one that would run in combined-cycle mode since this would change the intended nature of the Facility"); *see also In re Prairie State Generating Co.*, *supra* note 5, slip op. at 32 (referencing the EAB's recognition in *In re Kendall New Century Development* that "it [is] appropriate for the permitting authority to distinguish between electric generating stations designed to function as 'base load' facilities and those designed to function as 'peaking' facilities, and that this distinction affects how the facility is designed and the pollutant emissions control equipment that can be effectively used by the facility").) This issue is moot here, however, as the Air District has concluded that there are no superior alternatives even if such an analysis were required.

[6] *See* Russell City Energy Center Heat Balance Diagrams.

[7] GE Aero Energy Products, brochure, LM6000 SPRINT™ Gas Turbine Generator Set, available at: www.gepower.com/prod_serv/products/aero_turbines/en/downloads/lm6000_sprint.pdf.

[8] California Energy Commission, *Comparative Costs of California Central Station Electricity Generation Technologies*, Final Staff Report, December 2007, CEC-200-2007-011-SF, at pp. 10, 12; available at: www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SF.PDF. An LM6000 is the equivalent of "Small Simple Cycle" (50 MW) in the Energy Commission's report. Dollar figures are given in nominal 2007 dollars.

[9] *Id.* at p. 12.

[10] *Id.* at p. 10.

[11] City of Victorville, *Application for Certification, Victorville 2 Hybrid Power Project*, February 28, 2007, at 2.1-2.14; available at www.energy.ca.gov/sitingcases/victorville2/documents/applicant/afc/ (hereinafter, "Victorville 2 Application"). Again, it is not clear that the BACT requirement is intended to involve replacement of duct firing to meet peak capacity demand with a completely different type of facility design, but that issue is moot because the Air District has found that solar peaking capacity would not be feasible here.

[12] *See* Table, Comparison of FD3 Turbines with and without duct burner firing, prepared by Alex Prusi, P.E., Director of Engineering, Calpine, April 2, 2009.

land,[13] which would not be feasible given the space-constrained project site on the edge of the San Francisco Bay.[14] Redesigning the project to incorporate a solar system like Victorville's would therefore require the facility to be moved to another location, making it impossible to achieve the project objectives served by the current location, which include "[t]o locate near centers of demand and key infrastructure, such as transmission line interconnections, supplies of process water (preferably wastewater), and natural gas at competitive prices",[15] and "[t]o serve the electrical power needs of the East Bay, San Francisco Peninsula, and City of San Francisco."[16] Requiring additional space to build a solar system would also eliminate the environmental benefits of locating adjacent to the City of Hayward's waste water treatment plant so the facility can recycle approximately 4 million gallons per day of effluent from the plant and eliminate discharges of that waste water to the San Francisco Bay, and of locating at a previously-developed brownfield site. For these reasons, the Air District has found that thermal solar peaking capacity is not an available alternative to reduce the facility's use of duct burning to generate peak capacity.

The Air District therefore concludes that none of these alternative methods to generate the additional peak capacity needed to meet the facility's design load would be required under a BACT analysis for this facility, even if one were required.

C. Design of Facility for Intermediate-to-Baseload Service

The District also received comments noting that the facility would be operated to meet contractual load and spot sale demand, and may not operate on a full-time, base-loaded basis. These comments questioned the anticipated operating mode of the proposed Russell City Energy Center, suggesting that if it were intended for load-following or other duty that would involve frequent startup and shutdown events, the Applicant should be required to construct a fast-start-capable, peaking-to-intermediate duty plant instead.

The Air District has considered this issue further in light of these comments. The Air District notes that the Federal PSD Permit process is designed to ensure that a proposed facility will be as low-emitting as possible (among other requirements). It is not designed to require an applicant to propose a different type of project of a different fundamental scope and design, for example to substitute a simple-cycle peaking plant instead of a combined-cycle intermediate-to-baseload

[13] *See* Victorville 2 Application, *supra* note 11, at pp. 2-3.

[14] The project site for the Russell City Energy Center is a 14.7-acre area located in the West Industrial District of Hayward, California, adjacent to the City of Hayward Water Pollution Control Facility and near existing transmission facilities. *See* Calpine, *Application for Certification, Russell City Energy Center* (May 2001) (hereinafter, "RCEC Application for Certification"), at 9-3 – 9-4; available at: www.energy.ca.gov/sitingcases/russellcity/documents/applicant_files/afc/vol-1/.

[15] California Energy Commission, *Commission Decision, Russell City Energy Center* (July 2002, P800-02-007) (hereinafter, "2002 Energy Commission Decision"), pp. 17 (available at: www.energy.ca.gov/sitingcases/russellcity/index.html).

[16] RCEC Application for Certification, *supra* note 14, at pp. 9-1 – 9-2.

project as the commenters suggest here.[17] Moreover, it would not make any sense from an emissions standpoint to require a simple-cycle facility for the purpose that this facility is intended to be used for, which is to serve intermediate-to-baseload capacity. Simple-cycle facilities are less efficient than combined-cycle facilities, which recover the heat from the turbine exhaust (which would simply be emitted and wasted in a simple-cycle facility) and use it to generate additional electricity. Simple-cycle facilities are therefore generally inferior to combined-cycle facilities, except for applications where the generating capacity must come on-line in a very short time frame, which is not the case with the uses for which this facility has been proposed and designed. The Air District therefore disagrees that it should require the applicant to redesign the facility as a simple-cycle peaking facility.

D. <u>Source of Emissions Estimates</u>

Some commenters also criticized the Air District for relying on emissions estimates from the project applicant and from the CEC in its explanation of the emissions from the project. The Air District believes that the project applicant and the CEC are among the best sources of information about potential emissions from the facility based on their detailed knowledge and understanding of the proposed project and the type of operation involved. Moreover, the Air District has not seen any suggestion that any of the emissions estimates the Air District relied on may be unreliable in any way, or that there may be alternative sources of emissions estimates that it should consider instead. And in any event, the Air District is proposing to turn the emissions estimates into enforceable emissions limits in the PSD permit, along with monitoring and recordkeeping requirements to ensure that actual emissions stay below these limits. Thus, if the underlying estimates turn out to be inaccurate and actual emissions exceed the estimates as they have been incorporated into the permit limits, the facility will be in violation of its permit and will have to shut down or curtail operations unless it can fix whatever problems are causing the increased emissions. For all of these reasons, the Air District disagrees that it is inappropriate to consider emissions estimates from the project applicant or from the CEC in its permitting analysis. In light of this reasoning, if any members of the public believe that there are alternative sources of emissions information that would be relevant to the PSD permitting process for this facility, the Air District seeks input on what those sources of information may be and how they may be relevant.

E. <u>Specific Turbine Information</u>

Finally, the District also received some comments asking for detailed information about the combustion turbines the applicant intends to use at the facility, such as turbine serial numbers, dates of manufacture, cost, *etc.* But specific details such as these are not relevant to determining the Best Available Control Technology and applicable permit limits for this equipment or for analyzing the potential air quality impacts of the facility, and so the Air District has not sought such information from Calpine. For example, if the Air District determines that a certain type of turbine technology is BACT and imposes a BACT permit limit based on the achievable

[17] This principle has been well established by the Environmental Appeals Board in reviewing PSD permits. *See, e.g., In re Prairie State Generating Co.*, *supra* note 5, slip op. at 32; *In re Kendall New Century Development*, *supra* note 5, at 51-52.

emissions performance for that turbine technology, it makes no difference which particular turbine is used (*e.g.*, which particular serial number) as long as the facility complies with the applicable permit conditions. The Air District therefore disagrees that such specific information about individual pieces of equipment is relevant to the Federal PSD Permitting analysis. To the extent that information about particular types of turbine technologies is relevant (*e.g.*, costs, ancillary environmental or energy impacts, relative efficiency, achievable emissions performance standards, *etc.*) the Air District has sought that information and provided it in the relevant sections of its permitting analysis. To the extent that members of the public believe that additional information would be relevant to the PSD Permitting analysis, the District solicits further comment on how it could be relevant and how it could impact the PSD permit process.

III. GREENHOUSE GAS EMISSIONS

Since the Air District initially prepared its voluntary Greenhouse Gas BACT analysis in December of 2008, it has substantially revised the analysis based on the many insightful comments it received and on additional analysis by District staff and submissions by the Applicant. The Air District's revisions to its voluntary Greenhouse Gas BACT analysis are described in detail below. The corresponding proposed permit conditions are included in the Draft Federal PSD permit conditions at the end of this document, based on the applicant's agreement to be subject to greenhouse gas BACT limits despite the lack of guidance from EPA that BACT limits are required under its PSD regulations.

A. Applicability Of PSD Permit Requirements To Greenhouse Gas Emissions

In the Statement of Basis, the Air District noted that the status of greenhouse gas regulation is not as well developed at the federal level, particularly under the federal PSD permitting program. This continues to be the case, although there have been several additional developments since the Air District published its initial proposal. A number of commenters claimed that these recent developments make greenhouse gases "subject to regulation" under the Clean Air Act, and that as a result they must be subject to PSD Permitting. The Air District is therefore recounting these developments in this Additional Statement of Basis to clarify the record on whether the Federal PSD regulations require consideration of Greenhouse Gases. Ultimately, however, whether PSD review of greenhouse gases is required under the Federal PSD permit program is a moot issue in this case, as the applicant has agreed voluntarily to subject itself to PSD review regardless of whether it is legally required or not.

As the Air District noted in the Statement of Basis, EPA's Environmental Appeals Board found in November of 2008 in the *Deseret Power* case that EPA as an agency has the discretion to determine whether greenhouse gases should be subject to PSD regulation or not, but had not at that time adopted any definitive policy position on the issue.[18] The EAB also suggested that it may be more appropriate for EPA to address this issue through a nationwide rulemaking, rather than through individual case-by-case PSD permitting decisions. The issue was thus in a highly unresolved state when the Air District issued its initial proposal on December 8, 2008. Then, on December 18, 2008, EPA issued a policy memorandum in response to the EAB's *Deseret Power* opinion. The impact of EPA's December 18 memorandum is that EPA is not requiring greenhouse gases to be regulated under the Federal PSD permitting program (at least not at this time).[19] The Sierra Club then petitioned for reconsideration of the December 18, 2008, memorandum claiming that it was an unlawful interpretation of the Federal PSD permit

[18] *See In re Deseret Power Electric Cooperative*, PSD Appeal No. 07-03, slip op. at 63-65 (EAB Nov. 13, 2008).

[19] *See* Memorandum, Stephen L. Johnson, Administrator, *EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Permit Program*, December 18, 2008; notice provided at 73 Fed. Reg. 80300 (Dec. 31, 2008).

requirements, and on February 17, 2009, EPA granted the petition for reconsideration.[20] As a consequence, EPA is now reconsidering whether greenhouse gases are subject to Federal PSD permit requirements, and will be soliciting public comment on the issue. As EPA explained in its February 17, 2009, letter, "PSD permitting authorities should not assume that the [December 18, 2008] memorandum is the final word on the appropriate interpretation of Clean Air Act requirements." EPA declined to stay the effectiveness of the December 18, 2008, memorandum, however, and so that memorandum remains in effect as EPA policy for the time being.

Greenhouse gases are therefore currently not subject to Federal PSD Permit review pursuant to the December 18, 2008, memorandum because the memorandum has not been stayed. EPA has indicated that this interpretation is not necessarily "the final word" on the issue, however, and so greenhouse gases may become subject to Federal PSD permit requirements at some point in the future. The project applicant has therefore voluntarily agreed to go forward with the Air District's proposal to impose BACT permit limits on greenhouse gas emissions, so that the permit will satisfy PSD requirements for greenhouse gases in the event that they become subject to regulation in the future.

Several comments also stated that the Air District should impose greenhouse gas limits in the Federal PSD Permit under various authorities in California law. The District disagrees that it could impose greenhouse gas conditions under California law (or any other state-law conditions) in a federal PSD permit. It is certainly true that greenhouse gas issues are the subject of various California statutes and are being addressed by various California regulatory agencies, including the Air District, but that does not mean that the District can impose permit conditions under California law in a federal permit issued on behalf of the federal EPA.

Furthermore, the District also disagrees with assertions by certain commenters that the U.S. Supreme Court's decision in *Massachusetts v. EPA* means that greenhouse gases are "subject to regulation" under the Federal Clean Air Act. That case determined that greenhouse gases are within the definition of "air pollutant" as used in the Clean Air Act; it did not address the question of whether greenhouse gases are pollutants that are "subject to regulation" under the Clean Air Act.[21] Similarly, the Air District also disagrees that EPA's recent proposal to make a finding that greenhouse gases endanger public health and welfare[22] means that greenhouse gases are "subject to regulation". That proposal is not yet final, and even if EPA does finalize it as proposed the finding will not establish that greenhouse gases are subject to regulation under the PSD program. As EPA made clear in the proposal, that question will be answered in the reconsideration of the December 18, 2008, memorandum.[23]

[20] *See* Letter, Lisa P. Jackson to David Bookbinder, February 17, 2009, available at: www.epa.gov/air/nsr/documents/ 20090217LPJlettertosierraclub.pdf.
[21] *See generally In re: Christian County Generation, LLC*, PSD Appeal No. 07-01, 13 E.A.D. __, slip op. at 7 n. 12 (EAB Jan. 28, 2008).
[22] *See* Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act, US EPA (April 17, 2009), available at epa.gov/ climatechange/endangerment/downloads/GHGEndangermentProposal.pdf.
[23] *See id.* at n. 29.

In addition, after the close of the initial comment period, another issue was raised concerning greenhouse gases involving the potential for CO_2 emissions to contribute to increased ozone and particulate matter pollution in the vicinity where the CO_2 emissions occur. This issue was raised by recently-published research findings by Mark Z. Jacobson, a researcher at Stanford University, who has posited that locally-emitted CO_2 will form "domes" over urban areas where it is emitted, which will cause localized temperature increases under the "CO_2 domes", and the localized temperature increases will in turn increase the rate of formation of ozone and particulate matter in such areas.[24] The Air District notes that the concern expressed in this paper is similar to the general concern that has been expressed about greenhouse gases and the secondary pollution impacts that would arise from warmer temperatures on a global scale. This study is interesting in that it is the first time (that the Air District is aware of) that scientific research has focused on these issues on a local scale. With respect to whether the paper's findings mean that the Air District should treat greenhouse gases as pollutants "subject to regulation" for PSD permitting purposes, the Air District first notes that concerns about temperature increases from the greenhouse effect having secondary impacts on criteria pollutant formation have been known for some time, and yet have not led EPA to treat greenhouse gases as "subject to regulation" at this point as outlined above. The Air District is bound to follow EPA guidance with respect to the Federal PSD program, and so the Air District does not have the discretion to depart from EPA's position in response to a study such as this one. Moreover, since concerns about secondary pollutant effects from warming temperatures globally have not led EPA to consider greenhouse gases "subject to regulation" at this stage, it seems unlikely that consideration of such concerns on a local scale would do so either (at least, at this point in the evolution of EPA's approach to greenhouse gas regulation). This point is especially applicable here, where the first research supporting this hypothesis has only just emerged and there has not yet been time for a scientific consensus to develop around it. But in any event, as with all of these arguments about whether greenhouse gases should be considered "subject to regulation", the issue is moot in this case because the applicant has voluntarily agreed to have the Air District treat greenhouse gases as if they are regulated and to impose greenhouse gas BACT limits in the facility's PSD permit, as the Air District is proposing.

For all of these reasons, the Air District continues to regard the available guidance from EPA on this matter to direct that greenhouse gases are *not* "subject to regulation" under the Federal Clean Air Act and not legally required to be included in the Federal PSD Permit review. Nevertheless, since the District is treating greenhouse gases as subject to PSD permitting as discussed above, these issues are moot.

B. Greenhouse Gas BACT Technology Analysis For Combined-Cycle Power Generation Trains

The Air District has also conducted further analysis regarding the appropriate BACT standard for greenhouse gas emissions from combined-cycle intermediate-to-baseload combustion turbines, as explained in detail below. The District first looked at issues that have been raised about whether BACT requires an analysis of alternatives to fossil-fuel-fired combustion technology.

[24] *See The Enhancement of Local Air Pollution by Urban CO_2 Domes*, Mark Z. Jacobson, April 3, 2009, available at: www.stanford.edu/group/efmh/jacobson/PDF%20files/CO2loc0409.pdf.

The District next considered what emissions performance can be achieved by the most efficient combustion equipment available for the proposed facility here. Third, the Air District conducted additional analysis of what the most appropriate BACT permit conditions should be for such equipment, and as a result is substantially revising its proposed permit conditions.

1. Evaluation of Non-Fossil-Fuel-Fired Electrical Generation Alternatives

Of the comments the Air District has received so far, none has disagreed with the Air District's assessment that the only feasible control technology for reducing greenhouse gas emissions from fossil-fuel burning power generating facilities is to use the most efficient electrical generating technology,[25] and that at present there are no feasible post-combustion add-on controls for such facilities. The Air District did receive comments stating that the Air District should have evaluated alternative energy production methods that do not rely on fossil fuel combustion, however. These comments suggested that the District should not focus simply on turbine efficiency, as opposed to looking at more efficient ways of making electricity without using combustion turbines.

The Air District has considered these comments and is in agreement that the development of non-fossil-fuel electrical generating sources is of critical importance in meeting California's energy needs while at the same time furthering its air quality goals, especially in light of recent advances in the understanding of the problems posed by global climate change. The Air District recognizes, however, that alternative generating technologies are not currently capable of meeting the state's electrical power demand at all times and under all circumstances, and that some fossil-fuel generating capacity is still needed.[26] Determining the most appropriate mix of electrical generation sources under these circumstances is a highly complex engineering and policy exercise that is most appropriately undertaken by the California Energy Commission, the state's expert agency on energy policy matters. The Air District obviously has a supporting role to play in helping the Energy Commission to understand the air quality impacts of its siting decisions and to include appropriate air quality conditions in its licenses. But as an agency, the Air District does not have the expertise nor the authority to determine what type of generation sources are needed, of what capacity, and where. The Air District must therefore necessarily defer to the Energy Commission's decision that the proposed natural-gas fired, combined-cycle facility is the most appropriate alternative for this project. If it would be more appropriate to use wind or solar power to serve the function intended for the proposed Russell City project, the Energy Commission is the agency best suited – and specifically tasked by the California legislature – to make that determination.

[25] Notably, one comment expressly stated agreement with the District's assessment that the only currently feasible control option for CO_2 is more efficient energy production.

[26] *See, e.g.*, *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, consultant report prepared by MRW & Associates for the California Energy Commission (available at: www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009.PDF.

Here, the Energy Commission specifically evaluated potential non-fossil-fuel-fired alternatives, such as solar, wind, and biomass, in its licensing proceeding for the Russell City Energy Center. The Energy Commission ultimately rejected those alternatives as not feasible because "they do not fulfill a basic objective of the plant: to provide power from a baseload facility to meet the growing demands for reliable power in the San Francisco Bay Area."[27] The Energy Commission rejected wind and solar generating sources because of their inherently intermittent nature, which makes them inappropriate for a baseload generating resource intended to ensure an adequate supply of power in periods when solar and wind sources do not provide power to the grid.[28] The Energy Commission also noted that alternatives like wind and solar involve other environmental trade-offs that can offset the benefits of reduced air emissions. For example, the Energy Commission found that a "wind farm" capable of generating 600 megawatts of power would require 10,200 acres, approximately 690 times the amount of land needed for the Russell City project and associated facilities."[29] The Energy Commission similarly found that a solar thermal project would require approximately 3,000 acres, or over 200 times the amount of land needed for the Russell City project.[30] For all of these reasons, the Energy Commission determined that the better policy choice, taking into account all relevant factors, would be the facility as proposed and not a facility using alternative, non-fossil-fuel generating technology.[31] The Energy

[27] 2002 Energy Commission Decision, *supra* note 15, at p. 19. The Energy Commission made a further finding in its 2007 Amendment decision that no renewable alternatives would be able to meet the project's objectives. *See* California Energy Commission, *Final Commission Decision, Russell City Energy Center* (October 2007) (hereinafter, "2007 Energy Commission Decision"), p. 21, finding 3 (available at www.energy.ca.gov/2007publications/CEC-800-2007-003/CEC-800-2007-003-CMF.PDF). In making this finding, the Commission relied in part upon the detailed analyses that were undertaken in connection with the original licensing proceeding in 2002. *See id.* at pp. 20-21.

[28] 2002 Energy Commission Decision, *supra* note 15, at p. 18.

[29] *Id.*

[30] *Id.*

[31] One alternative that the Energy Commission did not consider was coal-fired generating technologies. Some have argued that coal and natural gas should be considered alternatives of one another, and if this approach were taken then coal should be considered as an alternative along with wind, solar and biomass. To the extent that the Energy Commission even considered this issue, it is likely that it did not undertake a considered evaluation of a coal-fired alternative because in most respects natural gas is a far cleaner fuel. For example, the average emissions rate from existing coal-fired generation in the United States has been estimated by U.S. EPA at 2,249 lbs/MWh of CO_2. (*See* Environmental Protection Agency, *Air Emissions* (hereinafter EPA Air Emissions Summary), available at www.epa.gov/cleanrgy/energy-and-you/affect/air-emissions.html.) Other sources have estimated an average emissions rate over 2,300 lbs/MW-hr. (*See* California Air Resources Board, *Documentation for Emission Default Factors in Joint Staff Proposal for an Electricity Retail Provider GHG Reporting Protocol R.06-04-009 and Docket 07-OIIP-01* (June 20, 2007), available at: www.arb.ca.gov/cc/ccei/presentations/OOS_EmissionFactors.pdf. Meanwhile, according to U.S. EPA, "[c]ompared to the average air emissions from coal-fired generation, [combustion of] natural gas produces half as much carbon dioxide," or about 1,135 lbs/MWh. (*See* EPA Air Emissions Summary, *supra*.) Other estimates put this number as low as 800 lbs/MWh. (*See* Pace, *Life Cycle Assessment of GHG Emissions*

Commission also considered biomass such as wood chips or agricultural waste as a fuel source, but found that such an alternative would not be feasible because no biomass fuel source is available in large enough quantities in the vicinity of the project.[32]

The Federal PSD BACT requirement is not designed to intrude upon this analysis by the expert state agency on power generation and supply policy. To the contrary, Federal PSD permitting explicitly contemplates that PSD permitting authorities will defer to other state agencies on siting decisions.[33] The Air District therefore disagrees that it should require a further review of alternative types of projects – even if they would involve fewer emissions – because that type of alternatives analysis is properly within the province of the Energy Commission's siting authority under the Warren-Alquist Act.

The Air District is of course cognizant of its obligation to provide a determination of what the Federal PSD BACT provision requires for a power plant like this one, in its role in advising the Energy Commission on Air Quality requirements. But the federal BACT framework is clear that it does not require consideration of the use of non-fossil-fuel-fired alternatives, and the Air District therefore could not suggest to the Energy Commission that such alternatives are required by the Federal PSD regulations, regardless of whether there are sound policy reasons to consider them. In determining the Best Available Control Technology for a proposed facility, EPA requires that the Air District examine the best technology for that particular type of facility. EPA requires that the Air District consider the purpose and basic design of the facility, and consider only control technologies consistent with that purpose and basic design. EPA has made clear that the BACT analysis should not include alternative technologies that would require the facility to undergo significant modifications that would alter its fundamental scope, or would change design elements inherent to the facility's purpose, or would call into question the existence of the facility, or would disrupt the applicant's basic business purpose for the proposed facility.[34] Here,

from LNG and Coal Fired Generation Scenarios: Assumptions and Results, prepared for Center for Liquefied Natural Gas (Feb. 3, 2009) at p. 13; available at: www.energy.ca.gov/lng/documents/2009-02-03_LCA_ASSUMPTIONS_LNG_AND_COAL.PDF.) Even the most recent advanced coal generation technologies such as an integrated gasification combined-cycle (IGCC) coal-fired plant, which emits over 1,700 lb/MW-hr, would not come close to the emissions performance of natural gas. (*See id* at 11-12.) Any comparison of natural gas and coal as fuels would therefore find that natural gas is by far the preferable alternative.

[32] 2002 Energy Commission Decision, *supra* note 15, at p. 18.

[33] *See In re Prairie State Generating Co.*, PSD Appeal 05-05, *supra* note 5, slip op. at 44; *In re SEI Birchwood, Inc.*, 5 E.A.D. 25, 33 (EAB 1994); *In re EcoEléctrica, LP*, 7 E.A.D. 56, 74 (EAB 1997); *In re Kentucky Utils. Co.*, PSD Appeal No. 82-5, at 2 (Adm'r 1982).

[34] *See generally* Draft New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting US Environmental Protection Agency (October 1990) (hereinafter "NSR Workshop Manual"), at p. B.13; *In re Prairie State Generating Co.*, *supra* note 5, slip op. at 32; *In re Kendall New Century Dev.*, *supra* note 5, at pp. 50-52 & n. 14; *In re Hillman Power Co.*, 10 E.A.D. 673, 691-92 (EAB 2002); *In re Knauf Fiber Glass, Gmbh*, 8 E.A.D. 121, 136 (EAB 1999); after remand, 9 E.A.D. 1, 8-11 (EAB 2000); *In re SEI Birchwood, Inc.*, 5 E.A.D. 25, 29-30 n.8 (EAB 1994); *In re Hawaii Commercial & Sugar Co.*, 4 E.A.D. 95, 99-100 (EAB 1992); *In re Old Dominion Elec. Coop.*, 3 E.A.D. 779, 793 n. 38 (Adm'r 1992).

non-fossil fuel technologies, such as wind and solar, would not be consistent with the facility's purpose and basic design. To the contrary, they would require a fundamental change in the facility's purpose – generating electric power from natural gas combustion – and would require a complete redesign of the basic elements of the facility. Moreover, changing to such technologies would likely call the existence of the facility into question, because it is far from clear whether wind or solar technologies could be used in lieu of combustion technology to meet the power generation demand the proposed facility will serve, according to the Energy Commission's findings discussed above. For all of these reasons, the BACT analysis is not required to consider such alternatives.

2. Evaluation of Most Efficient Combined-Cycle Combustion Turbine Technology

The Air District also received some comments that criticized the District's initial assessment that the Siemens-Westinghouse 501F turbines the applicant proposed for the project, which the District found to be 55.8% efficient, are the most efficient equipment available. Commenters stated that Siemens' new G-class turbines could be used to achieve a net plant efficiency of 58% and are already in operation at a number of plants. Commenters also stated that GE "H Class" turbines can achieve 60% efficiency, and have been in operation in Wales and Japan for some time. Commenters also claimed that the proposed Siemens F-Class turbines are at the bottom end of the 55.8-56.5% range found in similar turbines as evaluated in the Energy Commission's documents, and the Air District has not explained why more efficient turbines should not have been required.

Based on these comments, the Air District has further reviewed the types of gas turbine equipment available for this project to ensure that the facility will use the most efficient equipment. As noted above in Section II.A., the Air District found that recent advances in the Siemens F-class turbines have resulted in increased efficiency over the FD2 turbines that the applicant initially proposed. These FD3 upgrades can achieve a gross efficiency of 56.45% (LHV) for the combined-cycle facility (without duct burning), a small but significant increase over the 55.8% for the FD2 turbines as initially proposed. The Air District has therefore determined that an efficiency of 56.45% is achievable using FD3-equivalent technology, and is basing its revised greenhouse gas BACT analysis on this efficiency level.

Beyond the FD3-equivent technology, the Air District also examined the feasibility and potential emissions performance advantages of using next-generation turbine equipment such as G-Class or H-Class turbines at this facility. For G-Class turbines, this equipment would actually reduce the overall efficiency of the facility and increase greenhouse gas emissions per megawatt of power produced. This is because G-class turbines have a substantially greater power output than F-Class turbines. Thus, in order to build a 612-megawatt combined-cycle power plant as proposed here using G-Class turbines, the Applicant would need to use a substantially smaller steam turbine (143 MW) to provide the equivalent plant output, which is limited at 612.8 MW (net).[35] This would result in an inefficient bottoming cycle and would lower the overall plant

[35] *See* Table, Comparison of Plant Efficiency, 612.8 MW: FD2, FD3, G-Class and Flex 10 Configurations, Prepared by A. Prusi, Calpine, April 2, 2008. Siemens G-class turbines, when

gross efficiency rating to 49.8% (LHV), according to an analysis provided by the Applicant, compared to the 56.4% efficiency rating of the facility using the latest F-Class technology.[36] As a consequence, although the G-Class turbines may be marginally more efficient by themselves, when incorporated into a combined-cycle facility of this size they would result in lower efficiency for the facility as a whole. The Air District has therefore concluded that the use of G-class turbines would not be the top-ranked eliminated control technology here (i.e., would not lead to the most efficient plant), and would not constitute BACT.

As for H-Class turbines, that turbine class is not yet demonstrated and commercially available for the 60 Hz electrical power system used in the United States, and is therefore not a feasible control technology for purposes of the BACT analysis. GE does have an H-Class turbine that has been fairly well demonstrated for 50 Hz power systems used in other countries. It installed an initial 50 Hz technology validation project at Baglan Bay in Wales that has been in operation since 2003;[37] and it has a second 50 Hz project in Futtsu, Japan, that began operation in July 2008 (with a second turbine expected to come on-line in late 2009), which GE characterizes as "a key step in the commercial development of [the] H System gas turbine".[38] But GE's H-Class 60-Hz turbine is not as far along in the development process, and the company has only just installed its first 60-Hz H-class test turbine at the Inland Empire Energy Center in Riverside County, CA, which just began operation on January 28, 2009 (with a second turbine that is currently being installed but is not yet online).[39] This project will require extensive testing to ensure that it meets all design specifications and is sufficiently reliable for long-term

initially introduced in 1999, had an output of 235 MW. (*See* E. Bancalari & P. Chan, Siemens AG, *Adaptation of the SGT6-6000G to a Dynamic Power Generation Market*, December 2005, at 12 (available at: www.powergeneration.siemens.com/news-events/technical-papers/gas-turbines-power-plants/index.htm#AdaptationoftheSGT6-6000GtoaDynamicPowerGenerationMarket).) Using two such turbines in a 2x1 configuration would require a 142.8 MW steam turbine to meet a 612.8 MW design capacity (235+235+142.8=612.8). This is a conservative estimate because current G-class turbines are even larger (*see id.*), which would necessitate an even smaller steam turbine and even less overall efficiency.

[36] *See* Table, Comparison of Plant Efficiency, 612.8 MW: FD2, FD3, G-Class and Flex 10 Configurations, *supra* note 35.

[37] GE Energy Press Release, *GE's H System Gas Turbine Hits Project Milestone in Japan* (Dec. 11, 2007), *available at* www.gepower.com/about/press/en/2007_press/121107b.htm; Frank J. Bartos P.E., *New, efficient industrial gas turbines coming: Siemens, GE, Full Report* Control Engineering, (August 8, 2008) (available at mobile.controleng.com/article/268171-New_efficient_industrial_gas_turbines_coming_Siemens_GE_full_report.php).

[38] Steve Bolze, Vice President-Power Generation, GE Energy, *quoted in* GE Energy Press Release, *GE's H System Gas Turbine Hits Project Milestone in Japan* (Dec. 11, 2007), *available at* www.gepower.com/about/press/en/2007_press/121107b.htm.

[39] *See* GE Energy Press Release, *GE's H System Gas Turbine Hits Project Milestone in Japan*, supra note 37; Frank J. Bartos P.E., *The Hunt for 60%+ Thermal Efficiency*, Control Engineering (August 1, 2008) (available at www.controleng.com/article/CA6584899.html). The specific startup date for the Inland Empire project was provided by the applicant in communications in April of 2009.

operations,[40] and cannot be considered an available technology until this validation process is completed. As the Energy Commission noted in approving the installation of these H-Class turbines, the "install[ation], operat[ion] and test[ing of] this initial Frame 7H machine [is an] essential step in the development and marketing of this new product[.]"[41] The Air District has therefore concluded that H-Class turbines are not an available technology at the present time for this type of project.[42]

Based on this review, the Air District concludes that there is no other commercially available generating technology that would meet the needs of this project that would have a greater energy efficiency than the upgraded "FD3" turbines the applicant has proposed for use at the facility. The Air District also compared the 56.4% efficiency of this facility with other similar facilities in California that have been recently permitted or are currently undergoing review, and found it to be higher than any other comparable facility (with the exception of the Inland Empire Frame 7H demonstration turbines addressed above). The results of this comparison are summarized in Table 1 below.[43]

[40] *See generally* Frank J. Bartos P.E., *supra* note 37 ("Extensive, predefined testing is necessary to ensure that turbine performance meets design specs, along with reliable, long-term operation associated with power systems. With several different technology levels being validated, the long development cycle needed for these turbines—from first firing through commercialization—becomes evident.").

[41] Memorandum, *Inland Empire Energy Center Power Project (01-AFC-17C) Staff Analysis Of Proposed Modifications To Change To GE 107H Combined-Cycle Systems, Increase Generation and Add Additional Laydown Areas*, From Connie Bruins, CEC Compliance Division Manager, to Interested Parties (Jun. 8, 2005) (hereinafter "Inland Empire Energy Center Staff Analysis Memorandum"), at p. iii. (available at: www.energy.ca.gov/sitingcases/inlandempire/compliance/2005-06-10_FINAL_ANALYSIS.PDF.) The Commission staff also observed that "as with any emerging technology, the proposed project involves a heightened risk of underperformance." *Id.* at p. 2.

[42] The Air District also examined Siemens technology in addition to GE. Siemens is also developing an H-Class product, but it is farther behind than GE. Siemens has installed a 50 Hz test project in Irsching, Germany, but it is currently validating the turbine in simple-cycle mode, with build-out of a combined-cycle configuration not planned until 2009-2011. (*See* Frank J. Bartos P.E., *Largest Gas Turbine: 2,838 Sensors, 90 GB Data Per Hour of Testing* Control Engineering, (February 13, 2009) (available at www.controleng.com/article/ca6637328.html?nid=2488&rid=1768760).) Siemens does not yet have a 60-Hz application installed anywhere in the world.

[43] The information in this table was taken from documents on the Energy Commission's website at www.energy.ca.gov.

Table 1: Comparison of Thermal Efficiency of Similar Combined-Cycle Power Plants

Facility	CEC Application Date	Facility Size (MW)	Thermal Efficiency (LHV)
Colusa Generation Station	11/6/2006	660	56%
Blythe Energy Project Phase II	2/19/2002	520	55-58% (est.)
Lodi Energy Center	9/10/2008	255	55.6%
CPV Vaca Station Power Plant	11/18/2008	660	55%
Victorville 2 Hybrid Power Project	2/28/2007	563	52.7% (w/ duct burn)
Avenal Energy Power Plant[44]	2/21/2008	600	50.5%
Palomar Energy Project	8/2003	550	55.3% (w/o duct firing) 54.2% (w/ duct firing)
SMUD Consumnes Phase I	9/13/2001	500	55.1%

For all of these reasons, the Air District has determined that the 56.4% thermal efficiency proposed for the Russell City Energy Center is the best efficiency performance achievable from commercially available systems for a 600 MW combined-cycle power plant. The District invites members of the public to review and comment on this additional analysis regarding the most efficient generating equipment for the proposed facility with respect to greenhouse gases.

C. Expression Of BACT Emissions Limit In Permit Conditions

In addition to comments regarding the turbine technology that the applicant initially proposed for the facility, the Air District also received several comments critical of the District's proposal of a BACT limit for greenhouse gas emissions of 1100 lb/MW-hr. The commenters raised a number of related points in this regard.

- *Linkage Between lb/MW-hr* CO_2 *Emission Rates and Thermal Efficiency:* Some comments questioned the District's analysis of the range of lb/MW-hr CO_2 emissions performance levels among various turbines in the context of thermal efficiency. These comments referred to the fact that the BACT technology analysis was explained in terms of turbine thermal efficiency; yet when selecting the BACT performance level BACT was stated in terms of mass emissions per unit of power output. The commenters stated that the District had not explained how the range of turbine thermal efficiency percentages evaluated relates to the range of lb/MW-hr CO_2 emissions levels (although they stated that they presumed that the higher lb/MW-hr CO_2 emissions levels correspond to the less efficient turbines).
- *Use of Emissions Standard from SB 1368:* Commenters stated that the proposed 1100 lb/MW-hr permit limit was taken from SB 1368; and that it was developed in that context to accommodate existing facilities with older, higher-emitting equipment as well as new plants. The commenters claimed that this number can therefore at most be a floor for setting a BACT limit, and that it is not a measure of the best achievable performance.

[44] With respect to Avenal, one commenter stated that this proposed facility would be able to achieve a CO_2 emissions rate of 499.7 lb/MW-hr, but its calculation was based on estimated emissions at 50% load ("Case 12" in the table referenced by the commenter). At full load, emissions would be over 900 lb/MW-hr (using "Case 1") and a nominal power output of 600 MW based on the documentation cited by this commenter.

The commenters also claimed that the number was intended to apply to facilities state-wide, and it is not a case-specific determination of what a particular facility can achieve as required by BACT.

- *Data Showing Achievable Emissions ~800 lb/MW-hr:* The commenters stated that emissions data from new turbines show that current equipment should be able to achieve emissions as low as 800 lb/MW-hr. Commenters also stated that the District should look at the best achievable performance level of all turbines, including new turbines, and not limit its review to turbines that were built several years ago. Commenters also claimed that the District considered emissions data from only one year of operation from only two facilities, and should conduct a broader review.
- *Justification For Compliance Margin:* The commenters also criticized the District's claim that the BACT limit should be set at 1100 lb/MW-hr limit in order to provide a compliance margin. These commenters noted that 1100 lb/MW-hr is significantly higher than the emissions measured from the comparable facilities that the District examined (Metcalf and Delta). They asserted that the District should explain in more detail the need for a compliance margin and also the necessary magnitude of the margin. They claimed that the District should explain what foreseeable operating conditions might affect emissions performance, and provide data showing how much of a compliance margin these conditions would warrant.
- *Justification for Heat Input Limit:* One commenter framed its objection in terms of the heat input limit that the District derived from the 1100 lb/MW-hr emissions rate. The commenter noted that the corresponding heat input rate the District used as a BACT limit – 2944.3 mmBtu/hr – is 35% higher than what the rated maximum for the proposed turbines. The commenter objected that this approach would allow turbines with a much lower efficiency than the 55.8% level achievable by these turbines. The commenter claimed that this limit has no connection to actual emission rates achievable by such sources.
- *"Output-Based" Limit to Address Efficiency Changes Over Time:* Several commenters objected to the District's proposal to express the BACT limit for greenhouse gases as a limit on turbine heat input. These commenters claimed that instead of limiting heat input, the District should impose a limit on the mass of CO_2 emitted per MW-hr directly. The commenters claimed that if the limit is imposed on heat input only, emissions on a lb/MW-hr basis could rise if turbine efficiency declines because of maintenance issues, equipment modifications, or other reasons. Once commenter cited the *Steel Dynamics* EAB decision for the proposition that a BACT limit needs to ensure compliance on a continual basis over all levels of operation.

The Air District has reevaluated its proposed BACT emissions level in light these comments, and upon further consideration agrees that 1100 lb/MW-hr would not be an appropriate BACT limit for greenhouse gas emissions. Instead, the Air District is proposing a lower BACT emissions limit, as well as an "output-based" requirement for periodic compliance testing to ensure that the plant maintains the BACT efficiency standard over time. In particular, the Air District has adjusted its proposed BACT determination as follows.

- First, the Air District has focused its analysis of what emissions performance is achievable by generating equipment with a thermal efficiency at a BACT level of 56.4%. The Air District agrees with the comment that simply looking at lb/MW-hr numbers reported in the ARB database does not necessarily tie the analysis into thermal efficiency, which is the basis for the District's BACT analysis. Tying the analysis of the achievable numerical BACT emissions limitation to specific data about expected turbine performance is intended to address this issue. As explained below, for purposes of establishing an enforceable numerical efficiency limit the Air District has used heat input per unit of power output, in MMBtu/kWhr, as the appropriate metric for establishing the BACT limit because the objective, industry-standard method for measuring efficiency uses that metric.
- Second, the Air District agrees that using the 1100 lb/MW-hr number established for purposes of SB1368 as a performance standard for all turbines does not necessarily capture the best performance achievable by the most efficient turbines available for use in new projects, on which a BACT analysis should be based. Instead, the District has analyzed the greenhouse gas emissions that can be achieved by state-of-the-art FD3 class turbines, as noted above. The Air District has determined that the BACT emissions rate should be based upon a best achievable design base heat rate of 6852 Btu/kWhr (which is approximately equivalent to an emissions rate of 792-815 lb/MW-hr, depending on which emissions factor is used), with a reasonable compliance margin of a little over 12% to account for various factors that may make the best design performance unachievable during all operating scenarios over the life of the equipment. This compliance margin is based on a thorough analysis the various elements of turbine operation that may reduce turbine efficiency over time and thereby increase greenhouse gas emissions per unit of power output, as discussed in detail below.
- Third, the Air District agrees that the BACT limit as expressed in the permit needs to be "output based", instead of just an absolute limit on greenhouse gas emissions, in order to take into account the potential that maintenance issues may lead to declining efficiency. The Air District is therefore proposing to require both absolute mass emissions limits based on the amount of greenhouse gas emissions expected for combined-cycle turbines of this size and level of thermal efficiency, plus periodic compliance tests to ensure that the efficiency remains within the established BACT levels. The Air District is proposing to base the efficiency compliance test on an ASTM standard that measures heat rate per power output, which is a well-accepted engineering standard with objectively-defined measurement standards.

By adjusting its approach to the greenhouse gas BACT issue in this way, the Air District believes that its revised proposal will ensure a BACT standard that is based on the best achievable thermal efficiency of available equipment, with a reasonable and documented compliance margin to make sure it is as stringent as possible and still achievable across all operating scenarios. This revised approach also includes continuous short-term and long-term emissions monitoring as well as periodic efficiency monitoring to ensure that BACT performance does not unreasonably degrade over time because of maintenance lapses or similar concerns.

The Air District's revised analysis is set forth in full in the following sections. The Air District encourages all interested members of the public to review and comment on this revised analysis.

1. Conceptual Overview of Proposed Numerical Greenhouse Gas BACT Limits

The Air District is revising the draft Federal PSD Permit to incorporate two interrelated numerical BACT emissions limits for greenhouse gases. First, based on the Air District's technological analysis in the Statement of Basis and as further refined in this subsequent analysis, the Air District is proposing to adopt numerical greenhouse gas mass emissions limits based on the emissions expected from the facility's state-of-the-art electrical generating equipment. These proposed mass emissions limits are based on the maximum rated heat input capacity of the combustion turbines and HRSG duct burners needed to produce the power generation demand that the facility has been designed to serve. Every unit of heat input generates a known amount of greenhouse gas emissions, and so the Air District is proposing greenhouse gas mass emissions limits based on this heat input capacity, on an hourly, daily, and annual basis. The proposed heat input and greenhouse gas emissions limits the Air District is imposing are set forth in Table 2 below.

Table 2 - Proposed Heat Input and Greenhouse Gas Emissions Limit Summary

Averaging Period	Heat Input Limit (MMBtu)	Greenhouse Gas Emissions Limits (metric tons CO_2E)			
		CO_2	CH_4	N_2O	CO_2E
1-Hour	4,477.2	242	0.08	0.14	242
24-Hour	107,452.0	5,797	2.03	3.33	5,802
Annual	35,708,858.0	1,926,399	675	1,107.48	1,928,182

These proposed heat input and mass emissions limits are intended to ensure that the facility's turbines and HRSG duct burners will not use any more natural gas, and not have any more greenhouse gas emissions, than the Air District has determined is necessary to meet the design power generation capacity. As described in detail below, under this revised proposal the heat input and greenhouse gas emissions will be monitored in real time using natural gas usage information, which provides a very accurate indication of these parameters.

Second, the District is also proposing an "output-based" efficiency limit that takes into account the amount of power generated by the facility, in order to address the concern raised in comments that simply specifying maximum heat input and corresponding greenhouse gas output fails to address the potential that turbine efficiency may decline to the point where it no longer reflects BACT. The District is therefore proposing to impose a minimum turbine efficiency permit condition, expressed as MMBtu of heat input per megawatt of power output, that the facility will be required to achieve. The Air District is proposing to require the facility to conduct annual compliance tests in which heat input and power output are measured to a high degree of accuracy, and to ensure that gas turbine heat input remains below 7,730 Btu/kWHr (HHV), a rate equivalent to generating a minimum of one megawatt-hour of electric power per 7.73 MMBtu of natural gas burned.

The District is proposing this 7,730 Btu/kWHr (HHV) efficiency limit as the lowest heat input rate that can be reasonably assured under all operating scenarios. As outlined below, the limit was based upon the design efficiency of the 56.4% thermally-efficient FD3-equivalent combustion turbines[45] that the Air District has concluded are the BACT technology for a nominal 600-megawatt natural-gas fired combined-cycle electrical generating facility. This value, known as the "Design Base Heat Rate" for the facility, is 6,852 Btu/KW-hr (HHV), and reflects the thermal efficiency that the facility is designed for. To ensure that the numerical BACT efficiency limit reflects a reasonable margin of compliance, the District has evaluated the factors that could reasonably be expected to degrade the theoretical design efficiency of the turbines and increase the heat rate (*i.e.*, cause more fuel to be required to produce a megawatt of power). The Air District has considered a number of factors in this regard as explained in detail below, including (i) a reasonable design margin of 3.3% to reflect that the equipment as actually constructed and installed may not fully achieve the assumptions that went into the design calculations; (ii) a reasonable performance degradation margin of 6% to reflect reduced efficiency from normal wear and tear on the equipment between major maintenance overhauls; and (iii) an additional 3% degradation margin based on additional wear and tear caused by variability in the operation of the auxiliary plant equipment that will be powered by the turbines, including the natural gas compressors and water recycling system. These potential degradation factors are an unavoidable aspect of building and operating the facility, consistent with best engineering practices, and the ultimate BACT limit needs to account for them to ensure that it is achievable over all operating scenarios. Applying these potential degradation factors to the Design Base Heat Rate, the Air District has concluded that the appropriate numerical Greenhouse Gas BACT heat input efficiency limit for this equipment is 7,730 Btu/kWHr (HHV). The Air District is proposing this limit as an enforceable not-to-exceed permit limit, along with appropriate monitoring requirements.

In conducting this analysis, the Air District has also been mindful that under normal circumstances the establishment of a numerical BACT permit limit would often involve a review of permit limits imposed by other facilities and of monitoring data required under such permits. In this case, however, no facility the Air District is aware of has ever been subject to an enforceable BACT limit on its emissions of greenhouse gases; nor has any facility, to the Air District's knowledge, been subject to an enforceable limitation on its efficiency (heat rate per kW-hr of power output). Because this represents a "first of its kind" limitation in an air permit, there is little relevant performance data which might provide a basis for concluding that a lower Heat Rate Limit can consistently be met over time. An enforceable BACT limitation must be set at a level that the facility can achieve for the life of the facility, including as its equipment ages and incurs anticipated degradation. At the same time, the Air District believes the proposed Heat Rate Limit is stringent enough to assure that the facility operator will not allow the equipment to incur undue or extraordinary efficiency losses through deferral of necessary maintenance, such that the assumptions which supported this BACT determination are no longer valid.

2. Derivation of Numerical Greenhouse Gas BACT Limits

Greenhouse Gas Mass Emissions Limits: The Air District calculated the appropriate heat-rate limit and mass emissions rate limits using the maximum heat input capacity of gas turbines and duct burners combined (*i.e.*, at maximum plant capacity). The facility's maximum heat input

[45] The combustion turbine equipment on which the BACT heat rate analysis was based included the FD3 upgrades discussed above.

capacity is 4,477.2 MMBtu per hour; 107,452.0 MMBtu/day; and 35,708,858.0 per year. (*See* Proposed Permit Conditions 13, 14 & 15.) The Air District then calculated corresponding mass emissions rates for CO_2, CH_4, N_2O, and CO_2E using established emissions factors. For CO_2, emissions were calculated using the CO_2 emissions factor of 118.9 lbs/MMBtu, as required under EPA's Acid Rain Trading Program, 40 C.F.R. Part 75. For CH_4 and N_2O, emissions were calculated using the Air Resources Board's emissions factors of 0.0020 and 0.00022 lb/MMBtu, respectively. CO_2E was calculated by applying a global warming potential multiplier of 21 and 310 for CH_4 and N_2O, respectively, based upon the Air Resources Board's mandatory reporting rule.[46] The associated mass emissions limits are outlined in Table 2 above on an hourly, daily and annual basis.

Heat Rate Efficiency Limit: To determine the appropriate heat-input efficiency limit, the Air District started with the turbines' Design Base Heat Rate[47] and then calculated a reasonable compliance margin based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions as noted above.

- ***Net Design Base Heat Rate – 6,852 Btu/kWhr:***

The turbines' Design Base Heat Rate is 6,852 Btu/kWhr (HHV), based on operation of both combustion turbines with no duct firing, corrected to ISO conditions.[48] (For comparison with a pounds-per-megawatt-hour efficiency rating, this is between 792.9 and 815.5 lbs/MWhr, depending upon which CO_2 emissions factor is applied.[49]) This represents what the plant (at the design stage) is expected to achieve when it is new and clean; it does not represent what it will achieve over time as the equipment incurs degradation between major maintenance overhauls. It also does not represent the equipment manufacturer's guaranteed levels of performance.

[46] The Air District would also note that it is following the convention of stating emissions of greenhouse gases in terms of "CO_2-equivalents" (CO_2E), which, for this source, include emissions of methane (CH_4) and nitrous oxide (N_2O) as well. These two pollutants have a higher "global warming potential" than CO_2, reflecting their relative propensity to trap solar radiation within the Earth's atmosphere that would otherwise be reflected back into outer space and thereby contribute to global warming. The emissions factors and global warming potentials for N_2O and CH_4 are specified by the Air Resources Board's mandatory reporting rule: For N_2O, the emissions are 0.00022 lbs/MMBtu and the global warming potential is 310; for CH_4, the emissions are 0.0020 lbs/MMBtu and the global warming potential is 21.

[47] Electric generating facilities typically measure their efficiency in terms of the "heat rate", which is the energy content of the fuel, in British thermal units (Btu), that it takes to generate a kilowatt-hour (kW-hr) of electric power to the grid.

[48] *See* Russell City Energy Center Heat Balance Diagrams, *supra* note 6.

[49] The lower and higher figure reflect application of the emissions factors for CO_2 applicable under U.S. EPA's Climate Leaders program – 115.6 lb/MMBtu – and the Part 75 Acid Rain Monitoring Program, 118.9 lb/MMBtu. Other relevant emissions factors include the California Climate Action Registry's factor of 116.9 lb/MMBtu and the Air Resources Board's mandatory reporting rule, which applies emissions factors for CO_2 between 116.5 and 120.5 lb/MMBtu of natural gas, depending upon the Btu content of the gas stream.

Note that this Design Base Heat Rate of 6,852 Btu/kWhr (HHV) without duct firing and 6,970 Btu/kWhr (HHV) with duct firing reflects the facility's "net" power production, meaning the denominator is the amount of power provided to the grid; it does not reflect the total amount of energy produced by the plant, which also includes auxiliary load consumed by operation of the plant.[50] The total auxiliary load for this facility is 21.1 MW without duct firing or 24 MW with duct firing.[51] Accounting for this auxiliary load would result in a "gross" Design Base Heat Rate of 6,743 Btu/kWhr (HHV) when duct firing is not occurring, which would result in emissions between 780.3 and 802.5 lbs/MW-hr of CO_2E, depending upon which emissions factor is applied for CO_2. When duct firing is occurring, the "gross" Design Base Heat Rate would be 6,868 Btu/kWhr (HHV), or between 794.7 and 817.4 lbs/MWhr of CO_2E.

- ***Installed Design Base Heat Rate – 7,080 Btu/kWhr:***

While the Design Base Heat Rate reflects what the engineers aim to achieve in designing the facility, design and construction of a combined-cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which are often imprecise or not reflective of conditions once installed at the site. As a consequence, the facility also calculates an "Installed Base Heat Rate", which represents a design margin of 3.3% to address such items as equipment underperformance and short-term degradation. According to information provided by the Applicant, a design margin of up to 5% is typical in the commercial terms for the engineering, procurement and construction contracts for a combined-cycle power plant. Normally the performance guarantees from the combustion and steam turbine original equipment manufacturers and the contractual terms require demonstration that the project, as constructed, achieves the design output and heat rate, subject to a plus or minus 5% margin. For example, if the tested output is less than 95% of the guaranteed output, or the tested heat rate is more than 105% of the guaranteed heat rate, the original equipment manufacturer and engineering, procurement and construction contractor can declare substantial completion and pay liquidated damages to compensate for the performance shortfalls. The design margin also reflects some tolerance for uncertainties associated with the plant's auxiliary load, such as the potential variance between assumptions about the amount of load that will be required to conduct treatment and evaporation of the City's waste water within the facility, and actual experience. Adding this 3.3% design margin to the Design Base Heat Rate would result in an Installed Base Heat Rate of 7,080 Btu/kWhr (HHV), assuming dual unit operation without duct burner firing, corrected to ISO conditions.

[50] This auxiliary load includes power for the facility's recycling of wastewater from the adjacent City of Hayward's wastewater treatment plant. This system will recycle roughly 4 million gallons of water a day in the facility's operations instead of having to obtain it from other sources; and will use a "Zero Liquid Discharge" system so that none of that wastewater will be discharged to the Bay. The facility also will include a "Low Noise/Plume-Abated" cooling tower, which will consume additional load due to use of recycled waste water. These are important environmentally beneficial aspects of the project.

[51] *See* Russell City Energy Center Heat Balance Diagrams, *supra* note 6.

- ***Degraded Base Heat Rate – 7,730 Btu/kWhr:***

To establish an enforceable BACT condition that can be achieved over the life of the facility, the Air District also must account for anticipated degradation of the equipment over time between regular maintenance cycles.

For the gas turbines, the Air District is basing its analysis on a 48,000-operating-hour degradation curve provided by Siemens, which reflects anticipated recoverable and non-recoverable degradation in heat rate between major maintenance overhauls of approximately 5.2%.[52] According to combustion turbine manufacturers, anticipated degradation in heat rate of the gas turbines alone can be expected to increase non-linearly over time. The degradation curves relied upon by the Applicant describe the amount of "recoverable" and "non-recoverable" degradation. The former includes degradation that can be recovered through compressor water washing, filter changes, instrumentation calibration and auxiliary equipment maintenance. The latter includes degradation that cannot be restored upon a maintenance overhaul.

The 48,000-hour maintenance interval is based upon Siemens' recommendations, which provide detailed formulae for determining when the equipment should undergo certain inspection and maintenance activities, based upon the accumulated total for both "Equivalent Baseload Hours" and "Equivalent Starts".[53] By calculating Equivalent Baseload Hours and Equivalent Starts, the facility operator accounts for the specific operating conditions and events experienced by the facility that may impact the equipment's performance. These include the difference between baseload and peak firing hours and the impacts caused by instantaneous load changes (*i.e.*, outside of the expected ramp rate).

The original equipment manufacturer's degradation curves only account for anticipated degradation within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, because the projected 5.2% degradation rate represents the *average*, and not the maximum or guaranteed, rate of degradation for the gas turbines, the Air District has determined that, for purposes of deriving an enforceable BACT limitation on the proposed facility's heat rate, gas turbine degradation may reasonably be estimated at 6% of the facility's heat rate. A slightly higher than average expected degradation is justified for purposes of developing an enforceable emissions limit here, given the limited operational experience of the new FD3-level turbine technology. Adding this 6% degradation factor to the facility's "Installed Base Heat Rate" of 7,080 Btu/kWhr (HHV) (*i.e.*, the projected heat rate of the equipment in its original condition, after accounting for a predicted 3.3% design margin) would result in a potential heat rate of 7,505 Btu/kWhr (HHV) (without duct firing).

Finally, in addition to the heat rate degradation from normal wear and tear on the turbines, the Air District is also providing a reasonable compliance margin based on potential degradation in

[52] Siemens Power Generation, Inc, *Guiding Principles for Conducting Site Performance Tests on Siemens Industrial Gas Turbine-Generator Units*, EC-93208-R10 (July 15, 2008), Figure 3 "Degradation Effect on Gas Turbine Heat Rate" TT-DEG-76.

[53] Siemens Power Generation, Inc., Service Bulletin 36803, *Combustion Turbine Maintenance and Inspection Intervals*, Revision No. 10 (Oct. 7, 2004).

other elements of the combined cycle plant that would cause the overall plant heat rate to rise (*i.e.*, cause efficiency to fall). These other elements include the following:

- *Variability in Natural Gas Pressure:* The facility needs to bring the natural gas burned in the turbines up to a pressure of 500 psi, and uses gas compressors to do so because the natural gas supplied to the facility is delivered at a lower pressure. According to data from PG&E, the natural gas supplier, the delivery pressure may fluctuate between 170 and 355 psi (or between 250 and 410 psi with upgrades to the natural gas line).[54] Because of the variability in delivery pressure, the gas compressor engines may have to cycle up and down, which can result in increased wear and tear on the engine and decreased fuel efficiency. This would increase auxiliary load on the facility and reduce overall plant efficiency..
- *Variability in Natural Gas Quality:* In addition to changes in natural gas pressure, the gas supply for the facility may also experience substantial variation in the quality of the natural gas (in terms of its chemical constituents). This can further exacerbate degradation of the gas turbines, in the same way that using low-quality gasoline can affect an automobile's performance.
- *Variability in Cooling Water Quality:* The facility's water recycling system will treat approximately 4 million gallons per day of waste water from the City of Hayward's adjacent treatment plant for use in the plant's operations. Data from the water treatment plant shows a substantial degree of variability in the water quality, which in some cases may require additional recycling of the water supply prior to its use by the facility.[55] The additional recycling would require greater load to conduct such treatment and could result in accelerated degradation of various components of the water treatment system, including pumps and rotating equipment. The same is true of the evaporator and Zero Liquid Discharge system, as well as of the plume-abated cooling towers.
- *Degradation in Turbine Exhaust Flow:* The gas turbine manufacturer's degradation curves predict potential recoverable and non-recoverable degradation in gas turbine exhaust flow of 3.75% over the 48,000 maintenance cycle.[56] This degradation in exhaust flow will result in a direct reduction in the ability of the steam turbine to generate power, which will further degrade the plant's overall efficiency. While degradation in the exhaust flow is expected to be partially offset by degradation in exhaust temperature (which rises over the maintenance cycle)[57], this offset will not make up for anticipated degradation in the reduction in steam turbine power as a result of reduced exhaust flow.

[54] Letter, Rodney Boschee, Pacific Gas & Electric, Wholesale Marketing & Business Development, to Chris Delaney, CPN Pipeline Company, subject: Calpine Russell City Energy Center, December 2, 2008.

[55] *See* City of Hayward Wastewater Treatment Plant water monitoring data, November 1, 2008 – March 20, 2009; Summary data, *Reclaimed Water Project-2008, Final Clarifier* for sample dated April 16, 2008.

[56] Siemens Power Generation, Inc, *Guiding Principles for Conducting Site Performance Tests on Siemens Industrial Gas Turbine-Generator Units*, *supra* note 52, Figure 4 "Degradation Effect on Gas Turbine Exhaust Flow," TT-DEG-77.

[57] *Id.*, Figure 5, "Degradation Effect on Gas Turbine Exhaust Temperature" TT-DEG-78.

- *Degradation in Steam Turbine Performance:* Degradation in the performance of the heat recovery boilers and steam turbine is also expected to occur over the course of a major maintenance cycle.
- *Degradation in Gas Turbine Performance:* The influence of the bay-side environment on the air inlet filter may cause inlet air pressure to be reduced, which would further degrade the performance of the gas turbines.

The Air District found little documentation on which to base a specific numerical estimate of exactly what the efficiency impacts would be from these affects, in part because regulatory agencies have not had to undertake analyses in this area before. Without usable precedents or documentation regarding the precise potential for degradation from these issues, the Air District has had to use its best engineering judgment to assess how much additional degradation should be anticipated. The Air District believes in its engineering judgment that an additional 3% degradation is a reasonable and appropriate estimate under the circumstances, taking into account the fact that the limits being imposed based on this estimate will be enforceable, not-to-exceed permit conditions. The Air District solicits further comment on this issue.

3. Implementation of Numerical Greenhouse Gas BACT Limits In Permit Conditions

Finally, the Air District is proposing to implement these greenhouse gas BACT limits as enforceable permit conditions, with appropriate monitoring and recordkeeping requirements. For the heat-input and GHG mass emissions limits, the Air District is proposing to require the facility to demonstrate compliance by monitoring its fuel usage on a real-time basis, and then calculating heat-input and mass emissions based on the fuel usage. For CO_2, mass emissions would be calculated using the CO_2 emissions factor of 118.9 lbs/MMBtu, as required under EPA's Acid Rain Trading Program, 40 C.F.R. Part 75. For CH_4 and N_2O, mass emissions would be calculated using the Air Resources Board's emissions factors of 0.0020 and 0.00022 lb/MMBtu, respectively. CO_2E would be calculated by multiplying CH_4 and N_2O emissions by their respective global warming potentials of 21 and 310, based upon the Air Resources Board's mandatory reporting rule, and then adding them to CO_2 emissions.[58] The facility would be required to maintain records of its heat input and mass emissions monitoring data in order to ensure compliance.

For the turbine efficiency limit (the 7,730 Btu/kWhr heat-rate limit), the Air District is proposing to require compliance testing to demonstrate compliance within 90 days after the end of the commissioning period (as defined in the permit) and annually thereafter to ensure that efficiency is maintained at a BACT level. Under this periodic compliance test requirement, the facility would be required to perform a "Heat Rate Performance Test" using the industry-accepted method for heat rate and capacity testing, the American Society of Mechanical Engineers (ASME) Performance Test Code on Overall Plant Performance (ASME PTC 46-1996)). This

[58] For purposes of assuring consistency with existing reporting regimes for greenhouse gas emissions, it makes best sense to align monitoring and reporting requirements in the Federal PSD Permit with these prevailing methods for calculation and inventorying of greenhouse gas emissions.

test includes objective parameters that will ensure consistent and reliable reporting of actual turbine efficiency, and it is the accepted industry standard test for this purpose. The facility would be required to conduct the test at baseload (*i.e.*, full capacity), without duct firing. The facility will be required to submit a test plan to the Air District for its review and approval at least thirty (30) days in advance of the proposed test. The test will consist of three one-hour test runs, and the results of each test run will be averaged and then corrected back to ISO conditions of:

- Ambient Dry Bulb Temperature: 59°F
- Ambient Relative Humidity: 60%
- Barometric Pressure: 14.69 psia
- Fuel Lower Heating Value: 20,866 Btu/lb
- Fuel HHV/LHV Ratio: 1.1099

To determine compliance with this condition, the result of this test will be compared to the Heat Rate Limit of 7,730 Btu/kWhr (HHV).

These compliance monitoring requirements will be effective to ensure compliance with the greenhouse gas limits in the permit. The Air District has also considered whether to require the facility to use a Continuous Emissions Monitor (CEM) to measure greenhouse gas emissions directly (as CO_2), but has concluded that calculating emissions from heat input is preferable. Unlike some other pollutants such as NOx or carbon monoxide whose formation is heavily dependent on conditions of combustion and/or performance of add-on emissions controls, greenhouse gases are a direct and unavoidable byproduct of the combustion process. The amount of carbon within the fuel will all ultimately be emitted as greenhouse gases in a manner that is easily determined using well-established emissions factors. One can therefore determine with great accuracy what greenhouse gases are being emitted by measuring the amount of hydrocarbon fuel being burned (measured as heat input). For this reason, the test methods for measuring heat rate and capacity can achieve an accuracy of ±1.5%,[59] which is better than the relative accuracy of CEMs which typically ranges as high as ±10%.[60] The Air District is therefore proposing to require surrogate monitoring for greenhouse gas emissions using heat rate instead of a CEM.

The Air District also considered whether it would be possible to monitor thermal efficiency on a continuous basis in terms of emissions (or heat input) per unit of power output, but found that it would not be feasible to measure efficiency in this manner on a continual basis in any meaningful way. Measuring efficiency with a high degree of accuracy requires expertly-administered test procedures as set forth in the ASME PTC 46 standard, and it is not feasible to require this testing methodology to be implemented at all times of facility operation. Moreover,

[59] American Society of Mechanical Engineers (ASME), *Performance Test Code on Overall Plant Performance*, (PTC 46-1996), October 15, 1997, Table 1.1, "Largest Expected Test Uncertainties", at p. 4 (providing 1.5% variance in the corrected heat rate for "combined gas turbine and steam turbine cycles with or without supplemental firing to a steam generator").
[60] *See, e.g.*, 40 C.F.R. Part 75, Appendix A, § 3.3.3 ("The relative accuracy for CO_2 and O_2 monitors shall not exceed 10.0 percent.")

measuring efficiency by comparing heat input to power output would not be feasible during periods such as startup, shutdown, or tuning when no power is being produced for the grid. There will be heat input during this period, but with no power output the denominator in the pounds-per-megawatt-hour efficiency measurement will be zero. And finally, thermal efficiency is unlikely to experience major ups and downs over time. Unlike NOx or CO, which could fall out of compliance rapidly if good combustion conditions are not maintained or if an add-on control device fails, thermal efficiency is likely to degrade relatively slowly over time.[61] A one-day snapshot of turbine efficiency from a periodic compliance test is therefore likely to be relatively representative of efficiency over a longer time frame. For all of these reasons, the Air District is proposing to require the facility to demonstrate compliance with the heat rate BACT limit through periodic compliance testing, not continuous monitoring. The Air District is proposing an annual test requirement, which is the typical test frequency the District requires in periodic monitoring situations such as this. Based on the performance degradation documentation the Air District has reviewed, annual compliance testing is an appropriate testing frequency for this type of permit limit.

D. Other Greenhouse Gas Emissions

The District has also undertaken a BACT analysis for greenhouse gas emissions from the diesel firepump engine and circuit breakers, which were not included in the greenhouse gas analysis in the initial Statement of Basis. This equipment has the potential to emit greenhouse gases, and in order for a greenhouse gas BACT analysis to be comprehensive it should include these sources as well. The Air District is therefore including the emergency diesel firepump engine and the circuit breakers in the voluntary greenhouse BACT analysis, and is proposing mandatory permit conditions to ensure that they are subject to enforceable BACT emission limits.[62] The Air District invites interested members of the public to comment on these elements of the BACT analysis.

1. Diesel Fire Pump

The emergency diesel firepump engine will have the potential to emit greenhouse gases (CO_2, CH_4, and N_2O) because it will combust a hydrocarbon fuel, just as with the gas turbines and heat recovery boilers. There are no effective combustion controls to reduce the greenhouse gas emissions from hydrocarbon fuel combustion, and there are no currently available post-combustion controls, as the District explained in its greenhouse gas analysis for the gas turbines. The Air District therefore concludes that the only achievable technological approach to reducing greenhouse gases from the firepump engine is to use the most efficient engine that meets the stringent National Fire Protection Association ("NFPA") standards for reserve horsepower capacity, engine cranking systems, engine cooling systems, fuel types instrumentation and control and exhaust systems. (*See generally* Statement of Basis at pp. 55-56, describing the NFPA requirements.) As there is only one control technology to choose from, application of the 5 steps in the Top-Down BACT analysis results in the selection of that control technology.

[61] *See generally* documentation regarding heat rate degradation cited in heat rate discussion above, pp. 31-33.
[62] The District received one comment stating that the greenhouse gas BACT analysis should also include the facility's pre-heater. This project does not involve a pre-heater.

The 2100 R.P.M. 300-hp Clarke JW6H-UF40 diesel firepump engine that the applicant has proposed for use here has a fuel consumption rate of 14.0 gallons per hour.[63] The Air District has reviewed fuel-efficiency data for similarly-sized NFPA-20 certified firepump diesel engines rated at 2100 R.P.M., and has not found any such engines with a higher fuel efficiency.[64] The Air District has therefore concluded that the 14-gal/hr Clarke engine is the most efficient equipment available, and so it qualifies as the BACT control technology.[65]

The firepump engine may have to be used for up to 50 hours per year for reliability testing and maintenance purposes. Use of the engine at 14 gallons of diesel fuel per hour for up to 50 hours per year would result in total greenhouse gas emissions from the fire pump of 7.6 tons CO_2E per year.[66] The Air District is therefore imposing a greenhouse gas limit in the permit of 7.6 tons per year of CO_2E as a BACT limit. The facility will be required to demonstrate compliance with this limit by recording fuel usage and using an emissions factor of 21.7 lb/ CO_2E-gal to determine resulting CO_2E emissions.

As with turbine emissions, the Air District considered using a CEM to monitor greenhouse gas emissions directly. But it concluded that determining emissions based on fuel usage as a surrogate is a preferable approach, for similar reasons as with the turbines. Fuel usage can be accurately measured, and the amount of greenhouse gas equivalents can be calculated precisely based on well-established emissions factors.

Finally, the Air District also received a comment suggesting that the District should impose conditions to ensure that the firepump engine is used only in emergency circumstances. The Air District notes that the engine also needs to be operated for short periods for testing, maintenance, and reliability purposes. The permit conditions as proposed explicitly limit operation to emergencies and for these specific, necessary non-emergency purposes.

2. Circuit Breakers

The facility's circuit breakers will also have the potential to emit a greenhouse gas, sulfur hexafluoride (SF_6). Circuit breakers do not emit SF_6 directly, but they do have the potential for fugitive emissions (leaks).[67] The Applicant's facility will include a switchyard with five circuit

[63] *See* Clarke JW6H-UF40 Fire Pump Driver, Emission Data for California ATCM Tier 2, Clarke Fire Protection Products (Rev. E, July 12, 2007), at p.1.
[64] *Cf.* Cummins CFP11E-F10 Fire Pump Driver, California ATCM Tier 2 Emission Data (Aug. 26, 2008) (fuel consumption rate of 16.0 gal/hr); Deutz DFP6 1013 C25 fire protection engine, EPA Tier 2/CARB Technical Data Sheet (Apr. 2008) (fuel consumption rate 15 gal/hr).
[65] In the terminology of the "Top-Down" BACT analysis, the Clarke engine at 14.0 gal./hr would be ranked the No. 1 technically feasible control alternative at Step 3 of the analysis. Since the Air District is selecting the top technology, the additional steps in the analysis become moot.
[66] Unlike emissions of criteria pollutants, it is feasible here to impose a numerical emissions limitation for CO_2E because CO_2E has a direct correlation to fuel usage, which is readily measureable. The emissions factor for diesel fuel is 21.7 pounds of CO_2E per gallon.
[67] U.S. EPA, J. Blackman (U.S. EPA, Program Manager, SF_6 Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting), *SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse*

breakers, and the applicant has proposed breakers containing approximately 145 pounds of SF_6 each in an enclosed-pressure system.[68] SF_6, a gaseous dielectric used in the breakers, is a highly potent greenhouse gas, with a "global warming potential" over a 100-year period 23,900 times greater than carbon dioxide (CO_2).[69] Leakage is expected to be minimal, and is expected to occur only as a result of circuit interruption and at extremely low temperatures not anticipated in the Bay Area. Nevertheless, given SF_6's high global warming potential, even small amounts of leakage can be significant and should be considered for purposes of a greenhouse gas BACT analysis.

STEP 1: Identify Control Technologies for SF_6

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. One alternative the Air District has considered is to substitute another, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers. One alternative to SF_6 would be use of a dielectric oil or compressed air ("air blast") circuit breaker, which historically were used in high-voltage installations prior to the development of SF_6 breakers. This type of technology is feasible for use here, although SF_6 has become the predominant insulator and arc quenching substance in circuit breakers today because of its superior capabilities.[70]

Another alternative the Air District has considered is to use state-of-the-art SF_6 technology with leak detection to limit fugitive emissions. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. The best modern equipment can be guaranteed to leak at a rate of no more than 0.5% per year (by weight). In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

Gas Emissions Source, June 2006, first published in Proceedings of the 2006 IEEE Power Engineering Society General Meeting, Montreal, Quebec, Canada (June 2006), available at: www.epa.gov/electricpower-sf6/documents/leakrates_circuitbreakers.pdf.
[68] Alstom USA Inc., *Instruction Manual-Type HGF 1012/1014*, HG12IM, Revision 0, Part 1, Page 10, 19.
[69] Letter, David, Mehl (California Air Resources Board, Manager, Energy Section), *Re: Sulfur Hexafluoride (SF6) Emissions Survey for the Electricity Sector and Particle Accelerator Operators*, January 13, 2009, available at: www.arb.ca.gov/cc/sf6elec/survey/surveycoverletter.pdf.
[70] *See* Christophorou, L.G., J.K. Olthoff and D.S. Green, National Institute of Standards and Technology (NIST), Electricity Division (Electronics and Electrical Engineering Laboratory) and Process Measurements Division (Chemical Science and Technology Laboratory), *NIST Technical Note 1425: Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*, November 1997 (hereinafter, "*NIST Technical Note 142*"), available at: www.epa.gov/electricpower-sf6/documents/new_report_final.pdf.

The Air District also considered the possibility of other emerging technologies that would replace SF_6 with a material that has similar dielectric and arc-quenching properties, but without the drawbacks of oil and air-blast breakers.

STEP 2: Eliminate Technically Infeasible Options

The Air District next examined the technical feasibility of each of the control alternatives identified. Looking at oil or air-blast circuit breakers, the Air District concluded that this alternative is not technically feasible for this project because it would require significantly larger equipment to replicate the same insulating and arc-quenching capabilities of the SF_6 breakers.[71] The proposed project site does not have adequate space within the switchyard to accommodate oil or air-blast breakers. As previously noted, the project has been proposed for location in a densely populated area because, according to the Energy Commission, the project's objectives were "[t]o locate near centers of demand and key infrastructure, such as transmission line interconnections, supplies of process water (preferably wastewater), and natural gas at competitive prices", and "[t]o serve the electrical power needs of the East Bay, San Francisco Peninsula, and City of San Francisco."[72] As a consequence, replacement of the proposed circuit breakers with breakers that do not use SF_6 is not a feasible option for this Project, given the space constraints imposed by construction of the Project on a former industrial site near a source of recycled waste water.

As for the feasibility of enclosed-pressure SF_6 circuit breakers with leak detection, which are far smaller than oil/air-blast breakers for the same application, they are feasible for this location. The project proponent has proposed to use this equipment because of its performance benefits.

Finally, the Air District also evaluated the technical feasibility of emerging alternatives to SF_6. According to the most recent report released by the EPA SF_6 Partnership, "[n]o clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties."[73] Research and development efforts have focused on finding substitutes for SF_6 that have comparable insulating and arc quenching properties in high-voltage applications.[74] While some progress has reportedly been made using mixtures of SF_6 and other inert gases (*e.g.*, nitrogen or helium) in lower-voltage applications, most studies have concluded, "that there is no replacement gas immediately available to use as

[71] Although the Air District's assessment is that oil and air-blast breakers are not feasible for this project, the District also conducted a BACT comparison between oil/air-blast breakers and SF6 breakers in Step 4 discussed below. The Air District has concluded that oil/air-blast breakers would be eliminated from the BACT analysis for two separate and independent reasons, because they are technically infeasible under Step 2 and because their ancillary impacts outweigh their net emission benefits under Step 4.

[72] 2002 Energy Commission Decision, *supra* note 15, at p. 17.

[73] SF_6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report, December 2008, at p. 1 (available at www.epa.gov/electricpower-sf6).

[74] *See, e.g.*, NIST Technical Note 142, *supra* note 70; *see also* U.S. Climate Change Technology Program, Technology Options for the Near and Long Term, November 2003, § 4.3.5, "Electric Power System and Magnesium: Substitutes for SF_6", at 185; available at: www.climatetechnology.gov/library/2003/tech-options/tech-options-4-3-5.pdf

an SF_6 substitute"[75] for high-voltage applications. The Air District therefore eliminated this alternative as technically infeasible.

STEP 3: Rank Control Technologies

The Air District then ranked the feasible control technologies. The most effective (and only) control technology that the Air District found to be technically feasible is to use state-of-the-art enclosed-pressure SF_6 circuit breakers. According to information from circuit breaker manufacturers, this equipment can be guaranteed to achieve a leak rate of 0.5% or less.[76] This leak rate meets the current maximum leak rate standard established by the International Electrotechnical Commission ("IEC").[77] This leak rate performance will be further enhanced by an alarm system to alert operators to potential leak problems as soon as they emerge.

Although the District found that oil/air-blast breakers would not be feasible for this particular project, the District nevertheless undertook a comparison between this alternative and the enclosed-pressure SF_6 alternative, which is outlined below. Oil/air-blast breakers would be the top-ranked alternative (with essentially no greenhouse gas emissions) if they had not been eliminated as infeasible. The District has undertaken this additional analysis to compare these two technologies, even though oil/air-blast breakers have already been eliminated, to see whether this alternative would be more attractive if it were feasible here.

STEP 4: Evaluate Most Effective Controls and Economic Impacts and Document Results

Step 4 of the top-down analysis involves consideration of the ancillary energy, environmental and economic impacts associated with using the top-ranked control technologies. Although the Air District eliminated oil/air-blast circuit breakers as not technically feasible at Stage 2 of the Top-Down analysis, the Air District has nevertheless compared that technology to SF_6 breakers to see how it would compare if it were feasible. This comparison shows that the use of the larger oil/air-blast breakers would have significant ancillary environmental impacts that would offset its greenhouse gas benefits, even if it were feasible. Oil/air-blast breakers would require additional land to be devoted to the project, would generate additional noise, and would increase the risks of accidental releases of dielectric fluid and/or associated fires. By contrast, according to the National Institute for Standards and Technology, SF_6 "offers significant savings in land use, is aesthetically acceptable, has relatively low radio and audible noise emissions, and enables substations to be installed in populated areas close to the loads."[78] Accordingly, even if oil/air-blast breakers were not eliminated at Step 2 of the top-down analysis, they would not surpass the choice of SF_6 breakers in Step 4 because of their adverse ancillary environmental impacts.

[75] Siemens TechTopics No. 53, *Use of SF_6 Gas in Medium Voltage Switchgear*, Siemens Power Transmission & Distribution, Inc. (June 3, 2005), (available at www.energy.siemens.com/cms/us/US_Products/CustomerSupport/TechTopicsApplicationNotes/Documents/TechTopics53Rev0.pdf), at p. 3.

[76] Email message from Tony Conte, Sr. Account Manager, ABB, 4/28/09; email message from Jason Cunningham, Regional Sales Manager, HVB AE Power Systems, Inc., 4/27/09.

[77] IEC Standard 62271-1, 2004.

[78] *NIST Technical Note 1425*, supra note 70, at p. 3.

STEP 5: Select BACT

Based on this top-down analysis, Air District concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection would be the BACT control technology option. Breakers using oil or compressed air as a dielectric material are not technically feasible here because of their greatly increased size, and even if they were feasible the offsetting ancillary impacts would not preclude the choice of SF_6.

Select Appropriate BACT Emissions Limit

State-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection is BACT should be able to maintain fugitive SF_6 emissions below 0.5% (by weight).[79] The Russell City Energy Center will require 5 breakers using 145 lbs. of SF_6 each, for a total inventory of 725 lbs SF_6. At a leak rate of 0.5%, annual SF_6 emissions would be a maximum of 3.6 lbs/year, which would equal approximately 39.3 metric tons CO_2E per year. The Air District is therefore incorporating an annual emissions limit of 39.3 metric tons CO_2E per year into the final permit.

Fugitive emissions are, by their nature, very difficult to monitor directly as they are not emitted from a discrete emissions point. Fugitive SF_6 emissions can be estimated very accurately, however, by measuring "top-ups", *i.e.*, the replacement of lost SF_6 with new product.[80] One can conservatively (and very accurately) assume that the amount of SF_6 that has leaked and entered the atmosphere is the amount that has to be topped up to maintain a full SF_6 level. The Air District is therefore not requiring monitoring of SF_6 fugitive emissions directly, but is instead requiring surrogate monitoring through measuring the amount of SF_6 lost and using a conversion factor to assess annual SF_6 fugitive emissions in terms of CO_2E. The facility will be required to calculate annual fugitive emissions in this manner to ensure compliance with the 39.3 metric ton CO_2E limit. These monitoring and recordkeeping requirements are consistent with the requirements in other regulatory approaches to the SF_6 fugitive emissions issue.[81]

In addition, as mentioned above, the Air District will require the use of an alarm system to alert controllers when a circuit breaker loses 10% of its SF_6. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The facility will also be required to investigate any alarms and take any necessary corrective action to address any problems.

[79] IEC Standard 62271-1, 2004; email message from Tony Conte, Sr. Account Manager, ABB, 4/28/09; email message from Jason Cunningham, Regional Sales Manager, HVB AE Power Systems, Inc., 4/27/09.

[80] *SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source*, *supra* note 67, at p. 1.

[81] *See generally* California Air Resources Board's Regulation for the Mandatory Reporting of Greenhouse Gas emissions, 17 Cal. Code Regs. §§ 95100 *et seq.* (hereinafter, "Mandatory Reporting Rule") (available at: www.arb.ca.gov/regact/2007/ghg2007/frofinoal.pdf). (Note that the Mandatory Reporting Rule contains a *de minimis* exemption that is not being included in the Federal PSD Permit reporting requirements.) The Mandatory Reporting Rule adopts the reporting protocol developed by EPA's SF_6 Partnership methodology, which requires tracking of the change in inventory, purchases/acquisitions and sales/disbursements of SF_6, and the change in total nameplate capacity. It also adopts the EPA SF_6 Partnership's reporting protocol form, which appears at Appendix A-21.

E. Miscellaneous Greenhouse Gas Issues

The Air District has received comments stating that the District should include all greenhouse gas emissions in its BACT analysis, and not just CO_2. These comments specifically stated that the BACT analysis should include emissions of methane, N_2O, SF_6, and NH_3. In consideration of this comment, the Air District has ensured that its greenhouse gas BACT analyses do in fact take all greenhouse gases into account. The analyses and the associated emissions limits address greenhouse gases in terms of CO_2-equivalent emissions ("CO_2E"), which takes into account all greenhouse gases and provides a convenient measure for comparing the relative impacts of emissions from different sources. The Air District's analyses do not include NH_3 as a greenhouse gas, however, because it does not have a significant demonstrated potential for impacting climate change. If any members of the public continue to believe that NH_3 should be included as a greenhouse gas in these analyses, the Air District invites the public to submit additional comment as to why NH_3 should be considered a greenhouse gas.

The Air District also received comments stating that the "license should acknowledge the green house gas fees to be paid to the BAAQMD." These comments are correct that greenhouse gas emissions sources such as the proposed Russell City Energy Center will be subject to a permit fee that the Air District charges under its state-law authority to help defray the costs of its climate protection work, and the Air District acknowledges that here. But these fees are charged in connection with permit issuance and annual renewal, and are not established as permit conditions. There is no benefit from putting the fee requirement in the permit conditions, as the fees are enforceable and recoverable at the time when the permit is renewed each year. Moreover, these fees are not part of the federal PSD permit program, and so they would not belong in a Federal PSD permit in any event.

IV. NO_2 BACT ISSUES

The District also received several comments on its BACT analysis for NO_2. These comments are addressed in this section.

A. Control Technology Comparison/Selection

The Air District received several comments expressing a concern that some of the sources of information used to compare the energy and economic impacts of SCR and EMx control technologies are now several years old. For example, commenters questioned whether there may be some better method of estimating the costs of using an SCR control system than using the ONSITE SYCOM Energy Corp. cost analysis adjusted for inflation using the consumer price index; and whether it was appropriate for the District to rely on a study from 2000 in comparing the energy impacts of SCR and EMx control options.

The Air District continues to support its initial BACT analysis for NO_2, but would like to take this opportunity to clarify its analysis regarding these issues in the record. The Air District does not believe that any of the information it used to compare SCR and EMx as control technologies for NO_2 emissions is unreliable as a result of its age. With respect to the relative costs of the two technologies, some of the underlying information the Air District used in its analysis was several years old (although other sources were current), but the Air District adjusted those costs for inflation over that time period to obtain cost estimate information in current dollars. (*See* Statement of Basis at pp. 25-26 and fn. 19.) Adjusting costs for inflation in this way is a well-accepted method of estimating current costs, and the Air District has no reason to believe that these estimates are inaccurate. If any members of the pubic believe that these estimates are inaccurate, the Air District invites comment on how they are inaccurate. Moreover, if any members of the public believe that they have more accurate estimates, the Air District invites the public to submit their estimates during the comment period.

With respect to the analysis of ancillary energy and environmental impacts, these control technology alternatives have not changed in any significant way since the various sources of information cited in the Statement of Basis were published, and so there is no reason to doubt their current validity for purposes of the BACT comparison. Neither technology has changed in any significant way, and so attributes such as ammonia use, water consumption, and energy penalty implicit in these technologies have not changed in any significant way either. The Air District therefore does not find any reason to question the continued validity of the information it used in its energy and ancillary environmental impact comparison. If any members of the public believe that they have more accurate information in these areas, the Air District invites the public to submit this information during the further comment period.

Finally, the Air District notes that although the commenters have questioned the vintage of some of the sources of information that the Air District used in comparing these two technologies, the Air District did not receive any comments suggesting that its ultimate conclusion was incorrect: that neither of the two alternative technologies has any ancillary impacts significant enough to warrant elimination from consideration as a BACT technology. To the extent that any members of the public believe that the Air District should have used more accurate information in its

analysis, the District invites the public to comment on how different information would have led to a different conclusion in the BACT analysis of these two technologies.[82]

B. Potential Risks From Ammonia Spills/Releases

As the Air District found in the initial Statement of Basis, the risks of accidental releases of ammonia from the SCR system are relatively minor and will be adequately addressed under applicable industrial safety codes and standards, given the safety requirements outlined in the Energy Commission's licensing documentation. (*See* Statement of Basis at p. 26 and fn. 20.) These safety measures include the Risk Management Plan requirement pursuant to Section 112(r) of the Clean Air Act and the California Accidental Release Prevention Program, which must include an off-site consequences analysis and appropriate mitigation measures; a requirement to implement a Safety Management Plan (SMP) for delivery of ammonia and other liquid hazardous materials; a requirement to instruct vendors delivering hazardous chemicals, including aqueous ammonia, to travel certain routes; a requirement to install ammonia sensors to detect the occurrence of any potential migration of ammonia vapors offsite; a requirement to use an ammonia tank that meets specific standards to reduce the potential for a release event; and a requirement to conduct a "Vulnerability Assessment" to address the potential security risk associated with storage and use of aqueous ammonia onsite. Given the relatively low risk of accidental releases and the additional safeguards provided by these measures, the District concluded that the potential for impacts from the use of ammonia in the SCR system was not significant enough to reject SCR as a control alternative. The Air District continues to believe that this position is the correct one based on all of the available information, and solicits further public comment on this issue to the extent that any members of the public disagree.

The Air District did receive comments during the initial comment period claiming that the CEC found that the there will be a significant risk of health impacts from an accidental ammonia spill, and that the Air District incorrectly characterized the CEC's findings on this point. The Air District would like to take this opportunity to clarify the record on this point. The Energy Commission expressly found that "[t]he Hazardous Materials Management aspects of the project do not create significant direct or cumulative environmental effects."[83] This finding was based (at least in part) on the conclusions of the CEC staff's Final Staff Assessment, which found that with the appropriate mitigation measures and safeguards against accidental releases, "impacts

[82] One comment also questioned why, according to the Statement of Basis, it is "not known" whether Kawasaki Heavy Industries plans to make XONON technology available for other manufacturers' turbines, and whether the District should research this information further. The Air District has not researched whether XONON-brand catalytic combustors will be made available for other manufacturers' turbines because this type of combustion technology is available only for small turbine applications, and is not available for large-scale combustors used in large facilities such as this one. The Air District therefore concluded that this technology is not available as a BACT technology choice, making the issue of what manufacturers can provide the technology moot. If any members of the public believe that this is an issue that is relevant to the PSD Permit analysis, the Air District invites further comment as to why.

[83] 2007 Commission Decision, *supra* note 27, p. 115, Finding 3.

from the use and storage of hazardous materials [will be] less than significant."[84] Of course, if a major ammonia release was to occur, that situation would entail significant impacts. But the Energy Commission found that the safeguards in place to prevent and/or mitigate any accidental ammonia releases would adequately address this risk, and therefore that the overall impact from the use of ammonia at the facility would not be significant. This finding is consistent with the Air District's assessment in the Statement of Basis – that the potential for harm from accidental ammonia releases are not significant enough to rule out an SCR system using ammonia as a BACT technology. The commenters may have misunderstood the Air District's analysis on this point based on a sentence in the Statement of Basis that could be read to mean that the Air District believes that if an ammonia release occurred it would not have significant impacts. The Air District did not intend to take such a position, and agrees with the CEC and the commenters that an accidental ammonia release could potentially cause very significant impacts, and that this point is clear and indisputable regardless of any modeling that might be done. The Air District's conclusion in the Statement of Basis was that with the appropriate risk management requirements in place, the risk from the use of ammonia would not be significant enough to rule out SCR with ammonia use as a BACT alternative. The Air District invites any further comment that the public may have based on this analysis.

The Air District also received comments questioning whether the applicant has completed condition HAZ-2 of the CEC's conditions of certification (regarding preparation of a Risk Management Plan and Hazardous Materials Business Plan), and asking whether the District should review those plans in assessing the significance of the risks of a potential accidental ammonia releases. The Air District notes that this point that the detailed requirements for Risk Management Plans, Hazardous Materials Business Plans, and the other related hazardous materials safeguards are set forth in the applicable statutes and regulations that govern those plans. They are reviewed by the appropriate review bodies (*e.g.*, the hazardous materials division of the local fire department) before the facility begins operation. Those review bodies are the appropriate expert agencies to ensure that all of the applicable safeguards and precautions are in place. There Air District has no reason to believe that it should (or even could) conduct its own review to ensure that these safety requirements are being met. If any members of the public believe that the Air District cannot issue the Federal PSD Permit before the facility has completed these requirements (or before the District has reviewed them), the Air District solicits further comment as to why.

The Air District also received comments stating that if it does choose an SCR-type system, it should require the use of urea instead of ammonia in order to reduce the potential for impacts from accidental ammonia releases. The comments cited a technology called NOxOUT ULTRA that they claimed is feasible to allow the substitution of urea for ammonia. The NOxOUT ULTRA technology cited by the commenters generates ammonia from urea just before it is injected into the SCR system, which eliminates the need to store any significant amount of ammonia at the site. The elimination of ammonia storage would alleviate the risk of any significant amount of ammonia being released accidentally, and so it is worth evaluating as an

[84] California Energy Commission, *Russell City Energy Center, Staff Assessment – Part 1 and Part 2 Combined, Amendment No. 1 (01-AFC-7C)* (June 2007), CEC 700-2007-005-FSA, at pp. 4.4-5.

alternative technology. The Air District has considered this issue further in light of these comments and has concluded that requiring a urea SCR system over an ammonia system would not be the most appropriate BACT alternative. Although urea substitution could reduce the potential for accidental ammonia releases, the Air District has found that it would involve offsetting negative environmental impacts in the form of increased emissions of formaldehyde, a hazardous air pollutant and toxic air contaminant. The Air District reviewed data from a similar facility in Sumas, Washington, which demonstrated that urea injection (as opposed to the use of ammonia) resulted in a nearly five-fold increase in formaldehyde emissions.[85] These additional formaldehyde emissions, which would occur whenever the facility operates, substantially outweigh the benefits in further reducing the already low risk of a potential ammonia release event.

C. Secondary Particulate Impacts From Ammonia Slip

The Air District also received some comments suggesting that the potential for ammonia slip from the facility's NOx control equipment should be evaluated as a collateral environmental impact in terms of its potential for the ammonia slip to form secondary particulate matter. The Air District has considered that issue in detail as explained in the section on particulate matter emissions below. (*See* Section VI.C.) As explained there, the Air District has concluded that ammonia slip emissions are not a significant contributor to secondary particulate matter formation and thus are not a significant collateral environmental impact that would rule out the selection of SCR as a control technology for NO_2 compared with EMx technology.[86] The Air District examines collateral environmental impacts such as this on a case-by-case basis and does not have a bright-line rule for when a collateral impact would be considered "significant" or not. But certainly, in a case such as this one where the available evidence suggests that ammonia slip in fact will not cause significant secondary PM, the potential for such impacts would not be significant enough to eliminate a particular control technology.

D. NO_2 Permit Limits

The Air District also received a comment stating that the hourly BACT limit for NOx was updated in the 2007 permitting process, and was reduced from 2.5 ppm to 2.0 ppm, but the annual limit was not adjusted accordingly. In light of this comment, the District would like to clarify that the annual limit established in the 2002 permitting process was based on average annual emissions of 2.0. The Air District concluded during that permitting process that although short-term NOx emissions could be as much as 2.5 ppm, on average over the longer term they would not exceed 2.0 ppm. This new lower short-term limit represents a very stringent BACT

[85] *See* Valid Results, Inc., test report for June 13, 2002, EPA Method 316 Source Test (0.226 tpy formaldehyde emissions with urea); email message from Brian Fretwell to Barbara McBride, Calpine, March 4, 2009 (prior test without urea was 0.049 tpy formaldehyde emissions).

[86] The Air District notes that with respect to NOxOUT ULTRA, both SCR and NOxOUT ULTRA use ammonia in the NOx control reaction. The only difference with NOxOUT ULTRA is that it generates the ammonia from urea just prior to ammonia injection, so the facility does not have to store significant amounts of ammonia on-site. Ammonia emissions – as opposed to ammonia storage – is not a relevant issue in the comparison between these two technologies.

standard, and the Air District has no evidence to suggest that the facility will be able to maintain average emissions significantly below 2.0 over the long term. The Air District therefore used 2.0 ppm as the average emissions rate when calculating the annual facility NO_2 permit limit.

V. CARBON MONOXIDE BACT ISSUES

The Air District also received several comments on its BACT analysis for Carbon Monoxide suggesting that the CO BACT limit should be lower than the 4.0 ppm the Air District initially proposed. The Air District has reconsidered its BACT determination and is now proposing a lowered BACT limit for CO, at 2.0 ppm (1-hour average). The Air District reevaluated the operating data from the Metcalf Energy Center, which is a similar facility that the District looked to in its original analysis, and notes that the CEM data show that only 0.4% of the days of operation showed any exceedance of 2.0 ppm after the first year of operation. The Air District has concluded that a more critical analysis of this data suggests that it should be possible to design the system to ensure that Carbon Monoxide emissions are maintained below 2.0 ppm at all times.

The Air District also examined a number of other CO permit conditions for other facilities – many of which were pointed out in comments submitted during the initial comment period – and found that the consensus of permitting agencies around the country appears to be forming around a CO BACT limit of 2 ppm. The Air District notes that there were a total of 8 permits identified in the initial Statement of Basis with Carbon Monoxide limits of 2 ppm (either with 1-hour averages or 3-hour averages), suggesting an emerging consensus that this performance level is achievable. (*See* Statement of Basis, Table 11, pp. 32-33.) Based on this further assessment of the data, and on the large number of permitting agencies that have required other similar facilities to limit CO emissions to 2.0 ppm averaged over 1 hour, the Air District concludes that this 2.0 ppm limit (1-hour average) should be required here as BACT. If this limit is being applied and demonstrably achieved at other facilities, that fact supports a presumption that it is an achievable limitation at this facility for purposes of BACT.[87]

The Air District also considered whether it might be appropriate to impose a BACT CO limit below 2.0 ppm. The District notes that (as comments pointed out) permits have been issued containing Carbon Monoxide limits below 2.0 ppm for Kleen Energy Systems[88] and CPV Warren, suggesting that CO emission limits below 2.0 ppm may be achievable for certain facilities. The Air District notes that neither of these facilities has actually been built yet and so there is no operating data available on which to assess whether they will actually be able to meet these lower limits. This point, along with the fact that the consensus among other permitting

[87] The Air District disagrees with the comments that the mere issuance of a permit with a particular limit establishes that limit as BACT, without some further demonstration that the limit is achievable. A permitting agency may issue permits with very stringent limits with little or no technical justification at all if the applicant does not object to it. In such a situation, where there is no justification for the limit nor any operating data to show that the limit can be complied with, the mere existence of the permit limit would not, without more, establish that the limit is achievable as a technical matter. But this point is moot here, as the Air District has reviewed data and conducted a detailed analysis and has on this bases concluded that the 2.0 ppm limit is achievable as BACT.

[88] New Source Review Permit to Construct and Operate a Stationary Source, issued to Kleen Energy Systems, LLC, by Connecticut Department of Environmental Protection, Bureau of Air Management, February 25, 2008.

agencies appears to have coalesced around 2.0 for most facilities, underscores the requirement that lower limits must be considered on a case-by-case basis. The Air District has therefore evaluated whether a CO emissions limit of less than 2.0 ppm would be achievable by this particular facility, "taking into account energy, environmental and economic impacts and other costs" as is required in establishing a BACT limit.

To undertake this analysis, the Air District evaluated information from the applicant on the costs and emissions reduction benefits of installing a larger oxidation catalyst capable of consistently maintaining emissions below 1.5 ppm.[89] Based on these analyses, the cost of achieving a 1.5 ppm permit limit would be an additional $179,600 per year (above what it would cost to achieve a 2.0 ppm limit), and the additional reduction in CO emissions would be approximately 11 tons per year, making an incremental cost-effectiveness value of over $16,000 per ton of additional CO reduction.[90] Moreover, the total cost of achieving a 1.5 ppm CO limit (as opposed to the incremental costs of going from 2.0 ppm to 1.5 ppm) would be over $840,000 per year, and the total emission reductions of a 1.5 ppm limit would be 186 tons per year, making a total (or "average") cost effectiveness value of over $4,500.[91] Based on these high costs (on a per-ton basis) and the relatively little additional CO emissions benefit to be achieved (on a per-dollar basis), requiring a 1.5 ppm CO permit limit cannot reasonably be justified as a BACT limit. Requiring controls to meet a 1.5 ppm limit would be far more expensive, on a per-ton basis, than what other similar facilities are required to achieve. The Air District has not adopted its own cost-effectiveness guidelines for CO,[92] but a review of other districts in California found none that consider additional CO controls appropriate as BACT where the total (average) cost-effectiveness will be greater than $400 per ton, or where the incremental cost-effectiveness will be over $1,150 per ton.[93] Moreover, a review of recent CO BACT determinations in EPA's RACT/BACT/LAER Clearinghouse did not reveal any permits that had imposed CO controls at a cost-per-ton in the range that would be required here. The permits in the Clearinghouse going

[89] A potential lower limit of 1.5 ppm provides a reasonable basis for this analysis because that number is in the middle of the range of permit limits below 2.0 found in the other permits the Air District reviewed. Given that the results of the cost-effectiveness analysis for a 1.5 ppm limit are well above what has been required at other similar facilities to achieve CO reductions, the Air District has no reason to believe that any other limits below 2.0 ppm would be cost-effective for purposes of the BACT analysis, either.

[90] *See* Spreadsheet, Incremental Cost Effectiveness Analysis for CO Control From 2 to 1.5 ppmv, prepared by Barbara McBride, Calpine Corp., reviewed by Weyman Lee, P.E., BAAQMD.

[91] *See* Spreadsheet, Average/Total Cost Effectiveness Analysis for CO Control from 2 to 1.5 ppmv, prepared by Barbara Mcbride, Calpine Corp., reviewed by Weyman Lee, P.E., BAAQMD.

[92] Bay Area Air Quality Management District Best Available Control Technology (BACT) Guideline, § 1, Policy and Implementation Procedure, available at: www.baaqmd.gov/pmt/bactworkbook/default.htm.

[93] South Coast Air Quality Management District, *Best Available Control Technology Guidelines*, August 17, 2000, revised July 14, 2006, at 29; available at: http://www.aqmd.gov/bact/BACTGuidelines2006-7-14.pdf; Memorandum, David Warner, Director of Permit Services, to Permit Services Staff, Subject: "Revised BACT Cost Effectiveness Thresholds", May 14, 2008; available at: www.valleyair.org/busind/pto/bact/May%202008%20updates%20to%20BACT%20cost%20effectiveness%20thresholds.pdf.

back through 2005 that included cost-effectiveness information showed a limit of 1.8 ppm being imposed based upon an average cost-effectiveness of $1,750 per ton of CO;[94] a limit of 3.5 ppm based upon an average cost-effectiveness of $2,736 per ton and an incremental cost-effectiveness of $5,472 per ton;[95] and a limit of 2.0 ppm an average cost-effectiveness of $1,161 per ton of CO.[96] Both the average and incremental cost-effectiveness values of imposing a 1.5 ppm limit for the Russell City facility would be substantially higher than what was required for any of these other similar facilities.

Because both the average and incremental costs per ton of CO that would be reduced by imposition of a CO limit below 2.0 ppmvd are significantly higher than the costs that have been or would be required at other similar facilities, the Air District is proposing not to require that level of control as BACT. Although it appears that an additional reduction below 2.0 ppm may well be feasible based on permits that have been issued to other facilities, the Air District would eliminate it as a BACT requirement in Step 4 of the Top-Down BACT analysis because it is not "achievable" for purposes of a BACT analysis taking into account cost/economic impacts.

Finally, the Air District received a comment claiming that different types of oxidation catalysts available for controlling CO will have different impacts on HAP and POC emissions, citing a 2002 EPA memorandum regarding HAP emissions from combustion turbines ("Roy Memorandum").[97] This comment claimed that the District should evaluate the differences between different types of oxidation catalysts in its CO BACT analysis. The Air District disagrees that there is evidence that different kinds of oxidation catalysts will have different impacts on HAP and POC emissions. The memorandum the comment relies on does not state that different oxidation catalysts will have different impacts on HAP and POC emissions. To the contrary, the memorandum (including its attachment) identify several specific types of catalysts, such as platinum, palladium, rhodium, and metal oxides, and discusses them all generally simply as "oxidation catalysts". (*See* Roy Memorandum at p. 6.) Moreover, the memorandum does not claim that SCONOx has any different impact on HAP or POC emissions than any other type of oxidation catalyst. To the contrary, it explicitly states that the two technologies are "comparable" in this regard, and in fact bases its evaluation of all oxidation catalysts generally on an evaluation of SCONOx. (*See id* at p. 1.) The only difference the memorandum points out between the two technologies is that SCONOx uses a chemically modified catalyst so that the catalyst also removes NOx. (*See id.*) For the Russell City Energy Center, the District is proposing to approve SCR for NOx control, and so the NOx-removal aspect of SCONOx does not provide any improvement over the combination of SCR for NOx control and an oxidation catalyst for CO control. The Air District is unaware of any studies on different types of

[94] U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. GA-0127, for permit issued to Southern Company/Georgia Power Plant McDonough Combined Cycle, Permit No. 4911-067-0003-V-02-2, issued January 7, 2008.

[95] U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. NV-0035, for permit issued to Sierra Pacific Power Company Tracey Substation Expansion Project, Permit No. AP4911-1504, issued August 16, 2005.

[96] U.S. EPA RACT/BACT/LAER Clearinghouse Identification No. OR-0041, Wanapa Energy Center, Permit No. R10PSD-OR-05-01, August 8, 2005.

[97] The memorandum cited is available at www.epa.gov/ttn/atw/combust/turbine/cttech8.pdf.

oxidation catalysts and associated abatement efficiencies for VOCs and HAPs, and has found nothing in this comment or elsewhere that warrants revising the BACT analysis for CO.

VI. PARTICULATE MATTER ISSUES

The Air District has made several revisions to its permit analysis with respect to particulate matter issues. The Air District's further analysis on these issues is discussed in this section.

A. Additional BACT Analysis Regarding Lowering Particulate Matter Emissions

Since the Air District initially issued the Draft Federal PSD permit, the District has explored whether particulate emissions limits for the turbines and heat recovery boilers could be further reduced in order to ensure that the facility will not cause exceedances of the National Ambient Air Quality Standards for particulate matter. Based on this further review, the Air District is proposing a revised limit on particulate matter emissions (for both PM_{10} and $PM_{2.5}$) from each gas turbine and heat recovery boiler train of 7.5 lb/hr or 0.0036 lb/MMBTU natural gas fired (with or without duct firing). This emissions limit would include all filterable and condensable particulate emissions (*i.e.*, "front" and "back" half, respectively).

The Air District has concluded that a lower limit of 7.5 lb/hr would be achievable by this equipment based on a review of additional source testing data from a number of similar combined-cycle facilities. These 73 source tests showed average particulate emissions of 4.58 lb/hr, with a high of 10.65 lb/hr.[98] The Air District believes that some of the higher test results may be attributed to anomalies in the testing and analytical methods, the influence of which may be mitigated by application of more rigorous quality assurance/quality control ("QA/QC") by the testing contractor or analytical laboratory. The Air District has therefore concluded that it would not be appropriate to establish a compliance margin that would accommodate these high test results. Instead, the Air District is discounting the highest 5% of the test results (4 of the 73), and proposing a permit limit based on the remaining 95%. This approach yields a proposed permit limit of 7.5 lb/hr. The Air District has also reviewed available permits for other similar facilities and has not found any lower permit limits. The Air District is therefore proposing a revised $PM_{10}/PM_{2.5}$ limit for each gas turbine/heat recovery boiler train of 7.5 lb/hr, or 0.00335 lb/MMBTU of natural gas fired, as the BACT limit for the sources. The Air District is also revising its proposed conditions for the daily and annual particulate matter limits accordingly.

The Air District also conducted a similar review of the BACT limits for particulate matter emissions from the cooling tower. As noted in the initial Statement of Basis, the cooling tower can contribute to particulate matter emissions through solids dissolved in the water used in the cooling system, which can be emitted in the water vapor exhausted through the cooling tower. The Air District concluded that imposing a direct numerical limitation on emissions of PM from the cooling tower was infeasible, and instead proposed to limit the Total Dissolved Solids

[98] Each source test result represents the average of multiple test runs (3 in most cases) performed on the same unit. For a summary of the source test results, see spreadsheet, "Summary of Filterable PM_{10}", submitted by B. McBride (Director, Environment, Health and Safety, Calpine Corporation) to B. Bateman (Director, Engineering/Toxic Evaluation, Air District), W. Lee (Senior AQ Engineer, Engineering/Permit Evaluation, Air District) and B. Nishimura (Supervising AQ Engineer, Engineering/Permit Evaluation, Air District), by email dated June 10, 2009.

("TDS") in the cooling water to 8,000 parts per million by weight (along with a requirement to equip the cooling tower with high-efficiency drift eliminators guaranteed to achieve less than 0.0005 percent drift). (*See* Statement of Basis at p. 78 & proposed Condition No. 44.)

The Air District has conducted a further analysis of TDS data from the source of the proposed facility's cooling water, the City of Hayward's Waste Water Treatment Plant, which is adjacent to the proposed facility. Based on this analysis, the Air District has concluded that the facility should be able to keep the TDS of the cooling water at 6200 ppm or below. The Air District is therefore revising the proposed BACT limit for TDS from 8000 ppm to 6200 ppm.

B. Recent Regulatory Developments Regarding $PM_{2.5}$

There have also been several regulatory developments regarding particulate matter since the Air District issued the initial Draft PSD Permit and Statement of Basis. First, EPA has decided to reconsider (and apparently to repeal) its recently-adopted provision in 40 C.F.R. 52.21(i)(1)(xi) that directs PSD permitting agencies to use the so-called PM_{10} "surrogate" approach in addressing $PM_{2.5}$ compliance issues. EPA also stayed the effectiveness of Section 52.21(i)(1)(xi) while the reconsideration proceedings are underway. These developments make clear that EPA is changing its guidance on how to address $PM_{2.5}$ issues for PSD permitting purposes, and in response the Air District has concluded that $PM_{2.5}$ issues must be addressed directly and not through reliance on the surrogate policy.[99] This development means that the PSD permit analysis must (i) demonstrate that the facility will use Best Available Control Technology to control $PM_{2.5}$ emissions; and (ii) conduct an Air Quality Impact Analysis showing that the facility will not contribute to an exceedance of the $PM_{2.5}$ NAAQS (either the 24-hour standard or the annual standard).

Second, the outgoing EPA administrator signed a Federal Register notice on December 18, 2008, that would have the effect of designating the Bay Area as non-attainment of the National Ambient Air Quality Standard for $PM_{2.5}$ (24-hour average).[100] Although the document was signed by the outgoing EPA Administrator, the incoming administration has thus far declined to go ahead and actually publish it in the Federal Register. For that reason, the non-attainment designation has not become effective, and will not become effective for 90 days after Federal Register publication. This situation leaves the Bay Area in a sort of regulatory limbo on this issue, as the region is technically still unclassified for $PM_{2.5}$ (24-hour average) but is subject to an impending non-attainment designation that could become effective in the near future. This situation impacts the proposed Russell City permit because if the Bay Area remains unclassified, it will continue to be subject to PSD permitting requirements for $PM_{2.5}$ (24-hour average), but if the Bay Area becomes non-attainment the facility will be subject to Non-Attainment NSR permitting requirements for $PM_{2.5}$ (24-hour average).

[99] The granting of reconsideration and the issuance of the stay were made by letter from the EPA Administrator dated April 24, 2009, and in a subsequent Federal Register Notice dated June 1, 2009 (74 Fed. Reg. 26098). Before Section 52.21(i)(1)(xi) was adopted, the *status quo* was to follow published EPA policy guidance mandating the use of the surrogate approach, and there may be an argument that with Section 52.21(i)(1)(xi) stayed the situation should revert to that *status quo*. But the Administrator made clear in her letter that EPA considers that policy "no longer substantially justified . . . ," and will propose to repeal it. The Air District takes this as guidance rejecting the use of the surrogate policy, which would supersede any earlier guidance to the contrary.

[100] The re-designation as non-attainment was for the 24-hour standard only; the Bay Area would remain unclassifiable for the annual standard.

The Air District is addressing this rapidly-evolving situation by proposing two separate alternative routes for public review and comment: First, the Air District is proposing that in the event that the Bay Area remains unclassified for $PM_{2.5}$ (24-hour average), it will issue a Federal PSD Permit addressing $PM_{2.5}$ for both the 24-hour and annual standards. Second, the Air District is proposing that in the event the Bay Area is designated non-attainment during the remainder of this proceeding, the Air District will issue a Federal PSD Permit addressing $PM_{2.5}$ for the annual standard only, and will leave NSR applicability issues regarding the 24-hour standard subject to 40 C.F.R. Part 51, Appendix S, which contains the regulatory requirements for non-attainment areas in the interim between the date of designation as non-attainment and the time that the state can adopt its own SIP-approved Non-Attainment NSR permit requirements. These two alternative approaches are set forth below. The Air District seeks input and comment from the public on both alternatives, and proposes to proceed with the appropriate alternative depending on how regulatory developments unfold during the remainder of this permit proceeding.

1. Continued "Unclassifiable" Status For $PM_{2.5}$ (24-hour)

If the District continues to be designated unclassifiable for $PM_{2.5}$ (24-hour average), the proposed Russell City Energy Center will be subject to two additional general areas of regulatory requirements: BACT and the Air Quality Impacts Analysis.

The first main area of additional analysis is that the facility will have to use BACT to control $PM_{2.5}$ emissions in accordance with 40 C.F.R. Section 52.21(j). With respect to the combustion turbines and heat recovery boilers, the BACT analysis for $PM_{2.5}$ is the same as for PM_{10}. Particulate emissions from natural gas combustion are less than one micron in diameter, so by definition it is both $PM_{2.5}$ and PM_{10}.[101] $PM_{2.5}$ and PM_{10} are therefore one and the same for natural gas combustion, and so the District is therefore proposing to use the same BACT analysis for $PM_{2.5}$ as it is using for PM_{10}. The Air District incorporates by reference the analysis set forth in the initial Statement of Basis PM_{10} as applicable for $PM_{2.5}$ as well. The Air District is also adding proposed conditions that will be applicable for $PM_{2.5}$ for these sources, as well as monitoring and recordkeeping requirements to ensure compliance. For the diesel firepump engine, the BACT analysis concluding that BACT requires the use of ultra-low-sulfur diesel fuel and an EPA-certified engine is the same for $PM_{2.5}$ as well. This BACT requirement, which was described in the initial Statement of Basis on pp. 51-56, was applicable to all PSD pollutants covered in the initial Statement of Basis and is applicable to $PM_{2.5}$ as well. Use of ultra-low-sulfur diesel fuel and an EPA-certified engine will provide the maximum level of $PM_{2.5}$ emissions control that is achievable at this time. For the cooling tower, the BACT control requirements the District has proposed for PM_{10} – keeping Total Dissolved Solids (TDS) in the

[101] AP-42, Table 1.4-2, footnote c (available at www.epa.gov/ttnchie1/ap42/ch01/final/c01s04.pdf).

cooling water to the minimum feasible level and using high-efficiency drift eliminators[102] – are also the only effective mechanisms to control $PM_{2.5}$ emissions, and will ensure that $PM_{2.5}$ emissions are minimized to the maximum achievable extent consistent with the BACT requirements. The Air District solicits comment from interested members of the public on these $PM_{2.5}$ BACT issues.

Recent $PM_{2.5}$ regulations also require facilities to use BACT control technology to limit emissions of NOx and SO_2 as precursors to $PM_{2.5}$ formation, to the extent that the facility will emit those precursors in significant amounts.[103] NOx and SO_2 emissions are considered to be "significant" if they exceed 40 tons per year. (*See* 73 Fed. Reg. 28321, 28333 (May 16, 2008); 40 C.F.R. § 52.21(b)(23)(i).) The proposed Russell City facility will emit less than 40 tons per year of SO_2, but more than 40 tons per year of NOx. (*See* Statement of Basis at p. 14.) The facility must therefore use BACT to control NOx as a $PM_{2.5}$ precursor. The Air District has already evaluated NOx emissions and has proposed BACT limits for NOx in connection with the PSD requirements for NO_2, however. (*See* Statement of Basis at pp. 21-29.) No additional analysis or permit conditions are required to ensure compliance with this requirement.

The second main area of additional analysis is that the facility has to conduct an Air Quality Impact Analysis as required by 40 C.F.R. Sections 52.21(k)-(o). The facility has to undertake a Source Impact Analysis to show that it will not cause or contribute to an exceedance of the National Ambient Air Quality Standards or PSD increment for $PM_{2.5}$ as required by 40 C.F.R. Section 52.21(k); and has to conduct an additional impact analysis as required by 40 C.F.R. Section 52.21(o). These analyses have been conducted, and demonstrate that the proposed facility's $PM_{2.5}$ emissions (i) will not cause or contribute to an exceedance of any $PM_{2.5}$ NAAQS or increment; (ii) will not cause any significant impairment of visibility; and (iii) will not have any significant adverse impacts on soils and vegetation. These issues are discussed in detail in Section XI below, which addresses Air Quality Impacts Analysis issues. As explained in Section XI, the facility satisfies the Air Quality Impacts Analysis requirement in 40 C.F.R. Sections 52.21(k)-(o) with respect to $PM_{2.5}$ emissions.

2. Designation as "Non-Attainment" For $PM_{2.5}$ (24-hour)

In the event that the Bay Area is designated as non-attainment for the $PM_{2.5}$ 24-hour average standard, the Air District proposes to interpret this "split" designation (*i.e.*, non-attainment for the 24-hour standard and unclassifiable for the annual standard) as follows. Facilities that are major facilities for purposes of $PM_{2.5}$ under the PSD regulations will continue to be subject to PSD permitting, but only for the annual standard. That is, they will have to apply BACT for $PM_{2.5}$ and conduct an Air Quality Impact Analysis to show no violation of the annual standard. For facilities that are also major facilities for purposes of $PM_{2.5}$ under EPA's Non-Attainment NSR permitting requirements, these facilities will also be required to obtain Non-Attainment NSR permits for $PM_{2.5}$ in accordance EPA's Clean Air Implementation Rule, which applies to

[102] *See* Statement of Basis at pp. 50-51.

[103] The regulations also provide for states to require BACT for VOC and ammonia emissions if they determine to EPA's satisfaction that such emissions are a significant precursor to $PM_{2.5}$ formation, but no such determination has been made for the Bay Area.

sources in non-attainment areas while a state is developing its own Non-Attainment NSR requirements for $PM_{2.5}$. The Clean Air Implementation Rule is contained in Appendix S of 40 C.F.R. Part 51 ("Appendix S"). The Air District solicits comment on whether this is the correct approach, or whether Non-Attainment NSR permitting under Appendix S supersedes PSD permitting such that facilities would be subject to Appendix S permitting only for $PM_{2.5}$, as has been suggested from some quarters.

Based on this proposed approach for addressing "split" attainment designations, the Air District has analyzed the applicability of Appendix S in the event that the Bay Area's $PM_{2.5}$ (24-hour) re-designation becomes effective during this permitting proceeding. Here, the facility would be exempt from Appendix S because it will emit less than 100 tons per year of $PM_{2.5}$. (*See* 40 C.F.R. Appendix S, ¶ II.A.4(i)(a) (establishing 100 tpy threshold for regulation of Major Stationary Sources).[104]) There would be no additional Clean Air Act regulatory requirements applicable beyond the PSD regulations, and no additional federal permit required beyond the PSD Permit.[105]

With respect to PSD issues in the event the $PM_{2.5}$ (24-hour average) non-attainment designation becomes effective during the permit proceeding, the facility will remain subject to PSD permitting for the annual standard. The PSD analysis for this element of the permit will be the same as under the first scenario outlined above where the non-attainment designation does not become effective. The facility satisfies the $PM_{2.5}$ BACT and air quality impact analysis requirements for the annual standard as discussed above.

The District solicits public comment on all of these issues, including the applicability of $PM_{2.5}$ requirements, the $PM_{2.5}$ BACT analysis (as well as revised PM_{10} emissions limits), the determinations that the facility will not contribute to exceedances of the 24-hour or annual $PM_{2.5}$ NAAQS, the applicability of Appendix S in the event the Bay Area's redesignation becomes effective, and any other relevant issues.

C. <u>Ammonia Slip/Secondary Particulate Matter Formation</u>

The Air District also received comments questioning its analysis in the Statement of Basis that ammonia slip from the facility would not contribute to the formation of secondary particulate matter. The comments suggested that the memorandum the District cited in support of its conclusion that the Bay Area is nitric-acid limited was specific only to the San Jose/Livermore area and cannot be used to support a determination for the Hayward area. The comments further claimed that the District should undertake a BACT analysis for ammonia slip based upon the

[104] $PM_{2.5}$ is, by definition, a subset of PM_{10}. The fact that the facility will emit less than 100 tons per year of PM_{10} therefore establishes that it will emit less than 100 tons per year of $PM_{2.5}$. In addition, the facility will not emit more than 100 tons per year of $PM_{2.5}$ precursors, as defined in Appendix S ¶ II.A.31(iii). (*See* Statement of Basis, p. 14 Table 5.)

[105] In addition, it is worth noting that any Appendix S requirements would be applicable through a Non-Attainment NSR permit, not through the PSD Permit. There may be reasons to address both types of requirements in an integrated permit proceeding, but technically they are separate permitting programs applicable under different sections of the Clean Air Act.

potential for secondary PM formation. The comments also questioned the District's statement earlier in the permitting process that the potential impacts of ammonia slip emissions on the formation of secondary particulate matter within the boundaries of the San Joaquin Valley Air Pollution Control District are not known.

The Air District would like to take this opportunity to clarify its analysis in light of these comments. Although the comments are correct that the District's study finding nitric-acid limited conditions looked only at the San Jose and Livermore areas, which are south and east of the proposed project location, respectively, there is no indication that the same atmospheric conditions do not exist in the Hayward area as well. They are part of the same general airshed as Hayward, and the Air District is not aware of any data or other information to suggest that conditions may be materially different. The Air District therefore continues to believe that the evidence before it supports the conclusion that the air in the region of the proposed facility is nitric-acid limited, and that additional ammonia emissions in the form of ammonia slip are not likely to have any significant contribution to secondary particulate matter formation. If members of the public have data or information that the location of the proposed facility is in fact not nitric-acid limited, the Air District asks that the public submit it during the additional comment period so the District can consider it.

Moreover, secondary PM formation is a complex process that is not well understood at the present time. As EPA recently noted in its rulemaking on secondary particulate matter precursors, "Ammonia emission inventories are presently very uncertain in most areas, complicating the task of assessing potential impacts of ammonia emission reductions. In addition, data necessary to understand the atmospheric composition and balance of ammonia and nitric acid in an area are not widely available, making it difficult to predict the results of potential ammonia emission reductions."[106] Given this situation, the suggestion that ammonia slip from the facility may cause significant secondary Particulate Matter formation is speculative at most. EPA has made clear that it Federal PSD Permitting decisions should not be made based on potential impacts that are merely speculative in nature.[107] The Air District notes that the commenters' assertions about the areas in which the District's study could be made more comprehensive only highlight the uncertainties surrounding the issue of secondary Particulate Matter formation and the speculative nature of their claims that ammonia slip will cause additional Particulate Matter impacts.

Furthermore, EPA has found countervailing considerations that would counsel against unnecessarily restricting ammonia slip emissions, in the form of neutralizing harmful acids in the atmosphere. As EPA explained in its recent rulemaking, "Ammonia serves an important role in neutralizing acids in clouds, precipitation, and particles. In particular, ammonia neutralizes sulfuric acid and nitric acid, the two key contributors to acid deposition (acid rain)." EPA cited this trade-off between the potential benefits and drawbacks of ammonia restrictions, as well as

[106] Final Rule, Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$), 73 Fed. Reg. 28321, 28330 (May 16, 2008) (hereinafter, "$PM_{2.5}$ Implementation Rule").
[107] *See In re Three Mountain Power*, 10 E.A.D. 39, 57-58 (EAB 2001); *see also In re Sutter Power Plant*, 8 E.A.D. 680, 693-94 and n. 13 (EAB 1999). .

the uncertainties surrounding the formation of secondary Particulate Matter from ammonia emissions, in adopting a presumption that ammonia should not be regulated as a precursor to Particulate Matter formation.[108] The Air District is mindful of these issues and declines to depart from EPA's considered approach, especially where the evidence that is available indicates that ammonia slip will not be a significant contributor to Particulate Matter formation in this case.

For these reasons, the Air District concludes that the Federal PSD BACT requirement does not require an analysis of ammonia slip emissions, as would be required if ammonia slip was demonstrated to be a precursor to Particulate Matter formation and that it would be emitted in significant amounts. If members of the public have additional information that may be relevant to these issues, the Air District invites the public to submit it during the additional comment period so the Air District can consider it further.

[108] *See* $PM_{2.5}$ Implementation Rule, *supra* note 106, at p. 28330.

VII. STARTUP AND SHUTDOWN ISSUES

The Air District received a number of comments on the proposed BACT startup and shutdown emission limits and District's technical analysis supporting them. In response to these comments, the Air District has further reviewed the proposed startup limits and is now proposing to strengthen them in several areas. The Air District addresses these and other startup-related issues in this section.

A. Applicability of BACT Requirement to Startups And Shutdowns

The District received one comment that claimed to disagree with the District's statement that the stringent BACT limits proposed for normal operations would not be achievable during startups and shutdowns. The comment claimed that the permit needs to include BACT limits for all operating modes, and cannot exclude startups and shutdowns from the BACT requirement. In this context, the comment cited the Environmental Appeals Board's decisions in the *Indeck-Niles Energy Center* case (in which the EAB observed that the petitioner had failed to raise the issue of whether the permit should have imposed short-term BACT emission limits for startup and shutdown emissions) and the *Tallmadge Generating Station* case (in which the EAB held that that PSD permits need to include BACT limits for startup and shutdown events). To clarify the record on this issue, the Air District agrees that BACT is applicable to and required for startup and shutdown operations. The District included BACT limits for startups and shutdowns in its initial proposal, and is now proposing even more stringent BACT limits for startups and shutdowns in this revised proposal. The District's analysis and permit limits are consistent with the cited EAB precedents and other authorities regarding BACT. The commenter appears to have misunderstood the District's point that the specific BACT limits imposed for normal operations are not achievable during startups and shutdowns. That point does not mean that BACT does not apply during startups and shutdowns, it simply means that different limits specific to those operating periods (and achievable during those periods) must be imposed.[109] The Air District invites further public comment on this issue in light of this clarification. If any member of the public continues to believe that the Air District is not proposing to impose permit conditions that would limit emissions during startups and shutdowns; the public is invited to submit comments explaining the basis for such a belief.

B. Proposed BACT Limits For Startups

The District also received a number of comments on the permit limits it proposed for startups and shutdowns. Upon further review, the Air District agrees with many of these comments, and in response has reconsidered its earlier proposal and is now proposing to reduce the startup limits in several areas as outlined below.

[109] *See In re Indeck-Niles Energy Center*, PSD Appeal No. 04-01, slip op. at 14-15 (EAB Sep. 30, 2004).

1. Stringency of Startup Emissions Limits

Several commenters claimed that the Air District should impose more stringent emissions limits for startups. In support, these commenters cited several facilities that they claimed establish that lower startup limits would be achievable for this facility. In particular, the commenters pointed to the Palomar Energy Center in Escondido, CA; the Lake Side Power Plant in Vineyard, UT; and the Caithness Long Island Energy Center in Brookhaven, NY, as facilities that demonstrate that startup lower limits would be achievable as BACT here. The Air District evaluated data from the first of these, Palomar, in the initial Statement of Basis (*see* Statement of Basis at pp. 41-42), but the comments claimed that additional data from the facility is available and that the Air District should obtain and analyze all available data. Some commenters stated that the Air District should require the specific technologies used at these facilities as BACT; while others stated that the Air District should establish a BACT emissions limit reflecting the same level of startup emissions reductions as achieved at these facilities, if it does not impose a requirement specifying the particular type of equipment to use.

The Air District agrees with these comments that based on all of the available information, including the examples from these three facilities, the facility should be able to achieve lower BACT startup emissions limits than the Air District initially proposed in several areas. For NO_2 emissions, the Air District has concluded that the BACT limit for hot startups should be lowered from 125 lbs. to 95 lbs. based on further review of the emissions performance achieved by other facilities, including the Palomar Energy Center. For warm and cold startups, the Air District continues to believe that the NO_2 emissions limits it initially proposed are appropriate because the additional information it has reviewed supports these limits as the lowest that can reasonably be achieved over time. For CO emissions, the Air District has concluded that the emissions limits should be reduced from 5028 lbs. to 2514 lbs. for cold startups and from 2514 pounds to 891 pounds for hot startups. For warm startups, the Air District continues to believe that the CO limit of 2514 points initially proposed is the appropriate BACT limit. Table 3 below provides a summary comparison of the startup emissions limits the District initially proposed and the revised limits the District is now proposing.

Table 3: Summary of Initial and Revised Proposed Startup Emissions Limits

	NO_2 Emissions Limits (lbs/startup)		CO Emissions Limits (lbs/startup)	
	Initial Proposal	Revised Proposal	Initial Proposal	Revised Proposal
Hot Startups	125	95	2514	891
Warm Startups	125	125	2514	2514
Cold Startups	480	480	5028	2514

The Air District's further evaluation of the appropriate BACT startup limits, including its assessment of the three comparable facilities cited in the comments received so far, is set forth in detail in the following paragraphs.

- ***Palomar Energy Center, Escondido, CA***

With respect to the Palomar facility, the Air District obtained additional emissions data that has been reported to the San Diego Air Pollution Control District (SDAPCD). This data included all NOx emissions data for the facility from October of 2006 through the end of 2007, and covers approximately 36 startup events involving the two turbines at the facility.[110] This is substantially more data than the Air District had from this facility when it initially considered the proposed startup limits in the initial Statement of Basis, although it is still somewhat of a preliminary picture of what the facility will be able to achieve over the long term given that it represents only a little over a year's worth of operation. Nevertheless, the Air District believes that it can use the data for what it is – an early indication of what startup NO_2 emissions this facility is likely to be able to achieve.[111]

The Air District has therefore analyzed all of this data, in conjunction with the startup data from other facilities it reviewed in its original analysis for the proposed permit, to refine its BACT analysis for startups. The Air District's analysis was based on taking the raw, minute-by-minute CEM data from the facility and estimating when startups began and ended based on changes in O_2 concentrations. The Air District notes that the emission rates it arrived at through these calculations are somewhat lower than the emissions rates calculated by the SDAPCD for the four startups where SDAPCD calculations are available.[112] The Air District therefore concludes that its method is a conservative assessment of the actual emissions performance achieved during these events. The Air District also notes that it considered data only from after October 13, 2006, for turbine 1 and after October 12, 2006, for turbine 2, the dates on which the facility began to implement the full complement of efforts it has made to reduce startup emissions under

[110] The Air District sought additional data since the end of 2007, but the facility has not reported any to the SDAPCD. The Air District also contacted the Palomar facility directly and requested review of additional data, but the facility declined and the Air District had no way to compel release of the data. (Telephone conversation between Alexander G. Crockett, Esq., BAAQMD, and Taylor O. Miller, Esq., Sempra Energy, 4/15/09.) In addition, the applicable permit limits for Palomar are of little help in evaluating the appropriate BACT permit conditions here, as they are much higher than those proposed for Russell City and the Air District does not consider them to represent BACT limits.

[111] Note that the startup limits in the permit for the Palomar facility are far higher than anything the Air District has considered for Russell City: 400 lbs/hr NO_x and 2,000 lbs/hr CO (note that these limits are *hourly* limits, meaning that total emissions for an entire startup can be several times these hourly rates). (*See* Startup Authorization, SDG&E, 2300 Harveson Place, Escondido, CA 92029, San Diego County Air Pollution Control District, App. No. 984461, PO No. 976846, April 30, 2008, at Conditions No. 16-17.)

[112] The four startup events where SDAPCD calculations are available are the following:

Date	Turbine	SDAPCD Calculation	BAAQMD Calculation
12/10/06	1	26 pounds	22 pounds
10/22/07	1	285 pounds	225 pounds
12/23/06	2	115 pounds	111 pounds
10/22/07	2	437 pounds	375 pounds

In the following analysis, where data points are available from both the SDAPCD and BAAQMD calculations, both are given for the sake of completeness.

a variance from the SDAPCD Hearing Board. The Air District excluded data from these dates and before because the commenters who urged the Air District to consider the Palomar data asserted that it is the period after implementation of these efforts that evidences the best achievable startup emissions performance. Since the excluded data consist of, for the most part, data showing high emissions (for example, a cold startup event at turbine 1 on October 11, 2006, that produced 735 pounds of NO_2 emissions), the District's approach is, again, conservative.

Once the Air District collected and refined the data from Palomar, it broke the data out into cold, warm, and hot startups in order to compare it with the proposed Russell City limits.[113] (The Air District's summary of the Palomar data points is set forth in Appendix A.) Looking first at cold startups, the available data suggests that the Palomar facility is achieving cold startup emissions at levels very similar to the facilities on which the Air District based its initial proposed Russell City startup limits. The average NO_2 emissions for cold startups (defined as the turbine having been down for over 48 hours) were 182.8 pounds, which is very similar to the cold startup averages that the Air District reviewed for the Delta Energy Center and Metcalf Energy Center in the Statement of Basis, which were 193 pounds and 185 pounds, respectively (*see* Statement of Basis at page 46, tables 15 and 16). The highest NO_2 emissions during a cold startup at Palomar, on October 22, 2007, was 375 pounds according to the District's calculations or 437 pounds according to the SDAPCD's calculations, which again is similar to Delta and Metcalf, for which the highest cold startups were at 281 and 335 pounds, respectively (*see* Statement of Basis at page 46, tables 15 and 16). Based on this review, it appears that Palomar is performing at or near the level of the other similar facilities that the Air District considered in the Statement of Basis, but certainly not any better than that. The Air District concludes from this comparison that the Palomar data serve to confirm its earlier assessment of the appropriate cold startup limits for Russell City, and certainly do not suggest that the initial analysis was inaccurate.

The Air District did observe that the Palomar data showed a maximum startup emissions event of 375 or 437 pounds (depending on which calculation is used), which is somewhat below the proposed Russell City cold startup limit of 480 pounds, but the Air District does not consider this level of compliance margin – which is 9%-22% of the permit limit, depending on whose calculation is used – to be unreasonable for several reasons. First, the data from Palomar includes only five available data points for cold starts, which does not generate a great deal of statistical confidence that the maximum seen in this data set is representative of the maximum that can be expected over the entire life of the facility. Moreover, the wide variability in the data that is available highlights the variability in individual startups, underscoring the need to provide a sufficient compliance margin to allow the facility to be able to comply during all reasonably foreseeable startup scenarios. For both of these reasons, the Air District has concluded that a cold startup limit of 480 pounds of NO_2 is a reasonable BACT limit that is consistent with the startup emissions performance seen at the Palomar facility.

The Air District next reviewed the warm startup NO_2 emissions data from Palomar. The available Palomar data show NO_2 emissions from warm startups ranging as high as 111 pounds,

[113] Cold startups are startups when the turbine has been off-line for more than 48 hours; warm startups are when the turbine has been off-line for between 8 and 48 hours; and hot startups are when the turbine has been offline for less than 8 hours.

or 115 pounds according to SDAPCD's calculations (on December 23, 2006). This is just 14 pounds (or 10 pounds according to SDAPCD) below the proposed warm start limit of 125 pounds, or 11% (8%) of the proposed limit. The Air District concludes from this evidence that the proposed limit is at least as stringent as could consistently be expected at Palomar. It is statistically unlikely that the highest-emission startup event over the lifetime of the facility would occur during the first 14 months of available data, and it is therefore reasonable to anticipate that emissions could be even more than 111 pounds (or 114 pounds) during certain warm startups. A compliance margin of an additional 11% (or 8%) over the maximum observed over the first 14 months of data at Palomar is not unreasonable, and is appropriate to accommodate the variability in emissions among startup events over time. The Air District therefore finds no basis in the Palomar warm startup data to impose a more stringent NO_2 limit than the 125 pounds-per-startup limit it initially proposed.

Third, the Air District reviewed the hot startup NO_2 emissions data from Palomar. The data the Air District reviewed showed a startup designated as "regular" startup with NOx emissions of 145 pounds (May 1, 2007). "Regular" startups presumably indicate hot starts, as that is the most normal and frequent type of startup at the facility,[114] but the Air District finds it questionable as to whether this was actually a hot startup (*i.e.*, occurred when the turbine was down for less than 8 hours). Taking the data without this apparent outlier, the Palomar startup data show average NOx emissions of 30.3 pounds and a maximum startup event of 75 pounds (November 27, 2006). Looking at the average startup emissions, it appears that Palomar is actually experiencing *higher* average hot startup emissions than the Delta Energy Center on which the Air District based its initial startup limit evaluation. The average hot startup NO_2 emissions for the years 2005 through 2008 at Delta were 25, 26.6, 27.6, and 29.8 pounds respectively, which are all better than the 30.3 pound average at Palomar (and much better than the average of 38.5 pounds if the May 1, 2007 outlier startup is included). Looking at the highest reported startup events, the data from Palomar show a high similar to the highest high at Delta, although a little lower. The highest hot startup seen at Delta was 82.2 lbs, which is slightly higher than the 75 pound startup event at Palomar on November 27, 2006 (although still much better than the 145-pound outlier event of May 1, 2007). The Air District has therefore concluded that for hot startups that the Palomar facility is not achieving an overall startup emissions performance any better than the other comparable facilities the Air District evaluated in establishing the proposed BACT limits. In further considering all of this data, however, the Air District has concluded that a somewhat more stringent compliance margin would probably be achievable here for hot startups. At the 125 pounds hot-start limit initially proposed, the compliance margin would be 43 pounds more than the highest data point found at Delta and 50 pounds more than the highest data point from Palomar. The Air District is therefore proposing a lower NO_2 limit for hot starts in the revised draft permit of 95 pounds per startup. This lower limit would bring the permit limit more in line with the high-emissions startups that have been seen at other similar facilities, while still providing an appropriate margin of compliance to take into account the fact that startups are by their nature highly variable and the highest startup emissions seen in the data collected to date may not necessarily reflect the highest emissions that would reasonably be expected under all circumstances over the life of the facility.

[114] The Palomar facility most commonly operates during the day and shuts down overnight, so its most common startups are after less than 8 hours of down-time.

In summary, the Air District agrees with the commenters that the additional NO_2 startup data from Palomar shed more light on what level of startup emissions should be achievable at Russell City. The Air District reviewed the additional data and found that Palomar has so far been achieving emissions rates very similar to the facilities on which the Air District based its proposed limits. Based on its review of this data, the Air District has concluded that Palomar confirms the Air District's initial assessment in the Statement of Basis with respect to cold and warm startups, but provides evidence with respect to hot startups that the emissions limit can be reduced from the proposed 125 pounds to 95 pounds per startup. With this revised hot startup limit, the Russell City permit limits align very closely with the startup emissions seen at Palomar based on the available data, as summarized in Table 4 below:

Table 4: Comparison of Palomar Startup NOx Emissions Data to Proposed Russell City NOx Startup Limits

	Palomar 14-Month Maximum*	Russell City Permit Limit
Hot Startup	75 pounds	95 pounds
Warm Startup	111/115 pounds**	125 pounds
Cold Startup	375/437 pounds**	480 pounds

*excluding startups that occurred before implementation of startup emissions reduction measures.

**BAAQMD/SDAPCD calculations, respectively

- ***Lake Side Power Plant & Caithness Long Island Energy Center***

The Air District also reviewed the Lake Side Power Plant and Caithness Long Island Energy Center, the other two facilities that the commenters cited. The commenters discussed these two facilities primarily in the context of using an emerging startup technology – the "Fast-Start" once-through steam boiler design – in order to reduce startup emissions. As explained in greater detail in the startup technology section below, the Air District investigated these facilities further and found that they do not use Fast-Start technology, although they do utilize an auxiliary boiler that has a startup emissions benefit. Nevertheless, they are similar combined-cycle facilities and the Air District evaluated whether they are achieving better startup performance.

The only way to compare the Lake Side and Caithness facilities is based on their startup permit limits, as there is no published data from either facility because they are only just coming online. The Caithness facility has not yet been built, while the Lake Side facility has been operating only since December of 2008, as some commenters pointed out, and the Air District is not aware of any actual operating data that is available for it. Without actual operating data available for review, the Air District compared the permit limits for those facilities to see whether they suggest that lower permit limits might be appropriate for Russell City.

First, for Lake Side, the facility's permit has *no* limits whatsoever on emissions during startups.[115] The Air District does not believe that it would be appropriate to issue a permit for

[115] Utah DEQ Approval Order DAQE-AN3031001-05 (Lake Side Power Plant), Conditions 9 & 12 (available at www.airquality.utah.gov/Permits/DOCS/AN3031001-05.pdf.) The permit does

the Russell City Energy Center without limits on startup emissions, as discussed above. But to the extent that commenters contend that the Air District should look to Lake Side as a comparable facility, there are no startup limits to compare.

For Caithness, the permit does have emission limits for startups, and it is therefore possible to compare those limits with the proposed Russell City permit limits.[116] The Caithness permit establishes two tiers of startup limits, one for when the auxiliary boiler is being used and one for when the auxiliary boiler is not being used. The Air District evaluated the limits for startups without the auxiliary boiler first, which is the scenario corresponding to the applicant's proposed design for Russell City. For NO_2 emissions, the Caithness startup limits are all higher than the limits the Air District initially proposed for the Russell City permit here. The Air District therefore concludes that Caithness further supports the reasonableness of these NO_2 startup limits as the lowest achievable BACT limits. At the very least, the Caithness permit cannot be read to suggest that lower NO_2 startup limits are warranted. The story is slightly different for CO startup emissions, however, as the Caithness permits limits for hot and cold startups are below the CO startup limits the Air District initially proposed for Russell City. Specifically, the Caithness hot-startup limit for CO (without auxiliary boiler) is 891 pounds, which is significantly lower than the 2514 pound CO hot startup limit initially proposed for Russell City. Further, the Caithness cold startup limit for CO (without auxiliary boiler) is 2813 pounds, which is significantly lower than the 5028 pound CO cold startup limit initially proposed for Russell City. Upon further consideration, the Air District believes that revisiting the proposed Russell City limits for hot and cold startups would be appropriate in light of this new information from Caithness. The Air District is therefore lowering its proposal for the hot startup limit to 891 pounds of CO, based on the limit imposed in the Caithness permit for similar equipment. The Air District is also lowering its proposal for the cold startup limit to 2514 pounds of CO, based on the Caithness permit and on another lower permit limit the Air District examined in further considering this issue, the Sutter Power Plant. The Sutter facility has a permit limit of 2514 pounds of CO per cold startup and has been achieving this limit, and the Air District concludes that a 2514 pound limit would be achievable at Russell City as well.

Based on this review, the Air District has concluded that under this revised proposal, the Russell City startup limits will be as stringent as (or more stringent than) either Lake Side or Caithness

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contain daily emissions limits, towards which startup emissions are counted, but has no limits specifically for emissions during startups. In addition, the permit application provided startup information based on vendor data, which were referenced in the Utah DEQ analysis for the permit, but these numbers were for one specific operating temperature and were not presented as vendor guarantees of what the equipment could reliably achieve under all foreseeable operating circumstances. Moreover, the numbers do not identify whether they were for startups using the auxiliary boiler or not. *See* Notice of Intent and Prevention of Significant Deterioration Air Quality Application, Lake Side Power Plant (May 2004), Table 3-6.

[116] *Prevention of Significant Deterioration of Air Quality (PSD), Caithness Long Island Energy Center*, April 7, 2006 (with transmittal letter from W. Mugdan, Director, U.S. EPA Region 2, Division of Environmental Planning and Protection, to R. Ain); available at: www.caithnesslongisland.com/Final%20PSD%20Permt_4.7.06.pdf.

for startups without an auxiliary boiler. For ease of comparison, the Lake Side, Caithness and proposed Russell City permit limits are summarized in Table 5 below.

Table 5
Comparison of Lake Side, Caithness and Proposed Russell City Startup Emissions Limits (without Auxiliary Boiler)

Startup Scenario	Lake Side Permit Limit	Caithness Permit Limit	Proposed Russell City Permit Limit
Hot Startup	n/a	127 lbs. NOx	95 lbs. NO_2
	n/a	891 lbs. CO	891 lbs. CO
Warm Startup	n/a	488 lbs. NOx	125 lbs. NO_2
	n/a	2813 lbs. CO	2514 lbs. CO
Cold Startup	n/a	488 lbs. NOx	480 lbs. NO_2
	n/a	2813 lbs. CO	2514 lbs. CO

The Air District also considered the possibility of requiring an auxiliary boiler, which would presumably be able to achieve the lower emissions limits expressed in the Caithness permit applicable when the auxiliary boiler is used. Upon further consideration of this issue, the Air District has concluded that while auxiliary boilers are common technology in colder climates to keep equipment warm in cold weather, the costs associated with requiring such equipment at Russell City would not be justified by the relatively small startup emissions reductions that would be gained. (*See* discussion in Section VII C.2 below for the complete analysis.) The Caithness permit limits for this operating scenario are therefore not comparable to Russell City and the Air District does not consider them as indicative of what the Russell City facility will be able to achieve.

In summary, the Air District agrees with the comments that it should examine the Palomar, Lake Side, and Caithness facilities as potentially comparable facilities to determine if the startup limits in the Russell City permit are the lowest achievable. As outlined in this discussion, the conditions that the Air District is now proposing for this permit are the most stringent emissions performance levels that any of these facilities suggests is achievable for purposes of the BACT analysis. The Air District invites further comment on this additional analysis.

2. Startup Duration

The Air District also received some comments suggesting that the time it proposed to allow for startups is longer than it needs to be. The comments criticized the Air District's reliance on the startup limits for the Delta, Los Medanos, and Metcalf Energy Centers and the Sutter Power Plant in its analysis of the appropriate startup limits for Russell City, claiming that these facilities may not represent the best startup times achievable today using best work practices. The comments stated that the Air District should evaluate whether shorter startup timeframes would be achievable using best work practices, and cited one recent permit – for the Colusa Generating Station in Colusa, CA – that had been issued with shorter startup time limits of 4.5 hours for cold startups (compared with 6 hours proposed for Russell City) and 1.5 hours for hot startups (compared with 3 hours proposed for Russell City).[117]

At the outset, the Air District notes that startup duration, as opposed to startup emissions, is not technically subject to the BACT requirement. BACT is "an *emission limitation* . . . based on the maximum degree of *reduction for each pollutant*" achievable by the facility (40 C.F.R. § 52.21(b)(12) (emphasis added)). It is thus a limitation on the amount of pollution emitted, not on the duration of any particular operating mode. As long as a facility can achieve the lowest *emissions* from startups among sources of its type, the facility will satisfy BACT even if it has to take a longer *time* to get to steady-state operating conditions. The reason for this rule is obvious: it is the emissions that matter from an air quality standpoint, not the time involved, and so if two facilities can achieve the same emissions performance there is no air quality reason to prefer one startup duration over the other (and indeed if one can achieve lower total emissions but needs a longer time frame to do so, the longer lower-emissions startup should be encouraged). The Air District has traditionally included startup duration among its permit conditions because as a general rule shorter startups equate to lower startup emissions, but as long as the emissions rates are at the lowest level achievable the facility will satisfy BACT regardless of duration. Here, the Air District's evaluation has concluded that the Russell City Energy Center will be subject to the most stringent achievable startup *emissions* limits as explained in the initial Statement of Basis and as further refined in this Additional Statement of Basis, and so the facility satisfies the BACT requirement on that basis. Imposing an additional requirement on startup durations is not technically required by BACT.

Beyond this threshold point regarding BACT applicability, the Air District has in light of these comments considered further whether current best practices can achieve shorter startup times than what was achievable by the facilities that were permitted pre-2001, and has concluded that there is no reliable evidence that they can. The commenters do not cite any evidence of advances in startup performance since those facilities were permitted, and their criticism of the Air District's reliance on those facilities is based solely on the passage of time. Moreover, some of the commenters themselves cited contrary evidence, in the form of recent testimony before the California Energy Commission that using current technology, startups at combined-cycle facilities "can take a minimum of three and possibly six hours . . . ."[118] Based on this record, the Air District finds little compelling evidence that there have been any significant advances in operational practices in recent years that can reduce startup times.

The one recent permit the comments did cite on this issue is the Colusa permit, which the Air District reviewed in detail in response to this comment. Although that facility has not been built yet and so there are no actual operating data on which to assess its startup performance, the commenters are correct that the permit for the facility does include tentative initial time limits for

[117] Note also that commenters on this subject cited emerging technologies that they claimed can reduce startup times, which are addressed in the technology choice section below. This section of the discussion focuses on the startup time limits that can be achieved using best work practices, without additional technologies that the Air District is not proposing to require as BACT.
[118] *See* Comments of Chabot-Las Positas Community College District, p. 11 (citing testimony before the California Energy Commission on December 18, 2008).

hot and cold startups that are shorter than the Air District is proposing for Russell City, as noted above.[119] But even if the facility will be able to achieve steady-state operation within these time limits, that does not mean that it will achieve better startup performance. To the contrary, the startup limits for the Russell City Energy Center will be *lower* than for Colusa, notwithstanding Colusa's shorter time limits. Specifically, the Colusa permit allows up to 779.1 pounds of NO_2 per cold startup and 259.9 pounds of NO_2 per hot startup.[120] By contrast, Russell City will be limited to 480 pounds of NO_2 per cold startup and 95 pounds of NO_2 per hot startup, approximately half the amount allowed at Colusa.[121] The Air District therefore concludes based upon its review of the Colusa permit that the Russell City proposed permit limits do satisfy the Federal PSD BACT requirement.

Finally, with respect to startup and shutdown durations, one commenter apparently understood that the Air District had conducted a BACT review for startups and shutdowns, but stated that the limits on startup and shutdown duration are not included in the permit conditions. To clarify this situation, the Air District refers to the proposed definitions of startup and shutdown. Startup and shutdown periods are defined with a maximum duration, and after the end of the startup and shutdown period the turbines have to comply with the more stringent emissions limits applicable during normal, steady-state operation. If the startup is not complete by the time the maximum

[119] Because the facility has not yet been built, there is no evidence from this facility on which to rely other than the analysis and justification in the permitting agency's BACT analysis. But that analysis does not include any actual operating data showing that these limits are achievable. To the contrary, it appears that the permitting agency concluded that the startup limits satisfied BACT because the applicant had proposed them and because they were below the limits in other permits for similar facilities. (*See* Ambient Air Quality Impact Report, Colusa, at pp. 19-20.) Moreover, the permitting agency explicitly considered that the startup limits might not turn out to be achievable, explaining that if experience shows that they are unrealistic then they will have to be revaluated. (*See id.*) The Air District therefore finds it highly questionable whether the Colusa example provides any hard evidence on which to conclude that the short startup limits in the permit are achievable. The issue is moot, however, as regardless of startup times the Russell City permit limits require lower emissions than the Colusa permit limits.
[120] *See* Prevention of Significant Deterioration Permit, Colusa Generating Station (EPA Region 9, issued Sept. 29, 2008) at p. 8 (available at at www.regulations.gov/fdmspublic/component/main?main=DocketDetail&d=EPA-R09-OAR-2008-0436.
[121] The Air District notes that the Colusa startup limits for Carbon Monoxide are somewhat lower than the Russell City startup CO limits. (*See id.*) The fact that Colusa has higher NOx startup limits than Russell City in conjunction with lower CO startup limits highlights the NOx/CO tradeoff that the Air District noted in the Statement of Basis. The Air District does not agree with favoring reduced CO in exchange for increased NOx emissions because the Bay Area is in attainment of the applicable CO NAAQS but is non-attainment with the applicable ozone NAAQS (and NOx is an ozone precursor). The Air District therefore does not find that the Colusa permit provides evidence on which to justify a lower CO limit for startups. To the extent that the Colusa permit shows that lower CO startup limits are technically feasible, the Air District would reject them in favor of the limits it is imposing here based on the ancillary environmental impacts involved in going to those lower CO limits – that is, the increased NOx emissions that would be involved, as evidenced by the higher Colusa NOx limits.

startup duration has elapsed (*i.e.*, if the facility has not achieved normal, steady-state operation), the facility will have violated its permit conditions and will be subject to enforcement action.

C. BACT Technology Review

The Air District also received a number of comments regarding its analysis of the control technologies available to reduce startup emissions. A number of comments criticized the Air District's BACT technology review, claiming that certain technologies the Air District rejected should be required because they would result in lower BACT permit limits. Among the technologies cited in these comments were Fast-Start technology, which is an integrated system using a "once-through" steam boiler to reduce startup times; the use of an auxiliary boiler to keep equipment warm during shutdowns and therefore allow it to start back up more quickly; and Low-Load "turn down" technology, which aims to reduce emissions at lower loads and may potentially be effective to reduce emissions as the turbines ramp up to full load during startups. The Air District's has further analyzed these technologies in light of these comments, as follows.

1. "Fast Start" Once-Through Steam Boiler Technology

The Air District received comments asserting that "Fast Start" technology is available for combined-cycle facilities with higher-efficiency triple-pressure steam turbines of the type proposed for the Russell City facility. These comments claimed that the Siemens "Flex-Plant 30" design is available and could be used for this facility. The comments cited two projects – the Lake Side Power plant in Utah and the Caithness Long Island Energy Center in New York – that supposedly use FP-30 technology.

The Air District reviewed the situation regarding the availability of Fast Start technology in light of these comments. Siemens confirmed that no Flex Plant™ 30 has been constructed or proposed at this time for a full-scale power plant project. The term "Flex Plant™" is used to describe a family of Siemens' combined cycle "platforms" based on integration of one or more Siemens' SGT6-5000F gas turbines, a Siemens integrated cycle design and HRSG specification, a Siemens steam turbine, and a Siemens SPPA-T3000 control system[122] Siemens representatives have confirmed to the Air District that the Lake Side and Caithness facilities both use the same 501F turbine technology and conventional triple-pressure boiler technology as proposed for Russell City, *i.e.*, they do not include a "once-through" Benson boiler.[123] According to Siemens, "[n]either Lakeside [Power Plant] nor Caithness Long Island Energy Center (CLIEC) were represented as, nor [*sic*] sold as, a Flex Plant™ 30."[124] The Air District also contacted the plant manager from the Lake Side plant, who confirmed that the facility uses the Siemens 501F turbine with the latest FD3 technology, along with a conventional triple-pressure boiler and steam drum; the facility does not use a once-through boiler design.[125]

The commenters' confusion over whether these the Lake Side and Caithness facilities use Flex-Plant 30 technology may have arisen because they both use an auxiliary boiler to keep the equipment warm during cold weather.[126] The use of such an auxiliary boiler is common in colder regions where low temperatures can greatly prolong startups during cold weather, but such equipment does not constitute Flex-Plant™ 30 integrated plant design or similar "once-through" Benson boiler design. These two facilities do not, therefore, contradict the District's conclusion that Flex-Plant 30 technology is not yet available.

Regardless of this distinction in the types of technology used at Lake Side and Caithness, however, the Air District interprets the commenters' point to be that the Air District should consider whether to require the same type of technology used at those two plants to keep equipment warm and allow it to start up faster. The Air District considered the use of an auxiliary boiler as is used at Lake Side and Caithness, and its analysis is described in detail in subsection 2 below. As noted below, however, the Air District found that it would not be required as a BACT control because the economic impacts in having to install and operate the auxiliary boiler render it inconsistent with BACT, given the relatively small additional emissions reductions it would achieve. The Air District is therefore not requiring an auxiliary boiler as used at Lake Side and Caithness.

2. Use of Auxiliary Boiler

As noted above, in light of some of the comments that cited the Lake Side and Caithness facilities, which use an auxiliary boiler, the Air District considered whether it should require an auxiliary boiler to be used on this project. The District analyzed the startup emissions benefits of using an auxiliary boiler here in the context of the additional costs that would be involved. The District compared startup data from Calpine's facility in Mankato, Minnesota, a facility that is equipped with an auxiliary boiler. For some startups the plant uses the auxiliary boiler and for others it does not, and so the plant allows a direct comparison of the actual emissions reduction impact from using this technology. The data show that using the auxiliary boiler will reduce fuel usage (and consequently emissions) by approximately 18% for warm startups and approximately 31% for cold startups (with no impact on hot startups, as the HRSG and steam turbine are already at a high temperature).[127] Assuming an annual operating profile containing 6 cold startups and 100 warm startups (a conservative estimate because actual startups will likely be

[122] Siemens Statement Regarding Available Siemens Technology Which Appear in Comments on RCEC's Draft PSD Permit (hereinafter, "Siemens Technology Statement"), received by email from Candido Viega, Region Vice President, Pacific Northwest, Siemens Energy, Inc., to Richard Thomas, Calpine, March 16, 2009.

[123] *Id.* The BACT analysis performed by the Utah Department of Environmental Quality's, Division of Air Quality also suggests that the Lake Side Power Plant does not reflect advanced technology, as alleged by one commenter. The engineering analysis says that "[t]he project will consist of generating equipment in a configuration that has been permitted and is in use throughout the United States and the world." *Engineering Review, Summit Vineyard, LLC, Lake Side Power Plant* (October 25, 2004) (hereinafter, "Lake Side Engineering Review"), at p. 5; available at: www.airquality.utah.gov/Permits/DOCS/ RN3031001-04.pdf.

[124] Siemens Technology Statement, *supra* note 122.

[125] Telephone conversation between Weyman Lee, BAAQMD Engineer, and John Bowater, Plant Manager, Lake Side Power Plant, April 8, 2008.

[126] *See* Lake Side Engineering Review, *supra* note 123, at pp. 6-7; Caithness Long Island Energy Center, *Environmental Impact Statement*, June 2005, at 9-35 – 9-36, available at: www. lipower.org/company/powering/caithness.html.

[127] *See* Excel spread-sheet entitled "Aux Boiler start profile DJ.xls".

lower), a similar reduction at Russell City from using an auxiliary boiler would result in 0.9 tons of NOx and 12.4 tons of CO per year.[128] The Air District compared these potential emissions reductions to the costs of using an auxiliary boiler, based on a cost estimate provided by Calpine and reviewed by the District.[129] That cost estimate showed that the annualized cost of $1,029,521 for the installation and operation of the auxiliary boiler. In terms of dollars-per-ton, these figures yields a cost-effectiveness number of $1,143,912 per ton for the NOx reductions and $83,025 per ton for the CO reductions. In light of these cost-effectiveness numbers, the costs of requiring an auxiliary boiler here would greatly exceed what any permitting agency would require in order to achieve this level of additional emissions reductions.

3. Use of Single-Pressure "Flex Plant 10" Technology

The Air District also received comments noting that two other proposed facilities for which applications have been recently submitted (Willow Pass and Marsh Landing) are proposing to use Flex-Plant 10 technology. (Flex-Plant 10 technology is similar to Flex-Plant 30 technology, except that is uses a single-pressure steam boiler instead of a triple-pressure steam boiler.) These comments suggested that these permitting applications show that Flex-Plant 10 should be reviewed for "its appropriateness at Hayward". Other comments took the opposite position, however, stating that Flex-Plant 10 technology is not appropriate for this type of facility. These comments stated that a Flex-Plant 10 system is appropriate for peaking-to-intermediate duty operations, whereas the Flex-Plant 30 system is the appropriate technology for intermediate-to-baseload operations. These comments were based on the observation that there is an energy efficiency penalty when using the single-pressure steam boilers system, compared with the more efficient triple-pressure system that is being proposed here. The Air District agrees with the latter comments. Flex-Plant 10 is an excellent technology to allow peaking-to-intermediate plants – which have to be able to start up and come on line very quickly – to gain the benefits from using combined-cycle technology (as opposed to less efficient simple-cycle turbines). But it is not appropriate for intermediate-to-baseload facilities where quick startup times are less important because of the energy efficiency penalty associated with using a single-pressure steam turbine. For intermediate-to-baseload facilities, it is preferable to obtain the better overall emissions performance achievable through the use of a triple-pressure system instead of using a less efficient single-pressure system like the Flex-Plant 10. (Note that when Flex-Plant 30 technology becomes available it will allow suitable triple-pressure systems to achieve faster startups as well, but this technology is not yet available for this project.)

A related comment objected to the District's comparison of Flex-Plant 10 technology as being less efficient than triple-pressure steam turbine systems. The comment asserted that Westinghouse 501F turbines can be between 36.5% and 56% efficient, and the comparison with the FP-10's stated efficiency of 48% might be different if it is made at an efficiency different from the 55.8% efficiency value the District used. The Air District believes that this commenter may be misunderstanding the efficiency ratings for these turbines, and would like to take this

[128] *See id.* Note that these reductions are net of the small additional emissions that would be generated by the auxiliary boiler itself. The Air District agrees with the commenters who stated that the emissions reductions from the auxiliary boiler would be more than offset by the startup reductions.

[129] *See* Excel spread-sheet entitled "Aux Boiler-NOx-2.xls".

opportunity to clarify the issue for the record. The 36.5% efficiency factor cited by the commenter for operation of an F-class turbine would be for operation in a simple cycle facility; that is, using the turbine only and not taking advantage of the waste heat in the turbine exhaust to generate steam for the combined-cycle heat recovery boiler. The proposed facility here is a combined-cycle facility that will have a heat recovery boiler to generate steam for additional electrical generation. The steam boiler that is being proposed here is a triple-pressure turbine that is more efficient than the single-pressure system used in the Flex-Plant 10 system. The Air District invites further comment on the Flex-Plant 10 issue to the extent that any commenters have misunderstood the technical basis of the Air District's analysis.

4. Low-Load "Turn-Down" Technology

The Air District received several comments asserting that it should require Op-Flex low-load "turn-down" technology as a BACT technology for reducing startup emissions. These comments noted that the Palomar facility in Escondido discussed above has installed Op-Flex technology, and argued that this fact demonstrates that the technology is technically feasible for reducing startup emissions. The comments also noted that the CEC staff suggested that Op-Flex should be required as BACT in a comment letter. Some of the comments stated that if the Air District does not require Op-Flex technology to be used, as an alternative it should require the same level of startup emissions reductions as achieved by other facilities with Op-Flex.

The Air District reviewed its assessment of Op-Flex in light of these comments. The Air District notes at the outset that the Federal PSD BACT requirement is ultimately an emissions limit, not a control technology *per se* (although, obviously, it must be based on the performance of the best available technology taking into account all relevant factors).[130] Based on the data that the Air District has reviewed from the Palomar facility that uses Op-Flex and early ammonia injection, the District has concluded that the Russell City facility will have startup emissions that are the same as or lower than startup emissions achieved at Palomar. (*See* discussion in Section VII B.1, above.) The Air District therefore agrees with the comments stating that the Air District should require the same level of startup emissions reductions achieved at facilities that have installed Op-Flex. The Air District disagrees, however, with the commenters who claimed that the Air District should specifically require the use of Op-Flex as a technology.

Moreover, the Air District does not find any reason to alter its BACT analysis of Op-Flex as not yet "available" for BACT purposes as an effective technology for reducing startup emissions. The Air District's conclusion was based upon the lack of a manufacturer's guarantee; the limited nature of the data from the only facility using Op-Flex, which is not sufficient to allow a determination that Op-Flex really is achieving any significant reductions in emissions beyond what is already achievable using other approaches; and the fact that no other permitting agencies have ever found Op-Flex to be an achievable technology for reducing startup emissions. None of the commenters has provided any reason to reconsider any of these rationales.

[130] *See, e.g.*, *In re Three Mountain Power*, 10 E.A.D. 39, 54-55 (EAB 2001) (BACT is an emission limitation not a control technology and if two alternatives can achieve the same emissions performance the choice is in essence immaterial).

The Air District therefore continues to conclude that Op-Flex as not yet an available technology, and is appropriately eliminated in Step 2 of the Top-Down BACT analysis. Moreover, based on the additional analysis referred to above, even if the Air District were to address Op-Flex as an available technology in Step 3 of the Top-Down analysis, there is no indication based on the available data that it should be ranked higher than the alternative the District ultimately selected, best work practices. For all of these reasons, the Air District disagrees that Op-Flex should be required as the BACT technology for this facility.[131]

5. EPA Region 9's Colusa PSD Permit

The Air District also received comments that disagreed with the District's assertion that EPA Region IX does not require OpFlex as BACT, based on the permit Region IX issued for the Colusa Project. The comments noted that a commenter in the Colusa proceeding brought the issue to the Region's attention in a comment, but that the comment was withdrawn and so Region IX did not consider it. The comments requested that the District consider the comments that were submitted and subsequently withdrawn in the Colusa proceeding here.

The District agrees that that EPA Region IX did not formally respond to the withdrawn comments on the record. But once EPA was aware of the issue, it would not (and legally could not) fail to require OpFlex technology if that technology were BACT. The agency has an independent responsibility to impose BACT based on all of the information available to it, even if the specific comment that brought the issue to light was withdrawn. For this reason, the District stated in the initial Statement of Basis that EPA Region IX did not require OpFlex as BACT.[132]

[131] A comment also stated that the CEC found that Calpine rejected OpFlex because of the associated cost, and stated in this context that the District needs to ensure that its BACT analysis is "untainted" by considerations of things like costs. The District disagrees that cost was a part of the District's analysis of Op-Flex technology. The commenter has not identified any element of the Air District's BACT analysis regarding Op-Flex that is based on cost, and the District has not found any either.

[132] The same commenter also suggested that U.S. EPA Region 9's decision (or lack thereof) not to require OpFlex™ in the PSD permitting decision for Colusa Generating Station was irrelevant to the Air District's decision because the proposed Russell City Energy Center would be located in a populated metropolitan area designated as nonattainment for certain National Ambient Air Quality Standards. The Air District would note that the suggestion implicit in this comment – that the BACT standard should apply differently between a location in a "major metropolitan area" and one outside such an area – is without any basis in the federal PSD regulations. Further, to the extent that the commenter intended to suggest that PSD permits should not be issued or the BACT standard should be applied differently for sources located in non-attainment areas, the Air District notes that such sources are subject to non-attainment New Source Review for non-attainment pollutants. In those cases, the BACT determination would actually comprise a determination of the "Lowest Achievable Emissions Rate", which is not at issue in this permitting action.

Moreover, although the Air District pointed out that EPA had not required the use of OpFlex as BACT at Colusa, the Air District conducted its own case-by-case evaluation and reached its own independent conclusion that OpFlex should not be required as BACT here. That analysis, as further considered in this Additional Statement of Basis, provides a sufficient basis for the current permitting action regardless of EPA Region IX's analysis. The District continues to believe that EPA Region IX's conclusions lend further credence and support to its analysis, however.

Finally, as for considering the Colusa comments that were withdrawn, they were submitted in the Colusa proceeding and were not submitted on the record as comments in this proceeding, so the District is not obligated to respond to them. If the commenters believe that the Air District should consider them on the record in this proceeding, they have an obligation to submit them into the record for the Air District to review, but they did not do so here. Nevertheless, the Air District obtained a copy of the comments from EPA Region IX to ensure that it had researched all information that could have bearing on this issue, and found nothing whatsoever in those comments to suggest that OpFlex should be required here. The comment letter cited several of the same points about the Palomar Energy Center that have been raised in this proceeding, to which the Air District is responding in detail in this section.

6. Siemens "Low-Load Carbon Monoxide" Technology

Another comment claimed that, based upon telephone conversations with Siemens representatives, a low-load "turn-down" technology product is currently available for Siemens turbines. The Air District investigated this issue further, and reviewed communications from Siemens confirming in writing that it does not have a low-load product that is commercially available for F-class turbines. Siemens' LLOF product, known as "Low Load Carbon Monoxide" (LLCO), has been validated for G-class turbines as noted in the documentation the Air District relied on in the initial Statement of Basis. (*See* Statement of Basis at p. 41 and n. 33.) The Air District confirmed this with Siemens in response to this comment. Siemens reports that "LLCO validation for F-class turbine began in December 2008 and [is] currently in process [but] the validation for the F-class turbine has not been concluded."[133]

Further, for the reasons discussed in the section of this Response on the Air District's BACT analysis for greenhouse gas emissions (Section III), the Air District has found that use of G-class turbines in place of the Applicant's proposed F-class turbines does not constitute BACT for Russell City Energy Center. Rather, as discussed in Section III B.2, use of G-class turbines for a proposed nominal 600 MW combined-cycle power plant would require installation of a substantially smaller steam turbine, which would result in a significant reduction in the plant's overall efficiency rating. In light of the ancillary environmental and energy impacts that would result from this efficiency loss, the Air District in not requiring the use of G-class turbines as BACT for this project.

[133] *See* Siemens Technology Statement, supra note 122.

7. <u>Use of "Best Work Practices" as BACT for Startups</u>

The Air District also received a comment objecting to the selection of Best Work Practices as the BACT control technique, characterizing this approach as "simply following 'operating instructions' ". In light of this comment, the Air District would like to clarify for the record that optimizing a facility's operating procedures to implement best work practices is an effective and well-accepted method of minimizing emissions from startups and shutdowns.[134] The Air District does not find that the commenter's characterization of this approach to minimizing emissions provides any reason to alter its BACT analysis.

[134] *See, e.g.*, Memorandum from John B. Rasnic, Director, Stationary Source Compliance Division, Office of Air Quality Planning and Standards, U.S. EPA, to Linda M. Murphy, Director, Air, Pesticides and Toxics Management Division, U.S. EPA Region I (Jan. 28, 1993); Memorandum from Kathleen M. Bennett, Assistant Administrator for Air, Noise, and Radiation, U.S. EPA, to Regional Administrators, Regions I-X (Feb. 15, 1983); Memorandum from Kathleen M. Bennett, Assistant Administrator for Air, Noise, and Radiation, U.S. EPA, to Regional Administrators, Regions I-X (Sept. 28, 1982).

VIII. COMMISSIONING PERIOD

The Air District received a comment suggesting that the Air District should require a shorter commissioning period. The comment stated that the data the District reviewed demonstrates that a shorter time is feasible (citing examples of 96 hours and 207 hours taken to commission certain other turbines). The Air District reviewed the commissioning period BACT analysis in light of this comment, and does not believe that the data shows that a shorter commissioning period is feasible. The data shows that the time required for commissioning varies greatly from turbine to turbine, and that a reasonable allowance must be made for this variability. The data the Air District evaluated shows that although on occasion facilities have been able to complete commissioning in as little as 96 hours, on other occasions they have required as long as 297 hours. Based on this data, as well as the Air District's review of the applicant's estimate of the time that will be required, the Air District concludes that 300 hours is a reasonable time limit. The Air District therefore disagrees with this comment that a shorter time period is feasible as a BACT requirement.

IX. SULFURIC ACID MIST ISSUES

The Air District received a few comments on sulfuric acid mist, and takes this opportunity to clarify the record with respect to the issues raised.

First, the Air District received comments questioning the District's assertion that emissions of sulfuric acid mist are difficult to estimate because the conversion of fuel sulfur to SO_3 and then to H_2SO_4 is not well established. These comments suggested that the District should be in a position to explain more precisely what actual sulfuric acid mist emissions will be. The comments also questioned whether the facility will in fact emit less than the 7 tons-per-year PSD significance threshold. In addition, some comments claimed that the permit should limit sulfuric acid mist emissions to less than 38 pounds per day. The Air District has reexamined its analysis of sulfuric acid mist emissions in light of these comments, and has concluded that its initial analysis is sound. As explained in the initial Statement of Basis, Air District has estimated sulfuric acid mist emissions as accurately as it can, and believes that emissions will be below 7 tons per year. The Air District is not aware of any data or analysis suggesting that emissions will be over 7 tons per year, and none of the comments on this issue cited any, and so the Air District continues to believe that this is an accurate assessment. Moreover, the Air District is not simply relying on this estimate to ensure that emissions will in fact be below 7 tons per year. The permit includes an enforceable sulfuric acid mist limit to ensure that emissions stay below this level, and the facility will be required to conduct compliance testing to ensure that they do. This testing requirement will ensure that actual emissions are below 7 tons per year, regardless of the accuracy of the Air District's estimate. With respect to the need for a daily 38-pound emissions limit, EPA's Federal PSD permitting requirements regulate sulfuric acid mist on an annual basis and require annual emissions to be below 7 tons per year if a BACT analysis is not conducted. The Federal PSD requirements in 40 C.F.R. section 52.21 do not break that 7 tpy threshold down into a daily emissions limit.

The Air District also received comments questioning whether annual compliance testing will be adequate to ensure compliance with the 7 tpy permit limit. Comments suggested that the facility might simply "retest in the absence of oversight until compliance is demonstrated." Comments suggested that the District establish specific test dates "to prevent test manipulation by retesting." The Air District considered this issue as well, and notes that the permit conditions require all non-compliance to be reported to the Air District. (*See* Proposed Permit Condition No. 37.) Thus, any non-compliance discovered during a compliance test will be reported, and the facility will not be allowed to keep a failed test secret and conduct a further test to show compliance. The Air District has therefore concluded that the compliance testing requirements as proposed will not allow the potential for "test manipulation by retesting".

Finally, some comments also cited a paper on new methodologies for estimating total sulfuric acid emissions from power plants. The Air District is unclear as to why the commenters consider this paper relevant, as the comments did not explain how this information pertains to this permitting action. The Air District has reexamined the issue of sulfuric acid testing methodologies, however, to the extent that these comments were intended to question the testing methodologies that will be used to determine compliance with the permit limits. The Air District

notes in this regard that any testing methodology must be approved by the Air District. This approval requirement ensures that the Air District can require the most accurate and up-to-date testing methodologies to be used. The Air District acknowledges the information provided by these comments, but does not find anything in it to suggest that the proposed permit conditions should be changed in some way. The Air District solicits further input on this additional discussion regarding sulfuric acid mist issues.

X. MONITORING ISSUES

The Air District also received some comments on the proposed monitoring requirements for the facility. The Air District has conducted further review and analysis of the proposed monitoring requirements, as explained below.

One comment claimed that the proposed monthly monitoring of the sulfur content of the facility's natural gas fuel is not frequent enough. The comment claimed that the sulfur content of the natural gas can vary significantly from one quarter to another (citing data tabulations from PG&E's website), and states that for this reason "the need for increased accuracy is essential". The commenter suggested weekly sulfur monitoring, in order to "assure the accuracy" of monitoring of sulfur content. The Air District considered this issue further in light of this comment, and has concluded that weekly monitoring is not necessary to ensure compliance with the natural gas sulfur limits. The comment claims that sulfur content can vary from quarter to quarter, but even if this is so, a monthly testing requirement will be able to track such variations. The comment did not point to any evidence that the additional data that could be gained from weekly monitoring would be worth the additional burden of doing so, and the Air District is not aware of any.

Another comment criticized the District's proposal to allow Russell City to use PG&E's monthly gas sulfur content measurements if the facility can show that they are 'representative'. The commenter objected that "there are no objective criteria specified in the permit conditions as to what qualifies as 'representative' ". The commenter also claimed that "PG&E adds chemicals to its natural gas" and "does not assure the accuracy of its published information". The Air District reviewed the proposed requirements for sulfur monitoring in the draft permit in light of this comment, and has concluded that they are adequate to ensure compliance. The sulfur monitoring condition allows the facility to use PG&E data only if the facility can demonstrate that the data is representative. PG&E data will not be acceptable if it is not accurate. Moreover, "representative" has a well-understood meaning and does not need "objective criteria" to define it further. In plain English, this proposed condition would require that the PG&E data provide a true and accurate picture of the actual sulfur content of the natural gas to be acceptable. The Air District has therefore concluded that the proposed condition allowing the use of representative data from PG&E does not need to be revised.

Another comment stated that ASTM fuel sulfur analysis methods were updated to correspond to NSPS Subpart GG as revised July 2004. With respect to the information about the ASTM fuel sulfur analysis methods, the Air District acknowledges the information but does not find anything in the comment suggesting that the proposed permit conditions need to be changed. The condition requires accurate testing of the sulfur content of the natural gas, and the fact that testing standards may have been revised is not inconsistent with this requirement.

Another comment stated that the District should require more stringent monitoring for PM emissions. The comment asserted that PM emissions can increase from poor air/fuel mixing or maintenance problems, and that the District should require more frequent monitoring to ensure that such problems do not go undetected. The Air District has reviewed this issue as well in light of this comment, and disagrees that annual compliance testing for particulate matter emissions is

inappropriate. A primary factor influencing PM emissions is sulfur content in the natural gas, which will be monitored on a monthly basis. To the extent that poor air/fuel mixing or similar combustion problems (whether related to maintenance problems or otherwise) might also increase PM emissions, those conditions would also be manifested in higher Carbon Monoxide emissions. Carbon Monoxide emissions are monitored on a continuous basis, and so the problems would be detected and addressed immediately. The Air District does not find that it would be necessary to add more frequent PM monitoring as well to address these concerns.

XI. AIR QUALITY IMPACT ANALYSIS ISSUES

This section addresses the source impact analysis and additional analyses required by the Federal PSD regulations.

A. Air Quality Impact Analysis Issues

The Air District first addresses comments related to the PSD Air Quality Impact Analysis is has prepared for this project.

1. Use of NSR Workshop Manual As Guidance For AQIA

The Air District received a comment questioning the District's use of EPA's 1990 Draft NSR Workshop Manual as guidance for conducting the Air Quality Impact Analysis. The commenter noted that the NSR Workshop Manual is not a binding regulation, and suggested that it may have been superseded by more recent EPA regulatory enactments. In response to this comment, the Air District wishes to clarify that although the NSR Workshop Manual is not binding as the commenter points out, it does provide a useful framework for conducting an Air Quality Impact Analysis. The Air District therefore uses the NSR Workshop Manual as guidance in situations where there is not any other more authoritative binding guidance that has been provided by EPA. The comment did not point out any specific area where the Air District's reliance on the NSR Workshop Manual was improper, and the District is not aware of any. If any member of the public considers the Air District's use of the NSR Workshop Manual to have been improper in any respect, the Air District invites the public to comment further on how such reliance may have been improper and what other guidance or procedure the District should follow instead.

2. Use of Highest Modeled PM_{10} Value for Comparison With SIL

The Air District also received comments stating that it should use the highest modeled PM_{10} value to compare with the ambient air quality impact significance threshold, not the sixth-highest value as used in the initial Statement of Basis. The Air District believes that use of the sixth-highest modeled value is consistent with EPA's modeling guidelines, which specify that the sixth-highest modeled value should be used to compare with the significance threshold.[135] As 40 C.F.R. Part 51 Appendix W states, "[f]or the 24-hour PM-10 NAAQS (which is a probabilistic standard)—when multiple years are modeled, they collectively represent a single period. Thus, if 5 years of [National Weather Service] data are modeled, then the highest sixth highest concentration for the whole period becomes the design value." Furthermore, the EPA guideline model AERMOD is hardcoded with an algorithm using the sixth-highest daily concentration; if another approach is to be used, the guideline approach has to be overridden.[136] For these reasons, the Air District concludes that the best reading of the EPA guidance on this issue is that it requires the sixth-highest modeled value to be used for the PM_{10} analysis.

Nevertheless, in response to this comment the Air District evaluated the potential impacts from using the highest modeled value for the PM_{10} analysis. The Air District found that using the assumption that the cooling tower water could have up to 8,000 ppm (by weight) Total Dissolved Solids (TDS), the highest modeled value would exceed the PM_{10} Significant Impact Level of 5 $\mu g/m^3$. The Air District therefore explored with the applicant whether it could keep TDS levels within a lower limit. The applicant found that it could keep TDS within a limit of 6,200 ppmw, and so the Air District is lowering the TDS limit in the permit to that level. With the TDS limit reduced to 6,200 ppmw, the cooling tower's PM_{10} emissions would be reduced accordingly:

TDS:	8,000 ppmw	6,200 ppmw
Hourly PM_{10}	2.83 lbs	2.19 lbs
24-hour PM_{10}	67.9 lbs	52.6 lbs
Annual PM_{10}	12.1 tons	9.4 tons

The AERMOD modeling analysis was then re-run using a new pollutant ID to enable the program to predict the highest-high 24-hour concentration, and with the revised PM_{10} emissions rate. The analysis showed a highest modeled 24-hour PM_{10} concentration of 4.9 $\mu g/m^3$, which is below the Significant Impact Level. The Air District is revising proposed Condition No. 44 to in the final permit reflect this lowered TDS limit.

3. Representativeness of Meteorological and Background Air Quality Data

The Air District also received comments questioning the representativeness of the meteorological data and background air quality data that the District used in its analysis. The comments suggested that that meteorological data from Oakland Airport and the background ambient air quality data from the Fremont-Chapel Way Monitoring Station would not be representative of the project location. The comments also questioned why the District does not maintain a monitoring station in Hayward.

In response to these comments, the Air District would like to clarify that the meteorological and background air quality are representative of air quality in the vicinity of the project location. For the meteorological data, data from the Automated Surface Observing System (ASOS) at the Oakland International Airport was used. The site is located 20.8 kilometers to the northwest of the RCEC. AERSURFACE (version 08009) was used to determine surface characteristics in accordance with USEPA's January 2008 "AERMOD Implementation Guide" at both the Oakland Airport and the RCEC project site. The Oakland meteorological surface data (OAK) is representative of conditions at the Russell City Energy Center project site, based upon the requirements for representativeness set forth in the EPA's Guideline on Air Quality Models.[137]

[135] *Guideline on Air Quality Models*, 40 C.F.R. Part 51, Appendix W (July 1, 2008) (hereinafter, "Appendix W Modeling Guideline"), § 7.2.1.1.b., applicable to PSD Air Quality Impact Analyses per 40 C.F.R. § 52.21(*l*)(1).
[136] *See* Section 3.2.5 Specifying the Pollutant Type of User's Guide for the AMS/EPA Regulatory Model-AERMOD - EPA-454/B-03-001, September 2004.

[137] *See* Appendix W Modeling Guideline, *supra* note 135, Section 8.3 (Meteorological Input Data).

The Guideline on Air Quality Models states the following conditions should be considered when determining if weather data is representative: (1) The proximity of the meteorological monitoring site to the area under consideration; (2) the complexity of the terrain; (3) the exposure of the meteorological monitoring site; and (4) the period of time during which data are collected. The Oakland Airport data satisfies all four of these criteria for representativeness and is appropriate for modeling the proposed project. Both the Oakland Airport and the proposed project location are along the East Bay shoreline with similar predominant upwind fetches. The AERSURFACE analysis showed that both sites had similar land use characteristics. Both sites are located on simple terrain in similar proximity to the complex terrain to the east. The Oakland Airport site is a permanent National Weather Service/Federal Aviation Administration weather installation that operates 24 hours per day. The most recent five years of data at the time (2003-2007) were used for this modeling study. Based upon this comparison, the Oakland ASOS data were considered representative of the proposed project location and met all USEPA data completeness requirements.

With respect on ambient air quality data from the Fremont-Chapel Way monitoring station, the District notes at the outset that in the initial Source Impact Analysis it conducted in connection with its December, 2008, proposal, all of the modeled impacts for the regulated PSD pollutants examined in that analysis were below the SILs. Because all modeled impacts were below the SILs, no full impact analysis was required and background data did not have to be used. The Additional Impacts Analysis did take background levels into account in examining whether the facility's emissions, plus background concentrations, would cause ambient air concentrations at levels that might impact soils and vegetation. The District therefore wishes to clarify that the background data from the Fremont-Chapel Way station is representative for these purposes. That data is representative of the background air quality at the project location based upon the criteria EPA has established for assessing representativeness. EPA provides for monitoring data of this type to be used if it is sufficiently representative based on three factors: (i) monitor location, (ii) the quality of the data, and (iii) the currentness of the data.[138] The Fremont-Chapel Way data is representative under all three of these criteria. The Fremont-Chapel Way monitoring station is located approximately 18 km southeast of the project in an area within the same air basin and with the same general geography and level of development. In addition, the data from the Fremont-Chapel Way monitoring station is complete and of high quality, and it is current (2006-2008). The Air District therefore concluded that the Fremont-Chapel Way monitoring data is representative and appropriate for use in assessing the impacts from the proposed facility.[139]

In response to the comments suggesting that the Air District should establishing a monitoring station in Hayward, the Air District notes that maintaining a monitoring station is an expensive endeavor, and given the District's resource constraints it can only maintain a certain number throughout the entire Bay Area. The Air District maintains several monitoring sites in the East

[138] *See* NSR Workshop Manual, *supra* note 34, Section III.A., p. C.19.

[139] Note also that a full impact analysis was required for $PM_{2.5}$, based on regulatory developments since the initial Statement of Basis was published, and that analysis requires the use of $PM_{2.5}$ background monitoring data. Representativeness of the $PM_{2.5}$ data specifically is discussed further below in the discussion of the $PM_{2.5}$ source impact analysis.

Bay, which provide a good understanding of air quality conditions in the area given the District's resource constraints. The Air District will consider the needs for a monitoring station in Hayward, and in all other relevant areas in the East Bay and larger Bay Area, in its future planning for maintaining a representative monitoring network that will give an accurate picture of ambient air quality conditions.

4. Designation of Site as "Rural" for AERMOD Modeling:

The Air District received comments questioning whether the site location should have been designated as "rural" for the purposes of the AERMOD air quality impact modeling, given the development to the east of the project site. In this context, the commenters alluded to the fact that some areas near the project may be zoned for and used as urban, industrial land. In response to this comment, the Air District would like to clarify for the record that the "Rural" designation for purposes of AERMOD modeling is simply a variable that is used as an input in the model. It reflects the fact that the level of development in the project area is not of the intensity where increased surface heating would be expected due to the urban heat island effect. This designation is a 'term of art' based on an Auer land use analysis. The Air District's selection of the "Rural" designation for purposes of AERMOD modeling does not mean that the District considers the entire area to be rural in character. The Air District agrees with the commenter that areas in the project vicinity are light industrial in nature, but would like to clarify for the record that this does not mean that running the AERMOD model with a "rural" setting is inappropriate. To the contrary, the "rural" designation is appropriate for this facility based on the Auer land use analysis.

5. Completeness of Information Presented in Analysis

The Air District received comments suggesting that the Air Quality Impact Analysis's Table II (which presents emissions rates used for modeling for different pollutants and averaging times) and Table III (which presents the maximum predicted ambient air quality impacts that would result from the project) are incomplete. In light of these comments, the Air District would like to clarify for the record that certain boxes in these tables do not have data in them because they are not applicable. For example, in Table II, there are no emission rates provided for NO_2 and CO for the cooling tower because the cooling tower is not a source of emissions of these pollutants. To give another example, short-term emission rates are not provided for NO_2 because the NO_2 standard is an annual standard. The Air District did not put data in these boxes because it was not relevant to the PSD Air Quality Impact Analysis. If any members of the public believe that there is any data that is relevant and necessary to the Air District's that the Air District has overlooked, the District invites the public to comment further on what specific data is missing and how it would impact the outcome of the analysis.

6. Update to 2007 Air Quality Impacts Analysis:

The Air District received comments pointing out some changes that the District made to its Air Quality Impact Analysis it issued in connection with its December 2008 Statement of Basis and proposed permit compared with the analysis issued in connection with the District's 2007 permitting actions. For example, the comments pointed out that the analysis used for the

December 2008 Statement of Basis concludes that the maximum one-hour NO_2 impact will be 260 $\mu g/m^3$, whereas the analysis used for the 2007 permitting actions states that it will be 370 $\mu g/m^3$. In light of these comments, the Air District would like to take the opportunity to clarify the record on this issue. The modeling for the 2007 permitting actions was performed using the model ISCST. EPA has made that model a non-guideline model, and it has been replaced with AERMOD, the current EPA guideline model. The analysis used for the December 2008 Statement of Basis was performed using AERMOD, and represents the current best assessment of what project impacts will be. As the commenter noted, the maximum one-hour NO_2 impact will be 260 $\mu g/m^3$.

B. Air Quality Impact Analysis for $PM_{2.5}$

As noted above in Section VI in the discussion of Particulate Matter issues, EPA has stayed and proposed to repeal its exemption that provided for the analysis of PM_{10} impacts as a surrogate for analyzing $PM_{2.5}$. Because EPA has changed its position on the use of this surrogate policy, an analysis of $PM_{2.5}$ impacts is required for this permit. The project applicant therefore conducted an Air Quality Impact Analysis for $PM_{2.5}$ in conjunction with the Air District,[140] and the District has reviewed and documented the results of that analysis.[141] This section briefly sets forth the results of this analysis.[142]

1. Source Impact Analysis (40 C.F.R. § 52.21(k))

The principal element of the Air Quality Impacts Analysis is the source impact analysis required under 40 C.F.R. Section 52.21(k), which is designed to ensure that the project's emissions will not cause or contribute to any violation of the NAAQS or any established PSD increment. The source impact analysis is a two-step process that compares the projected air pollutant concentrations in the ambient air around the facility's location with the NAAQS and PSD increments. The first step in the process is to evaluate the air pollutant concentrations that would result from the project by itself, without any additional contributions from other sources. If the project's contribution would be less than "Significant Impact Levels" ("SILs") adopted by EPA, then the project is presumed not to cause or contribute to any exceedance of any NAAQS or PSD Increment and no further analysis needs to be conducted.[143] EPA has explained that it considers sources whose impacts fall below the SIL will have at most a *de minimis* impact on air quality concentrations.[144]

If the concentrations from the project by itself would be above the Significant Impact Level, a full impact analysis is required based on multi-source modeling. The full impact analysis considers the project's contribution to ambient air pollution levels in conjunction with the contributions from other nearby sources and background levels to determine what the total ambient air concentrations would be if the project is built. If the total ambient air concentrations would not exceed the NAAQS at any location, or the project's contribution is below the Significance level at every location where the NAAQS would be exceeded, then the project does not "cause or contribute to air pollution in violation [a] national ambient air quality standard" within the meaning of 40 C.F.R. section 52.21(k)(1). If the total concentrations would exceed the NAAQS, and the project's contribution to that exceedance is above the Significance level at the location of the exceedance, then project is not eligible for a PSD permit.[145]

For $PM_{2.5}$, EPA has proposed three different alternative sets of SILs, but has not finalized its decision on which one to adopt.[146] To address this situation most conservatively, the Air District is proposing to use the lowest of the proposed SILs, which are 1.2 $\mu g/m^3$ for 24-hour average $PM_{2.5}$ concentrations and 0.3 $\mu g/m^3$ for annual average $PM_{2.5}$ concentrations. The Air District has found that emissions from the project by itself will cause ambient $PM_{2.5}$ concentrations above both of these SILs. For 24-hour average concentrations the project will have a maximum impact of 4.9 $\mu g/m^3$, and for annual average concentrations the project will have a maximum impact of 0.5 $\mu g/m^3$.[147] Because the project's contribution will be above these significance thresholds, a full impact analysis must be conducted utilizing multi-source modeling.

The first element of the full impact analysis is to define the "impact area" within which ambient concentrations must be evaluated through multi-source modeling. The "impact area" for this analysis is a circular area centered on the project location and extending outwards to the most distant point where the project's impacts are modeled to be above the SIL. Once the impact area is defined, the analysis then requires the project's contributions to be added to background ambient $PM_{2.5}$ concentrations obtained from air quality monitoring data, as well as emissions from any other point sources in the vicinity of the proposed project that should be addressed in addition to the contributions accounted for by the background monitoring data. All of these contributions must then be added together to determine whether the project's emissions will cause or contribute to any violation of the NAAQS within the impact area.

[140] *See* Atmospheric Dynamics, Inc., *PM2.5 PSD Source Impact Analysis for the Russell City Energy Center Draft Prevention of Significant Deterioration (PSD) Permit* (July 30, 2009) (hereinafter, "Applicant's $PM_{2.5}$ Source Impact Analysis").
[141] *See* Summary of Air Quality Impact Analysis for $PM_{2.5}$ From the Russell City Energy Center, attached to Memorandum from Glen Long to Weyman Lee, July 27, 2009 (hereinafter, "Summary of $PM_{2.5}$ Air Quality Impact Analysis").
[142] Several comments criticized the use of the surrogate policy and stated that the District should conduct a $PM_{2.5}$-specific analysis. The District's analysis set forth in this section responds to those comments.
[143] *See* NSR Workshop Manual at pp. C.24-C.25.

[144] *See* Proposed Rule, "Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)—Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC)", 72 Fed. Reg. 54112, 54138-39 (Sept. 21, 2007) (hereinafter, "Proposed $PM_{2.5}$ Increment, SIL & SMC Rule").
[145] In such cases, a project applicant can agree to shut down existing sources in the area to reduce ambient air pollutant concentrations such that there will be no exceedances of the NAAQS after the project is built.
[146] *See* Proposed $PM_{2.5}$ Increment, SIL & SMC Rule, *supra* note 144.
[147] *See* Summary of $PM_{2.5}$ Air Quality Impact Analysis, *supra* note 141, Table III.

The District used monitoring data from its Fremont-Chapel Way monitoring station as a measure of background ambient air quality. Ambient air quality data from this monitoring station is representative of the background conditions in the vicinity of the proposed project, and it satisfies all of EPA's requirements for representativeness as discussed above. EPA provides that regional monitoring data can be used as long as it is representative, based on (i) monitor location, (ii) the quality of the data, and (iii) the currentness of the data.[148] The Fremont-Chapel Way data is highly representative under all three of these criteria. The Fremont-Chapel Way monitoring station is located approximately 18 km southeast of the project in an area within the same air basin and with the same general geography and level of development. Moreover, $PM_{2.5}$ emissions in the wintertime (when particulate matter ambient concentrations are the worst) are similar at the Fremont-Chapel Way monitoring station and the proposed project site, further suggesting that background ambient concentrations are similar as well. (In fact, emissions at Fremont-Chapel Way monitoring station are slightly higher, suggesting that this is a conservative choice of representative monitoring data.) In addition, the data from the Fremont-Chapel Way monitoring station is of high quality and is current (2006-2008). The Fremont-Chapel Way station is also sited and operated in accordance with EPA's ambient monitoring data requirements set forth in EPA's "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (May 1987). For all of these reasons, the data satisfies EPA's requirements for representativeness of the background ambient air quality at the proposed project's location. The three-year average of the 98th percentile 24-hour average is 29.0 µg/m³ and annual average is 9.5 µg/m³.[149]

After background concentrations from air monitoring data are added, any other nearby point sources that are expected to cause a significant concentration gradient in the vicinity of the proposed project must be modeled. The contributions from all of these sources (the project itself, general background concentrations, and nearby point sources) are then summed and compared against the NAAQS at each modeled location within the impact area.[150] If, at any location within the impact area, the project's contribution is above the SIL, and the total of all contributions from all sources is above the NAAQS that that location, then the PSD requirements are violated. Conversely, if for each modeled location within the impact area, either (i) the total contribution from all sources is below the NAAQS or (ii) the project's contribution is below the SIL, then the project satisfies the PSD requirements.[151]

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[148] EPA regulations provide that a project can be excused from the requirement to use actual monitoring data in its PSD analysis where the project's contribution to ambient air concentrations will be less than EPA's Significant Monitoring Concentration leves ("SMCs"). As with the $PM_{2.5}$ SILs, EPA has proposed three separate alternative sets of SMCs, but has not finalized its selection of which one should be used. The District is therefore conservatively proposing to assume that the lowest SMCs will be chosen. The project exceeds these lowest most-conservative SMCs.

[149] *See* Summary of $PM_{2.5}$ Air Quality Impact Analysis, *supra* note 141, Table V.

[150] Per EPA regulations, the 98th percentile concentration predicted by the model is used to compare with the NAAQS. *See* Appendix W Modeling Guideline, *supra* note 135, § 10.1.c.

[151] *See* NSR Workshop Manual, *supra* note 34, at p. C.52 ("The source will not be considered to cause or contribute to the violation if its own impact is not significant at any violating receptor at the time of each predicted violation.").

The Source Impact Analysis undertook this exercise for both the 24-hour NAAQS and the annual NAAQS as discussed below, and also considered concerns regarding $PM_{2.5}$ increments and Class I impacts.

- *24-Hour NAAQS Analysis*

For the 24-hour standard, modeling of the facility's potential ambient air quality impacts showed emissions over the most-conservative 1.2 µg/m³ SIL. The receptor locations where the facility's impacts were over the SIL were mostly within the immediate vicinity of the facility out to a distance of up to 1.26 km, but also at six specific more remote spots in the East Bay hills out to a furthest distance of 8.1 km. The Air District therefore considers the "impact area" for the full impacts analysis to consist of a circle around the facility with a radius of 8.1 km. For the full modeling analysis, the Air District considered the cumulative impact of the facility's emissions, background ambient air concentrations, and emissions from other nearby sources on receptors located within this impact area.

The facility's contribution was based on modeling using the facility's emissions, and the background contribution was based on the Fremont-Chapel Way monitoring data as discussed above. For the contribution from other nearby sources, the Air District undertook a search of its database of $PM_{2.5}$ sources within a radius of six miles (9.7 km) around the facility location that have been permitted since January 1, 2007, and located a total of 29 such sources (21 of which are diesel backup generators). The Air District also evaluated non-point sources within this area that could cause a significant concentration gradient at any of the areas where the facility's impact was above the SIL. The Air District identified a portion of Highway 92 that is located approximately 1 km south of the facility as such a non-point source, and included it in the analysis. The cumulative impact from all of these contributions (the facility, the 29 point sources, and Highway 92) was then modeled for each receptor location within the impact area where the facility's impact was above the SIL.

Based on this cumulative analysis, the District evaluated whether the highest 98th percentile (highest 8th high) $PM_{2.5}$ ambient air concentrations would be above the NAAQS at any receptor location where the project's contribution would be above the most-conservative 1.2 µg/m³ SIL.[152] This evaluation examined whether the modeled concentration from the proposed facility plus other modeled sources would be above 6.0 µg/m³ at any such receptor location, because the background level is 29.0 µg/m³, meaning a further increase above 6.0 µg/m³ would exceed the 24-hour NAAQS of 35 µg/m³. The analysis concluded that there would not be any locations where both the project's contribution would be above 1.2 µg/m³ and the total contribution from the project plus the other modeled sources would be above 6.0 µg/m³. The Analysis found some locations where the total contribution from all modeled sources was over 6.0 µg/m³. For example, the highest 98th percentile modeled concentration from these sources was 11.27 µg/m³. But in each of these situations, the project's contribution at that location was well below the SIL,

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[152] EPA guidance requires the highest 98th percentile value is used because compliance with the NAAQS is determined on this basis. *See* Appendix W Modeling Guideline, *supra* note 135, Section 10.1.c.

meaning that the project would not be causing or contributing to any NAAQS violation within the meaning of Section 52.21(k). Similarly, the analysis found some locations where the project's contribution was above the SIL, but in each of these situations the total contribution from all modeled sources was below 6.0 $\mu g/m^3$. This situation arises from the fact that when the wind is from the northwest, the project's impacts can sometimes exceed the SILs, but at those times the wind is blowing the contributions from other sources (such as Highway 92) in the other direction and not causing an exceedance of the NAAQS. Similarly, when the wind is blowing from the Southeast emissions from sources like Highway 92 can cause exceedances of the NAAQS within the impact area, but at those times the wind is blowing the project's contribution the other way such that the project's emissions are below the SIL. The proposed project therefore satisfies the Section 52.21(k) NAAQS compliance requirements for the 24-hour $PM_{2.5}$ standard.[153]

- *Annual NAAQS Analysis*

For the annual-average $PM_{2.5}$ NAAQS, the Source Impact Analysis conducted a similar multi-source modeling analysis. The impact area for the annual analysis is the same as the larger area for the 24-hour analysis, because the largest radius applicable to any averaging period should be used in establishing the impact area. The impact area for the annual analysis therefore extends out to the same 8.1 km distance from the facility as with the 24-hour impact area. The Air District conducted a cumulative analysis adding the contributions from the facility and the other modeled sources identified above plus background levels. This analysis found that the maximum total combined annual-average ambient air concentration would be 10.56 $\mu g/m^3$, which is well below the annual NAAQS standard of 15 $\mu g/m^3$. The proposed project therefore satisfies the Section 52.21(k) NAAQS compliance requirements for the annual $PM_{2.5}$ standard as well.[154]

- *PSD Increment Consumption Discussion*

With respect to exceedance of any PSD Increment for $PM_{2.5}$, the project cannot cause any such exceedance because EPA has not established any $PM_{2.5}$ increments yet. EPA has proposed increments, however, and so the District examined whether the facility would exceed any increment if they had been finalized. EPA's proposed Class II increments are 9 $\mu g/m^3$ and 4 $\mu g/m^3$ for the 24-hour and annual standards, respectively, and the facility's maximum impacts of 4.9 $\mu g/m^3$ and 0.5 $\mu g/m^3$, respectively, are well below these levels. Thus even if the proposed increments were in effect today, the facility would not cause any exceedance of them.[155]

- *Class I Areas Analysis*

Finally, EPA also requires an analysis of the potential for impacts to any Class I areas within 100 km of the proposed facility. Point Reyes National Seashore is located approximately 62 km from the project, so the Air District conducted a Class I area impact analysis for $PM_{2.5}$. The District

[153] *See* further detailed analyses in Summary of $PM_{2.5}$ Air Quality Impact Analysis, *supra* note 141; and Applicant's $PM_{2.5}$ Source Impact Analysis, *supra* note 140.
[154] *See* Summary of $PM_{2.5}$ Air Quality Impact Analysis, *supra* note 141, at p. 11.
[155] *See id.*

used the previously-conducted AERMOD analysis for PM_{10} impacts, and conservatively assumed that all of the PM_{10} from the project is $PM_{2.5}$. The AERMOD analysis showed that the particulate matter impact would be only 0.06 $\mu g/m^3$ at Point Reyes National Seashore, which is well below EPA's significance level of 1.0 $\mu g/m^3$. The Air District therefore concludes that the project will not have any significant air quality impact on any Class I area.[156]

2. Additional Impact Analysis (40 C.F.R. § 52.21(o))

In addition to the Source Impact Analysis required under 40 C.F.R. section 52.21(k), the PSD regulations also require an additional impacts analysis under 40 C.F.R. section 52.21(o). This additional impacts analysis consists of an analysis of visibility impacts, of soils and vegetation impacts, and of impacts from general commercial, residential, industrial and other growth associated with the project.

The District conducted a visibility impairment analysis using EPA's VISCREEN model and also with the Calpuff model. Both analyses show that the proposed project's $PM_{2.5}$ emissions will not cause any impairment of visibility at Point Reyes National Seashore.[157]

The District also added a $PM_{2.5}$ analysis to its revised Soils & Vegetation analysis, which is discussed in more detail in the next section. As explained there, the Air District concludes that the project's $PM_{2.5}$ emissions will not have any significant adverse impacts on soils and vegetation.

Finally, the District's associated growth analysis is not impacted by EPA's stay of the PM_{10} surrogate policy and by the inclusion of $PM_{2.5}$ impacts in the Air Quality Impacts Analysis. The District's associated growth analysis is set forth in the initial Statement of Basis at p. 16. Specific Associated Growth issues are also addressed in further detail in Section XI.D. below.

C. Revised Soils & Vegetation Analysis

The Air District received a number of comments on its Soils and Vegetation analysis. The Air District has now revised its analysis, based on the comments received and on additional investigation and analysis undertaken since the December 2008 Statement of Basis was published (including an analysis of $PM_{2.5}$ emissions as discussed above).[158] This section addresses some of the specific comments received regarding the Soils & Vegetation analysis.

1. Survey of Existing Soils & Vegetation Resources:

The Air District received several comments criticizing the inventory of existing soils and vegetation resources in the vicinity of the project. These comments criticized the use of a soils and vegetation survey conducted for the original Energy Commission proceeding in 2001, and

[156] *See id.*
[157] *See id.* at p. 12.
[158] The Air District's Revised Soils & Vegetation analysis is included with the Memorandum from Glen Long to Weyman Lee, July 27, 2009.

claimed than an updated survey should be used. The comments stated that the soils and vegetation inventory omitted several plant species in the vicinity of the project location because of this situation. In response to these comments, the Air District has revised its inventory of soils and vegetation resources based on an updated survey of the project location. This updated inventory is outlined in the revised soils and vegetation analysis, and it now includes all plant species found in the vicinity of the proposed project. The Air District invites further public comment if any member of the public believes that there are any soils or vegetation resources that have not been included.

2. Consideration of Hayward Regional Shoreline and East Bay Hills

The Air District also received comments stating that it should evaluate the potential for soils and vegetation impacts in the Hayward Regional Shoreline and in several park areas in the East Bay hills. These comments coincided with further evaluation of the potential for endangered species impacts in these areas by EPA Region 9 and the Fish and Wildlife service. Further investigation of the potential for soils and vegetation impacts (as well as related wildlife impacts) in these areas as a result of the facility's emissions was conducted, and the Air District has included this further evaluation in its soils and vegetation analysis. The Air District invites the public to review and comment on this further analysis.

3. Endangered Species and Wildlife Issues

The Air District also received several comments criticizing the Air District's soils and vegetation analysis for failing to specifically address the potential for impacts to wildlife such as small mammals and birds. In response to these comments, the Air District wishes to clarify for the record that although potential impacts to wildlife are important resource considerations, they are addressed primarily through other regulatory mechanisms such as the Endangered Species Act and CEQA, not through the Federal PSD regulations. Looking specifically at the requirements of the Federal PSD regulations, they address only impacts to soils and vegetation. The Air District has evaluated the potential for such impacts as explained in its soils and vegetation analysis and has found that there will not be any significant soils and vegetation impacts as a result of air emissions from the facility. Soils and vegetation issues can often be related to wildlife issues because soils and vegetation provide habitat and food for wildlife, and so to the extent that there is such a connection here, the Air District's findings of no significant impact on soils and vegetation would support a finding of no significant impacts on wildlife, either. Moreover, EPA Region 9 and the US Fish and Wildlife Service are evaluating the potential for wildlife impacts in more detail, and the Air District has agreed not to take final action on this permit before those agencies can complete their consultation.

4. Nitrogen Deposition Issues

The Air District also received several comments criticizing its soils and vegetation analysis for not considering the potential for impacts from nitrogen deposition as a result of the project. These comments were based on a concern that non-native vegetation would be able to out-compete native vegetation, which is better adapted to nitrogen-poor soils, if significant additional nitrogen deposition caused those soils to become more nitrogen-rich. These comments also

coincided with further evaluation of the potential for nitrogen deposition-related impacts by EPA Region 9 and the Fish & Wildlife Service. In response to these comments, a nitrogen deposition analysis was undertaken for the project, as described in more detail in the Air District's revised soils and vegetation analysis.[159] Nitrogen deposition was modeled using both the AERMIC Model (AERMOD) and CALPUFF air dispersion model. According to the Applicant's assessment, the maximum annual deposition rates calculated by AERMOD in areas potentially occupied by selected species range from 0.02 to 0.37 kilograms per hectare per year (kg/ha/yr), which is more than ten times below the levels where limited invasion of non-native species have been observed (4-5 kg/ha/yr). The maximum annual deposition rates calculated by CALPUFF are more than 100 times below such levels. These results demonstrate that nitrogen deposition from the proposed facility will not result in adverse effects on soils or vegetation resources. The modeled deposition rates reflect a number of conservative assumptions and therefore represent an over-estimation of the actual deposition expected to occur as a result of the project. Even so, the modeled impacts fall far below the levels of concern identified by earlier studies. The Air District invites further public comment on this nitrogen deposition analysis.

D. <u>"Associated Growth" And "Secondary Emissions" Analyses</u>

The Air District also received comments questioning the associated growth analysis performed as part of the AQIA. Some comments noted that there may be emissions associated with temporary and permanent workers at the site, for example through commuting. Others suggested that the new electrical generating capability provided by the facility may cause associated growth, and that the Air District should take into account the air emissions from such growth.

With respect to emissions from the workforce that will be associated with the project, the Air District addressed this issue in its Air Quality Impact Analysis prepared in connection with the December 2008 proposed permit (*see* Statement of Basis at pp. 16, 93-94). The need for workers for the project will not cause any significant associated growth because they will come from the existing workforce, which is more than adequate to meet the facility's needs. As the project will not cause any significant increase in the size of the workforce in the Bay Area, there will not be any need for any significant expansion of associated infrastructure such as housing. With respect to the new electrical generating capacity that the project will provide, it is speculative whether this new capacity will be a cause or any significant growth in the region. Some of it may be used to take the place of older generating capacity that is being taken off-line, and even if it does provide some overall expansion of the region's total electric generating capacity there is no indication that this would cause any new development. It is unlikely that any new growth or development will occur simply because of the existence of excess electrical generating capacity, as opposed to some other independent reason. For these reasons, new electrical generating capacity is not an issue that falls within the "associated growth" analysis required by EPA's PSD permitting regulations.

The District also received a comment disagreeing with the District's assertion that the project will not involve secondary growth, claiming that it already has generated secondary growth in

[159] *See Russell City Energy Center: Nitrogen Deposition at East Bay Regional Parks*, Technical Memorandum from Craig Williams, Biologist, CH2M Hill, to Barbara McBride, Calpine, February 19, 2009.

the form of an expanded local water treatment plant the capacity of which was increased to handle cooling water for the project. This comment appears to be based on a misconception regarding the proposed facility's relationship with the City of Hayward's wastewater treatment plant. The proposed facility has been designed to handle wastewater from the treatment plant and use it as cooling water, not the other way around – the wastewater treatment plant was not built to handle wastewater from the proposed facility. This will be an environmentally beneficial aspect of the facility in that it will obviate the need for the City of Hayward to discharge its wastewater into the Bay. The project will require a new tertiary treatment plant to treat the wastewater from the wastewater treatment plant in order to make it clean enough to use in the facility's cooling system, but it will not involve any expansion to the capacity of the wastewater treatment plant. The District is unaware of any other relevant changes that have been made to the wastewater treatment plant, and in particular of any changes that may impact air quality. The Air District invites members of the public to comment further if they are aware of any increases in air emissions from any associated growth with respect to the wastewater treatment plant as a result of this project.

XII. HEALTH RISK ASSESSMENT ISSUES

The Air District also received some comments on issues related to the Health Risk Assessment it prepared for the proposed project. The Air District addresses Health Risk Assessment issues in this section.

1. Health Risk Assessment Methodology

The Air District received comments questioning the Health Risk Assessment methodology it used, and in particular whether it is appropriate for use in federal PSD Permitting. One comment also questioned why health impacts with a hazard index of less than 1 are not significant. Another comment criticized the District's methodology for assessing risk with respect to morbidity, and claimed that the District should consider mortality instead.

In response to these comments, the Air District wishes to clarify that the PSD permitting requirements do not directly require a Health Risk Assessment to be performed at all. PSD permitting does tangentially involve the District's Health Risk Assessment in areas such as the BACT comparison of alternative control technologies, which can involve an assessment of collateral environmental impacts such as toxics risk, but EPA does not specify any particular methodology for conducting such an assessment. Instead, EPA allows permitting agencies to use whatever methodology is most appropriate. The Air District uses the methodology developed by California's Office of Environmental Health Hazard Assessment ("OEHHA"), which is highly appropriate for this purpose. No commenters provided any specific information to suggest that this methodology is not appropriate for use here, or that some alternative methodology would be preferable, and the Air District is not aware of any.

With respect to why a hazard index of less than one is not significant, a hazard index below one means that the toxic exposure is less than the "Reference Exposure Level", which is a level developed by health professionals as an indicator of potential adverse health impacts. The hazard index is the sum of the individual hazard quotients for toxic air contaminants identified as affecting the same target organ or organ systems. A hazard quotient is the ratio of the estimated exposure level to the Reference Exposure Level, which is the concentration level at or below which no adverse health effects are anticipated. An exposure below the Reference Exposure Level means that no adverse health effects are anticipated for the exposure duration involved. The Hazard Index measures exposure relative to this Reference Exposure Level; a Hazard Index of less than 1 means that the exposure will be less than the Reference Exposure Level and thus protective of public health.

With respect to considering morbidity instead of mortality in assessing the level of risk, morbidity is an appropriate measure for health risk assessment purposes. Looking at morbidity is broader and more conservative in that it captures all potential health problems, not just those that are fatal. That is, morbidity encompasses all potential health effects that could arise from toxic exposures, whereas mortality encompasses only those health effects that might cause death, which is a smaller subset of exposures. The Air District therefore disagrees that the morbidity approach is inappropriate for a health risk analysis.

2. Exposure Assumptions for Non-Carcinogenic Chronic Risk

The Air District received comments stated that the chronic exposure modeling was based on the assumption that chronic exposure to toxic compounds will last one year, which they claimed is inappropriate for a power plant that will likely be in operation for a longer time period. In light of this comment, the Air District would like to clarify the record on how non-carcinogenic chronic health risks are assessed. For chronic risks, the Health Risk Assessment looks at the annual exposure rate for the maximally exposed individual, and then assumes that the individual will be exposed to this maximum annual exposure rate for the entire year over every year of an assumed 70-year life span. The Health Risk Assessment therefore appropriately captures lifetime risk; it does not assume that exposure occurs for one year and then stops.[160]

3. Health Risk Assessment for Ammonia Emissions

Commenters stated that ammonia emissions will be up to 15.2 lb/hr, which they claimed exceeds the acute trigger level of 7.1 lb/hr. The commenters claimed that the District should "thoroughly analyze potential health impacts from the ammonia emissions". The Air District would like to clarify for the record that the Health Risk Assessment did in fact take ammonia emissions into account.[161]

4. Health Risks From Legionnaire's Disease

Commenters suggested that the wet cooling system could involve a risk of causing Legionnaire's disease, and claimed that this potential health risk should be investigated further as part of the Health Risk Analysis. The Air District notes that its expertise as a public health agency is primarily in the area of chemical air pollutant and the health problems they can cause, not in medical pathogens. For this reason, the Air District does not address medical concerns such as issues related to Legionnaire's disease in its Health Risk Assessment. To the extent that the proposed project may raise concerns about Legionnaire's disease, those concerns should appropriately be addressed in the broader environmental review context through the Energy Commission's CEQA-equivalent process.

5. Health Risk Assessment for Aircraft Pilots and Passengers

Commenters claimed that the Health Risk Assessment should take into account potential health risks to pilots and passengers flying in the vicinity of the proposed facility. In response to these comments, the Air District has conducted an additional health risk assessment using an air dispersion model to determine emissions impact above ground level (*i.e.*, using a "flagpole receptor"). The maximum potential hazardous air pollutant emission rates were used. Flagpole receptor is defined where persons (pilots and passengers) may be exposed to concentrations above ground level (flight area) of a particular compound or substance. The locations are not necessarily a residence or a location where people actually exist; it may be any offsite above ground level where a person could potentially be present.

[160] *See* Memorandum from Glen Long to Weyman Lee, February 28, 2007, at 1.
[161] *See id.*, p. 1 of attached supporting documentation showing ammonia analysis.

The proposed project will have two stacks each having a height of 150 feet above the ground level. The acute hazard index was calculated to be 0.52.[162] A value below 1.0 means that the exposure would not cause any acute adverse health effects. The location of the maximum acute hazard index is very close to the RCEC stacks and is based on one-hour exposure level. This is most likely a conservative assumption, as it is unlikely that that pilots and/or passengers would remain at this location in the airspace for a continuous hour and be exposed to the full extent assumed in the District's analysis.

6. Health Impacts of Fine Particulate Matter

The Air District received comments citing recent developments in the understanding of the health impacts of fine particulate matter. These comments suggested that the Air District should consider fine particulate matter in its Health Risk Assessment.

The District has considered adding fine particulate matter in our permitting procedures. In addition, OEHHA is planning to develop new procedures to address fine particulate matter and to incorporate them into its health risk assessment guidelines that are used by air districts. The District intends to participate in the public process to develop future updates to the risk assessment guidelines and procedures. These guidelines have not been developed at this stage, however, and so the Air District does not have the appropriate tools to include fine particulate matter in its formal Health Risk Assessment. The Air District has addressed fine particulate matter in its PSD Air Quality Impact analysis, however, as detailed above. That analysis found that emissions from the proposed facility would not have any significant contribution to any fine particulate matter pollution in violation of the stringent new National Ambient Air Quality Standards, which are health-protective standards established by EPA.

[162] *See* email memorandum from Glen Long to Bob Nishimura, March 12, 2009.

XIII. ENVIRONMENTAL JUSTICE ISSUES

The Air District received several comments regarding environmental justice issues. Commenters stated that there are areas near the proposed facility with low-income and minority residents, and claimed that the project disparately places environmental burdens on such residents. Some commenters also referenced an Environmental Justice analysis undertaken by the CEC that found that the area is "majority-minority". The Air District is aware of the CEC's analysis regarding the demographic makeup in areas near the project site. But the Air District's conclusion that there will be no disproportionate adverse impacts on any environmental justice community was not based on an assumption that there are no environmental justice communities near the project site, it was based on the District's assessment that there will be no significant adverse impacts to any community, regardless of demographic makeup. (*See* Statement of Basis, pp. 65-66.) The Air District continues to believe that there will not be any significant adverse impacts on any community regardless of demographic makeup.

The District also received comments claiming that the Air District cannot use the same Health Risk Assessment methodology it uses for other projects to assess potential impacts to Environmental Justice communities. These commenters claimed that environmental justice communities have specific attributes that make them susceptible to air pollution impacts in unique ways, such as increased susceptibility to diseases such as asthma, chronic lung disease, congestive heart failure and other chronic conditions, higher overall mortality rates, and less access to medical insurance coverage. In light of these comments, the Air District would like to clarify for the record that its Health Risk Assessment methodology is designed to take sensitive populations, such as those who may be particularly sensitive to air pollution concerns, into account.[163] This is an important consideration for all communities, as every community has some members who may have heightened sensitivity to potential airborne health hazards to some extent. The Air District supports its Health Risk Assessment methodology as an appropriate way to characterize the potential health risks associated with the proposed Russell City Energy Center with respect to communities that have members with heightened environmental sensitivies.

The Air District also received comments asserting that the District should also have examined the "synergistic effects" of existing pollution sources in the area. These comments asserted that the District should analyze the cumulative impacts of the emissions from the Russell City project in conjunction with existing sources in the area. The Air District's Health Risk Assessment methodology does not include an assessment of cumulative risk from project plus existing background sources for several reasons. First, where level of risk from a project is found to be

[163] OEHHA's methodology for deriving health effects values (CPFs and RELs) are protective of public health and account for potential exposure to sensitive populations. In accordance with OEHHA, the concentration, at or below which no adverse health effects are anticipated in the general human population, is termed the reference exposure level (REL). RELs are based on the most sensitive relevant adverse health effect reported in the medical and toxicological literature. RELs are designed to protect the most sensitive individuals in the population by the inclusion of margins of safety. CPFs (cancer potency factors), developed by OEHHA, are based on the use of the linearized 95% upper confidence interval of risk as a dose-response assessment, which is considered protective of public health.

so low that it is below the HRA significance thresholds, the project is not expected to make more than a *de minimis* contribution to any cumulative risk. Assessing the facility's addition to the overall cumulative risk burden would therefore add relatively little to the understanding of the cumulative concern. Moreover, undertaking a risk assessment encompassing all emission sources in the region of the facility would require resources that do not exist at this time. There are significant technical difficulties associated with completing a neighborhood-scale cumulative HRA, which are largely related to incompleteness of data (*e.g.*, spatial and temporal emission patterns) needed to estimate exposures and health risks, and to ascertain source contributions. Furthermore, unlike for criteria air pollutants, no standards have been established for health risks associated with cumulative exposure to TACs emitted from all sources, and so it would be difficult to assess at what level additional cumulative impacts would become significant. And finally, cumulative environmental impacts must be assessed for any project in California under CEQA, and so to the extent that cumulative toxic risks have the potential to be significant they can be addressed in that context. For all of these reasons, the Air District does not currently conduct an evaluation of a project's addition to cumulative health risk in its Health Risk Assessment process. But the District certainly does share the commenters' concerns about issues surrounding siting new projects in locations where there is already an elevated background level of toxic air contaminants. The Air District has recently issued a proposal to establish more stringent air permitting requirements for toxic air contaminants as a measure to address cumulative air pollution in more highly impacted communities. This proposal, if adopted, would represent the most stringent air permitting requirements for TACs in the country, as far as District staff are aware. The approach involves reducing the allowable project risk thresholds by a factor of two for projects located within more highly impacted communities. The maximum project risks for Russell City Energy Center are much less than these proposed more stringent project health risk standards.

Finally, the Air District received comments asserted that the District should have conducted a broader public outreach regarding environmental justice concerns. The Air District believes that it has conducted a very robust level of public outreach regarding all aspects of this project, including environmental justice issues. The Air District widely publicized its proposal to issue the Federal PSD permit in the community, and held a public hearing at Hayward City Hall to allow residents to express their views on the proposal. Notably, the Air District went well beyond what is required by the Federal PSD regulations in providing notice to Spanish-speaking populations and in providing a translation service at the public hearing to ensure the broadest possible opportunity for public participation.

PROPOSED PSD PERMIT CONDITIONS

The Air District is proposing the following permit conditions to ensure that the proposed project will comply with all applicable Federal PSD requirements. Compliance with emissions limits will be verified by continuous emission monitors and/or periodic source tests. The proposed facility will be required to maintain records of emissions and report them to the Air District for compliance purposes..

The Air District developed the following list of proposed permit conditions as part of its integrated permit review process covering both Federal PSD and state law requirements. As such, the entire list contains some conditions required by the Federal PSD Regulation and some conditions required under state law. In some instances a permit condition may be required under both the Federal PSD Regulation and state law, for example with certain Best Available Control Technology requirements where federal and state law overlap. The requirements of the Federal PSD Regulation are those discussed in the previous sections of this document, and the proposed conditions that are being implemented pursuant to the Federal PSD Regulation are the conditions necessary to ensure compliance with the requirements discussed above. To help the reader understand which requirements are part of the proposed amended Federal PSD Permit and which are based solely on state law requirements, the state-law requirements are presented in "strike-through" format below. For a full understanding of what permit conditions are required by the Federal PSD Regulation, the reader should consult the detailed analyses of Federal PSD requirements set forth in the previous sections of this document and in the initial Statement of Basis published in December of 2008; the Federal PSD Regulation itself; relevant decisions of the Environmental Appeals Board; and other related authorities. Permit conditions that are not being proposed pursuant the Federal PSD Regulation are not part of this proposed permitting action; persons interested in any such conditions will need to take up their concerns in the appropriate state law forum (to the extent one is available at this stage).[164]

The Air District is also providing citations to relevant authorities following certain conditions to help the reader understand the legal authority under which the Air District is proposing the condition. These citations are intended as reader aids only, and should not be considered the Air District's definitive analysis of the legal authorities underlying each condition. In particular, many conditions may be authorized by or otherwise implicate multiple legal authorities, some of which may not be listed for each condition. For a complete discussion of what permit requirements are being imposed pursuant to the Federal PSD Regulation, the reader should refer to the relevant discussions in previous sections of this document in the initial Statement of Basis published in December of 2008.

The readers should also note that the proposed conditions below constitute revisions from the conditions as initially proposed in December of 2008, in accordance with the Air District's additional and revised analysis set forth above. For the convenience of members of the public who have been following this permitting proceeding and are familiar with the December 2008 proposed conditions, a comparison of the December 2008 proposed conditions and the current proposed conditions is presented in "track changes" format in Appendix B.

[164] As noted in the December 2008 Statement of Basis, the state-law permitting process has been completed and is now final. Avenues for reviewing state-law conditions have therefore been exhausted.

Russell City Energy Center
Proposed Permit Conditions

(A) Definitions:

Clock Hour:	Any continuous 60-minute period beginning on the hour
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours
Year:	Any consecutive twelve-month period of time
Heat Input:	All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in BTU/scf
Firing Hours:	Period of time during which fuel is flowing to a unit, measured in minutes
MM BTU:	million British thermal units
Gas Turbine Warm and Hot Start-up Mode:	The lesser of the first 180 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 19(b) and 19(d)
Gas Turbine Cold Start-up Mode:	The lesser of the first 360 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 19(b) and 19(d)
Gas Turbine Shutdown Mode:	The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 19(b) through 19(d) until termination of fuel flow to the Gas Turbine
Gas Turbine Combustor Tuning Mode:	The period of time, not to exceed 360 minutes, in which testing, adjustment, tuning, and calibration operations are performed, as recommended by the gas turbine manufacturer, to insure safe and reliable steady-state operation, and to minimize NO_x and CO emissions. The SCR and oxidation catalyst are not operating during the tuning operation.
Gas Turbine Cold Start-up:	A gas turbine start-up that occurs more than 48 hours after a gas turbine shutdown
Gas Turbine Hot Start-up:	A gas turbine start-up that occurs within 8 hours of a gas turbine shutdown

Gas Turbine Warm Start-up:	A gas turbine start-up that occurs between 8 hours and 48 hours of a gas turbine shutdown
Specified PAHs:	The polycyclic aromatic hydrocarbons listed below shall be considered to be Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds Benzo[a]anthracene Benzo[b]fluoranthene Benzo[k]fluoranthene Benzo[a]pyrene Dibenzo[a,h]anthracene Indeno[1,2,3-cd]pyrene
Corrected Concentration:	The concentration of any pollutant (generally NO_x, CO, or NH_3) corrected to a standard stack gas oxygen concentration. For emission points P-1 (combined exhaust of S-1 Gas Turbine and S-3 HRSG duct burners), P-2 (combined exhaust of S-2 Gas Turbine and S-4 HRSG duct burners), the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the RCEC construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems during the commissioning period
Commissioning Period:	The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange.
Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager
RCEC:	Russell City Energy Center
CO_2E:	Combined emissions of CO_2, CH_4, and N_2O, expressed in terms of the amount of CO_2 emissions that would have the equivalent impact on global climate change.

(B) Applicability:

Conditions 1 through 11 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 12 through 49 shall apply after the commissioning period has ended. Conditions 50 through 61 shall apply at all times.

A. Conditions for the Commissioning Period

1. The owner/operator of the RCEC shall minimize emissions of carbon monoxide and nitrogen oxides from S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period.
2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the owner/operator shall tune the S-1 & S-3 Gas Turbines combustors and S-2 & S-4 Heat Recovery Steam Generators duct burners to minimize the emissions of carbon monoxide and nitrogen oxides.
3. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, owner/operator shall install, adjust, and operate the A-2 & A-4 Oxidation Catalysts and A-1 & A-3 SCR Systems to minimize the emissions of carbon monoxide and nitrogen oxides from S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators.
4. The owner/operator of the RCEC shall submit a plan to the District Engineering Division and the CEC CPM at least four weeks prior to first firing of S-1 & S-3 Gas Turbines describing the procedures to be followed during the commissioning of the gas turbines, HRSGs, and steam turbines. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-NO_x combustors, the installation and operation of the required emission control systems, the installation, calibration, and testing of the CO and NO_x continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4) without abatement by their respective oxidation catalysts and/or SCR Systems. The owner/operator shall not fire any of the Gas Turbines (S-1 or S-3) sooner than 28 days after the District receives the commissioning plan.
5. During the commissioning period, the owner/operator of the RCEC shall demonstrate compliance with conditions 7, 8, 9, and 10 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:
   - firing hours
   - fuel flow rates
   - stack gas nitrogen oxide emission concentrations,
   - stack gas carbon monoxide emission concentrations
   - stack gas oxygen concentrations.

   The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-1 & S-3), HRSGs (S-2 & S-4). The owner/operator shall use District-approved methods to calculate heat input rates, nitrogen dioxide mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. The owner/operator shall retain records on site for at least 5 years from the date of entry and make such records available to District personnel upon request.
6. The owner/operator shall install, calibrate, and operate the District-approved continuous monitors specified in condition 5 prior to first firing of the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4). After first firing of the turbines, the owner/operator shall adjust the detection range of these continuous emission monitors as necessary to

accurately measure the resulting range of CO and NO_x emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

7. The owner/operator shall not fire the S-1 Gas Turbine and S-2 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-1 SCR System and/or abatement of carbon monoxide emissions by A-2 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-1 Gas Turbine and S-2 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Engineering and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.
8. The owner/operator shall not fire the S-3 Gas Turbine and S-4 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-3 SCR System and/or abatement of carbon monoxide emissions by A-4 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-3 Gas Turbine and S-4 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Engineering and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.
9. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM_{10} and $PM_{2.5}$, and sulfur dioxide that are emitted by the Gas Turbines (S-1 & S-3), Heat Recovery Steam Generators (S-2 & S-4) and S-6 Fire Pump Diesel Engine during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 23.
10. The owner/ operator shall not operate the Gas Turbines (S-1 & S-3) and Heat Recovery Steam Generators (S-2 & S-4) in a manner such that the combined pollutant emissions from these sources will exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-1 & S-3).

NO_x (as NO_2)	4,805 pounds per calendar day	400 pounds per hour
CO	20,000 pounds per calendar day	5,000 pounds per hour
~~POC (as CH_4)~~	~~495 pounds per calendar day~~	
$PM_{2.5}/PM_{10}$	413 pounds per calendar day	
~~SO_2~~	~~298 pounds per calendar day~~	

11. No less than 90 days after startup, the Owner/Operator shall conduct District and CEC approved source tests to determine compliance with the emission limitations specified in condition 19. The source tests shall determine NO_x, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods and shall include at least one cold start, one warm start, and one hot start. Thirty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of the source testing date.

B. Conditions for the Gas Turbines (S-1 & S-3) and the Heat Recovery Steam Generators (HRSGs; S-2 & S-4)

12. The owner/operator shall fire the Gas Turbines (S-1 & S-3) and HRSG Duct Burners (S-2 & S-4) exclusively on PUC-regulated natural gas with a maximum sulfur content of 1 grain per 100 standard cubic feet. To demonstrate compliance with this limit, the operator of S-1 through S-4 shall sample and analyze the gas from each supply source at least monthly to determine the sulfur content of the gas. PG&E monthly sulfur data may be used provided that such data can be demonstrated to be representative of the gas delivered to the RCEC. In the event that the rolling 12-month annual average sulfur content exceeds 0.25 grain per 100 standard cubic feet, a reduced annual heat input rate may be utilized to calculate the maximum projected annual emissions. The reduced annual heat input rate shall be subject to District review and approval. (BACT for SO_2 and PM_{10}/ $PM_{2.5}$)
13. The owner/operator shall not operate the units such that the combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) exceeds 2,238.6 MM BTU (HHV) per hour. (PSD for NO_x)
14. The owner/operator shall not operate the units such that the combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) exceeds 53,726 MM BTU (HHV) per day. (PSD for PM_{10}/ $PM_{2.5}$)
15. The owner/operator shall not operate the units such that the combined cumulative heat input rate for the Gas Turbines (S-1 & S-3) and the HRSGs (S-2 & S-4) exceeds 35,708,858 MM BTU (HHV) per year. (Offsets)
16. The owner/operator shall not fire the HRSG duct burners (S-2 & S-4) unless its associated Gas Turbine (S-1 & S-3, respectively) is in operation. (BACT for NO_x)
17. The owner/operator shall ensure that the S-1 Gas Turbine and S-2 HRSG are abated by the properly operated and properly maintained A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst System whenever fuel is combusted at those sources and the A-1 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x, POC and CO)
18. The owner/operator shall ensure that the S-3 Gas Turbine and S-4 HRSG are abated by the properly operated and properly maintained A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst System whenever fuel is combusted at those sources and the A-3 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x, POC and CO)
19. The owner/operator shall ensure that the Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4) comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode. Requirements (a) through (h) do not apply during a gas turbine start-up, combustor tuning operation or shutdown. (BACT, PSD, and Regulation 2, Rule 5)
   (a) Nitrogen oxide mass emissions (calculated as NO_2) at P-1 (the combined exhaust point for S-1 Gas Turbine and S-2 HRSG after abatement by A-1 SCR System) shall not

exceed 16.5 pounds per hour or 0.00735 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-2 (the combined exhaust point for S-3 Gas Turbine and S-4 HRSG after abatement by A-3 SCR System) shall not exceed 16.5 pounds per hour or 0.00735 lb/MM BTU (HHV) of natural gas fired.

(b) The nitrogen oxide emission concentration at emission points P-1 and P-2 each shall not exceed 2.0 ppmv, on a dry basis, corrected to 15% O_2, averaged over any 1-hour period. (BACT for NO_x)

(c) Carbon monoxide mass emissions at P-1 and P-2 each shall not exceed 10 pounds per hour or 0.0045 lb/MM BTU of natural gas fired, averaged over any 1-hour period. (PSD for CO)

(d) The carbon monoxide emission concentration at P-1 and P-2 each shall not exceed 2.0 ppmv, on a dry basis, corrected to 15% O_2 averaged over any 1-hour period. (BACT for CO)

~~(e) Ammonia (NH_3) emission concentrations at P-1 and P-2 each shall not exceed 5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-2 and A-4 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-2 and A-4 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1 and P-2 shall be determined in accordance with permit condition 29 or District approved alternative method. (Regulation 2-5)~~

~~(f) Precursor organic compound (POC) mass emissions (as CH_4) at P-1 and P-2 each shall not exceed 2.86 pounds per hour or 0.00128 lb/MM BTU of natural gas fired. (BACT)~~

~~(g) Sulfur dioxide (SO_2) mass emissions at P-1 & P-2 each shall not exceed 6.21 pounds per hour or 0.0028 lb/MM BTU of natural gas fired. (BACT)~~

(h) Particulate matter (PM_{10} and $PM_{2.5}$) mass emissions at P-1 & P-2 each shall not exceed 7.5 pounds per hour or 0.0036 lb PM_{10}/ $PM_{2.5}$ per MM BTU of natural gas fired. (BACT)

20. The owner/operator shall ensure that the regulated air pollutant mass emission rates from each of the Gas Turbines (S-1 & S-3) during a start-up or shutdown does not exceed the limits established below. (PSD, CEC Conditions of Certification)

Pollutant	Cold Start-Up Combustor Tuning	Hot Start-Up	Warm Start-Up	Shutdown
	lb/start-up	lb/start-up	lb/start-up	lb/shutdown
NO_x (as NO_2)	480.0	95	125	40
CO	2514	891	2514	100
~~POC (as CH_4)~~	~~83~~	~~35.3~~	~~79~~	~~16~~

21. The owner/operator shall not perform combustor tuning on Gas Turbines more than once every rolling 365 day period for each S-1 and S-3. The owner/operator shall notify the District no later than 7 days prior to combustor tuning activity. (Offsets, Cumulative Emissions)

22. The owner/operator shall not allow total combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4), S-5 Cooling Tower, and S-6 Fire Pump Diesel Engine, including emissions generated during gas turbine start-ups, combustor tuning, and shutdowns to exceed the following limits during any calendar day:
(a) 1,453 pounds of NO_x (as NO_2) per day (Cumulative Emissions)
(b) 1,225 pounds of NO_x per day during ozone season from June 1 to September 30. (CEC Condition of Certification)
(c) 7,360 pounds of CO per day (PSD)
~~(d) 295 pounds of POC (as CH_4) per day (Cumulative Emissions)~~
(e) 413 pounds of PM_{10} and $PM_{2.5}$ per day (PSD)
~~(f) 292 pounds of SO_2 per day (BACT)~~

23. The owner/operator shall not allow cumulative combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4), S-5 Cooling Tower, and S-6 Fire Pump Diesel Engine, including emissions generated during gas turbine start-ups, combustor tuning, and shutdowns to exceed the following limits during any consecutive twelve-month period:
(a) 127 tons of NO_x (as NO_2) per year (Offsets, PSD)
(b) 330 tons of CO per year (Cumulative Increase, PSD)
~~(c) 28.5 tons of POC (as CH_4) per year (Offsets)~~
(d) 71.8 tons of PM_{10} and $PM_{2.5}$ per year (Cumulative Increase, PSD)
~~(e) 12.2 tons of SO_2 per year (Cumulative Increase, PSD)~~

24. The owner/operator shall not allow sulfuric acid emissions (SAM) from stacks P-1 and P-2 combined to exceed 7 tons in any consecutive 12 month period. (Basis: PSD)

~~25. The owner/operator shall not allow the maximum projected annual toxic air contaminant emissions (per condition 28) from the Gas Turbines and HRSGs (S-1, S-2, S-3 & S-4) combined to exceed the following limits:~~

~~formaldehyde 10,912 pounds per year~~
~~benzene 226 pounds per year~~
~~Specified polycyclic aromatic hydrocarbons (PAHs) 1.8 pounds per year~~

~~unless the following requirement is satisfied:~~

~~The owner/operator shall perform a health risk assessment to determine the total facility risk using the emission rates determined by source testing and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. The owner/operator shall submit the risk analysis to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will not result in a significant cancer risk, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (Regulation 2, Rule 5)~~

26. The owner/operator shall demonstrate compliance with conditions 13 through 16, 19(a) through 19(d), 20, 22(a), 22(b), 23(a) and 23(b) by using properly operated and maintained continuous monitors (during all hours of operation including gas turbine start-up, combustor tuning, and shutdown periods) for all of the following parameters:

(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-1 & S-3 combined, S-2 & S-4 combined.

(b) Oxygen (O_2) concentration, Nitrogen Oxides (NO_x) concentration, and Carbon Monoxide (CO) concentration at exhaust points P-1 and P-2.

~~(c) Ammonia injection rate at A-1 and A-3 SCR Systems~~

The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing hours, the average hourly fuel flow rates, and pollutant emission concentrations.

The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

(d) Heat Input Rate for each of the following sources: S-1 & S-3 combined, S-2 & S-4 combined.

(e) Corrected NO_x concentration, NO_x mass emission rate (as NO_2), corrected CO concentration, and CO mass emission rate at each of the following exhaust points: P-1 and P-2.

For each source, source grouping, or exhaust point, the owner/operator shall record the parameters specified in conditions 26(d) and 26(e) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

(f) total Heat Input Rate for every clock hour.

(g) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-1, S-2, S-3 and S-4) combined.

(h) the average NO_x mass emission rate (as NO_2), CO mass emission rate, and corrected NO_x and CO emission concentrations for every clock hour..

(i) on an hourly basis, the cumulative total NO_x mass emissions (as NO_2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-1, S-2, S-3 and S-4) combined.

(j) For each calendar day, the average hourly Heat Input Rates, corrected NO_x emission concentration, NO_x mass emission rate (as NO_2), corrected CO emission concentration, and CO mass emission rate for each Gas Turbine and associated HRSG combined.

(k) on a monthly basis, the cumulative total NO_x mass emissions (as NO_2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all four sources (S-1, S-2, S-3 and S-4) combined.

(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

27. To demonstrate compliance with conditions ~~19(f), 19(g),~~ 19(h), 22(c), ~~22(d),~~ 22(c), ~~23(e),~~ 23(d), ~~23(e),~~ the owner/operator shall calculate and record on a daily basis, the ~~Precursor Organic Compound (POC) mass emissions,~~ Fine Particulate Matter (PM_{10} and $PM_{2.5}$) mass emissions (including condensable particulate matter)~~, and Sulfur Dioxide (SO_2) mass emissions~~ from each power train. The owner/operator shall use the actual heat input rates measured pursuant to condition 26, actual Gas Turbine start-up times, actual Gas Turbine shutdown times, and CEC and District-approved emission factors developed pursuant to source testing under condition 30 to calculate these emissions. The owner/operator shall present the calculated emissions in the following format:

(a) For each calendar day, ~~POC,~~ PM_{10} and $PM_{2.5}$~~, and SO_2~~ emissions, summarized for each power train (Gas Turbine and its respective HRSG combined) and all four sources (S-1, S-2, S-3 & S-4) combined

(b) on a monthly basis, the cumulative total ~~POC,~~ PM_{10} and $PM_{2.5}$~~, and SO_2~~ mass emissions, for each year for all four sources (S-1, S-2, S-3 & S-4) combined

(Offsets, PSD, Cumulative Increase)

~~28. To demonstrate compliance with Condition 25, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAH's. The owner/operator shall calculate the maximum projected annual emissions using the maximum annual heat input rate of 35,708,858 MM BTU/year and the highest emission factor (pounds of pollutant per MM BTU of heat input) determined by any source test of the S-1 and S-3 Gas Turbines and/or S-2 and S-4 Heat Recovery Steam Generators. If the highest emission factor for a given pollutant occurs during minimum load turbine operation, a reduced annual heat input rate may be utilized to calculate the maximum projected annual emissions to reflect the reduced heat input rates during gas turbine start-up and minimum load operation. The reduced annual heat input rate shall be subject to District review and approval. (Regulation 2, Rule 5)~~

~~29. Within 90 days of start-up of the RCEC, the owner/operator shall conduct a District approved source test on exhaust point P-1 or P-2 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 19(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-2 or A-4 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-1 or P-2. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to, minimum and full load modes) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. The owner/operator shall repeat the source testing on an annual basis thereafter. Ongoing compliance with condition 19(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (Regulation 2, Rule 5)~~

30. Within 90 days of start-up of the RCEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1 and P-2 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load to determine compliance with Conditions 19(a), 19(b), 19(c), 19(d), ~~19(f), 19(g),~~ and 19(h) and while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 19(c) and 19(d), and to verify the

accuracy of the continuous emission monitors required in condition 26. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, ~~precursor organic compound concentration and mass emissions,~~ nitrogen oxide concentration and mass emissions (as NO_2), carbon monoxide concentration and mass emissions, ~~sulfur dioxide concentration and mass emissions, methane, ethane,~~ and particulate matter (PM_{10} and $PM_{2.5}$) emissions including condensable particulate matter. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (BACT, offsets)

31. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM_{10} and $PM_{2.5}$ emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

~~32. Within 90 days of start-up of the RCEC and on a biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-1 or P-2 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 25. The owner/operator shall also test the gas turbine while it is operating at minimum load. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 25 for any of the compounds listed below are less than the BAAQMD trigger levels, pursuant to Regulation 2, Rule 5, shown, then the owner/operator may discontinue future testing for that pollutant:~~

~~Benzene~~	~~≤~~	~~6.4 pounds/year and 2.9 pounds/hour~~
~~Formaldehyde~~	~~≤~~	~~30 pounds/year and 0.21 pounds/hour~~
~~Specified PAHs~~	~~≤~~	~~0.011 pounds/year~~

~~(Regulation 2, Rule 5)~~

33. The owner/operator shall calculate the SAM emission rate using the total heat input for the sources and the highest results of any source testing conducted pursuant to condition 30. If this SAM mass emission limit of condition #24 is exceeded, the owner/operator must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist emissions pursuant to Regulation 2-2-306. (PSD)

34. Within 90 days of start-up of the RCEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1 and P-2 while each gas turbine and HRSG duct burner is operating at maximum heat input rates to demonstrate compliance with the SAM emission rates specified in condition 24. The owner/operator shall test for (as a minimum) SO_2, SO_3, and H_2SO_4. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (PSD)

35. The owner/operator of the RCEC shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)

36. The owner/operator of the RCEC shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)

37. The owner/operator of the RCEC shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)

38. The owner/operator shall ensure that the stack height of emission points P-1 and P-2 is each at least 145 feet above grade level at the stack base. (PSD, Regulation 2-5)

39. The Owner/Operator of RCEC shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall comply with the District Manual of Procedures, Volume IV, Source Test Policy and Procedures, and shall be subject to BAAQMD review and approval. (Regulation 1-501)

40. Within 180 days of the issuance of the Authority to Construct for the RCEC, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous emission monitors, sampling ports, platforms, and source tests required by conditions 29, 30, 32, 34, and 43. The owner/operator shall conduct all source testing and monitoring in accordance with the District approved procedures. (Regulation 1-501)

41. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.1, the owner/operator of the RCEC shall submit an application to the BAAQMD for a major facility review permit within 12 months of completing construction as demonstrated by the first firing of any gas turbine or HRSG duct burner. (Regulation 2-6-404.1)

42. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the Russell City Energy Center shall submit an application for a Title IV operating permit to the BAAQMD at least 24 months before operation of any of the gas turbines (S-1, S-3, S-5, or S-7) or HRSGs (S-2, S-4, S-6, or S-8). (Regulation 2, Rule 7)

43. The owner/operator shall ensure that the Russell City Energy Center complies with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

C. Permit Conditions for Cooling Towers

44. The owner/operator shall properly install and maintain the S-5 cooling tower to minimize drift losses. The owner/operator shall equip the cooling towers with high-efficiency mist

eliminators with a maximum guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 6,200 ppmw (mg/l). The owner/operator shall sample and test the cooling tower water at least once per day to verify compliance with this TDS limit. (PSD)

45. The owner/operator shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the Russell City Energy Center, the owner/operator shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminators and certify that the installation was performed in a satisfactory manner. Within 60 days of the initial operation of the cooling tower, the owner/operator shall perform an initial performance source test to determine the PM_{10} and $PM_{2.5}$ emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 44. The CEC CPM may require the owner/operator to perform source tests to verify continued compliance with the vendor-guaranteed drift rate specified in condition (PSD)

D. Permit Conditions for S-6 Fire Pump Diesel Engine

46. The owner/operator shall not operate S-6 Fire Pump Diesel Engine more than 50 hours per year for reliability-related activities. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(2)(A)(3)or (e)(2)(B)(3), offsets)

47. The owner/operator shall operate S-6 Fire Pump Diesel Engine only for the following purposes: to mitigate emergency conditions, for emission testing to demonstrate compliance with a District, state or Federal emission limit, or for reliability-related activities (maintenance and other testing, but excluding emission testing). Operating hours while mitigating emergency conditions or while emission testing to show compliance with District, state or Federal emission limits is not limited. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(2)(A)(3) or (e)(2)(B)(3))

48. The owner/operator shall operate S-6 Fire Pump Diesel Engine only when a non-resettable totalizing meter (with a minimum display capability of 9,999 hours) that measures the hours of operation for the engine is installed, operated and properly maintained. ("Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(G)(1), cumulative increase)

49. Records: The owner/operator shall maintain the following monthly records in a District-approved log for at least 60 months from the date of entry. Log entries shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request.
 a. Hours of operation for reliability-related activities (maintenance and testing).
 b. Hours of operation for emission testing to show compliance with emission limits.
 c. Hours of operation (emergency).

 d. For each emergency, the nature of the emergency condition.
 e. Fuel usage for each engine(s).

(Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(I), cumulative increase)

E. Greenhouse Gas PSD Permit Conditions.

The following conditions shall apply at all times, and are based on the owner/operator's agreement to be subject to enforceable BACT permit limits for greenhouse gas emissions as a condition for receiving a Federal PSD Permit.

Conditions for the Gas Turbines (S-1 & S-3) and the Heat Recovery Steam Generators (HRSGs; S-2 & S-4)

50. The owner/operator shall not emit more than 242 metric tons of CO_2E from the S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) per hour. (Basis: Voluntary Greenhouse Gas BACT Requirement)

51. The owner/operator shall not emit more than 5,802 metric tons of CO_2E from the S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) per day. (Basis: Voluntary Greenhouse Gas BACT Requirement)

52. The owner/operator shall not emit more than 1,928,182 metric tons of CO_2E from the S-1 & S-3 Gas Turbines and S-2 & S-4 Heat Recovery Steam Generators (HRSGs) per year. (Basis: Voluntary Greenhouse Gas BACT Requirement)

53. The owner/operator shall maintain the S-1 & S-3 Gas Turbines such that the heat rate of each turbine does not exceed 7,730 Btu/kWhr. (Basis: Voluntary Greenhouse Gas BACT Requirement)

54. The owner/operator shall maintain the following monthly records in a District-approved log for at least 60 months from the date of entry. Log entries shall be retained on-site, either at a central location or at each circuit breaker's location, and made immediately available to the District staff upon request.
 a. Hourly, daily, and annual heat input.
 b. Hourly, daily, and annual greenhouse gas emissions, expressed in metric tons of CO_2E and calculated by multiplying the hourly, daily, and annual heat input by an emissions factor of 119.0 pounds of CO_2E per MMBtu of heat input.

(Basis: Voluntary Greenhouse Gas BACT Requirement)

55. Within 90 days of start-up of the RCEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved heat rate performance test on exhaust points P-1 and P-2 while each Gas Turbine is operating at maximum load to determine compliance with Condition 54. The owner/operator shall conduct this heat rate performance test according to the requirements of the American Society of Mechanical Engineers Performance Test Code

on Overall Plant Performance, ASME PTC 46-1996. (Basis: Voluntary Greenhouse Gas BACT Requirement)

Conditions for S-6 Fire Pump Diesel Engine

56. The owner/operator shall not emit more than 7.6 metric tons CO_2E from the S-6 Fire Pump Diesel Engine per rolling 12-month period during operation subject to Condition 46. (Basis: Voluntary Greenhouse Gas BACT Requirement)
57. The owner/operator shall operate S-6 Fire Pump Diesel Engine only when a non-resettable totalizing fuel meter for the engine is installed, operated and properly maintained. (Basis: Voluntary Greenhouse Gas BACT Requirement)
58. The owner/operator shall maintain the following monthly records in a District-approved log for at least 60 months from the date of entry. Log entries shall be retained on-site, either at a central location or at each circuit breaker's location, and made immediately available to the District staff upon request.
    a. Monthly fuel usage.
    b. Monthly greenhouse gas emissions, expressed in metric tons of CO_2E and calculated by multiplying the amount of fuel used per month by an emissions factor of 21.7 pounds of CO_2E per gallon of fuel used.

    (Basis: Voluntary Greenhouse Gas BACT Requirement)

Conditions for S-7 through S-11 Circuit Breakers

59. The owner/operator shall not emit more than 39.3 metric tons of CO_2E from the S-S-7 through S-11 circuit breakers per rolling 12-month period. (Basis: Voluntary Greenhouse Gas BACT Requirement)

60. The owner/operator shall maintain the following monthly records in a District-approved log for at least 60 months from the date of entry. Log entries shall be retained on-site, either at a central location or at each circuit breaker's location, and made immediately available to the District staff upon request.
    a. Amount of dielectric fluid added to the circuit breakers for each month of facility operation.
    b. Greenhouse gas emissions from the circuit breakers for each month of facility operation, expressed in metric tons of CO_2E and calculated by multiplying the amount of dielectric fluid added by an emissions factor of 10.84 metric tons of CO_2E per pound of dielectric fluid added during the month.

    (Basis: Voluntary Greenhouse Gas BACT Requirement)

61. The owner/operator shall install and maintain a leak detection system on the circuit breakers that signals an alarm in the facility's control room in the event that any circuit breaker loses more than 10% of its dielectric fluid. The owner/operator shall promptly respond to any alarm, investigate the circuit breaker involved, and fix any leak-tightness problems that caused the alarm. (Basis: Voluntary Greenhouse Gas BACT Requirement)

PROPOSED FEDERAL PSD PERMIT DECISION

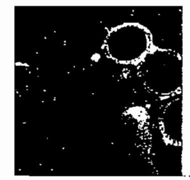
The Air District's Air Pollution Control Officer ("APCO") has concluded that the proposed Russell City Energy Center power plant, which is composed of the permitted sources listed below, will comply with all applicable Federal PSD Permit requirements. The APCO is therefore proposing to issue a Federal PSD Permit for the Russell City Energy Center as set forth in the December 8, 2008, Statement of Basis, and as revised and updated in this Additional Statement of Basis. The following sources will be subject to the proposed permit conditions discussed previously.

S-1	Combustion Turbine Generator (CTG) #1, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst
S-2	Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst
S-3	Combustion Turbine Generator (CTG) #2, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst
S-4	Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst
S-5	Cooling Tower, 9-Cell, 141,352 gallons per minute.
S-6	Fire Pump Diesel Engine, Clarke JW6H-UF40, 3400 hp, 2.02 MMBtu/hr rated heat input.
S-7	Circuit Breaker
S-8	Circuit Breaker
S-9	Circuit Breaker
S-10	Circuit Breaker
S-11	Circuit Breaker

Pursuant to the requirements of 40 C.F.R. Part 124, the Air District's revised proposal to issue a Federal PSD Permit for this project is subject to public notice and an opportunity for interested members of the public to review and comment on it. Information on how the public can participate in and comment on this revised proposed decision is provided in the opening pages of this document, and is also being provided to the public by formal legal notice.

ATTACHMENT C

H System™ Combined Cycle Gas Turbine



60 Percent Fuel Efficiency
GE's H System – an advanced combined cycle system capab breaking the 60 percent efficiency barrier – integrates the gas steam turbine and heat recovery steam generator into a seam system, optimizing each component's performance. Undoubte leading technology for both 50 and 60 Hz applications, the H (higher efficiency and output to reduce the cost of electricity of fired power generation system.

Features & Benefits

Closed-Loop Steam Cooling
Open loop air-cooled gas turbines have a significant temperature drop across the first stage nozzles, which reduces firing temperature. The closed-loop steam cooling system allows the turbine to fire at a higher temperature for increased performance, yet without increased combustion temperatures or their resulting increased emissions levels. This closed-loop steam cooling enables the H System to achieve 60 percent fuel efficiency at rated conditions while adhering to the strictest low nitrogen oxide standards and reducing carbon dioxide emissions. Additionally, closed-loop cooling also minimizes parasitic extraction of compressor discharge air, thereby allowing more air to flow to the combustor for fuel premixing.

Single Crystal Materials
The use of these advanced materials on the first stage nozzles and buckets, and thermal barrier coatings on the first and second stage nozzles and buckets, ensures these components stand up to high firing temperatures while meeting maintenance intervals.

Dry Low NOx Combustors
Building on GE's design experience, the H System employs a can-annular lean pre-mix DLN-2.5 Dry Low NOx (DLN) Combustor System. Fourteen combustion chambers are used on the 9H, and 12 combustion chambers are used on the 7H. GE DLN combustion systems have demonstrated the ability to achieve low NOx levels in several million hours of field service around the world. The H System DLN 2.5 combustion system wil have increased fuel flexibility, while maintaining the capability to achieve low NOx between 50 and 100% load.

Small Footprint/High Power Density
The H System offers improved power density per installed megawatt compared to other combined cycle systems, once

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News Archive

Dec 11, 2007 GE's H Sys Gas Turbine Hits Project Milestone In Japan

Sep 10, 2007 GE'S First Hertz H System* Gas Tu Project Moves Toward Commercial Startup Next again helping to reduce the overall cost of producing electricity.

Thoroughly Tested
The design, development and validation of the H System has been conducted under a regimen of extensive component, sub-system and full unit testing. Broad commercial introduction has been controlled to follow launch units demonstration. This thorough testing approach provides the introduction of cutting edge technology with high customer confidence The first H System located at Baglan Bay, Wales has been in commercial operation since September 2003 and has achieved significant operating experience.

Learn more about the H System launch site, Baglan Bay

Combined Cycle Performance at Rated Conditions	60 Hz (S107H)	50 Hz (S 109H)
Plant Output	400 MW	520 MW
Heat Rate	5,690 Btu/kWh (6,000 kj/kWh)	5,690 Btu/kWh (6,000 kj/kWh)
Net Plant Efficiency	60 Percent	60 Percent
Gas Turbine Number and Type	1x MS7001H	1x MS9001H

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H System™ Combined Cycle Gas Turbine

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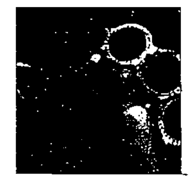

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Dry Low NOx Combustors
Building on GE's design experience, the H System employs a can-annular lean pre-mix DLN-2.5 Dry Low NOx (DLN) Combustor System. Fourteen combustion chambers are used on the 9H, and 12 combustion chambers are used on the 7H. GE DLN combustion systems have demonstrated the ability to achieve low NOx levels in several million hours of field service around the world. The H System DLN 2.5 combustion system wil have increased fuel flexibility, while maintaining the capability to achieve low NOx between 50 and 100% load.

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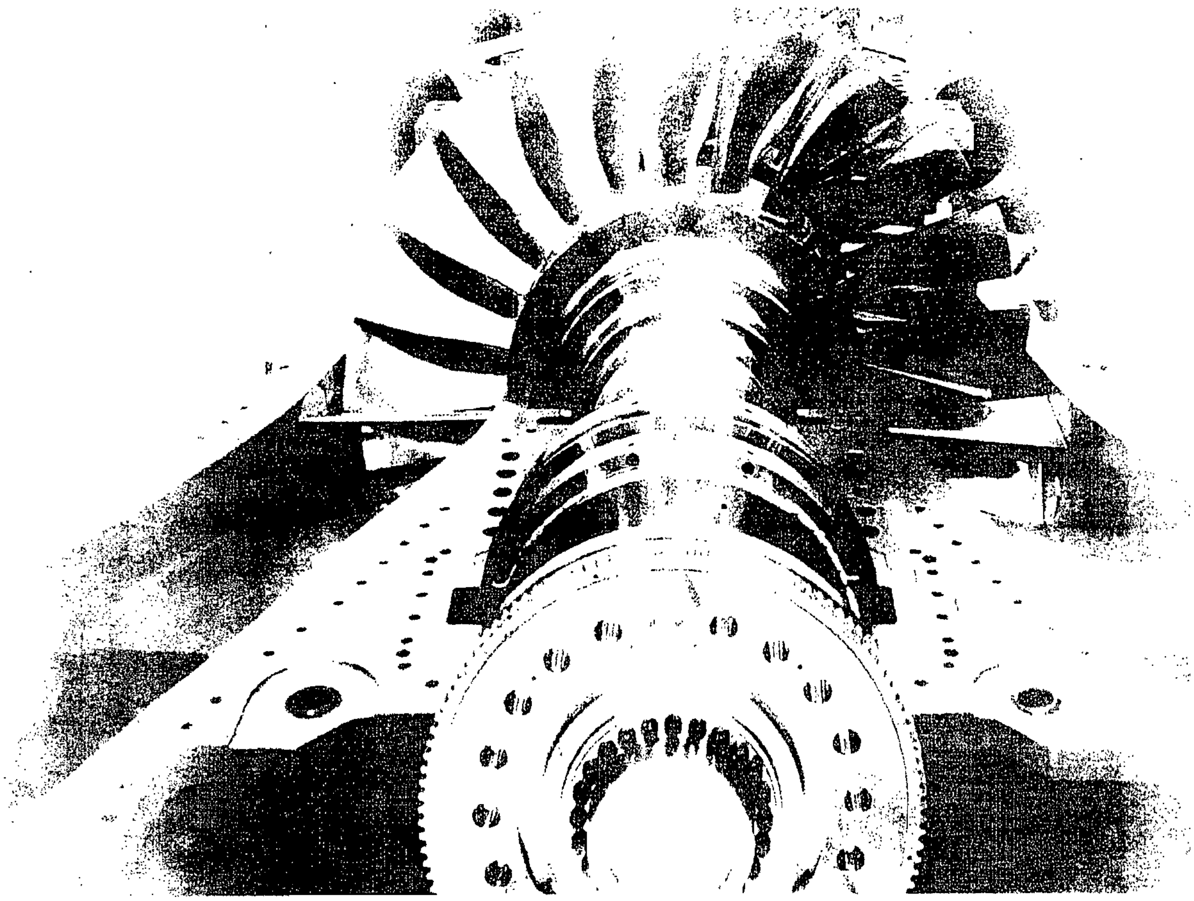
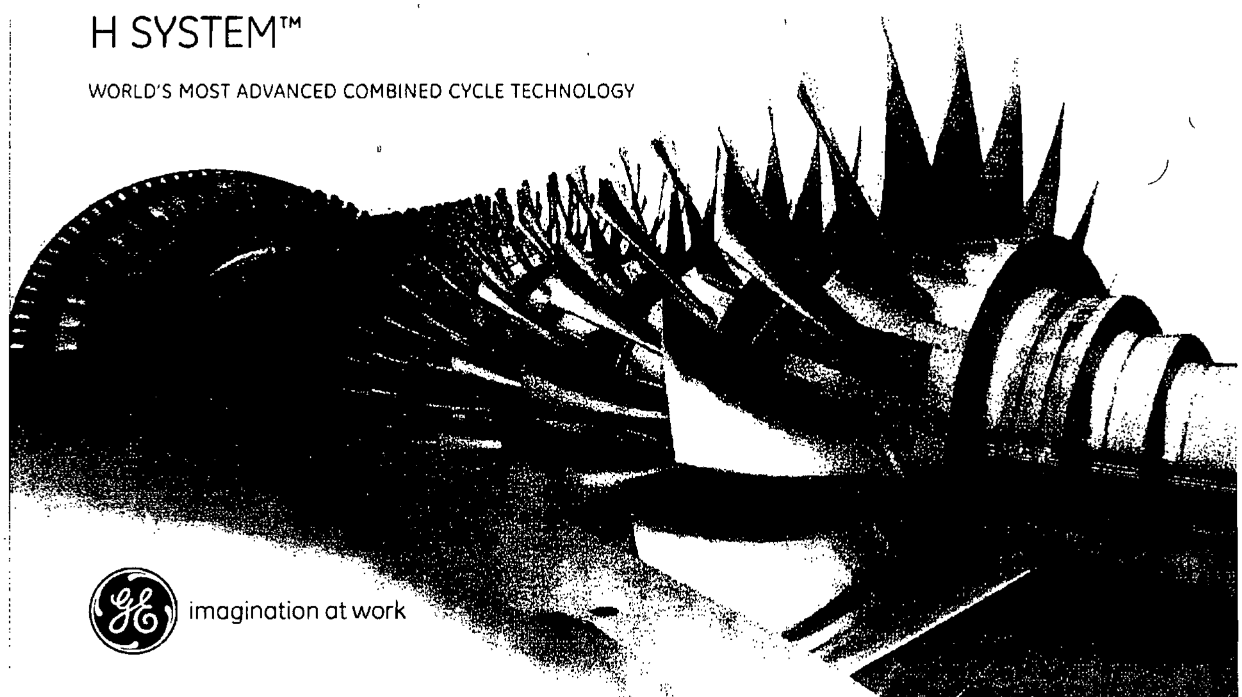
Net Plant Efficiency	60 Percent	60 Percent
Gas Turbine Number and Type	1x MS7001H	1x MS9001H



GE Energy

H SYSTEM™

WORLD'S MOST ADVANCED COMBINED CYCLE TECHNOLOGY



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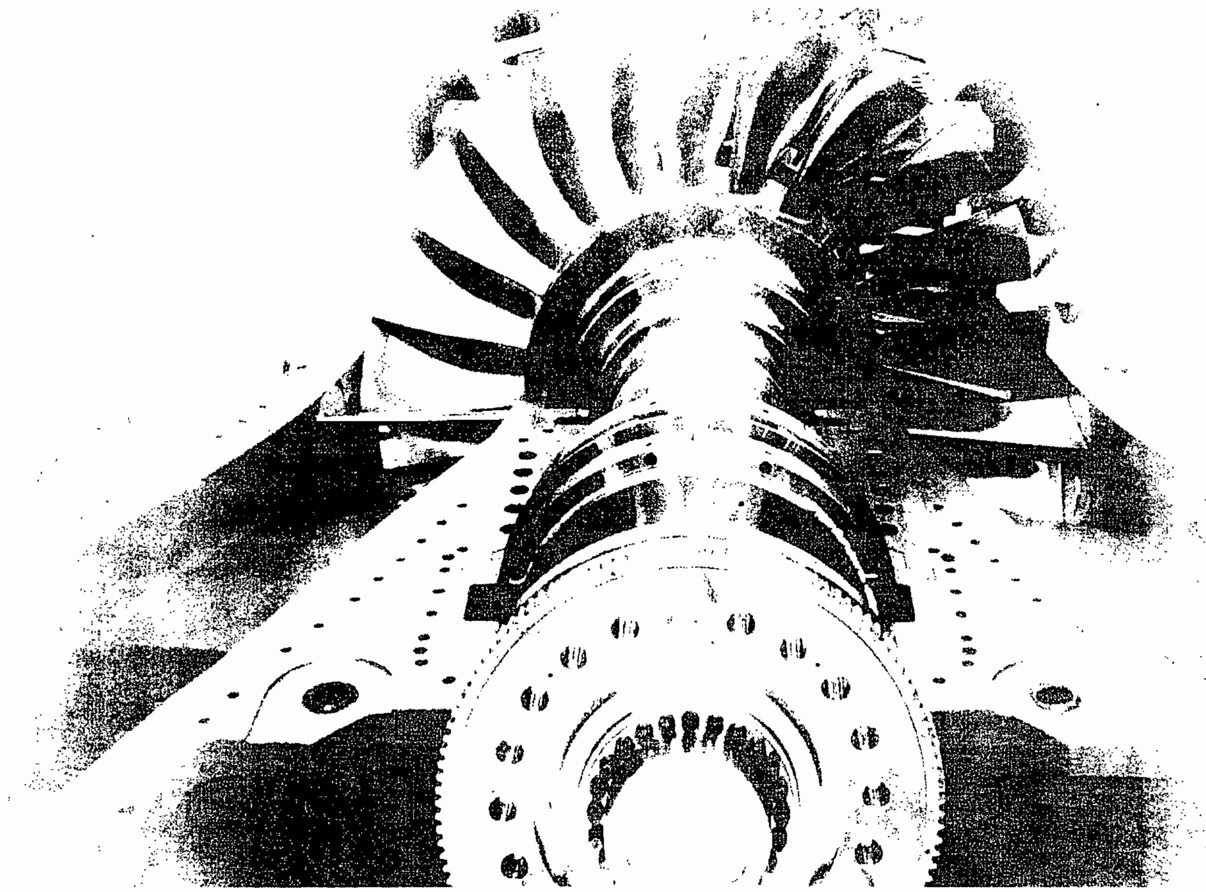

World's Most Advanced Combined Cycle Gas Turbine Technology

GE's H System™—the world's most advanced combined cycle system and the first capable of breaking the 60% efficiency barrier—integrates the gas turbine, steam turbine and heat recovery steam generator into a seamless system, optimizing each component's performance. Undoubtedly the leading technology for both 50 and 60 Hz applications, the H delivers higher efficiency and output to reduce the cost of electricity of this gas-fired power generation system.

H System™

Closed-Loop Steam Cooling

Open-loop air-cooled gas turbines have a significant temperature drop across the first stage nozzles, which, for a given combustion temperature, reduces firing temperature. The closed-loop steam cooling system allows the turbine to fire at a higher temperature for increased performance. It is this closed-loop steam cooling that enables the H System™ to achieve 60% fuel efficiency capability while maintaining strict adherence to environmental standards. For every unit of power it will use less fuel and produce fewer greenhouse gas emissions compared to other large gas turbines.

Baglan Bay Power Station Port Talbot Wales, UK is the launch site for GE's H System™

Single Crystal Materials

The use of these advanced materials, on the first stage nozzles and buckets, and Thermal Barrier Coatings, on the first and second stage nozzles and buckets, ensures that these components will stand up to high firing temperatures while meeting maintenance intervals.

Dry Low NO_x Combustors

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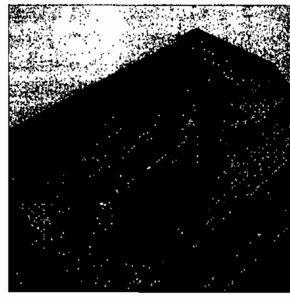

An MS9001H is seen during assembly in the factory.

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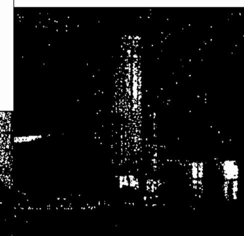

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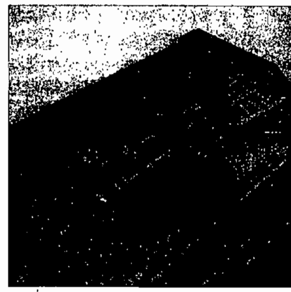
The use of these advanced materials, on the first stage nozzles and buckets, and Thermal Barrier Coatings, on the first and second stage nozzles and buckets, ensures that these components will stand up to high firing temperatures while meeting maintenance intervals.

Dry Low NO_x Combustors

Building on GE's design experience, the H System™ employs a can-annular lean pre-mix DLN-2.5 Dry Low NO_x (DLN) Combustor System. Fourteen combustion chambers are used on the 9H, and 12 combustion chambers are used on the 7H. GE DLN combustion systems have demonstrated the ability to achieve low NO_x levels in several million hours of field service around the world.



An MS9001H is seen during assembly in the factory.

Small Footprint/High Power Density

The H System™ offers approximately 40% improvement in power density per installed megawatt compared to other combined cycle systems, once again helping to reduce the overall cost of producing electricity.

Thoroughly Tested

The design, development and validation of the H System™ has been conducted under a regimen of extensive component, sub-system and full unit testing. Broad commercial introduction has been controlled to follow launch units demonstration. This thorough testing approach provides the introduction of cutting edge technology with high customer confidence.

A 9H gas turbine is readied for testing.

MS9001H/MS7001H Combined Cycle Performance

		Net Plant Output (MW)	Heat Rate (Btu/kWh)	Heat Rate (kJ/kWh)	Net Plant Efficiency	GT Number & Type
50 Hz	S109H	520	5,690	6,000	60.0%	1 x MS9001H
60 Hz	S107H	400	5,690	6,000	60.0%	1 x MS7001H

Baglan Bay Power Station Port Talbot, Wales*

100% GE-owned investment in validation of the revolutionary H System™ technology and turnkey construction—comprised of two power plants.

109H System Combined Cycle Power Plant

- 520 MW; single shaft
- Firing temperature class: 1430°C (2600°F)
- 18 stage compressor w/23:1 pressure ratio; airflow 1510 lbs/sec
- 14 can DLN 2.5; NO_x emissions: < 25 ppm

Steam Turbine: GE design; reheat, single flow exhaust; co-mfg. with Toshiba

Generator: GE 550 MW LSTG; 660 MVA liquid cooled

HRSG: 3 pressure level reheat

LM2500 Combined Heat and Power Plant

- 33 MW GE LM2500
- HRSG; auxiliary boiler and 2 cell process cooling tower
- Plant provides utility supply to Baglan Energy Park**
  - Electricity, steam, demineralized and attemperated water, process cooling
- Blackstart capability

Other Baglan Power Station Features

- GE Mark VI-based Integrated Control System
- 10 cell cooling tower
- Chimney: triple flue; slip form poured
- GE Water Technologies Treatment Plant
- 275 kV switchyard connecting to National Transmission (Electricity) System
- 33 kV switchyard with local supply to Baglan Energy Park
- Pipeline Reception Facility (PRF)
  - For 12 km Baglan pipeline spur to National Transmission (Gas) System
  - Gas compression and pressure reduction capability, featuring GE centrifugal compressors

* Plant located on site leased from BP
** Baglan Energy Park
* Joint development among BP, Welsh Development Agency and Neath Port Talbot County Borough Council

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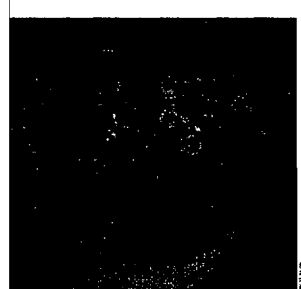

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GE Products and Services Used at Baglan Include:

9H Gas Turbine, LP Steam Turbine, Generator and other Power Train Equipment and Accessories

EPC Project Management

Technical Advisors

Operations & Maintenance; Monitoring and Diagnostics

LM2500, Plant Compressors, Gas Compressors

Water Treatment Systems

2 MW Diesel Generator

Construction and Testing Power (Energy Rentals)

Switchyard Control System; GT Instruments

BOP PLCs and Operator Interfaces

Plant-Merchant Systems Integration Software

IT Integration Support

Plant Financing

Integrated Control System with Mark VIs

6.9 kV Switchgear

Various Pump and Valve Motors

Turbine Hall and BOP Lighting

PRF Control Systems Integration

Commissioning

Pipe Installation Technical Advisors

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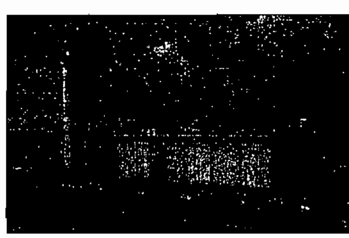

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GEA 13585C (11/05)

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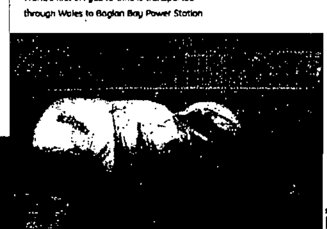

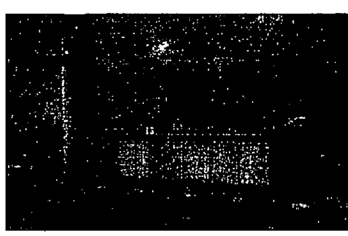

GER-3935B

GE Power Systems

Power Systems for the 21st Century – "H" Gas Turbine Combined Cycles

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To illustrate the methodical product development strategy used by GE, this paper discusses several technologies which are essential to the introduction of the *H System*™. Also included herein are analyses of the series of comprehensive tests of materials, components and subsystems which necessarily preceded full-scale field testing of the *H System*™. This paper validates one of the basic premises on which GE started the *H System*™ development program: Exhaustive and elaborate testing programs minimize risk at every step of this process, and increase the probability of success when the *H System*™ is introduced into commercial service.

In 1995, GE, the world leader in gas turbine technology for over half a century, introduced its new generation of gas turbines. This *H System*™ technology is the first gas turbine ever to achieve the milestone of 60% fuel efficiency. Because fuel represents the largest individual expense of running a power plant, an efficiency increase of even a single percentage point can substantially reduce operating costs over the life of a typical gas-fired, combined-cycle plant in the 400 to 500 megawatt range.

The *H System*™ is not simply a state-of-the-art gas turbine. It is an advanced, integrated, combined-cycle system every component of which is optimized for the highest level of performance.

The unique feature of an H technology, combined-cycle system is the integrated heat transfer system, which combines both the steam plant reheat process and gas turbine bucket and nozzle cooling. This feature allows the power generator to operate at a higher firing temperature, which in turn produces dramatic improvements in fuel-efficiency. The end result is generation of electricity at the lowest, most competitive price possible. Also, despite the higher firing temperature of the *H System*™, combustion temperature is kept at levels that minimize emission production.

GE has more than two million fired hours of experience in operating advanced technology gas turbines, more than three times the fired hours of competitors' units combined. The *H System*™ design incorporates lessons learned from this experience with knowledge gleaned from operating GE aircraft engines. In addition, the 9H gas turbine is the first ever designed using "Design for Six Sigma" methodology, which maximizes reliability and availability throughout the entire design process. Both the 7H and 9H gas turbines will achieve the reliability levels of our F-class technology machines.

GE has tested its *H System*™ gas turbine more thoroughly than any system previously introduced into commercial service. The *H System*™ gas turbine has undergone extensive design validation and component testing. Full-speed, no-load testing (FSNL) of the 9H was achieved in May 1998 and pre-shipment testing was completed in November 1999. This *H System*™ will also undergo approximately a half-year of extensive demonstration and characterization testing at the launch site.

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Background and Rationale for the H System™

The use of gas turbines for power generation has been steadily increasing in popularity for more than five decades. Gas turbine cycles are inherently capable of higher power density, higher fuel efficiency, and lower emissions than the competing platforms. Gas turbine performance is driven by the firing temperature, which is directly related to specific output, and inversely related to fuel consumption per kW of output. This means that increases in firing temperature provide higher fuel efficiency (lower fuel consumption per kW of output) and, at the same time, higher specific output (more kW per pound of air passing through the turbine).

The use of aircraft engine materials and cooling technology has allowed firing temperature for GE's industrial gas turbines to increase steadily. However, higher temperatures in the combustor also increase NO_x production. In the "Conceptual Design" section of this paper, we describe how the GE *H System*™ solved the NO_x problem, and is able to raise firing temperature by 200°F / 110°C over the current "F" class of gas turbines and hold the NO_x emission levels at the initial "F" class levels.

The General Electric Company is made up of a number of different businesses. The company has thrived and grown due, in part, to the rapid transfer of improved technology and business practices among these businesses. The primary technology transfer channel is the GE Corporate Research & Development (CR&D) Center located in Schenectady, NY. The *H System*™ new product introduction (NPI) team is also located in Schenectady, facilitating the efficient transfer of technology from CR&D to the NPI team. Formal technology councils, including, for instance, the Thermal Barrier Coatings Council, High Temperature Materials Council, and the Dry Low NO_x (DLN) Combustion Council, also promote synergy among the businesses, fostering development of advanced technology.

GE Power Systems (GEPS) and GE Aircraft Engines (GEAE) share many common links, including testing facilities for DLN, compressor components, and steam turbine components. In a move which could only have occurred within GE, with its unique in-house resources, over 200 engineers were transferred from GEAE and CR&D to GEPS, to support the development of the *H System*™. These transfers became the core of the *H System*™'s "Design and Systems" teams. *H System*™ technology is shared in its entirety between GEPS and GEAE, including test data and analytical codes.

In contrast to the free exchange of core technical personnel between GEPS and GEAE, several of GE's competitors have been forced to purchase limited aircraft engine technology from outside companies. This approach results in the acquisition of a specific design with limited detail and flexibility, but with no understanding of the underlying core technology.

In contrast, the transfer from GE Aircraft Engines to GEPS includes, but is not limited to, the following technologies, which are described later in the paper:

- Compressor aerodynamics, mechanical design and scale model rig testing
- Full-scale combustor testing at operating pressures and temperatures
- Turbine aerodynamics, heat transfer, and nozzle cascade testing
- Transfer of materials and coating data
- Processing for turbine blade and wheel superalloys

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- Gas turbine instrumentation application and monitoring.

Technology contributed by CR&D includes:

- Development of heat transfer and fluid flow codes
- Process development for thermal barrier coatings
- Materials characterization and data
- Numerous special purpose component and subsystem tests
- Design and introduction of non-destructive evaluation techniques.

Conceptual Design

The GE *H System*™ is a combined-cycle plant. The hot gases from the gas turbine exhaust proceed to a downstream boiler or heat recovery steam generator (HRSG). The resulting steam is passed through a steam turbine and the steam turbine output then augments that from the gas turbine. The output and efficiency of the steam turbine's "bottoming cycle" is a function of the gas turbine exhaust temperature.

For a given firing temperature class, 2600°F / 1430°C for the *H System*™, the gas turbine exhaust temperature is largely determined by the work required to drive the compressor, that is, in turn, affected by the "compressor pressure ratio". The *H System*™'s pressure ratio of 23:1 was selected to optimize the combined-cycle performance, while at the same time allowing for an uncooled last-stage gas turbine bucket, consistent with past GEPS practice.

The 23:1 compressor-pressure ratio, in turn, determined that using four turbine stages would provide the optimum performance and cost solution. This is a major change from the earlier "F" class gas turbines, which used a 15:1 compressor-pressure ratio and three turbine stages. With the *H System*™'s higher pressure ratio, the use of only three turbine stages would have increased the loading on each stage to a point where unacceptable reduction in stage efficiencies would result. By using four stages, the H turbine is able to specify optimum work loading for each stage and achieve high turbine efficiency.

The Case for Steam Cooling

The GE *H System*™ gas turbine uses closed-loop steam cooling of the turbine. This unique cooling system allows the turbine to fire at a higher temperature for increased performance, yet without increased combustion temperatures or their resulting increased emissions levels. It is this closed-loop steam cooling that enabled the combined-cycle GE *H System*™ to achieve 60% fuel efficiency while maintaining adherence to the strictest, low NO_x standards (*Figure 1*).

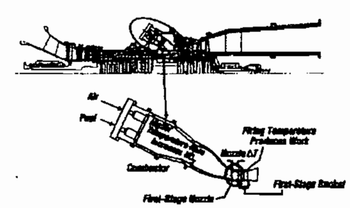
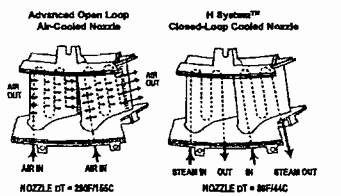


Figure 1. Combustion and firing temperatures

Combustion temperature must be as low as possible to establish low NO_x emissions, while the firing temperature must be as high as possible for optimum cycle efficiency. The goal is to adequately cool the stage 1 nozzle, while minimizing the decrease in combustion product temperature as it passes through the stage 1 nozzle. This is achieved with closed-loop steam cooling.

In conventional gas turbines, with designs predating the *H System*™, the stage 1 nozzle is cooled with compressor discharge air. This cooling process causes a temperature drop across the stage 1 nozzle of up to 280°F/155°C. In H System™ gas turbines, cooling the stage 1 nozzle with a closed-loop steam coolant reduces the temperature drop across that nozzle to less than 80°F/44°C (*Figure 2*). This results in a firing temperature class of 2600°F/1430°C, or 200°F/110°C higher than in preceding systems, yet with no increase in combustion temperature. An additional benefit of the *H System*™ is that while the steam cools the nozzle, it picks up heat for use in the steam turbine, transferring what was traditionally waste heat into usable output. The third advantage of closed-loop cooling is that it minimizes parasitic extraction



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of compressor discharge air, thereby allowing more to flow to the head-end of the combustor for fuel premixing.

In conventional gas turbines, compressor air is also used to cool rotational and stationary components downstream of the stage 1 nozzle in the turbine section. This air is traditional labeled as "chargeable air", because it reduces cycle performance. In *H System*™ gas turbines, this "chargeable air" is replaced with steam, which enhances cycle performance by up to 2 points in efficiency, and significantly increases the gas turbine output, since all the compressor air can be channeled through the turbine flowpath to do useful work. A second advantage of replacing "chargeable air" with steam accrues to the *H System*™*'s* cycle through recovery of the heat removed from the gas turbine in the bottoming cycle.

H Technology, Combined-Cycle System

The H technology, combined-cycle system consists of a gas turbine, a three-pressure-level HRSG and a reheat steam turbine.

The features of the combined-cycle system, which include the coolant steam flow from the steam cycle to the gas turbine, are shown in *Figure 3*. The high-pressure steam from the HRSG is expanded through the steam turbine's high-pressure section. The exhaust steam from this turbine section is then split. One part is returned to the HRSG for reheating; the other is combined with intermediate-pressure (IP) steam and used for cooling in the gas turbine.

Steam is used to cool the stationary and rotational parts of the gas turbine. In turn, the heat transferred from the gas turbine increases the steam temperature to approximately reheat temperature. The gas turbine cooling steam is returned to the steam cycle, where it is mixed with the reheated steam from the HRSG and introduced to the IP steam turbine section. Further details about the H combined-cycle system and its operation can be found in GER 3936A, "Advanced Technology Combined-Cycles" and will not be repeated in this paper.

H Product Family and Performance

The H technology, with its higher pressure ratio and higher firing temperature design, will establish a new family of gas turbine products. The 9H and 7H combined-cycle specifications

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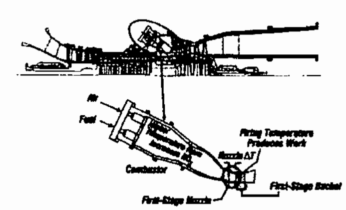

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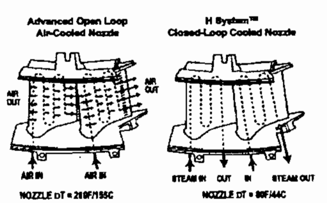

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The features of the combined-cycle system, which include the coolant steam flow from the steam cycle to the gas turbine, are shown in *Figure 3*. The high-pressure steam from the HRSG is expanded through the steam turbine's high-pressure section. The exhaust steam from this turbine section is then split. One part is returned to the HRSG for reheating; the other is combined with intermediate-pressure (IP) steam and used for cooling in the gas turbine.

Steam is used to cool the stationary and rotational parts of the gas turbine. In turn, the heat transferred from the gas turbine increases the steam temperature to approximately reheat temperature. The gas turbine cooling steam is returned to the steam cycle, where it is mixed with the reheated steam from the HRSG and introduced to the IP steam turbine section. Further details about the H combined-cycle system and its operation can be found in GER 3936A, "Advanced Technology Combined-Cycles" and will not be repeated in this paper.

H Product Family and Performance

The H technology, with its higher pressure ratio and higher firing temperature design, will establish a new family of gas turbine products. The 9H and 7H combined-cycle specifications

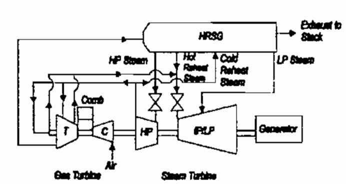


Figure 3. H Combined-cycle and steam description

are compared in *Tables 1 and 2* with the similar "F" technology family members.

The 9H and 7H are not scaled geometrically to one another. This is a departure from past prac-

	9FA	9H
Firing Temperature Class, F (C)	2400 (1316)	2600 (1430)
Air Flow, lb/sec (kg/sec)	1376 (625)	1510 (685)
Pressure Ratio	15	23
Combined Cycle Net Output, MW	391	480
Net Efficiency, %	56.7	60
NO_x (ppmvd at 15% O_2)	25	25

Table 1. H Technology performance characteristics (50 Hz)

	7FA	7H
Firing Temperature Class, F (C)	2400 (1316)	2600 (1430)
Air Flow, lb/sec (kg/sec)	953 (433)	1230 (558)
Pressure Ratio	15	23
Combined Cycle Net Output, MW	263	400
Net Efficiency, %	56.0	60
NO_x (ppmvd at 15% O_2)	9	9

Table 2. H Technology performance characteristics (60 Hz)

tices within the industry, but has been driven by customer input to GE. The specified output of the H technology products is 400 MW at 60 Hz and 480 MW at 50 Hz in a single-shaft, combined-cycle system. The 9H has been introduced at 25 ppm NO_x, based on global market needs and economics.

One extremely attractive feature of the H technology, combined-cycle power plants is the high specific output. This permits compact plant designs with a reduced "footprint" when compared with conventional designs, and consequently, the potential for reduced plant capital costs (*Figure 4*). In a 60 Hz configuration, the H technology's compact design results in a 54% increase in output over the FA plants with an increase of just 10% in plant size.

GE is moving forward concurrently with development of the 9H and 7H. However, in response to specific customer commitments, the 9H was

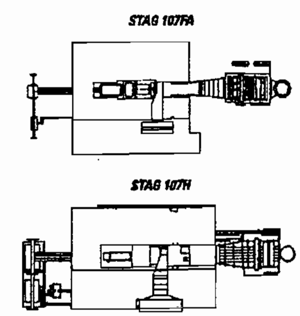


Figure 4. 7H and 7FA footprint comparison

introduced first. The 7H program is following closely, about 12 months behind the 9H.

The 7H development has made progress as part of the Advanced Turbine Systems program of the U.S. Department of Energy and its encouragement and support is gratefully acknowledged.

System Strategy and Integration

While component and subsystem validation is necessary and is the focus of most NPI programs, other factors must also be considered in creating a successful product. The gas turbine must operate as a system, combining the compressor, combustor and turbine at design point (baseload), at part load turndown conditions, and at no load. The power plant and all power island components must also operate at steady state and under transient conditions, from start-up, to purge, to full speed.

Unlike traditional combined-cycle units, the *H System*™ gas turbine, steam turbine and HRSG are linked into one, interdependent system. Clearly, the reasoning behind these GE *H System*™ components runs contrary to the traditional approach, which designs and specifies each component as a stand-alone entity. In the *H System*™, the performance of the gas turbine, combined-cycle and balance of plant has been modeled, both steady state and transient; and analyzed in detail, as one large, integrated system, from its inception.

The GE *H System*™ concept incorporates an integrated control system (ICS) to act as the glue, which ties all the subsystems together (*Figure 5*).

Systems and controls teams, working closely with one another as well as with customers, have formulated improved hardware, software, and control concepts. This integration was facilitated by a new, third-generation, full-authority digital system, the Mark VI controller. This control system was designed with and is supplied by GE Industrial Systems (GEIS), which is yet another GE business working closely with GEPS.

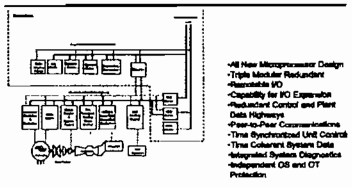


Figure 5. Mark VI – ICS design integrated with *H Systems*™ design

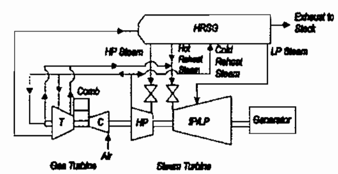
The control system for the *H System*™ manages steam flows between the HRSG, steam turbine and gas turbine. It also schedules distribution of cooling steam to the gas turbine. A diagnostic capability is built into the control system, which also stores critical data in an electronic historian for easy retrieval and troubleshooting.

The development of the Mark VI and integrated control system has been deliberately scheduled ahead of the H gas turbine to reduce the gas turbine risk. With the help of GE CR&D, the Mark VI followed a separate and rigorous NPI risk abatement procedure, which included proof of concept tests and shake down tests of a full combined-cycle plant at GE Aircraft Engines in Lynn, Massachusetts.

The Systems and controls teams have state-of-the-art computer simulations at their disposal to facilitate full engineering of control and fall-back strategies. Digital simulations also serve as a training tool for new operators.

Simulation capability was used in real time during the 9H Full-Speed No-Load (FSNL)-1 test in May 1998. This facilitated revision of the accelerating torque demand curves for the gas turbine and re-setting of the starter motor current and gas turbine combustor fuel schedule. The end result was an automated, one-button, soft-start for the gas turbine, which was used by the TEPCO team to initiate the May 30, 1998 customer witness test.

The balance of this paper will focus on the gas turbine and its associated development program.



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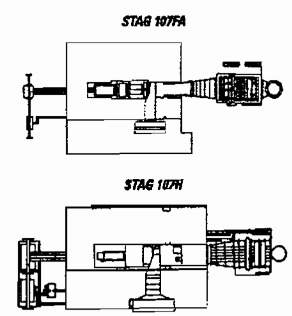

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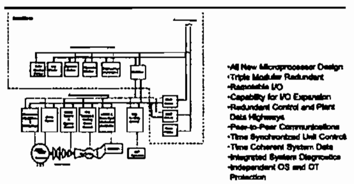

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H Gas Turbine

The heart of the GE *H System*™ is the gas turbine. The challenges, design details, and validation program results follow. We start with a brief overview of the 9H and 7H gas turbine components (*Figure 6*).

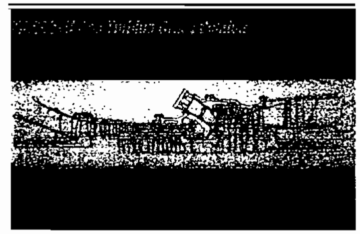

Figure 6. Cross-section H gas turbine

Compressor Overview

The H compressor provides a 23:1 pressure ratio with 1510 lb/s (685 kg/s) and 1230 lb/s (558 kg/s) airflow for the 9H and 7H gas turbines, respectively. These units are derived from the high-pressure compressor GE Aircraft Engines (GEAE) used in the CF6-80C2 aircraft engine and the LM6000 aeroderivative gas turbine. For use in the H gas turbines, the CF6-80C2 compressor has been scaled up (2.6:1 for the MS7001H and 3.1:1 for the MS9001H) with four stages added to achieve the desired combination of airflow and pressure ratio. The CF6 compressor design has accumulated over 20 million hours of running experience, providing a solid design foundation for the *H System*™ gas turbine.

In addition to the variable inlet guide vane (IGV), used on prior GE gas turbines to modulate airflow, the H compressors have variable stator vanes (VSV) at the front of the compressor. They are used, in conjunction with the IGV, to control compressor airflow during turndown, as well as to optimize operation for variations in ambient temperature.

Combustor Overview

The *H System*™ can-annular combustion system is a lean pre-mix DLN-2.5 *H System*™, similar to the GE DLN combustion systems in FA-class service today. Fourteen combustion chambers are used on the 9H, and twelve combustion chambers are used on the 7H. DLN combustion systems have demonstrated the ability to achieve low NO_x levels in field service and are capable of meeting the firing temperature requirements of the GE *H System*™ gas turbine while obtaining single-digit (ppm) NO_x and CO emissions.

Turbine Overview

The case for steam cooling was presented earlier under Conceptual Design. The GE *H System*™ gas turbine's first two stages use closed-loop steam cooling, the third stage uses air cooling, while the fourth and last stage is uncooled.

Closed-loop cooling eliminates the film cooling on the gas path side of the airfoil, and increases the temperature gradients through the airfoil walls. This method of cooling results in higher thermal stresses on the airfoil materials, and has led GEPS to use single-crystal super-alloys for the first stage, in conjunction with thin ceramic thermal barrier coatings (*Figure 7*). This is a combination that GEAE has employed in its jet engines for 20 years. GEPS reached into the extensive GEAE design, analysis, testing and production database and worked closely with GEAE, its supplier base, and CR&D to translate this experience into a reliable and effective feature of the *H System*™ gas turbine design.

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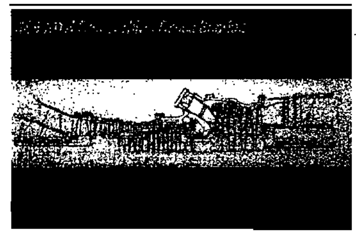

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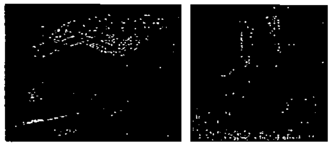

Figure 7. H Stage 1 nozzle and bucket – single crystal

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Gas Turbine Validation: Testing to Reduce Risk

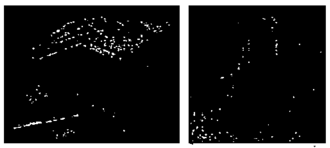
Although GEPS officially introduced the *H System*™ concept and two product lines, the 9H and 7H gas turbines, to the industry in 1995, *H System*™ technology has been under development since 1992. The development has been a joint effort among GEPS, GEAE, and CR&D, with encouragement and support from the U.S. Department of Energy, and has followed GE's comprehensive design and technology validation plan that will, when complete, have spanned 10 years from concept to power plant commissioning.

The systematic design and technology-validation approach described in this paper has proved to be the aerospace and aircraft industry's most reliable practice for introduction of complex, cutting-edge technology products. The approach is costly and time consuming, but is designed to deliver a robust product into the field for initial introduction. At its peak, the effort to develop and validate the *H System*™ required the employment of over 600 people and had annual expenses of over $100 million.

Other suppliers perceive that design and construction of a full-scale prototype may be a faster development-and-design approach. However, it is difficult, if not impossible, for a prototype to explore the full operating process in a controlled fashion. For example, prototype testing limits the opportunity to evaluate alternative compressor stator gangs and to explore cause-and-effect among components when problems are encountered. The prototype approach also yields a much greater probability of failure during the initial field introduction of a product than does the comprehensive design approach, coupled with "Six Sigma" disciplines and the technology validation plan used by GE (*Figure 8*).

The first phase in the *H System*™ development process was a thorough assessment of product options, corresponding design concepts, and system requirements. Also crucial in the first phase was careful selection of materials, components and subsystems. These were sorted into categories of existing capabilities or required technology advancements. All resources and technological capabilities of GEAE and CR&D were made available to the Power Systems' H-technology team.

For each component and subsystem, risk was assessed and abatement analyses, testing, and



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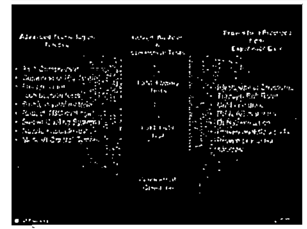


Figure 8. GE validation process

data were specified. Plans to abate risk and facilitate design were arranged, funded, and executed.

The second development phase covered product conceptual and preliminary designs, and included the introduction of knowledge gained through experience, materials data, and analytical codes from GEPS and GEAE.

The *H System*™ development program is currently in its third and final phase, technology readiness demonstration. This phase includes execution of detailed design and product validation through component and gas turbine testing. A high degree of confidence has been gained through component and subsystem testing and validation of analysis codes. Completion of the development program results in full-scale gas turbine testing at our factory test stand in Greenville, SC, followed by combined-cycle power plant testing at the Baglan Energy Park launch site, in the United Kingdom.

Compressor Design Status

Modifications and proof-of-design are made through a rigorous design process that includes GEAE and GEPS experience-based analytical tools, component tests, compressor rig tests and instrumented product tests. The aerodynamic design process uses pitchline design and off-design performance evaluation, axisymmetric streamline curvature calculations with empiricism for secondary flows and mixing, two-dimensional inviscid blade-to-blade analysis and three dimensional viscous CFD blade row analysis. The aerodynamic design is iterated in concert with the aeromechanical design of the individual blade stages, optimizing on GEAE and GEPS experience-supported limits on blade loading, stage efficiency, surge margin, stress limits, etc.

The program has completed the third and final compressor rig test at GEAE's Lynn, MA test facility.

Tests are run with CF6 full-scale hardware, which amounts to a one-third scale test for the 9H and 7H gas turbines. Each rig test is expensive, approximately $20M, but provides validation and flexibility, significantly surpassing any other test options. The 7H rig test had over 800 sensors and accumulated over 150 hours to characterize the compressor's aerodynamic and aeromechanical operations (*Figure 9*). Key test elements include optimum ganging of the variable guide vanes and stators; performance mapping to quantify airflow, efficiency, and stall margins; stage pressure and temperature splits; start-up, acceleration, and turndown character-

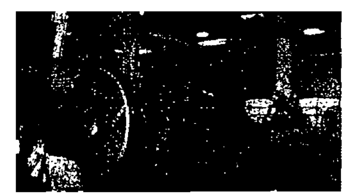


Figure 9. 7H compressor test rig

istics; and identification of flutter and vibratory characteristics of the airfoils (aeromechanics).

The three-test series has accomplished the following:

- Proof of concept, with four stages added to increase pressure ratio, and initial power generation operability – completed August 1995.
- 9H compressor design validation and maps including tri-passage diffuser performance and rotor cooling proof-of-concept – completed August 1997.
- 7H compressor design validation – completed August 1999, (*Figure 10*)

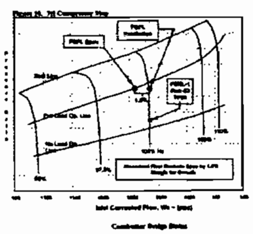


Figure 10. Compressor map

Combustor Design Status

Figure 11 shows a cross-section of the combustion system. The technical approach features a tri-passage radial prediffuser which optimizes the airflow pressure distribution around the combustion chambers, a GTD222 transition piece with an advanced integral aft frame mounting arrangement, and impingement sleeve cooling of the transition piece. The transition piece seals are the advanced cloth variety for minimum leakage and maximum wear resistance. The flow sleeve incorporates

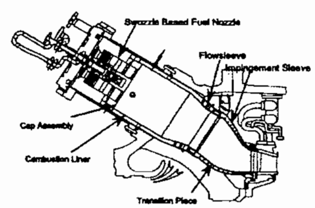
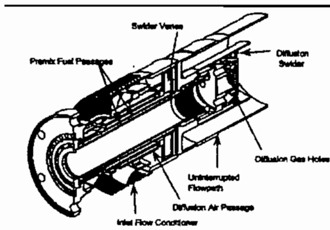


Figure 11. Combustion system cross-section

impingement holes for liner aft cooling. The liner cooling is of the turbolator type so that all available air can be allocated to the reaction zone to reduce NO_x. Advanced 2-Cool™ composite wall convective cooling is utilized at the aft end of the liner. An effusion-cooled cap is utilized at the forward end of the combustion chamber.

Fuel Injector Design Status

The *H System*™ fuel injector is shown in *Figure 12* and is based on the swozzle concept. The term swozzle is derived by joining the words "swirler" and "nozzle." The premixing passage of the swozzle utilizes swirl vanes to impart rotation to the admitted airflow, and each of these swirl vanes also contains passages for injecting fuel into the premixer airflow. Thus, the premixer is very aerodynamic and highly resistant



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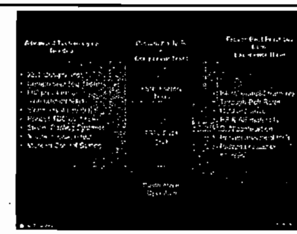

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The *H System*™ development program is currently in its third and final phase, technology readiness demonstration. This phase includes execution of detailed design and product validation through component and gas turbine testing. A high degree of confidence has been gained through component and subsystem testing and validation of analysis codes. Completion of the development program results in full-scale gas turbine testing at our factory test stand in Greenville, SC, followed by combined-cycle power plant testing at the Baglan Energy Park launch site, in the United Kingdom.

Compressor Design Status

Modifications and proof-of-design are made through a rigorous design process that includes GEAE and GEPS experience-based analytical tools, component tests, compressor rig tests and instrumented product tests. The aerodynamic design process uses pitchline design and off-design performance evaluation, axisymmetric streamline curvature calculations with empiricism for secondary flows and mixing, two-dimensional inviscid blade-to-blade analysis and three dimensional viscous CFD blade row analysis. The aerodynamic design is iterated in concert with the aeromechanical design of the individual blade stages, optimizing on GEAE and GEPS experience-supported limits on blade loading, stage efficiency, surge margin, stress limits, etc.

The program has completed the third and final compressor rig test at GEAE's Lynn, MA test facility.

Tests are run with CF6 full-scale hardware, which amounts to a one-third scale test for the 9H and 7H gas turbines. Each rig test is expensive, approximately $20M, but provides validation and flexibility, significantly surpassing any other test options. The 7H rig test had over 800 sensors and accumulated over 150 hours to characterize the compressor's aerodynamic and aeromechanical operations (*Figure 9*). Key test elements include optimum ganging of the variable guide vanes and stators; performance mapping to quantify airflow, efficiency, and stall margins; stage pressure and temperature splits; start-up, acceleration, and turndown character-

Figure 9. 7H compressor test rig

istics; and identification of flutter and vibratory characteristics of the airfoils (aeromechanics).

The three-test series has accomplished the following:

- Proof of concept, with four stages added to increase pressure ratio, and initial power generation operability – completed August 1995.
- 9H compressor design validation and maps including tri-passage diffuser performance and rotor cooling proof-of-concept – completed August 1997.
- 7H compressor design validation – completed August 1999. (*Figure 10*)

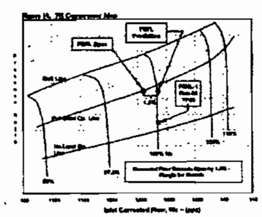

Figure 10. Compressor map

Combustor Design Status

Figure 11 shows a cross-section of the combustion system. The technical approach features a tri-passage radial prediffuser which optimizes the airflow pressure distribution around the combustion chambers, a GTD222 transition piece with an advanced integral aft frame mounting arrangement, and impingement sleeve cooling of the transition piece. The transition piece seals are the advanced cloth variety for minimum leakage and maximum wear resistance. The flow sleeve incorporates

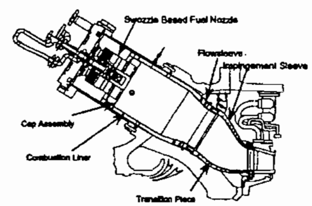

Figure 11. Combustion system cross-section

impingement holes for liner aft cooling. The liner cooling is of the turbolator type so that all available air can be allocated to the reaction zone to reduce NO_x. Advanced 2-Cool™ composite wall convective cooling is utilized at the aft end of the liner. An effusion-cooled cap is utilized at the forward end of the combustion chamber.

Fuel Injector Design Status

The *H System*™ fuel injector is shown in *Figure 12* and is based on the swozzle concept. The term swozzle is derived by joining the words "swirler" and "nozzle." The premixing passage of the swozzle utilizes swirl vanes to impart rotation to the admitted airflow, and each of these swirl vanes also contains passages for injecting fuel into the premixer airflow. Thus, the premixer is very aerodynamic and highly resistant

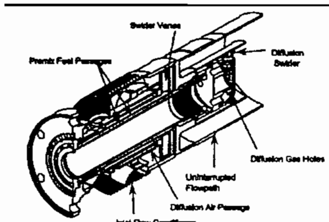

Figure 12. Fuel injector system cross-section

to flashback and flameholding. Downstream of the swozzle vanes, the outer wall of the premixer is integral to the fuel injector to provide added flameholding resistance. Finally, for diffusion flame starting and low load operation, a swirl cup is provided in the center of each fuel injector.

The *H System*™ combustor uses a simplified combustion mode staging scheme to achieve low emissions over the premixed load range while providing flexible and robust operation at other gas turbine loads. *Figure 13* shows a schematic diagram of the staging scheme. The most significant attribute is that there are only

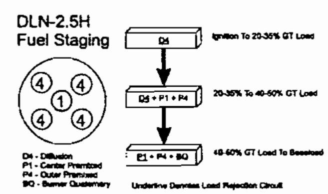

Figure 13. Combustion mode staging scheme

three combustion modes: diffusion, piloted premix, and full premix mode. These modes are supported by the presence of four fuel circuits: outer nozzle premixed fuel (P4), center nozzle premixed fuel (P1), burner quaternary premixed fuel (BQ), and diffusion fuel (D4). The gas turbine is started on D4, accelerated to Full-Speed No-Load (FSNL), and loaded further. At approximately 20-35% gas turbine load, two premixed fuel streams P1, and P4, are activated in the transfer into piloted premix. After loading the gas turbine to approximately 40-50% load, transfer to full premix mode is made and all D4 fuel flow is terminated while BQ fuel flow is activated. This very simplified staging strategy has major advantages for smooth unit operability and robustness.

The *H System*™ combustor was developed in an extensive test series to ensure low emissions, quiet combustion dynamics, ample flashback/flameholding resistance, and rigorously assessed component lifing supported by a complete set of thermal data. In excess of thirty tests were run at the GEAE combustion test facility, in Evendale, OH, with full pressure, temperature, and airflow. *Figure 14* shows typical NO_x baseload emissions as a function of combustor exit temperature, and *Figure 15* shows the comparable combustion dynamics data. The H components have significant margin in each case. In addition, hydrogen torch

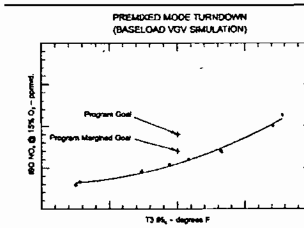

Figure 14. NO_x baseload emissions as a function of combustor exit temperature

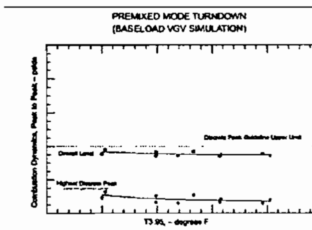

Figure 15. Comparable combustion dynamics data

ignition testing was performed on the fuel injector premixing passages. In all cases the fuel injectors exhibited well in excess of 30 ft/s flameholding margin after the hydrogen torch to flashback and flameholding. Downstream of the swozzle vanes, the outer wall of the premixer is integral to the fuel injector to provide added flameholding resistance. Finally, for diffusion flame starting and low load operation, a swirl cup is provided in the center of each fuel injector.

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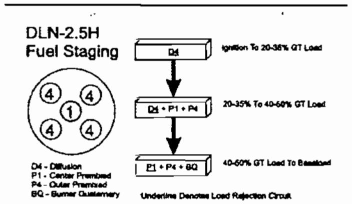

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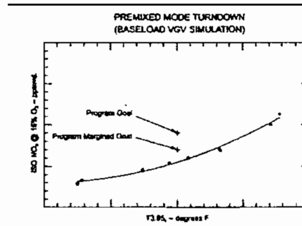

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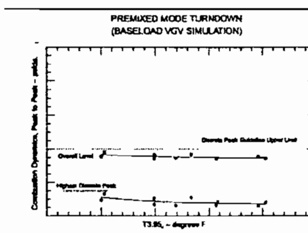

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Turbine Design Status

The turbine operates with high gas path temperatures, providing the work extraction to drive the compressor and generator. Two of the factors critical to reliable, long life are the turbine airfoil's heat transfer and material capabilities. When closed circuit steam cooling is used, as on the H turbine, the key factors do not change. However, the impact of steam on the airfoil's heat transfer and material capabilities must also be considered.

For many years, the U.S. Department of Energy (DOE) Advanced Turbine System has provided cooperative support for GE's development of the H System™ turbine heat transfer materials capability and steam effects. Results have fully defined and validated the factors vital to successful turbine operation. A number of different heat transfer tests have been performed to fully characterize the heat transfer characteristics of the steam-cooled components. *Figure 16*

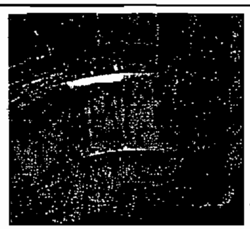

Figure 16. Full-scale stage 1 nozzle heat transfer test validates design and analysis predictions

shows results for stage 1 nozzle internal cooling heat transfer. An extensive array of material tests has been performed to validate the material characteristics in a steam environment. Testing has included samples of base material and joints and the testing has addressed the following mechanisms: cyclic oxidation, fatigue crack propagation, creep, low-cycle fatigue and notched low-cycle fatigue (*Figure 17*).

Figure 17. Materials validation testing in steam

Thermal barrier coating (TBC) is used on the flowpath surfaces of the steam-cooled turbine airfoils. Life validation has been performed using both field trials (*Figure 18*) and laboratory analysis. The latter involved a test that duplicates thermal-mechanical conditions, which the TBC will experience on the H System™ airfoils.

Long-term durability of the steam-cooled components is dependent on avoidance of internal deposit buildup, which is, in turn, dependent on steam purity. This is accomplished through system design and filtration of the gas turbine cooling steam. Long-term validation testing,

Figure 18. Thermal barrier coating durability

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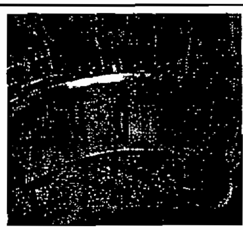

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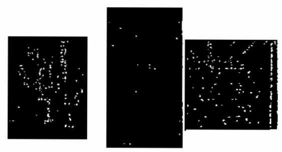

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currently underway at an existing power plant, has defined particle size distribution and validated long-term steam filtration. As further validation, specimens duplicating nozzle cooling passages have initiated long-term exposure tests. A separate rotational rig is being used for bucket validation.

The H turbine airfoils have been designed using design data and validation test results for heat transfer, material capability and steam cooling effects. The durability of ceramic thermal barrier coatings has been demonstrated by three different component tests performed by CR&D:

- Furnace cycle test
- Jet engine thermal shock tests
- Electron beam thermal gradient testing

The electron beam thermal gradient test was developed specifically for GEPS to accurately simulate the very high heat transfers and gradients representative of the *H System*™ gas turbine. Heat transfers and gradients representative of the *H System*™ gas turbine have also been proven by field testing of the enhanced coatings in E- and F-class gas turbines.

The stage 1 nozzle, which is the H System™ component subjected to the highest operating temperatures and gradients, has been validated by another intensive component test. A nozzle cascade facility was designed and erected at GEAE (*Figure 19*). It features a turbine segment carrying two closed-loop steam-cooled nozzles downstream from a full-scale H System™ combustor and transition piece. This testing facility accurately provides the actual gas turbine operating environment. Two prototype nozzles complete with pre-spalled TBC were tested in April 1998. Data was obtained validating the aerodynamic design and heat transfer codes. Accelerated endurance test data was also obtained. A second test series, with actual 9H production nozzles, is scheduled to start in the 4th quarter of 2000).

Figure 19. Nozzle cascade test facility

The rotor steam delivery system delivers steam for cooling stage 1 and 2 turbine buckets. This steam delivery system relies on "spoolies" to deliver steam to the buckets without detrimental leakage, which would lead to performance loss and adverse thermal gradients within the rotor structure. The basic concept for power system steam sealing is derived from many years of successful application of spoolies in the GE CF6 and CFM56 aircraft engine families.

In the conceptual design phase, material selection was made only after considering the effects of steam present in this application. Coatings to improve durability of the spoolie were also tested. These basic coupon tests and operational experience provided valuable information to the designers.

In the preliminary design phase, parametric analysis was performed to optimize spoolie configuration. Component testing began for both air and steam systems. The spoolie was instrumented to validate the analysis. Again, the combination of analysis and validation tests provided confirmation that the design(s) under consideration were based on the right concept.

Over 50 component tests have been conducted on these spoolies, evaluating coatings, lateral loads, fits, axial motion, angular motion, temperature and surface finish.

The detailed design phase focused on optimization of the physical features of the subsystem, spoolie-coating seat. In addition, refined analysis was performed to allow for plasticity lifecycle calculations in the region of the highest stresses. This analysis was again validated with a spoolie cyclic life test, which demonstrated effective sealing at machine operating conditions with a life over of 20,000 cycles.

Spoolies were also used on the *H System*™ FSNL gas turbine tests. During the 9H FSNL-2 testing, compressor discharge air flowed through the circuit. This is typical of any no-load operation. Assembly and disassembly tooling and processes were developed. The spoolies were subjected to a similar environment with complete mechanical G loading. Post-testing condition of the seals was correlated to the observation made on the component tests. This provided another opportunity for validation.

A rotating steam delivery rig (*Figure 20*) has been designed and manufactured to conduct cyclic endurance testing of the delivery system under any load environment. The rotating rig will subject components to the same centrifugal forces and thermal gradients that occur during actual operation of the turbine. This system testing will provide accelerated lifecycle testing.

Leakage checks will be completed periodically to monitor sealing effectiveness. Test rig instrumentation will insure that the machine matches the operating environment. The rig has been installed in the test cell, and testing should resume in April 2000.

Gas Turbine Factory Tests

The first six years of the GE H System™ validation program focused on sub-component and component tests. Finally, in May 1998, the program moved on to the next stage, that of full-scale gas turbine testing at the Greenville, South Carolina factory (*Figure 21*). The 9H gas turbine achieved first fire and full speed and, then, over a space of five fired tests, accomplished the full set of objectives. These objectives included confirmation of rotor dynamics: vibration levels and onset of different modes; compressor airfoil aero-mechanics; compressor performance, including confirmation of airflow and efficiency scale-up effects vs. the CF6 scale rig tests; measurement of compressor and turbine rotor clearances; and demonstration of the gas turbine with the Mark VI control system.

The testing also provided data on key systems:

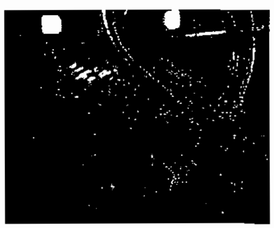

Figure 20. Rotating rig installed in test stand

Figure 21. 9H gas turbine in half shell prior to first FSNL test

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bearings, rotor cooling, cavity temperatures and effectiveness of the clearance control systems.

Following the testing, the gas turbine was disassembled in the factory and measured and scrutinized for signs of wear and tear. The hardware was found to be in excellent condition.

The 9H gas turbine was rebuilt with production turbine airfoils and pre-shipment tests performed in October and November 1999. This unit was fully instrumented for the field test to follow and, thus, incorporated over 3500 gauges and sensors (*Figure 22*).

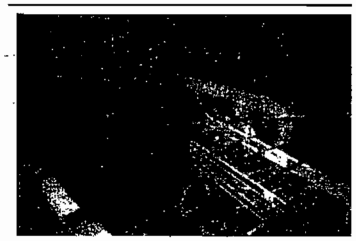

Figure 22. 9H gas turbine in test stand for pre-shipment test

This second 9H test series took seven fired starts and verified that the gas turbine was ready to ship to the field for the final validation step. Many firsts were accomplished. The pre-shipment test confirmed that the rotating air/steam cooling system performed as modeled and designed. In particular, leakage, which is critical to the cooling and life of the turbine airfoils and the achievement of well-balanced and predictable rotor behaviors, was well under allowable limits.

Compressor and turbine blade aeromechanics data were obtained at rates of up to 108% of the design speed, clearing the unit to run at design and over-speed conditions. Rotor dynamics were once again demonstrated, and vibration levels were found to be acceptable without field balance weights.

The Mark VI control system demonstrated full control of both the gas turbine and the new *H System*™ accessory and protection systems.

The first 7H gas turbine was assembled and moved to the test stand in December 1999 (*Figure 23*). This 7H went through a test series similar to that for the first 9H factory test. However, the 7H not only covered the 9H test objectives described earlier, but also ran separately with deliberate unbalance at compressor and turbine ends to characterize the rotor sensitivity and vectors. The rotor vibrations showed excellent correlation with the rotor dynamic model and analysis.

The 7H gas turbine is now back in the factory for disassembly and inspection, following the same sequence used for the 9H.

Figure 23. 7H gas turbine being installed in test stand

Validation Summary

GE is utilizing extensive design data and validation test programs to ensure that a reliable *H System*™ power plant is delivered to the customer. A successful baseline compressor test program has validated the *H System*™ compressor design approach. As a result of the 9H and bearings, rotor cooling, cavity temperatures and effectiveness of the clearance control systems.

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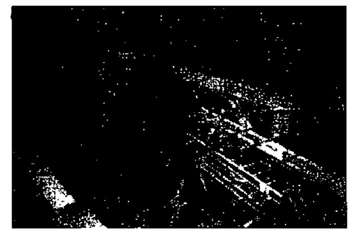

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Both 9H and 7H gas turbines have undergone successful factory testing and the 9H is now poised for shipment to the field and final validation test.

Conclusion

The rigorous design and technology validation of the *H System*™ is an illustration of the GE NPI process in its entirety. It began with a well-reasoned concept that endured a rigorous review and validation process. This ensures the highest probability of success, even before the product or shipping to customers and/or the product has begun operation in the field.

The H technology, combined-cycle power plant creates an entirely new echelon of power generation systems. Its innovative cooling system allows a major increase in firing temperature, which allows the turbine to reach record levels of efficiency and specific work while retaining low emissions capability.

The design for this "next generation" power generation system is now established. Both the 50 Hz and 60 Hz family members are currently in the production and final validation phase. The extensive component test validation program, already well underway, will ensure delivery of a highly reliable, combined-cycle power generation system to the customer.

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Conclusion

The rigorous design and technology validation of the *H System*™ is an illustration of the GE NPI process in its entirety. It began with a well-reasoned concept that endured a rigorous review and validation process. This ensures the highest probability of success, even before the product or shipping to customers and/or the product has begun operation in the field.

The H technology, combined-cycle power plant creates an entirely new echelon of power generation systems. Its innovative cooling system allows a major increase in firing temperature, which allows the turbine to reach record levels of efficiency and specific work while retaining low emissions capability.

The design for this "next generation" power generation system is now established. Both the 50 Hz and 60 Hz family members are currently in the production and final validation phase. The extensive component test validation program, already well underway, will ensure delivery of a highly reliable, combined-cycle power generation system to the customer.

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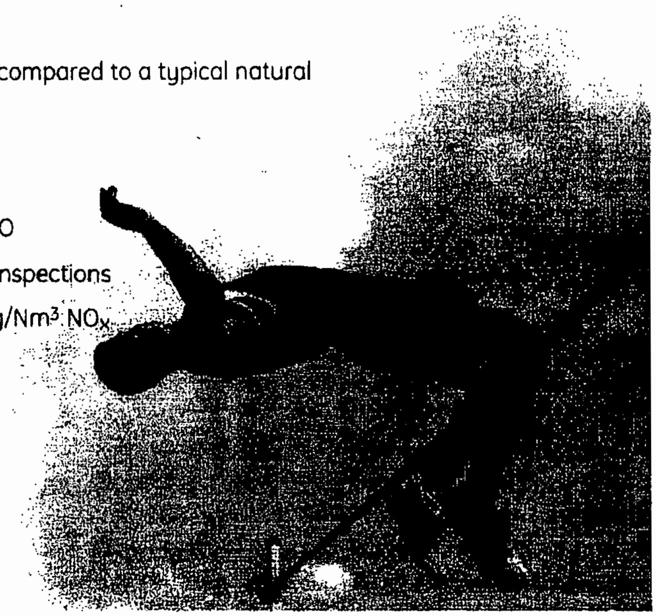
GE Energy

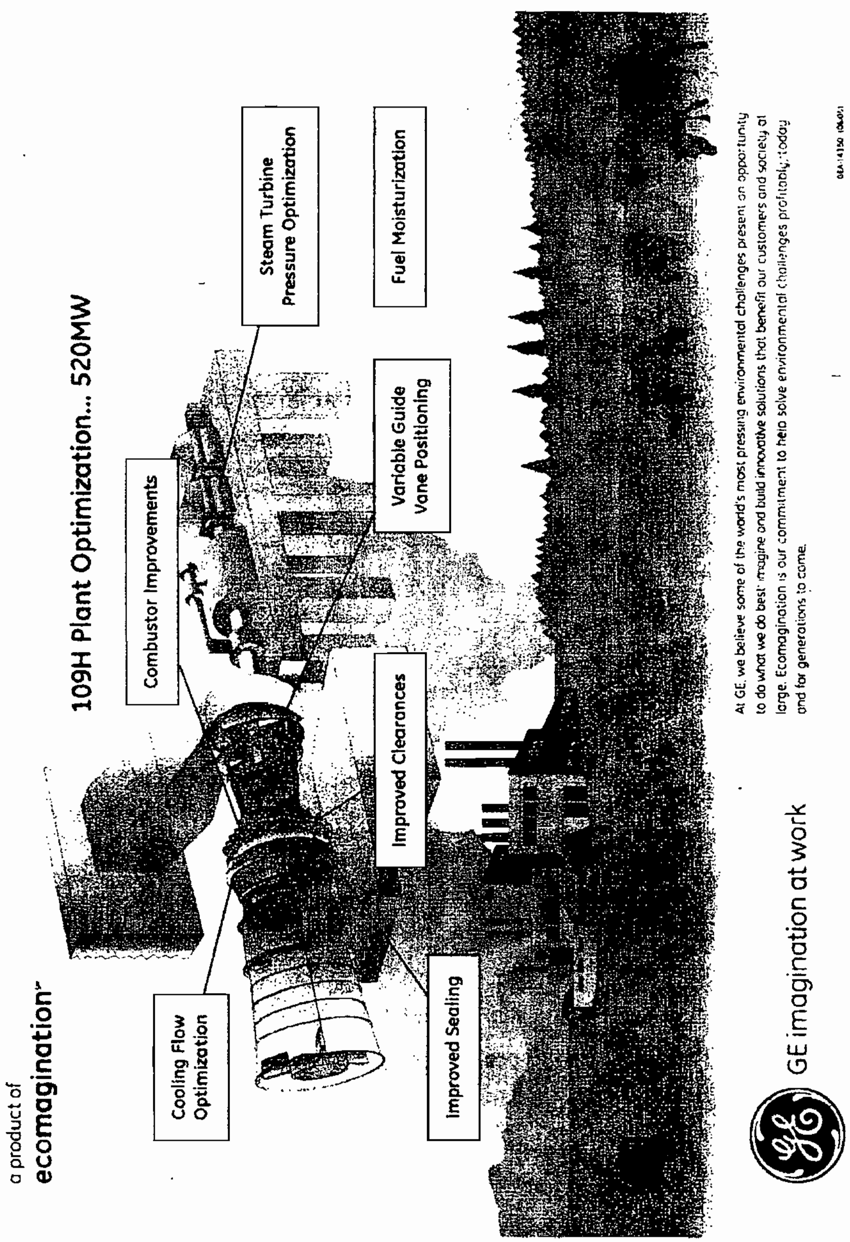
H System™ – Raising the Bar for Large Combined Cycle

- 9,000 fired hours experience at Baglan Bay
- Lower NO_x and CO_2 per unit of electricity when compared to a typical natural gas fired combined cycle power plant
  - New rating: 520MW @ 60% efficiency
- Operational flexibility similar to F Class
  - 50% combined cycle part load operation at ISO
  - 24,000 hour hot gas path; 48,000 hour major inspections
  - 12,000 hour combustion inspection with 30mg/Nm^3 NO_x
  - 60 minute hot start-up time



gepower.com

GE imagination at work



Press Release

GE's H System* Gas Turbine Hits Project Milestone In Japan
First Firing at TEPCO Plant

NEW ORLEANS, LA - December 11, 2007 : – GE Energy's first commercial H System gas turbi achieved first firing at Tokyo Electric Power Company's Futtsu Thermal Power Station. TEPCO F first commercial site for GE's most advanced, gas turbine combined-cycle system.

Futtsu Thermal Power Station will feature three H Systems, each including GE Energy's 9H gas t with a steam turbine and generator provided by Toshiba under an agreement with GE. The three cycle blocks will enter commercial operation between 2008 and 2010, with a total output of 1,520

"This successful milestone of unit 1 for the Futtsu project is a key step in the commercial develop H System gas turbine," said Steve Bolze, vice president-power generation for GE Energy. "It is a chapter in an on-going relationship with TEPCO, which has been implementing our technology fo years."

With a total production of 60 gigawatts, TEPCO is one of the largest utilities in the world, and is o largest customers. Other TEPCO sites utilizing GE Energy's gas turbine combined-cycle technolo Yokohama, Chiba and Shinagawa.

Futtsu Thermal Power Station marks the second location where GE Energy's H System gas turbi operation. The world's first 50-hertz 9H combined-cycle system entered service in 2003 at Baglar South Wales, and has surpassed 26,500 operating hours. The first 60-hertz project is the Inland E Energy Center in California, scheduled to begin service in 2008

H System gas turbine
The H System gas turbine integrates a gas turbine, steam turbine and heat recovery steam gene GE Energy's most advanced gas turbine combined-cycle system. The technology features an inn closed-loop steam cooling system that allows the turbine to fire at higher temperatures, enabling efficiency, reduced emissions and less fuel consumption per megawatt of power generated.

The H System gas turbine is the industry's first combined-cycle system designed with the capabil achieve 60 percent thermal efficiency, an industry milestone. It also offers 40 percent improveme density per installed megawatt compared to other combined-cycle systems, reducing the overall producing electricity.

The H system gas turbine is capable of producing 87,000 fewer metric tons of greenhouse gases when compared to a typical gas turbine combined-cycle plant generating an equivalent amount o The H System gas turbine is ecomagination certified, a GE product-line certification based on op environmental performance.

* H System gas turbine is a trademark of the General Electric Company.

About GE Energy
GE Energy (www.ge.com/energy) is one of the world's leading suppliers of power generation and delivery technologies, with 2006 revenue of $19 billion. Based in Atlanta, Georgia, GE Energy wo areas of the energy industry including coal, oil, natural gas and nuclear energy; renewable resou water, wind, solar and biogas; and other alternative fuels. Numerous GE Energy products are cer

ecomagination, GE's corporate-wide initiative to aggressively bring to market new technologies tl
customers meet pressing environmental challenges

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GE Energy

WORLDWI

Press Release

GE'S First 60-Hertz H System* Gas Turbine Project Moves Toward Commercial Startu, Year

Milestones Mark Progress at Inland Empire Energy Center

ATLANTA, GEORGIA - September 10, 2007 :- The world's first installation of GE Energy's 60-h System* gas turbine, the Inland Empire Energy Center in southern California, remains on target f commercial startup in the summer of 2008.

In a recent project milestone, back feed power was provided to one of the two GE Frame 107H g at the site, clearing the way for startup and commissioning of the power plant auxiliary systems.

A GE-designed demineralization water system is currently being commissioned. This system will demineralized water purified from recycled water feedstock to provide all needed steam plant ma for the entire site operation.

The first 107H gas turbine at the site (unit #1) is expected to achieve first firing by the end of this unit #2 first firing expected in early 2008. Unit #1 will be heavily instrumented and will undergo ex validation testing throughout the first half of 2008, to validate the 107H combined-cycle system.

An innovative, closed-loop steam cooling system and advanced coating materials are key feature System gas turbine's ability to achieve the higher firing temperatures required for increased effici also translates into improved environmental performance. For every unit of electricity generated, System gas turbine uses less fuel and produces fewer greenhouse gases and other emissions w compared to other large gas turbine combined-cycle systems The H System gas turbine is a key GE ecomagination, a corporate-wide initiative to develop and market technologies that will help c meet pressing environmental challenges.

Operating on natural gas, the two GE 107H combined-cycle systems at Inland Empire will produc 775 megawatts, or enough power to supply nearly 600,000 households. Located in Romoland, n Riverside, the plant will come on line in the summer of 2008, in time to help offset state-forecaste shortfalls in southern California.

"We're extremely pleased with the progress to date on the Inland Empire project," said John Reir manager of gas turbine and combined-cycle products for GE Energy. "Southern California, with it focus on finding more efficient methods to meet its growing power requirements, is an ideal place showcase our most advanced 60-hertz combined-cycle technology."

GE is financing and will own the Inland Empire Energy Center. Calpine Power Services is manag construction and Calpine Energy Services will market the plant's output and manage fuel require a long-term marketing arrangement with GE. Following an extended period of GE ownership, Cal expects to purchase the plant and become its sole owner and operator, with GE continuing to prc maintenance services under a contractual agreement with Calpine.

The 50-hertz version of GE's H System gas turbine made its global commercial debut in 2003 at Bay Power Station in South Wales, where it recently surpassed 24,000 hours of service. The wor installation of 109H technology is Tokyo Electric Power Company's Futtsu Thermal Power Statior where the first of three 109H combined-cycle systems will enter service in 2008.

About GE Energy
GE Energy (www.ge.com/energy) is one of the world's leading suppliers of power generation and delivery technologies, with 2006 revenue of $19 billion. Based in Atlanta, Georgia, GE Energy wc areas of the energy industry including coal, oil, natural gas and nuclear energy; renewable resoui water, wind, solar and biogas; and other alternative fuels. Numerous GE Energy products are cei ecomagination, GE's corporate-wide initiative to aggressively bring to market new technologies tl customers meet pressing environmental challenges.

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* H System is a trademark of General Electric Company.

It's been 12 years from drawing board to commercial operation, but GE's revolutionary H System gas [illegible]

The 510MW Baglan Bay power station in Port Talbot, Wales.

Without doubt, the 9H is the most carefully designed, engineered, tested and validated gas turbine in power generation history.

Its specifications also make it the largest, most powerful and efficient such machine in the world. Using the 50Hz 9H or 60Hz 7H turbine, GE's H System combined-cycle configuration is the first capable of breaking the 60 per cent thermal efficiency barrier. The turbine was more than a decade in the making; it finally saw its commercial launch in September at Baglan Bay power plant in the UK (see sidebar page 12).

The higher thermal efficiency of the H System will translate into lower generating costs and less plant emissions. GE estimates that a natural gas-fired CCGT plant using the technology has the capability of realising fuel cost savings of US$2 million a year, compared to existing combined-cycle plant, which operate in the range of 57-58 per cent at best.

The $500m Baglan Bay power station, is built on land leased from BP Chemicals, and provides electricity and process steam to the adjacent Baglan Energy Park and BP's isopropanol plant. Remaining electricity goes to the UK national grid.

Baglan Energy Park is a joint development between BP, Neath Port Talbot County Borough Council and the Welsh Development Agency. The Energy Park currently comprises approximately 200 acres of development land and will feature business and manufacturing facilities. The Baglan Bay redevelopment is the largest single such site in the UK and is made up of several phases, to be developed over the next 20 years.

The availability of clean, low-cost power is expected to play a significant role in attracting new businesses to the park. With the power plant's proximity and high efficiency, businesses in the Energy Park can potentially benefit from up to a 30 per cent saving in electrical costs.

Development programmes

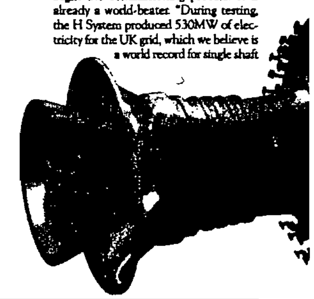
The energy source behind the Park started many years before however. GE engineers produced the H System concept in 1991. It took four years refining the turbine technology before a development programme was announced in 1995.

This was done as part of the US Department of Energy's Advanced Turbine System programme, and included GE Aircraft Engines and the company's Global Research Centre. Two years later the compressor was tested and the first set of single crystal airfoils produced.

Future shipments for the H System will be covered under a previously announced agreement signed by GE and Toshiba of Japan in 1998. Under this agreement, GE has H System integration and performance responsibility, and will design and manufacture the H gas turbines and supply the integrated systems controls for the power train. Toshiba will manufacture the GE-designed compressors, along with Toshiba-designed generators and steam turbines.

A full speed, no-load test was carried out in 1998 at GE's Greenville, South Carolina facility, and the first Frame 9H gas turbine left that factory bound for the Baglan Bay site in December 2000.

Characterisation testing of the 9H began in November last year, and was completed in May. Following a planned outage for instrumented component replacement, the plant was re-started to begin the commissioning process. It is already a world-beater. "During testing, the H System produced 530MW of electricity for the UK grid, which we believe is a world record for single shaft



combined-cycle power generation," says Mark Little, vice-president, Energy Products at GEPS. That recorded output was achieved at site conditions of 7°C, even on a warmer day, the H still produced in excess of 500MW.

The H System integrates gas and steam turbine (single-shaft configuration at Baglan Bay), represure heat recovery steam generator (HRSG) and 660MVA liquid-cooled generator into one unit; optimising each component's performance. The steam turbine is a D10 three-pressure reheat, single-flow exhaust machine, co-manufactured with Toshiba. Baglan Bay also uses a ten cell cooling tower with low plume, and has its own 2MW diesel generator for black start capability, also used by the CHP plant. The 9H transformer is 22kV, stepped up to 275kV for transmission to the UK national grid.

In addition to the H System, the power station also includes a 33MW combined heat and power plant based on a GE LM2500 gas turbine (see right sidebar).

World's largest turbine

But it is the gas turbine represents the heart and focus of the project. The 50Hz 480MW-rated Frame 9H gas turbine measures 12 metres long, five meters in diameter; and weighing 370 metric tonnes – it is the largest gas turbine in the world. Much of the H design is based on proven turbine technology.

The compressor system is derivative of GE's Aircraft Engine business, the CF6-80C2 engine (and its aero-derivative LM6000 turbine), a core machine with more than 10 million flight hours.

Building on GE's design experience, the H employs a can-annular lean pre-mix DLN-2.5 dry low NOx (DLN) combustor system. Fourteen combustion chambers are used on the 9H, and 12 combustion chambers are used on the 7H. It mixes fuel and air prior to ignition to reduce emissions to 25ppm.

This type of combustion system has been proven in millions of hours of operation on other GE gas turbines around the world. It produces more than a million horsepower alone and is the key energy source for the entire plant, including the power turbine, HRSG and steam turbine.

But the revolution so far as gas turbine design is concerned is the firing temperature and cooling system. The 60 per cent plant thermal efficiency is made possible by an increase in gas turbine firing temperature of more than 212°F (100°C) above the most efficient combined-cycle systems currently operating, including GE's own F-technology. Current combined-cycle systems achieve a firing temperature at the gas turbine inlet of around 1,300°C; the new H System increases that to 1,430°C (2,606°F).

This higher firing temperature is made possible by a series of technological advances including the world's largest single crystal airfoils, superior component and coating materials, and an advanced closed-loop steam cooling system.

"It is conditions friendly because the steam cooling in the H System allows the combustion system of the engine to run essentially at the same temperatures as our current F-technology," says Jon Ebacher, vice president of power systems technology at GEPS. "While the turbine inlet is 110°C above that and this is the section that produces power in the gas turbine."

Use of single crystal materials on the first stage nozzles and blades plus the special coatings used ensures that the parts can withstand the high temperatures – temperatures that are significantly higher than the melting point of most metals.

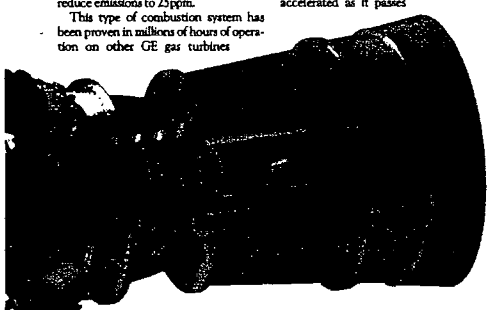
The most critical element of an advanced gas turbine is its hot gas path. The compressor discharge air and fuel are mixed and combusted in a chamber at a specific condition-combustion temperature. The flow stream of high-pressure, high-temperature combustion products is accelerated as it passes through the first stationary airfoil (stage 1 nozzle segment). The firing temperature – the flow stream temperature at the inlet to the first rotational state (stage 1 blade) – establishes the power output. The difference between firing temperature and combustion temperature entering the first stage nozzle is the temperature drop across the stage 1 nozzle.

The cogeneration plant

[illegible] process steam that is supplied to BP," says Brian Ray, [illegible]

[illegible]

The CHP plant also provides process cooling for BP Chemicals, so there is a separate two cell cooling tower for that purpose. In addition, an attemperated feedwater line also gives BP that product along with demineralised water from the site's water treatment plant.



Cooling process

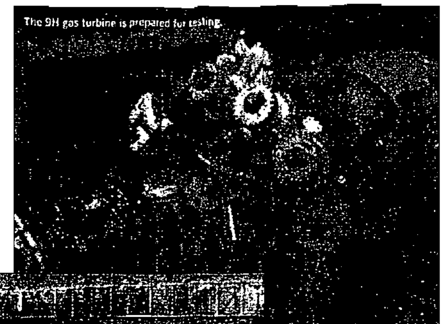
In current advanced gas turbines, the stage 1 nozzle is cooled with compressor discharge air flowing through the airfoil and discharging out into the combustion gas stream as the airfoil is cooled. The cooling process causes a temperature drop of up to 155°C across the stage 1 nozzle. If the nozzle can be cooled with a closed-loop coolant without film cooling, the temperature drop across the stage 1 nozzle would be less than 44°C, which would permit a 110°C rise in firing temperature with no increase in combustion temperature. That in turn, of course, means no increase in NOx emissions. This is the basis behind GE's steam cooling with the H System.

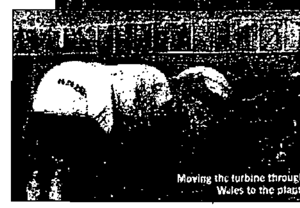
Steam exiting the HP turbine flows through gas turbine blades, nozzles and other parts, cooling them, and simultaneously re-heating the steam before it enters the IP steam turbine.

The steam cooling concept has a dual effect, allowing higher firing temperatures to be achieved without combustion temperature increases and permitting more compressor discharge air to flow to the head-end of the combustor for fuel premixing.

"The benefit is that for about 8 per cent more airflow than a 50Hz 9F we get 25 per cent more power with similar conditions," says Ebacher. "As the combustor is running at about the same temperature, there's 200°F less drop across the stage 1 nozzle, so as we go into the first stage blade, that generates the real power, 200°F hotter than we do in the F machine, and that's why we get more power.

"We start the machine on air-cooling, waste heat generates steam and at about 10 per cent power we do a transition to steam cooling. When we first looked at this system we knew that the control system would be challenging to make sure that there was no load transients visible to the grid during the transition to steam cooling."


The 9H gas turbine is prepared for testing.


Moving the turbine through Wales to the plant.

Most tested turbine

With revolutionary steam cooling capability and the new materials and use of high temperatures, it is little wonder that GE has been extremely cautious with the commercial introduction of the H-technology. The H System represents the most thoroughly tested industrial gas turbine technology in the company's 100-year-plus history. Tests, which involved more than 7,000 sensors placed on the equipment, validated GE's closed-loop steam cooling system.

Following the successful conclusion of the tests, instrumented components used to gather data were replaced with commercial non-instrumented components. The system has been restarted for commercial operation.

The H benefits from four years of extensive testing and design validation," says Mark Little. "From compressor blade tests, combustion tests and launch system integrated control test. Prior to shipping to the Baglan site the 9H gas turbine underwent two full speed no-load tests in the factory, which fully met our design expectations.

"Here at Baglan, GE has undertaken a further five months of full characterisation testing during which time we've validated key technologies at the heart of the H turbine."

This testing phase encompassed materials, component, subsystem, and system testing of the compressor rigs, as well as tests of the combustion, inlet aero, and Mark VI-based integrated control systems.

First firing

First firing of the turbine occurred in November, with validation testing lasting until May. Having met its expectations, GE is naturally proud of the new machine's performance. "As anyone involved in commissioning combined-cycle plant knows it is a difficult process," says Don Hoffmann, H System product line manager.

"Since first firing in November 2002, we've had 29 start attempts and everyone of those has been successful, no failures at all." And after 12 years of design, engineering and testing commercial launch of the Baglan Bay CCGT plant took place in September.

The H System gas turbine plant has been the most eagerly awaited project for many years. On its launch GE executives and UK politicians lauded the technology. Known for its caution and procrastination, the power industry as a whole will watch with close interest the performance of the turbine at Baglan. IPG

The plant launch

[illegible]

Also announced at the September launch was that GE expects to begin offering the H System as a commercial product beginning in the last quarter of this year. It already has an order from TEPCO to supply three 109H systems for a project in Japan. Meanwhile GE is actively looking for a launch site for its 60Hz 7H gas turbine.

GE Energy

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Small Heavy Duty
Combined Cycle
IGCC
Services
Lifecycle Services

H System Launch Site

Baglan Bay Power Station Port Talbot, Wales*
100% GE-owned investment in validation of the revolutionary technology and turnkey construction-comprised of two power

View the 9H photo gallery

Features

109H System Combined Cycle Power Plant
- 480 MW; single shaft; 60% CC efficiency platform
- Firing temperature class: 1430°C (2600°F)
- 18 stage compressor w/23:1 pressure ratio; airflow 1510 lbs/sec
- 14 can DLN 2.5; NO_x emissions: 25 ppm

Steam Turbine: GE design; reheat, single flow exhaust; co-mfg. with Toshiba
Generator: GE 550 MW LSTG, 660 MVA liquid cooled
HRSG: 3 pressure level reheat

LM2500 Combined Heat and Power Plant
- 33 MW GE LM2500
- HRSG; auxiliary boiler and 2 cell process cooling tower
- Plant provides utility supply to Baglan Energy Park** and BP Chemical Plant*** - electricity, steam, demineralized and attemperated water, process cooling
- Blackstart capability

Other Baglan PowerStation Features
- GE Mark VI based Integrated Control System
- 10 cell cooling tower
- Chimney: triple flue; slip form poured
- GE Water Technologies treatment plant
- 275 kV switchyard connecting to National Transmission (Electricity) System
- 33 kV switchyard with local supply to BP Chemicals and Baglan Energy Park
- Pipeline Reception Facility (PRF)
  - For 12 km Baglan pipeline spur to National Transmission (Gas) System
  - Gas compression and pressure reduction capability, featuring GE centrifugal compressors

GE Products & Services Used at Baglan

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Power Systems for the 2 Century: "H" Gas Turbine Combined Cycles (252KE
MPG Video: H System: W Most Advanced Combine Gas Turbine (19MB ZIP)

GE
- 9H gas turbine, LP steam turbine, generator, other power train equipment and accessories
- EPC project management
- Technical advisors
- Operations & maintenance; monitoring and diagnostics
- LM2500, plant compressors, gas compressors
- Water treatment systems
- 2 MW diesel generator
- Construction and testing power (GE Rentals)
- Switchyard control system; GT instruments
- BOP PLCs and operator interfaces
- Plant-merchant systems integration software

GE Capital
- IT integration support
- Plant financing

GE Industrial Systems
- Integrated control system with Mark VIs
- 6.9 kV switchgear
- Various pump and valve motors

GE Lighting
- Turbine hall and BOP lighting

Silvertech
- PRF control systems integration

Penpower
- Commissioning

QCI
- Pipe installation technical advisors

* Plant located on site leased from BP

** Baglan Energy Park is a joint development among BP, Welsh Development Agency and Neat Talbot County Borough Council

*** BP Chemicals Limited - Isopropanol plant adjacent to power station

ATTACHMENT D

WESTINGHOUSE'S ADVANCED TURBINE SYSTEMS PROGRAM

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ABSTRACT

The paper describes the goals of the Westinghouse Advanced Turbine Systems program. This program is being undertaken in response to the DOE Fossil Energy requirements for improved efficiency, lower cost of electricity, lower emissions, and state-of-the-art reliability levels.

It describes in detail the objectives of the program and the approach taken by Westinghouse to achieve those goals. The evolutionary approach taken by Westinghouse is explained together with the development program and component testing undertaken in the last year.

The benefits of this new advanced turbine are discussed and the future activities of the program are explained.

INTRODUCTION

U.S. Department of Energy, Office of Fossil Energy Advanced Turbine Systems Program is a multi-year effort to develop the necessary technologies, which will result in a significant increase in natural gas-fired power generation plant efficiency, a decrease in cost of electricity and a decrease in harmful emissions. In Phase 1 of the ATS Program, preliminary investigations on different gas turbine cycles demonstrated that net plant efficiency greater than 60% is achievable. The more promising cycles were evaluated in greater detail in Phase 2 and the closed-loop cooled combined cycle was selected because it offered the best solution with the least risk for achieving the ATS Program goals of net plant efficiency, emissions, cost of electricity, reliability-availability-maintainability (RAM), as well as commercial operation by the year 2000.

The Westinghouse ATS plant is based on an enhanced technology gas turbine design combined with an advanced steam turbine and a high efficiency generator. To meet the challenging performance, emissions, and RAM goals, existing technologies were extended and new technologies developed. The attainment of ATS performance goal necessitated advancements in aerodynamics, sealing, cooling, coatings, and materials technologies. To reduce emissions to the required levels, demanded a development effort in the following combustion technology areas: lean premixed ultra-low NOx combustion, catalytic combustion, combustion instabilities, and optical diagnostics. To achieve the RAM targets, required the utilization of proven design features, with quantified risk analysis, and advanced materials, coatings, and cooling technologies.

The 501ATS engine is the next frame in the series of successful utility turbines developed by Westinghouse over the last 50 years. During that time, Westinghouse engineers made significant contributions in advancing gas turbine technology as applied to heavy-duty industrial and utility engines. Some of the innovations included single-shaft two-bearing engine design, cold-end drive, axial exhaust, first cooled turbine airfoils in an industrial engine, and tilting pad bearings, features which all major gas turbine manufacturers have incorporated in their designs. The evolution of large gas turbines started at Westinghouse with the introduction of the 45 MW 501A engine in 1968 (see Table 1). Continuous enhancements in performance were made up to the 100 MW 501D5 introduced in 1981. The next engine was the 160 MW 501F introduced in 1991. The 230 MW 501G was next in the series and is the initial step in ATS engine development. Each successive engine design was based on the proven concepts used in the previous design.

The 501F was introduced at 160 MW and a simple cycle efficiency of 36%. Its current uprated rating is 167 MW and its combined cycle net efficiency is greater than 55%. The first four 501F engines that entered service with Florida Power and Light have demonstrated 99% reliability and 94% availability in over 33,000 operating hours each.

The 501G produces 230 MW in simple cycle and its combined cycle net efficiency is 58%. This engine incorporates further advancements in materials, cooling technology, and component aerodynamic design. The 19:1 pressure ratio compressor uses advanced profile high efficiency airfoils. The combustion system incorporates 16 dry low NOx combustors, with similar flame temperature as in the 501F, and hence, the same low emissions. This was made possible by the closed-loop steam cooled transition design, which eliminated transition cooling air ejection into the gas path. The four-stage 501G turbine uses full 3-D design airfoils and proven aeroderivative materials and coatings.

Westinghouse's strategy to achieve, and exceed, the ATS Program goals is to build on the proven technologies used in the successfully operating fleet of its utility gas turbines, such as the 501F, and to extend the technologies developed for the 501G.

ATS DESCRIPTION

The ATS plant consists of the gas turbine, generator, and steam turbine, connected together in an in-line arrangement with a clutch located between the generator and the steam turbine. The gas turbine exhaust gases produce steam in the three-pressure level heat recovery steam generator. The high pressure steam turbine exhaust steam is used to cool the transitions and two rows of stators. The reheated steam is then returned to the steam cycle for induction into the intermediate pressure steam turbine.

The ATS engine is a state-of-the-art 300 MW class design incorporating many proven design features used in previous Westinghouse gas turbines and new design features and technologies required to achieve the ATS Program goals.

Compressor

The compressor shares many common parts with the 501G 16-stage compressor. The mass flow is identical, but the ATS higher rotor inlet temperature and closed-loop cooling has required an increase in pressure ratio from 19:1 to 29:1. This increased pressure ratio was achieved by adding stages to the rear of the 501G compressor. The latest 3-D viscous codes and custom-designed airfoils were used in the compressor aerodynamic design. Variable stators have been added to stages 1 and 2 to improve starting capability and part-load performance.

Combustion System

The 501ATS incorporates 16 combustors based on the lean premixed multi-stage piloted ring design. The burner outlet temperature was kept at the same level as in the 501F and 501G, by using closed-loop steam cooling (with air as an alternate coolant) in the transitions and turbine stators, so that more compressor delivery air was available in the combustor head end. Therefore, this allowed very lean, premixed combustion and hence single digit NOx emissions.

To aid in ATS combustor design and development, extensive use was made of computational fluid dynamics (CFD) analysis. Using CFD analysis expedited combustion system development and allowed screening of modifications prior to testing. This resulted in combustors with more predictable performance and reliability.

Turbine

The four-stage turbine design was based on 3-D design philosophy and viscous analysis codes. The airfoil loadings were optimized to enhance aerodynamic performance while minimizing airfoil solidity. The reduced solidity resulted in lower cooling requirements and increased efficiency. To further enhance plant efficiency, the following features were included: turbine airfoil closed-loop cooling, active blade tip clearance control on the first two stages, improved rotor sealing, and optimum circumferential alignment of airfoils.

The ATS engine utilized advanced thin wall designs with thermal barrier coatings and the state-of-the-art aero engine cooling technology. The first and second stage vanes used closed-loop steam cooling and the first two stages of blades used closed-loop air cooling. Air was chosen for blade cooling because it does not have the risks of steam corrosion, deposition, and complexity that closed-loop cooling with steam poses. In addition, the air can be cooled after it is removed from the combustor shell so that only relatively small amounts of cooling air are needed for the rotor. The cooling air is filtered to remove dirt particles before being ducted to the rotor blades. The difference in plant thermal efficiency between blade closed-loop cooling by air instead of steam is about 0.2%. Thus, based on a cost benefit analysis and RAM analysis, closed-loop air cooling is the preferred approach.

Westinghouse has been using thermal barrier coatings (TBC) on turbine airfoils since 1986 and has built an extensive experience base. It is a standard "bill of material" for new 501D5, 501F, and 251B11/12 engines. Recent field trials have demonstrated excellent results after operation for 24,000 hours. In the 501ATS engine, further improvements in TBC coating, with improved bond coats and new ceramic materials, will be utilized.

The 501ATS turbine design used the latest aero engine blade and vane nickel-based alloys. Single crystal nickel alloy, CMSX-4, was employed on the first stage vanes and blades to provide increased creep strength and fatigue resistance compared to conventional materials.

Rotor Design

The power level transmitted through the rotor and the resulting high stresses make rotor design an extremely important component of the engine. The 501ATS rotor consists of four ruggedized alloy steel discs clamped together with 12 through-bolts. Alloy steel was used to extend the excellent past operating experience with this material to the ATS engine and to reduce engine cost. In this design, torque transmission and alignment are achieved by the use of a Curvic™ clutch, which is a beveled male and female tooth form. This design has been proven by use on all Westinghouse-designed gas turbines over the past 40 years.

During the rotor design process, extensive finite element analysis modeling was carried out to calculate rotor critical speeds and cyclic life. In order to ensure rotor stability, a transient analysis from startup to baseload was carried out to verify that there was no slipping or gapping of the torque carrying members. The analysis has demonstrated that during all conditions analyzed, the torque carrying Curvic™ clutch arms do not come out of engagement. This virtually eliminates frettage or slippage which could give rise to vibration or cracking.

The compressor rotor is a series of discs clamped together with 12 through-bolts. However, the torque transmission is via friction and radial keys between all discs. This method was also used on the 501F and shown to be reliable. Alignment of the discs is maintained by a spigot at the base of the discs and by the shoulder on the radial pins. Computer modeling was used to ensure the rotor stability over its complete operating range with no chance of slippage or gapping.

TECHNOLOGY VERIFICATION PROGRAMS

To ensure that ATS program goals are achieved, an extensive technology verification program is in progress in the following areas: combustion, cooling, aerodynamics, leakage control, coatings, and materials.

Combustion

The 501ATS piloted ring combustor is the most successful candidate of combustors developed by Westinghouse over the past 10 years. It consists of a pilot and two separate premixed zones arranged axially, the primary and secondary zones. Premixed fuel and air enter the primary zone where combustion is stabilized by a swirl-produced recirculation zone and a centrally located pilot. The second zone is located downstream and is fed premixed fuel and air through an annular passage surrounding the primary zone. This combustor, which achieved single digit NOx emissions and excellent stability on low pressure tests, is currently undergoing evaluation at high pressures.

Cooling

Elimination of cooling air injection into the turbine flow path, as a result of closed-loop steam cooling, is the major contributor to the increase in ATS plant efficiency. This results in an increase in gas temperature downstream of the first stage vane and hence an increase in gas energy level during the expansion process. A secondary contributor is the elimination of mixing losses associated with cooling air ejection. The combination of these effects results in a significant increase in ATS plant efficiency. In addition, NOx emissions are reduced because more air is available for the lean premixed combustor at the same burner outlet temperature. Achieving acceptable blade metal temperatures in a closed-loop cooling design is a challenge due to the absence of a cooling air film to shield the turbine airfoil and shroud wall, and no shower-head or trailing edge ejection to provide enhanced cooling in the critical leading and trailing edge regions. To produce an optimized closed-loop cooling design, the following approaches were utilized: (1) airfoil aerodynamic design tailored to provide minimum gas side heat transfer coefficients, (2) minimum coolant inlet temperature, (3) thermal barrier coating applied on airfoil and end wall surfaces to reduce heat input, (4) maximized cold side surface area, (5) turbulators to enhance cold side heat transfer coefficients, and (6) minimum outside wall thicknesses to reduce wall temperature gradients and hence the internal heat transfer coefficients required to cool the airfoil.

The thin-wall closed-loop cooled first stage vane and blade design was completed and casting development started at Allison-Single Crystal Operations. To verify the critical cooling designs, a three part program was undertaken. The internal heat transfer coefficients and pressure drops are being measured on plastic models of the different vane and blade cooling features at Carnegie Mellon University. A liquid crystal thermochromic paint technique was used to measure the internal heat transfer coefficients. The outside heat transfer coefficients will be measured on model turbine tests. The first stage vane cooling design will be verified at ATS operating conditions in a hot cascade test rig in the Westinghouse high pressure combustion test facility located at the Arnold Engineering Development Center, in Arnold AFB, Tennessee.

Compressor Aerodynamics Development

To determine its performance and operating characteristics over the complete operating range, the full-scale ATS compressor was tested in a specially designed facility located at the U.S. Navy Base in Philadelphia. The facility was designed for subatmospheric inlet pressure to reduce the power required to drive the compressor. The inlet system consisted of a filter house, straight pipe with a flow straightener and a flow meter, inlet throttle valve, diffuser with flow straightening devices, 90° bend with turning vanes, and a silencer. Because of the subatmoshperic operation, two stages of compressor bleed air were ducted into the inlet diffuser, after passing through coolers. The exhaust system included a large diameter back pressure valve to provide control on the test pressure ratio. A small diameter quick-acting valve, located in a bypass line around the large back pressure valve, was used for recovery from compressor surge.

The compressor was instrumented with static pressure taps, fixed temperature and pressure rakes, thermocouples, tip clearance probes, blade vibration monitoring probes, rotor vibration probes, acoustic probes, and strain gauges. Provisions were made for radial traverses in eight axial locations in the compressor and four radial locations in the inlet duct. More than 500 individual measurements were recorded. A dedicated data acquisition system was used to collect and reduce the test data. Important performance and health monitoring parameters were displayed on computer screens in real time. After the compressor test facility was commissioned, an extensive test program was performed. The test program included design point performance verification, blade vibration and diaphragm strain gauge measurements, inlet guide vane and variable stator optimization, compressor map definition and starting characteristics optimization.

Turbine Aerodynamic Development

The first two 501ATS turbine stages will be tested at 1/3-scale in a model turbine test rig, located at Ohio State University, to verify aerodynamic performance with reduced airfoil solidity, to quantify performance benefits due to optimum circumferential alignment of turbine airfoils, and to measure outside heat transfer coefficients on the airfoils of this advanced 3-D aero design turbine. The model turbine component manufacture was completed. Pressure sensor and thermocouple installation on the model turbine airfoils was also completed. The heat flux gauge installation is nearing completion. The test facility, which was moved from Buffalo to Ohio State University, was commissioned and is ready for model turbine testing.

Leakage Control

To reduce air leakage, as well as hot gas ingestion into turbine disc cavities, brush seals were incorporated under the compressor diaphragms, turbine disc front, turbine rim, and turbine interstage locations. A development program was initiated to incorporate an effective, reliable, and long-lasting brush seal system into a heavy-duty industrial gas turbine. Tests were performed to select the appropriate bristle materials, to quantify wear characteristics and to determine leakage. The brush seal performance under the compressor diaphragms was verified during the 501ATS compressor testing. To test their performance over long operating times, turbine interstage seals were installed on a new 501F engine and will be retrofitted into 501D5 engines.

A face seal was designed to prevent rotor cooling air leakage as it is introduced at the rotor rear. Seal hardware has been ordered and a test rig is being constructed. Tests will be carried out to verify the face seal performance.

Coatings

The ATS engine turbine component coatings must be capable of operation for 24,000 hours. To ensure this, a program is in progress to develop an improved bond coat/TBC system. Different bond coats are being evaluated under accelerated oxidation test conditions. New ceramic candidate materials are also undergoing testing. The objective of this program is to combine the optimum bond coat with the best performing TBC to provide a coating system with maximum service life at the ATS operating conditions. An advanced bond coat/TBC system has accumulated more than 20,000 hours in cyclic testing at 1010°C (1850°F) with excellent results.

Materials

To enhance performance and reliability, single crystal (SC) blades are used in the ATS engine. A casting development program was carried out to demonstrate castability of large industrial turbine blades in CMSX-4 material. Existing 501F engine tooling was used to cast single crystal blades. The castings were evaluated by grain etching, selected NDE methods and dimensional inspection methods to determine their metallurgical acceptability. After several trials, excellent results were obtained on a solid and a cored blade thus demonstrating that SC blades are castable in CMSX-4 alloy. Further process development is in progress to optimize post-cast heat treatment, evaluate effects of grain defects, generate SC material design data, and further develop the casting process.

FUTURE ACTIVITIES

Technology development efforts to date have demonstrated that ATS Program goals are obtainable. The results have been incorporated into the 501ATS design. Future ATS Phase 3 activities will complete the technology verification process. High pressure testing on the ATS piloted ring combustor will be carried out to optimize the design and demonstrate single digit NOx emissions. Catalytic combustion development will proceed toward full-scale testing of catalytic combustor by the end of the year. The two-stage model turbine tests, to verify aerodynamic performance and to measure outside heat transfer coefficients, will be completed. Rig testing will be completed on the turbine brush seals and rotor face seal. Abradability tests will be carried out on the turbine blade tip treatments, which will be applied to blade tips for wear protection. Pre-production casting development will continue on the single crystal thin wall stage 1 vanes and blades and thick wall stage 2 blades. Long term verification tests on advanced bond coat/TBC system will be carried out on test rigs and rainbow tests with coated blades on operating engines. The next phase of the ATS Program includes building the prototype 501ATS engine and carrying out extensive testing to verify its performance and mechanical integrity.

ACKNOWLEDGMENTS

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ATTACHMENT E

Engine	501A	501B	501D	501D5	501D5A	501F	501G	501/ATS
Commercial Operation	1968	1973	1976	1982	1994	1993	1997	2000
Power, MW	45	80	95	107	120	160	230	420*
Rotor Inlet Temp.,°F	1615	1819	2005	2070	2150	2330	2583	2750
Air Flow, Lb/Sec	548	746	781	790	832	961	1200	1200
Pressure Ratio	7:5	11:2	12:6	14:1	15:1	15:1	19:1	29:1
No. Comp. Stages	17	17	19	19	19	16	16	20
No. Turbine Stages	4	4	4	4	4	4	4	4
No. Cooled Rows	1	3	4	4	4	6	6	6
Exhaust Temp., °F	885	907	956	981	1004	1083	1100	1100
Heat Rate (Btu/kWh)								
Simple	12,600	11,600	10,925	10,040	9,900	9,610	8,860	--
Combined	9,000	7,350	7,280	7,055	7,024	6,429	5,881	5,686

*Combined cycle output power

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT

STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE

This permit includes designated equipment to New Source Performance Standards (NSPS).

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

CPV Warren LLC
409 East Main Street
Front Royal, Virginia 22630
Registration No.: 81391
Plant ID No.: 51-187-0041

is authorized to construct and operate

an electric power generation facility

located

in Warren County, off State Route 522, approximately one mile north of Interstate 66 (Exit 2) and approximately one-half mile east on Rockland Road (Route 658) to Kelly Drive; facility entrance is one-half mile south on Kelly Drive

in accordance with the Conditions of this permit.

Approved on July 30, 2004

Director, Department of Environmental Quality

Permit consists of 22 pages.
Permit Conditions 1 to 54.
Source Testing Report Format.

PERMIT CONDITIONS - the regulatory reference or authority for each condition is listed in parentheses ( ) after each condition. All parts per million (ppm) are parts per million by volume on a dry gas basis (ppmvd), corrected to 15 percent oxygen, unless otherwise stated. All heat inputs in British thermal units (Btu) are based on higher heating values.

APPLICATION

1. Except as specified in this permit, the permitted facility is to be constructed and operated as represented in the permit application dated December 11, 2001, including amendment information dated February 18, 2002, April 1, 2002, February 4, 2003, March 26, 2003, April 7, 2003, April 23, 2003, May 21, 2003, June 9, 2003, September 12, 2003, and May 18, 2004, and supplemental information dated November 14, 2003. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action.
(9 VAC 5-50-390, 9 VAC 5-80-1210 D, and 9 VAC 5-80-1720)

PROCESS REQUIREMENTS

2. **Equipment List** - Equipment to be constructed at this facility consists of:

   – two combined cycle power generating units (CC1 & CC2) where each unit includes the following emission units:

     • one General Electric natural-gas-fired combustion turbine (CT) generator, Model 7FA, rated at 180,000 KW and 1,717 million Btu per hour heat input (CT1 & CT2) (NSPS Subpart GG);

     • one heat recovery steam generator (HRSG) with supplementary natural gas-fired duct burners, each duct burner with a design rating of 500 million Btu per hour heat input when firing natural gas (DB1 & DB2) (NSPS Subpart Da);

   – one diesel-fired emergency fire water pump, rated at 2.3 million Btu per hour heat input (EG1); and

   – one diesel-fired emergency generator, rated at 1500 KW (EG2).

   Exempt equipment to be constructed at this facility consists of:

   – one 6,000 gallon distillate oil storage tank.

   (9 VAC 5-80-1100 and 9 VAC 5-80-1700 A)

3. **Emission Controls: Nitrogen Oxides** – Oxides of nitrogen (NO_x) emissions from each CT (CT1 & CT2) and HRSG duct burner (DB1 & DB2) shall be controlled by use of a

two-stage, lean pre-mix dry low-NO_x combustor, a selective catalytic reduction (SCR) control system using ammonia injection, and good combustion practice. The SCR system shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 15).
(9 VAC 5-50-260, 9 VAC 5-80-1180 and 9 VAC 5-80-1800 B)

4. **Emission Controls: Carbon Monoxide** – Carbon monoxide (CO) emissions from each CT (CT1 & CT2) and HRSG duct burner (DB1 & DB2) shall be controlled by an oxidation catalyst and good combustion practice. The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 15).
(9 VAC 5-50-260, 9 VAC 5-80-1180 and 9 VAC 5-80-1800 B)

5. **Emission Controls: Volatile Organic Compounds** – Volatile Organic Compound (VOC) emissions from each CT (CT1 & CT2) and HRSG duct burner (DB1 & DB2) shall be controlled by an oxidation catalyst. The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 15).
(9 VAC 5-50-260, 9 VAC 5-80-1180 and 9 VAC 5-80-1800 B)

6. **Monitoring Devices: SCR** - Each SCR system shall be equipped with devices to continuously measure and record ammonia feed rate, gas stream flow rate, and catalyst bed inlet gas temperature. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the SCR system is operating.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, 9 VAC 5-50-260, and 9 VAC 5-80-1800 B)

7. **Monitoring Devices: Oxidation Catalyst** - Each oxidation catalyst shall be equipped with a device to continuously measure and record temperature at the catalyst bed inlet and outlet. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, at a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the oxidation catalyst is operating.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, 9 VAC 5-50-260, and 9 VAC 5-80-1800 B)

8. **Monitoring Device Observation: SCR** – The devices used to continuously measure ammonia feed rate, gas stream flow rate, and SCR catalyst bed inlet gas temperature shall be observed by the permittee with a frequency sufficient to ensure good performance of

the SCR system but not less than once per day of operation. The permittee shall continuously record measurements from the control equipment monitoring devices.
(9 VAC 5-50-50 H)

9. **Monitoring Device Observation: Oxidation Catalyst** - The devices used to continuously measure catalyst bed inlet and outlet gas temperatures for each oxidation catalyst shall be observed by the permittee with a frequency sufficient to ensure good performance of the oxidation catalyst but not less than once per day of operation. The permittee shall continuously record measurements from the control equipment monitoring devices.
(9 VAC 5-50-50 H)

<u>OPERATING/EMISSION LIMITATIONS – COMBINED CYCLE UNITS (CC1 & CC2)</u>

10. **Fuel** - The approved fuel for each CT (CT1 & CT2) and each HRSG duct burner (DB1 & DB2) is pipeline natural gas with a maximum sulfur content of 0.002 percent by weight. A standard cubic foot of gas is defined as a cubic foot of gas at standard conditions as specified in 40 CFR 72.2 (68°F and 29.92 in Hg). A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-410, 9 VAC 5-80-1800, 9 VAC 5-80-1810, 9 VAC 5-50-260, and 40 CFR 60.333)

11. **Fuel Throughput** – The combustion turbines and duct burners combined shall consume no more than 35,920 x 10^6 scf of natural gas per year, calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180 and 9 VAC 5-80-1810)

12. **Fuel Monitoring** – The permittee shall monitor and record sulfur content and nitrogen content of the natural gas being fired at the electric power generation facility on a daily basis. The permittee or fuel vendor may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved in writing by the Administrator.
(9 VAC 5-80-1180, 9 VAC 5-50-410, and 40 CFR 60.334)

13. **Short-Term Emission Limits** - Emissions from the operation of each combined cycle power generating unit (CC1 & CC2) shall not exceed the limits specified below:

	Short term limits
PM-10 (includes condensable PM)	0.013 lb/MMBtu
Sulfur dioxide	0.0016 lb/MMBtu
Oxides of nitrogen (as NO_2)	17.9 lbs/hr 2.0 ppmvd
Carbon monoxide	▪ 1.3 ppmvd without power augmentation ▪ 7.2 lbs/hr and 1.8 ppmvd with power augmentation and without duct burner firing ▪ 12.8 lbs/hr and 2.5 ppmvd with power augmentation and duct burner firing
Volatile organic compounds	▪ 0.7 ppmvd without duct burner firing ▪ 1.0 ppmvd with duct burner firing ▪ 1.4 ppmvd with duct burner firing and power augmentation
Sulfuric acid mist (H_2SO_4)	0.0005 lb/MMBtu

ppmvd ≡ parts per million by volume on a dry gas basis, corrected to 15 percent O_2.

Short-term emission limits represent averages for a three-hour sampling period except for nitrogen oxides, which shall be calculated as a one-hour average.

Limits apply at all times except during startup, shutdown, and malfunction. Periods considered startup and shutdown are defined in Condition 15 of this permit.

(9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-1800, 9 VAC 5-80-1810, and 40 CFR 60.332)

14. **Annual Emission Limits** – Total emissions from the operation of both combined cycle power generating units (CC1 & CC2) shall not exceed the limits specified below:

PM-10 (includes condensable PM)	134.0	tons/year
Sulfur Dioxide	24.4	tons/year
Oxides of Nitrogen (as NO_2)	141.8	tons/year
Carbon Monoxide	97.2	tons/year

Volatile Organic Compounds	22.9	tons/year
Sulfuric Acid Mist (H_2SO_4)	7.4	tons/year

Annual emission limits are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits.
(9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-1800, 9 VAC 5-80-1180 and 9 VAC 5-80-1810)

15. **Startup/Shutdown** – The short-term emission limits contained in Condition 13 apply at all times except during periods of startup and shutdown.

a. Startup and shutdown periods are defined as follows:

i. Cold Startup – refers to restarts made 72 hours or more after shutdown. Exclusion from the short-term emissions limits for cold startup periods shall not exceed 4 hours per occurrence.

ii. Warm Startup – refers to restarts made more than 8 but less than 72 hours after shutdown. Exclusion from the short-term emissions limits for warm startup periods shall not exceed 2.1 hours per occurrence.

iii. Hot Startup – refers to restarts made 8 hours or less after shutdown. Exclusion from the short-term emissions limits for hot startup periods shall not exceed 1.5 hours per occurrence.

iv. Shutdown – refers to the period between the time the turbine load drops below 50% operating level and the fuel supply to the turbine is cut. Exclusion from the short-term emissions limits for shutdown shall not exceed 1.5 hours per occurrence.

b. The permittee shall operate the CEMS during periods of startup and shutdown.

c. The permittee shall record the time, date and duration of each startup and shutdown period.

d. The permittee shall operate the facility so as to minimize the frequency and duration of startup and shutdown events.

(9 VAC 5-50-260, 9 VAC 5-80-1810, 9 VAC 5-80-1180 and 9 VAC 5-80-1800)

16. **Emission Limits: Duct Burners** – For each stack servicing a GE 7FA combustion turbine and associated duct burners, the emissions from the operation of the duct burners shall not exceed:

    0.03 pounds of particulate matter per million Btu heat input

    0.20 pounds of sulfur dioxide per million Btu heat input

    1.6 pounds of nitrogen oxides (as NO_2) per megawatt-hour, gross energy output;

    The particulate matter and nitrogen oxides limits apply at all times except startup, shutdown, or malfunction. The sulfur dioxide limit applies at all times except startup, shutdown, or when both emergency conditions exist and the procedures under 40 CFR 60.46a(d) are implemented. Compliance with the sulfur dioxide and nitrogen oxides emission limits of this condition shall be determined on a 30-day rolling average basis. Compliance with the nitrogen oxides limits of this condition shall be determined by one of the methods allowed by 40 CFR 60.46a(k) for an affected duct burner used in combined cycle systems.
    (9 VAC 5-80-1180 and 9 VAC 5-50-410)

17. **Pollution Prevention: Ammonia** – The permittee shall minimize emissions of ammonia resulting from unreacted ammonia emitted from the SCR (ammonia slip) to 5 parts per million by volume, dry basis, corrected to 15% O_2. Compliance with the ammonia slip limit shall be determined based on a three-hour block average. At least three months prior to startup, the permittee shall submit a plan for approval for monitoring the ammonia slip and demonstrating compliance with the ammonia slip limit from each SCR system to the Director, Valley Regional Office. Implementation of the plan shall commence upon startup of the facility. The permittee shall demonstrate compliance with the ammonia slip limit at least 95 percent of the time the SCR is operating. Compliance with the 95% time percentage requirement shall be calculated daily and based on a 30-day rolling period. Alternatively, if on a given day less than 100 hours of operation has occurred in the prior 30 days, compliance with the 95% limits may be based on the most recent 100 hours of SCR operation.
    (9 VAC 5-80-1180, 9 VAC 5-170-160 and Virginia Pollution Prevention Act, § 10.1-1425.11)

18. **Pollution Prevention: SCR Replacement** – At least two years prior to a planned replacement of the entire SCR system, the permittee shall conduct a study of technically and economically feasible and commercially available NOx control devices. The study shall include the cost effectiveness for each control device evaluated, including SCR. The results of the evaluation shall be submitted to the Director, Valley Regional Office, prior to ordering a replacement system. In the event the permittee wants to replace the SCR

with an alternative control device, such a replacement may not require a permit to modify and operate, providing the new system provides an equal or better level of control.
(9 VAC 5-80-1180, 9 VAC 5-170-160 and Virginia Pollution Prevention Act, § 10.1-1425.11)

19. **Visible Emission Limit** - Visible emissions from each combined cycle (CC1 and CC2) stack shall not exceed 10 percent opacity, except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by the EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown (as defined in Condition 15), and malfunction.
    (9 VAC 5-50-20, 9 VAC 5-50-260, 9 VAC 5-80-1800, and 9 VAC 5-50-410)

20. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the CTs described in Condition 2 (CT1 & CT2) shall be operated in compliance with the requirements of 40 CFR 60, Subpart GG.
    (9 VAC 5-50-400 and 9 VAC 5-50-410)

21. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the duct burners as described in Condition 2 (DB1 & DB2) shall be operated in compliance with the requirements of 40 CFR 60, Subpart Da.
    (9 VAC 5-50-400 and 9 VAC 5-50-410)

22. **NOx Budget Trading Requirements** - A review of the air emission units included in this permit approval has determined that the combined-cycle units listed in Condition 2 meet the definition of a NO_x Budget Unit and fall subject to the NO_x Budget emission limitations under 9 VAC 5-140-40 or for opt-in sources 9 VAC 5-140-800. As required by 9 VAC 5-140-200 A, for each NO_x Budget source required to have a federally enforceable permit, such permit will include the NO_x Budget permit to be administered by the permitting authority. The following requirements pertain to the NOx Budget Trading program:

    a. Prior to operation commencement, the permittee shall obtain a NOx Budget permit, as required by 9 VAC 5-140-200 A, to be administrated by the Virginia Department of Environmental Quality (VADEQ) under the authority of 9 VAC 5-80-360 *et seq.*, and 9 VAC 5-140-10 *et seq.*

    b. As of commencement of operation of the permitted facility (the first day either of the combustion turbines burns fuel), the permittee shall comply with the requirements of the NOx Budget emission limitations under 9 VAC 5-140-40.

    c. Each combined-cycle unit (combustion turbine and heat recovery steam generator) in Condition 2 meets the applicability requirements as provided in 9 VAC 5-140-40 A.1 and A.2. The permittee shall meet the monitoring, emission calculation, recordkeeping, reporting, and testing requirements as applicable under 9 VAC 5 Chapter 140 Article 8.

(9 VAC 5-80-1180 and 9 VAC 5 Chapter 140 Article 8)

23. **NOx Offsets** - Pursuant to the State Air Pollution Control Board's June 29, 2004 directive, the permittee shall obtain NOx offsets for the purpose of showing a demonstrable benefit to Shenandoah National Park, in accordance with the following:

   a. The permittee shall secure a reduction in NOx emissions of no less than 175 tons from a source or sources in the manner prescribed as follows:

      i. The offsets shall be creditable (i.e., not otherwise required by law, regulation, or existing permit), quantifiable, permanent, and federally enforceable as defined in 40 C.F.R. Part 51, App. S § II.A.12. The baseline for calculating the offsets shall be determined pursuant to the method set forth in 40 C.F.R. Part 51, App. S § IV.C.

      ii. In addition to satisfying the geographical and other requirements of Condition 23.a. iii below, the offsets shall be obtained as close as practicable to the Shenandoah National Park boundary.

      iii. The offsets shall be located within the geographic boundaries of the local or inner domain of the Shenandoah National Park airshed for oxidized nitrogen deposition as defined by Figure IV-8.a of the National Park Service report <u>Assessment of Air Quality and Related Values in the Shenandoah National Park (May 2003).</u>

   b. The offsets shall be in effect prior to startup of the equipment listed in Condition 2.

   c. Prior to commencing operation, the permittee shall provide to the Director, Valley Regional Office, official certification from the air pollution control agency that regulates each source which provides offsets that the offsets meet the requirements of Condition 23.a, at a minimum documenting that the emissions reductions obtained as offsets are recognized by the agency as surplus (not otherwise required by regulation), permanent, and federally enforceable. The document shall state that the emissions reduction has not been and will not be credited toward another reduction requirement. The facility shall not commence operation until the Director, Valley Regional Office, has approved in writing the certification and/or other documentation submitted by the permittee pursuant to this subsection as satisfying the requirements of Condition 23.a.

   d. The permittee shall maintain at the permitted facility a copy of the following:

      i. Identification of each source from which offsets were obtained. Identification shall include the name, address and Universal Transverse Mercator (UTM) coordinates of the facility and any identification number assigned to the facility by the air pollution control authority that regulates it.

      ii. Certification document from each air pollution control agency required by Condition 23.c and any supporting documentation.

(9 VAC 5-170-160)

<u>OPERATING/EMISSION LIMITATIONS – EMERGENCY UNITS (EG1 & EG2)</u>

24. **Fuel: Prior to the Final Implementation Date of Federal Motor Vehicle Diesel Fuel Standards** - Prior to the final implementation date of the federal standards for motor vehicle diesel fuel at retail outlets and wholesale purchaser-consumer facilities contained in 40 CFR 80.500 and 40 CFR 80.520, the approved fuel for the emergency fire water pump (EG1) and the emergency generator (EG2) is distillate fuel oil with a maximum sulfur content per shipment of 0.05% by weight. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-260, 9 VAC 5-80-1180, 9 VAC 5-80-1800 and 9 VAC 5-80-1810)

25. **Fuel: After the Final Implementation Date of Federal Motor Vehicle Diesel Fuel Standards** – After the final implementation date of federal standards for motor vehicle diesel fuel at retail outlets and wholesale purchaser-consumer facilities contained in 40 CFR 80.500 and 40 CFR 80.520, the approved fuel for the emergency fire water pump (EG1) and the emergency generator (EG2) is distillate fuel oil with a maximum sulfur content per shipment of 0.0015% by weight. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-260, 9 VAC 5-80-1180, 9 VAC 5-80-1800 and 9 VAC 5-80-1810)

26. **Operating Hours: Emergency Firewater Pump** - The emergency fire water pump (EG1) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period.
(9 VAC 5-80-1180 and 9 VAC 5-80-1810)

27. **Operating Hours: Emergency Generator** - The emergency generator (EG2) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. The emergency generator (EG2) shall operate only when neither combustion turbine (CT1 or CT2) is operating or for testing or maintenance.
(9 VAC 5-80-1180 and 9 VAC 5-80-1810)

28. **Fuel Certification** - The permittee shall obtain a certification from the fuel supplier with each shipment of distillate oil. Each fuel supplier certification shall include the following:

   a. The name of the fuel supplier;

   b. The date on which the distillate oil was received;

   c. The volume of distillate oil delivered in the shipment; and
   d. The sulfur content of the distillate oil.

   (9 VAC 5-80-1180)

29. **Emission Limits (P2)** - Emissions from the operation of the emergency firewater pump (EG1) shall not exceed the limits specified below:

Nitrogen Oxides (as NO_2)	10.2 lbs/hr	2.6 tons/yr
Carbon Monoxide	2.2 lbs/hr	0.6 tons/yr

   These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition 26.
   (9 VAC 5-50-260, 9 VAC 5-80-1180 and 9 VAC 5-80-1810)

30. **Emission Limits (P2)** - Emissions from the operation of the emergency generator (EG2) shall not exceed the limits specified below:

Nitrogen Oxides (as NO_2)	34.0 lbs/hr	8.5 tons/yr
Carbon Monoxide	12.8 lbs/hr	3.2 tons/yr

   These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition 27.
   (9 VAC 5-50-260, 9 VAC 5-80-1180 and 9 VAC 5-80-1810)

CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS)

31. **CEMS** - Continuous Emission Monitoring Systems meeting the design specifications of 40 CFR Part 75 shall be installed to measure and record the emissions of NO_x (measured

as NO_2), in ppmvd corrected to 15% O_2, from each combined cycle unit (CC1 & CC2). The CEMS shall also measure and record the oxygen content of the flue gas at each location where NO_x emissions are monitored and measure heat input and power output. A CEMS shall also measure sulfur dioxide to comply with the requirements of 40 CFR Part 75 (acid rain program monitoring), unless an alternative method of determining sulfur dioxide emissions has been approved by EPA Region III for that purpose. Each CEMS shall be installed, calibrated, maintained, audited and operated in accordance with the requirements of 40 CFR 75. For compliance with the NO_x limits contained in Condition 13, data shall be reduced to 1-hour block averages.
(9 VAC 5-50-40, 9 VAC 5-80-420, and 40 CFR 75)

32. **CEMS Performance Evaluations** - Performance evaluations of the continuous monitoring systems shall be conducted in accordance with 40 CFR Part 75, Appendix A, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. One copy of the performance evaluation report shall be submitted to the Director, Valley Regional Office, within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30-day notification, prior to the demonstration of the continuous monitoring system's performance, and subsequent notifications shall be submitted to the Director, Valley Regional Office.
(9 VAC 5-50-40 and 40 CFR 75)

33. **CEMS Quality Control Program** - A CEMS quality control program which is equivalent to the requirements of 40 CFR 60.13 and 40 CFR 60, Appendix F shall be implemented for all continuous monitoring systems.
(9 VAC 5-50-40, 40 CFR 60.13, and 40 CFR 60)

34. **Reports for Continuous Monitoring Systems** - The permittee shall furnish written reports to the Director, Valley Regional Office, of excess emissions from any process monitored by a continuous emission monitoring system (CEMS) on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to, the following information:

   a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

   b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, or malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments;

d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report; and

e. Excess emission reports for sulfur dioxide and nitrogen dioxide as required in 40 CFR 60.334 (c).

(9 VAC 5-50-50, 9 VAC 5-50-410, and 40 CFR 60.334)

RECORDS

35. **On Site Records** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Director, Valley Regional Office. The records shall include, but are not limited to:

a. Annual throughput of natural gas to each CT (CT1 & CT2), calculated monthly as the sum of each consecutive 12-month period.

b. Annual throughput of natural gas to each duct burner (DB1 & DB2) calculated monthly as the sum of each consecutive 12-month period.

c. Time, date and duration of each startup, shutdown, reduced load, and malfunction period for each combined cycle power generating unit (CC1 & CC2).

d. Annual number of startup and shutdown occurrences, calculated monthly as the sum of each consecutive 12-month period (CC1 & CC2).

e. Pipeline natural gas sulfur content monitoring results to demonstrate compliance with Conditions 10 and 12.

f. Pipeline natural gas nitrogen content monitoring results.

g. Continuous records of heat input for each combined cycle power generating unit (CC1 & CC2).

h. Continuous records of power output from combined cycle power generating units (CC1 & CC2) and the steam turbine generator.

i. Emissions calculations sufficient to verify compliance with the annual emission limitations in Conditions 14, 29, and 30, calculated monthly as the sum of each

consecutive 12-month period. Calculation methods shall be approved by the Director, Valley Regional Office.

j. Continuous monitoring system emissions data, calibrations and calibration checks, percent operating time, and excess emissions.

k. Records to verify compliance with the emission limits in Condition 16.

l. Annual hours of operation for the emergency fire water pump (EG1) and the emergency generator (EG2), calculated monthly as the sum of each consecutive 12-month period.

m. All fuel supplier certifications for the emergency units (EG1 & EG2).

n. Operation and control device monitoring records for each SCR system and each oxidation catalyst.

o. Ammonia slip monitoring results.

p. Scheduled and unscheduled maintenance and operator training.

q. Results of all stack tests, visible emission evaluations, visible emission inspection results, and performance evaluations.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-50-50, 40 CFR 60.335, 40 CFR 60.48a and 40 CFR 60.49a)

INITIAL COMPLIANCE DETERMINATION

36. **Testing/Monitoring Ports** - The permitted facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing stack or duct that is free from cyclonic flow. Test ports shall be provided in accordance with the applicable performance specification (reference 40 CFR Part 60, Appendix B).
(9 VAC 5-50-30 F)

37. **Stack Test – Combustion Turbines** - Initial performance tests shall be conducted on each combined cycle unit (CC1 & CC2) for the following pollutants using the specified methods:

Pollutant	Test Method
Carbon Monoxide (CO)	40 CFR 60, Appendix A, Method 10
Volatile organic compounds (VOC)	40 CFR 60, Appendix A, Method 25A

PM-10 (All particulate matter shall be considered PM-10 and shall include condensables)	40 CFR 60, Appendix A, Methods 5 or 17 and 19, and 40 CFR 51, Appendix M, Method 202

Tests shall be conducted to determine compliance with the emission limits contained in Condition 13. The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. CO and VOC emissions shall be determined at each of the operating conditions indicated for each pollutant contained in Condition 13. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Director, Valley Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Director, Valley Regional Office, within 45 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, and 9 VAC 5-50-410)

38. **Stack Test – Duct Burners** - Initial performance tests shall be conducted for particulate matter, sulfur dioxide, and nitrogen oxides from the duct burners using U.S. EPA reference methods 5, 6c, 7e, and 19 to determine compliance with the emission limits contained in Condition 16. The tests shall be performed, reported and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Valley Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Valley Regional Office within 45 days of test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, and 9 VAC 5-50-410)

39. **Stack Test** – Initial performance tests shall be conducted on each combined cycle unit (CC1 & CC2) for oxides of nitrogen (as NO_2) and sulfur dioxide to determine compliance with the limits contained in Condition 13 as follows:

a. 40 CFR 60, Appendix A, Method 20 shall be used to determine the oxides of nitrogen (as NO_2), sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of oxides of nitrogen and 21 percent oxygen (see 40 CFR 60.335(c)(3). The oxides of nitrogen emissions shall be determined at four points in the normal operating range of the combined cycle unit including the ranges contained in Condition 13. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

b. The oxides of nitrogen emission rate shall be computed for each run using the following equation:

$$NO_x = (NO_{xo})(P_r / P_o)^{0.5} e^{19(Ho - 0.00633)} (288°K / T_a)^{1.53}$$

Where:
NO_x = emission rate of NO_x at 15 percent O_2 and ISO standard ambient conditions, ppm by volume
NO_{xo}= observed NO_x concentration, ppm by volume at 15 percent O_2
P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mmHg
P_o = observed combustor inlet absolute pressure at test, mmHg
H_o = observed humidity of ambient air, g H_2O/g air
e = transcendental constant, 2.718
T_a = ambient temperature, °K

c. The permittee may use the following as alternatives to the reference methods and procedures specified in this condition. Instead of using the equation contained in paragraph b of this condition, the CT manufacturer may develop ambient condition correction factors to adjust the oxides of nitrogen emission level measured by the performance test as provided in 40 CFR 60.8 to ISO standard day conditions. These factors are developed for each gas turbine model they manufacture in terms of combustion inlet pressure, ambient air pressure, ambient air humidity, and ambient air temperature. They shall be substantiated with data and must be approved for use by EPA, Region III before the initial performance test required by this condition. Notices of approval of custom ambient condition correction factors will be published in the Federal Register.

d. The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Director, Valley Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Director, Valley Regional Office, within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.

(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-50-410, and 40 CFR 60.335)

40. **Compliance Demonstration – Duct Burners** – The permittee shall determine compliance with the NOx standard in Condition 16 by using the procedures described in 40 CFR 60.46a(k)(1) or 40 CFR 60.46a(k)(2).

(9 VAC 5-50-30, 9 VAC 5-50-410, and 40 CFR 60.46a(k)(1))

41. **Fuel Testing** – The permittee shall conduct fuel testing on the pipeline natural gas as follows:

    a. To compute the oxides of nitrogen emissions, the permittee shall use analytical methods and procedures that are accurate to within 5 percent and are approved by EPA, Region III to determine the nitrogen content of the fuel being fired (F-value).
    b. The permittee shall determine compliance with the sulfur content of the pipeline natural gas contained in Condition 10 using ASTM D 1072-80 or 90 (Reapproved 1994), D3031-81, D 4084-82 or 94, or D 3246-81, 92, or 96. The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of EPA, Region III.

    c. To comply with the requirement contained in Condition 12, the permittee shall use the methods specified in paragraphs a and b of this condition to determine the nitrogen and sulfur contents of the pipeline natural gas. The analysis may be performed by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency.

    (9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-50-410, and 40 CFR 60.335)

42. **Visible Emissions Evaluation** - Concurrently with the initial performance tests, visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on each combined cycle generating unit stack. Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. At least one VEE shall be conducted for each of the operating scenarios and loads for which emissions tests are required for the stack tests contained in Condition 39. The details of the tests are to be arranged with the Director, Valley Regional Office. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the facility will be operated but in no event later than 180 days after start-up of the permitted facility.

    Should conditions prevent concurrent opacity observations, the Director, Valley Regional Office, shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the Director, Valley Regional Office, within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
    (9 VAC 5-50-30, 9 VAC 5-80-1180, and 9 VAC 5-50-410)

CONTINUING COMPLIANCE DETERMINATION

43. **Stack Tests** - Upon request by the DEQ, the permittee shall conduct additional performance tests to demonstrate compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the Director, Valley Regional Office.
    (9 VAC 5-50-30 G)

44. **Visible Emissions Evaluation** – The permittee shall conduct visible emission inspections on each combined cycle generating unit stack in accordance with the following procedures and frequencies:

    a. At a minimum of once per week, the permittee shall determine the presence of visible emissions. If during the inspection, visible emissions are observed, a visible emission evaluation (VEE) shall be conducted in accordance with 40 CFR 60, Appendix A, EPA Method 9. The VEE shall be conducted for a minimum of six minutes. If any of the observations exceed the applicable standard, the VEE shall be conducted for a total of 60 minutes.

    b. If visible emissions inspections conducted during 12 consecutive weeks show no visible emissions for a particular unit stack, the permittee may reduce the monitoring frequency to once per month for that unit stack. Anytime the monthly visible emissions inspections show visible emissions, or when requested by DEQ, the monitoring frequency shall be increased to once per week for that stack.

    All visible emission inspections, observations and VEE results shall be recorded.

    (9 VAC 5-50-20)

NOTIFICATIONS

45. **Initial Notifications** - The permittee shall furnish written notification of the following to the Director, Valley Regional Office:

    a. The actual date on which construction of the electric power generation facility commenced, within 30 days after such date.

    b. The anticipated start-up date of the electric power generation facility, postmarked not more than 60 days nor less than 30 days prior to such date.

    c. The actual start-up date of the electric power generation facility, within 15 days after such date.

    d. The anticipated date of continuous monitoring system performance evaluations, postmarked not less than 30 days prior to such date.

c. The anticipated date of performance tests of the electric power generation facility, postmarked at least 30 days prior to such date.

Copies of the written notification referenced in items a through c above are to be sent to:

Associate Director
Office of Air Enforcement (3AP10)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9 VAC 5-50-50 and 9 VAC 5-50-410)

GENERAL CONDITIONS

46. **Permit Invalidation** - This permit to construct and operate an electric power generation facility shall become invalid, unless an extension is granted by the DEQ, if:

  a. A program of continuous construction is not commenced before the latest of the following:

    i. 18 months from the date of this permit;

    ii. Nine months from the date that the last permit or other authorization was issued from any other governmental agency;

    iii. Nine months from the date of the last resolution of any litigation concerning any such permits or authorization; or

  b. A program of construction is discontinued for a period of 18 months or more, or is not completed within a reasonable time.

  c. DEQ may extend the 18-month period upon a satisfactory showing that an extension is justified.

  d. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date.

(9 VAC 5-80-1180 and 9 VAC 5-80-1880 B)

47. **Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

  a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

  b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

  c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

To sample or test at reasonable times.

For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
(9 VAC 5-170-130)

48. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the Director, Valley Regional Office, of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but not later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within 14 days of the discovery. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the Director, Valley Regional Office, in writing.
(9 VAC 5-20-180 C)

49. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9 VAC 5-20-180 I)

50. **Maintenance/Operating Procedures** - The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment, monitoring devices, and process equipment which affect such emissions:

  a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

b. Maintain an inventory of spare parts.

c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.
(9 VAC 5-50-20 E)

51. **Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:

a. Knowingly makes material misstatements in the application for this permit or any amendments to it;

b. Fails to comply with the conditions of this permit;

c. Fails to comply with any emission standards applicable to the equipment listed in Condition 2;

d. Causes emissions from this facility which result in violations of, or interferes with the attainment and maintenance of, any ambient air quality standard;

e. Fails to operate this facility in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect on the date that the application for this permit is submitted;

f. Fails to construct or operate this facility in accordance with the application for this permit or any amendments to it; or

g. Allows the permit to become invalid.

(9 VAC 5-80-1180 and 9 VAC 5-80-1950)

52. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the Director, Valley Regional Office, of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1180 and 9 VAC 5-80-1940)

53. **Registration/Update** - Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact. The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.1-340 through 2.1-348 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.
(9 VAC 5-170-60 and 9 VAC 5-20-160)

54. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-170-160)

ATTACHMENT F

SOURCE TESTING REPORT FORMAT

Cover
1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Tester; name, address and report date

Certification
1. Signed by team leader / certified observer (include certification date)
* 2. Signed by reviewer

Introduction
1. Test purpose
2. Test location, type of process
3. Test dates
* 4. Pollutants tested
5. Test methods used
6. Observers' names (industry and agency)
7. Any other important background information

Summary of Results
1. Pollutant emission results / visible emissions summary
2. Input during test vs. rated capacity
3. Allowable emissions
* 4. Description of collected samples, to include audits when applicable
5. Discussion of errors, both real and apparent

Source Operation
1. Description of process and control devices
2. Process and control equipment flow diagram
3. Process and control equipment data

* Sampling and Analysis Procedures
1. Sampling port location and dimensioned cross section
2. Sampling point description
3. Sampling train description
4. Brief description of sampling procedures with discussion of deviations from standard methods
5. Brief description of analytical procedures with discussion of deviation from standard methods

Appendix
* 1. Process data and emission results example calculations
2. Raw field data
* 3. Laboratory reports
4. Raw production data
* 5. Calibration procedures and results
6. Project participants and titles
7. Related correspondence
8. Standard procedures

* Not applicable to visible emission evaluations.

Comparison of the Most Recent BACT/LAER Determinations for Combustion Turbines by State Air Pollution Control Agencies

Paper #: 42752
AWMA Meeting June 2002

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ABSTRACT

A survey was conducted of state air pollution control agencies to determine the most recent Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) determinations for natural gas combustion turbines used in electric power generation facilities. BACT and LAER for both simple cycle and combined cycle modes of turbine operation were evaluated.

Any new major stationary source or major modification locating in an area attaining the National Ambient Air Quality Standard (NAAQS) is subject to Prevention of Significant Deterioration (PSD) requirements and must conduct an analysis to ensure the application of BACT. Also, any new major stationary source or major modification locating in an area not attaining the NAAQS is subject to non-attainment new source review permitting requirements and must conduct an analysis to ensure the application of LAER.

Air pollution permitting agency decisions on BACT/LAER determinations weigh heavily on the most recent BACT/LAER determinations. This most recent data is not always readily available in the US EPA BACT/LAER Clearinghouse. This often results in a delay as applicants and state agencies search for the most recent BACT/LAER determinations.

This paper is intended to address the need for current BACT/LAER determinations used by the state air pollution agencies and private industries.

The study involved a survey of 28 state air pollution agencies in the eastern half of the United States. Each state was queried on the most recent BACT/LAER analysis for simple and combined cycle combustion turbines; compliance averaging time applicable to these determinations; different types of control technologies required by each state agency; the cost per ton of pollutant removed threshold for economic feasibility; and the total number of BACT/LAER determinations made by each state during the last 12 months for this source group. This investigation primarily focused on the following pollutants: PM_{10}, NOx, CO. SO_2 and hydrocarbons.

The data obtained from this study was statistically analyzed to prepare tables showing comparative analyses between states. Conclusions on regional differences between the states were made based on the BACT/LAER determinations obtained.

INTRODUCTION

Any new major stationary source or major modification locating in an area attaining the National Ambient Air Quality Standard (NAAQS) is subject to Prevention of Significant Deterioration (PSD) requirements and must conduct an analysis to ensure the application of BACT. Also, any new major stationary source or major modification locating in an area not attaining the NAAQS is subject to non-attainment new source review permitting requirements and must conduct an analysis to ensure the application of LAER.

The regulatory decisions on BACT and LAER can have significant economic impacts on a proposed project (e.g. emission limits, allowable operating conditions). Thus, at the time of project development and the decision to proceed with the project, it is important to have timely information on the BACT and LAER determinations that will actually apply to the project.

To provide a central clearinghouse for BACT, LAER and Reasonably Available Control Technology (RACT) determinations throughout the nation; U.S. EPA has established the RACT/BACT/LAER Clearinghouse. As described on its web page, "the RACT/BACT/LAER Clearinghouse (RBLC) database contains information distilled from early notification submittals and air permits received from State and local air pollution control programs in the United States. The RBLC Web site also contains summary information on air pollution emission standards. The data assists State/local agency personnel and private companies in determining what types of controls and pollution prevention measures have been applied to and/or are required for various sources and the effectiveness of these technologies." (1)

The challenge is that early in the planning process for a new project, the project developer needs access to the most recent BACT/LAER determinations to make decisions on project design and to fully evaluate the economic feasibility of the project.

The time between the state or local regulatory decision on a BACT/LAER determination and the inclusion of that decision in the RBLC varies by state and can be substantial.

The purpose of this paper is to present the results of a survey conducted of recent BACT/LAER determinations in states in the eastern half of the U.S. for a major source category - - new large combustion turbines form power generation. We compare these determinations state by state and see whether these determinations are, in fact, included in the RBLC database.

SURVEY PROCEDURES

The survey questions are given in Table 1. Questions addressed included date of permit issuance, combustion turbine type and size, pollutants for which BACT or LAER determinations were made and the determination for each pollutant, compliance averaging time in the determination, required control technology and the cost per ton of pollutant removed threshold for economic feasibility in the determination.

Table 1. Survey questions

Questionnaire on State Agency Experience in BACT and LAER Determinations for Three Most Recent Large Combustion Turbines Permitted			
State: Person Providing Response: Date: Email: Phone #:			
	Permit #1	Permit #2	Permit #3
Permit #			
Date Permit Issued			
Combustion Turbine Type: (Combined Cycle (CC), Simple Cycle (SC))			
Size: (Megawatts (MW) output[a], MMBTU/hour fuel input)			
Pollutant: (NOx, CO, SO2, PM10, HC)			
Type of Determination: (BACT, LAER)			
Emission Standard: (ppm, lbs/MMBTU, % sulfur fuel, etc.)			
Compliance Averaging Time: (1 hour, rolling 4-hour, etc.)			
Required Control Technology: (SCR and/or LNB for NOx, catalytic oxidation for CO, etc.)			
Cost per ton of pollutant removed threshold for economic feasibility in the determination (dollars/ton)			
Note: (a) MW output for combined cycle combustion turbines is upstream of the HRSG.			

Table 2 lists the 28 states contacted in this survey and those states that responded. In each state, we sought to contact the person in charge of the control technology determinations in the new source review process. Surveys were sent by e-mail with phone call follow up as needed. 10 of the 28 states provided survey responses that were sufficiently complete to include in the results. A total of 75 BACT determinations and 16 LAER determinations are included in the survey results.

Table 2. States contacted in survey.

State	Status	State	Status
Alabama	Complete	Mississippi	Pending
Arkansas	Complete	New Hampshire	Complete
Connecticut	Complete	New Jersey	Pending
Delaware	Complete	New York	Complete
Florida	Complete	North Carolina	Pending
Georgia	Pending	Ohio	Pending
Illinois	Pending	Pennsylvania	Complete
Indiana	Complete	Rhode Island	Pending
Kentucky	Pending	South Carolina	Pending
Louisiana	Pending	Tennessee	Pending
Maine	Pending	Vermont	Pending
Maryland	Pending	Virginia	Pending
Massachusetts	Pending	West Virginia	Pending
Michigan	Complete	Wisconsin	Pending

RESULTS

Survey results are presented in the following five tables.

Table 3 presents the average BACT determination by state for simple cycle, combined cycle and all combustion turbines for up to five air pollutants. Based on natural gas firing, for NOx, these average BACT determinations vary from a low of 3.5 to 7.67 ppm. For CO they vary from 7.67 to 22.5 ppm. For SO2, they vary from 0.00145 to 0.0055 lbs/MMBTU, for PM10 they vary from 0.0059 to 0.021 lbs/MMBTU and for HC they vary from 2.2 to 6.7 ppm.

Table 4 presents the average LAER determination by state for simple cycle, combined cycle and all combustion turbines for up to five air pollutants. Based on natural gas firing, for NOx, these average LAER determinations vary from 2.0 to 3.0 ppm. For CO the determination is 3.0 ppm. For PM10 the determination is 0.0155 lb/MMBtu and for HC they vary from 1.3 to 1.56 ppm.

Table 5 presents the compliance averaging times included in the BACT and LAER determinations. Based on natural gas firing, for NOx, these compliance averaging times vary from one-hour never to be exceeded to four-hour rolling averages never to be exceeded. For CO they vary from one hour to 24 hour rolling never to be exceeded. For SO2, they vary from one hour to 3 hour never to be exceeded. For PM10, they vary from 1 hour to 24 hour rolling and for HC they vary from one hour to 24 hour rolling.

Table 3. The average BACT determination by state for simple cycle, combined cycle and all combustion turbines.

State	Pollutant	Average BACT Determination					
		Simple Cycle Combustion Turbine		Combined Cycle Combustion Turbine		All Combustion Turbines	
		#	Avg. BACT	#	Avg. BACT	#	Avg. BACT
Alabama	NOx			3	5.0 ppm	3	5.0 ppm
	CO			3	12.0 ppm	3	12.0 ppm
	PM10			3	0.0059 lb/mmBtu	3	0.0059 lb/mmBtu
	VOC			3	3.2 ppm	3	3.2 ppm
Arkansas	NOx			3	3.5 ppm	3	3.5 ppm
	CO			2	22.5 ppm	2	22.5 ppm
	PM10			1	0.013 lb/mmBtu	1	0.013 lb/mmBtu
	VOC			2	6.7 ppmv	2	6.7 ppmv
Connecticut	SO2			1	.005 lb/mmBtu	1	.005 lb/mmBtu
	PM10			1	0.011 lb/mmBtu	1	0.011 lb/mmBtu
Delaware	NOx	1	9 ppm	1	3 ppm	2	6 ppm
	CO	1	9 ppm	1	9 ppm	2	9 ppm
	SO2	1	0.003 lb/mmBtu	1	0.003 lb/mmBtu	2	0.003 lb/mmBtu
	PM10	1	0.02 lb/mmBtu	1	0.021 lb/mmBtu	2	0.0205 lb/mmBtu
Florida	NOx	1	9 ppm	2	3 ppm	3	6 ppm
	CO	1	9 ppm	2	8.5 ppm	3	8.75 ppm
	SO2	1	0.0056 lb/mmBtu	1	0.0052 lb/mmBtu	2	0.0054 lb/mmBtu
	VOC			1	2.2 ppm	1	2.2 ppm
Indiana	NOx	1	9 ppm	2	3.0 ppm	3	6.0 ppm
	CO	1	25 ppm	2	10.6 ppm	3	17.8 ppm
	SO2	1	0.0052 lb/mmBtu	2	0.0058 lb/mmBtu	3	0.0055 lb/mmBtu
	PM10	1	0.0095 lb/mmBtu	2	0.0125 lb/mmBtu	3	0.011 lb/mmBtu
Michigan	NOx	2	12 ppm	3	3.33 ppm	5	7.67 ppm
	CO	1	25 ppm	3	5.57 ppm	4	15.29 ppm
	VOC			3	6.47 ppm	3	6.47 ppm
New Hampshire	CO			2	15 ppm	2	15 ppm
	SO2			2	0.00145 lb/mmBtu	2	0.00145 lb/mmBtu
	PM10			2	0.0095 lb/mmBtu	2	0.0095 lb/mmBtu
New York	SO2			2	0.0038 lb/mmBtu	2	0.0038 lb/mmBtu
	PM10			1	0.021 lb/mmBtu	1	0.021 lb/mmBtu
Pennsylvania	CO			3	7.67 ppm	3	7.67 ppm

Table 4. The average LAER determination by state for simple cycle, combined cycle and all combustion turbines.

State	Pollutant	Average BACT Determination					
		Simple Cycle Combustion Turbine		Combined Cycle Combustion Turbine		All Combustion Turbines	
		#	Avg. LAER	#	Avg. LAER	#	Avg. LAER
Connecticut	NOx	1	2.0 ppm			1	2.0 ppm
New Hampshire	NOx			2	2.5 ppm	2	2.5 ppm
New York	NOx			2	2 ppm	2	2 ppm
	CO			2	2 ppm	2	2 ppm
	PM10			1	0.0155 lb/mmBtu	1	0.0155 lb/mmBtu
	VOC			2	1.3 ppm	2	1:3 ppm
Pennsylvania	NOx			3	3 ppm	3	3 ppm
	VOC			3	1.56 ppm	3	1.56 ppm

Table 5. Comparison of compliance averaging times in BACT/LAER determinations.

State	Pollutant	Compliance Averaging Times Used in BACT/LAER Determinations
Alabama	NOx	3 hour
	CO	3 hour
Arkansas	NOx	24 hour; 3 hour
	CO	24 hour
	PM10	3 hour
	VOC	3 hour
Connecticut	NOx	3 hour
	CO	1 hour
	SO2	3 hour
Delaware	NOx	1 hour
	CO	1 hour
	SO2	1 hour
	PM10	1 hour
Florida	NOx	24 hour block; 3 hour
	CO	24 hour block
	VOC	3 hour
Indiana	NOx	24 hour operating; 3 hour block
	CO	24 hour
Michigan	NOx	Day; 24 hour rolling; 3 hour
	CO	24 hour rolling; day
	PM10	Day; 24 hour rolling
	VOC	24 hour rolling
New Hampshire	NOx	3 hour block average
	CO	1 hour block average
	SO2	3 hour rolling
	PM10	1 hour block average
New York	NOx	3 hour rolling average
	CO	1 hour average
	SO2	1 hour; continuous
	PM10	1 hour; 1 hour average
	VOC	1 hour; 1 hour average
Pennsylvania	NOx	1 hour average
	CO	1 hour average
	SO2	1 hour average
	PM10	1 hour average
	VOC	1 hour average

Table 6 presents the required control technologies in the BACT/LAER determinations.

Table 7 presents the average cost per ton of pollutant removed threshold for economic feasibility in the BACT determination and in the LAER determination separately by state. The average cost per ton varies significantly by pollutant and among states.

Finally, Table 8 provides an indication of how up to date the RLBC Clearinghouse data is. For each state, we show how many of the three most recent BACT/LAER determinations are in the RLBC Clearinghouse data. Overall, 14% of the most recent BACT/LAER determinations in this survey were in the RLBC Clearinghouse.

CONCLUSIONS

BACT and LAER determinations for large combustion turbines vary significantly by state. Similarly, the compliance averaging times also vary significantly. However, both the control technologies selected for BACT and LAER and the average cost per ton of pollutant removed threshold for economic feasibility are more consistent among the states.

Finally, only 14% of the most recent BACT/LAER determinations in this survey were included in the RLBC database. U.S. EPA could help states make better BACT and LAER determinations by speeding up the process of incorporating the most recent BACT and LAER determinations in the RLBC database.

REFERENCES

(1) 40 CFR §52.21, *Prevention of Significant Deterioration of Air Quality*.

(2) 40 CFR Part 51, *Appendix S, Emission Offset Interpretive Ruling*.

(3) U.S. EPA web page. http://www.epa.gov/ttncatc1/rblc/htm/bl02.cfm

KEY WORDS

Combustion Turbines
PSD
BACT
LAER
RACT/BACT/LAER Clearinghouse

Table 6. Required control technologies in the BACT/LAER determinations.

State	Pollutant	Required Control Technologies in the BACT/LAER Determinations
Alabama	NOx	Dry Low NOx; SCR
	CO	Good Combustion
	PM10	Good Combustion
	VOC	Good Combustion
Arkansas	NOx	Dry Low NOx w/SCR
	CO	Catalytic Oxidation
	SO2	Fuel Sulfur limitation
	VOC	Catalytic Oxidation
Connecticut	NOx	SCR
	CO	Catalytic Oxidation
Delaware	NOx	SCR
	CO	Fuel Sulfur limitation
Florida	NOx	Dry Low NOx; SCR; SONOx
	CO	Combustion control; Catalytic Oxidation
	SO2	Low sulfur fuels
Indiana	NOx	Dry Low NOx Combustors; SCR
	CO	Good design/operation
	SO2	Low sulfur fuel
	PM10	Good combustion
	VOC	Good combustion
Michigan	NOx	DLNB, SCR, Catalytic Oxidation
	CO	DLNB, SCR, Catalytic Oxidation
	PM10	DLNB, SCR, Catalytic Oxidation
	VOC	DLNB, SCR, Catalytic Oxidation
New Hampshire	NOx	LNB with SCR
	CO	Low NOx burner with good combustion practices
	SO2	Low sulfur fuels, < 0.05% sulfur
	PM10	Low sulfur fuels
New York	NOx	SCR, LNB
	CO	Catalytic Oxidation
	SO2	Low sulfur fuel
	PM10	Fire only natural gas
	VOC	Catalytic Oxidation
Pennsylvania	NOx	DLNC + SCR
	CO + VOC	DLNC, Oxidation Catalyst
	SO2	Low sulfur fuel
	PM10	NG

Table 7. Average cost per ton of pollutant removed threshold for economic feasibility in the BACT/LAER determination.

State	Pollutant	BACT Determinations Average Cost per Ton	LAER Determinations Average Cost per Ton
Arkansas	CO/VOC	3,373	
	NOx	5,108	
Connecticut	NOx	9,000	
Florida	NOx	2,606	
Michigan	NOx	$22,000	
	CO	$4,944	
	PM10	$85,000	

Table 8. BACT/LAER determinations from this survey that are in U.S. EPA's RACT/LAER/BACT Clearinghouse Database

State	Pollutant	BACT /LAER Determinations in This Survey	BACT/LAER Determinations from Survey that are in U.S. EPA's RACT/LAER/BACT Clearinghouse Database	Percentage of BACT/LAER Determinations from Survey that are in U.S. EPA's RACT/LAER/BACT Clearinghouse Database
Alabama	NOx	3	0	0
	CO	3	0	0
	PM10	3	0	0
	VOC	3	0	0
Arkansas	NOx	3	2	66.6
	CO	3	2	66.6
	PM10	3	2	66.6
	VOC	3	2	66.6
Connecticut	NOx	1	1	100
	SO2	1	1	100
	PM10	1	1	100
Delaware	NOx	2	0	0
	CO	2	0	0
	SO2	2	0	0
	VOC	2	0	0
Florida	NOx	3	0	0
	CO	3	0	0
	SO2	2	0	0
	VOC	1	0	0
Indiana	NOx	3	1	33.3
	CO	3	1	33.3
	SO2	3	1	33.3
	VOC	3	1	33.3
Michigan	NOx	5	0	0
	CO	5	0	0
	PM10	5	0	0
	VOC	5	0	0
New Hampshire	NOx	2	0	0
	CO	2	0	0
	SO2	2	0	0
	PM10	2	0	0
New York	NOx	2	0	0
	CO	2	0	0
	SO2	2	0	0
	PM10	2	0	0
	VOC	2	0	0
Pennsylvania	NOx	3	0	0
	CO	3	0	0
	SO2	3	0	0
	PM10	3	0	0
	VOC	3	0	0

ATTACHMENT G

GEOPHYSICAL RESEARCH LETTERS, VOL. 35, L03809, doi:10.1029/2007GL031101, 2008

On the causal link between carbon dioxide and air pollution mortality

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[1] Greenhouse gases and particle soot have been linked to enhanced sea-level, snowmelt, disease, heat stress, severe weather, and ocean acidification, but the effect of carbon dioxide (CO_2) on air pollution mortality has not been examined or quantified. Here, it is shown that increased water vapor and temperatures from higher CO_2 separately increase ozone more with higher ozone; thus, global warming may exacerbate ozone the most in already-polluted areas. A high-resolution global-regional model then found that CO_2 may increase U.S. annual air pollution deaths by about 1000 (350–1800) and cancers by 20–30 per 1 K rise in CO_2-induced temperature. About 40% of the additional deaths may be due to ozone and the rest to particles, which increase due to CO_2-enhanced stability, humidity, and biogenic particle mass. An extrapolation by population could render 21,600 (7400–39,000) excess CO_2-caused annual pollution deaths worldwide, more than those from CO_2-enhanced storminess. **Citation:** Jacobson, M. Z. (2008), On the causal link between carbon dioxide and air pollution mortality, *Geophys. Res. Lett.*, *35*, L03809, doi:10.1029/2007GL031101.

1. Introduction

[2] Because carbon dioxide's (CO_2's) ambient mixing ratios are too low to affect human respiration directly, CO_2 has not been considered a classic air pollutant. Its effects on temperatures, though, affect meteorology, and both feed back to air pollution. Several studies have modeled the sensitivity of ozone to temperature [*Sillman and Samson*, 1995; *Zhang et al.*, 1998] and the regional or global effects of climate change from all greenhouse gases on ozone [*Thompson et al.*, 1989; *Evans et al.*, 1998; *Dvortsov and Solomon*, 2001; *Mickley et al.*, 2004; *Stevenson et al.*, 2005; *Brasseur et al.*, 2006; *Murazaki and Hess*, 2006; *Steiner et al.*, 2006; *Racherla and Adams*, 2006] and aerosol particles [*Aw and Kleeman*, 2003; *Liao et al.*, 2006; *Unger et al.*, 2006]. Some studies have highlighted the effect of water vapor on chemistry [*Evans et al.*, 1998; *Dvortsov and Solomon*, 2001; *Stevenson et al.*, 2005; *Steiner et al.*, 2006; *Racherla and Adams*, 2006; *Aw and Kleeman*, 2003]. However, none has isolated the effect of CO_2 alone on ozone, particles, or carcinogens, applied population and health data to the pollution changes, or examined the problem with a global-regional climate/air pollution model.

[3] Here, a box photochemistry calculation is first used to show how increases in water vapor and temperature independently increase ozone more with high than low ozone. This analysis helps to explain the causal link between CO_2 and health in areas where most people live, as subsequently found in 3-D global-regional simulations.

2. Chemical Effects of CO_2 on Ozone

[4] The SMVGEAR II chemical solver was used first in box mode, without dilution or entrainment, to solve chemistry for 12 hours among 128 gases and 395 inorganic, organic, sulfur, chlorine, and bromine reactions (including 57 photoprocesses) (mostly given by *Jacobson et al* [2007], also see the supplementary material of *Jacobson* [2007]). Cases with different initial NO_x and organic gas were run.

[5] Figure 1 shows the water-vapor (H_2O) and temperature-dependence of ozone under several ozone precursor combinations. For initial NO_x < 8 ppbv, ozone decreased with increasing H_2O. For initial NO_x > 80 ppbv and moderate initial NO_x with low organics, though, ozone increased with increasing H_2O, by up to 2.8 ppbv-O_3 per 1 ppthv-H_2O. Between these extremes, ozone increased with increasing H_2O at low H_2O and stayed constant or slightly decreased at high H_2O (see the auxiliary material).[1] Figure 1 also shows that, generally (but not always), increasing water vapor increased ozone more with higher ozone.

[6] Further, the more ozone present, the more temperature-dependent chemistry increases ozone (Figure 1), consistent with *Sillman and Samson* [1995] and *Zhang et al.* [1998]. The ozone increase ($\Delta\chi$, ppbv) per 1 K change in temperature (ΔT) from all points in Figure 1 were fit to

$$\Delta\chi/\Delta T = -0.13034 - 0.0045585\chi + 0.00028643\chi^2 - 4.6893 \times 10^{-7}\chi^3 \quad (1)$$

where χ is ozone (ppbv) at 298.15 K (32–250 ppbv). A 1 K rise increased ozone by about 0.1 ppbv at 40 ppbv but 6.7 ppbv at 200 ppbv. *Olszyna et al.* [1997] reported an observed correlation in the rural southeast U.S. of 2.4 ppbv ozone per 1 K. If temperature-dependent chemistry alone were causing this increase, ozone would need to be about 115 ppbv (equation 1) in that study, but it was 30–90 ppbv. Thus, other factors not accounted for in Equation 1, such as H_2O increases (described above) and biogenic gas emission increases [e.g., *Guenther et al.*, 1995], due to higher temperatures, may have caused the larger observed temperature-ozone correlation. Also, both temperature and ozone increase with sunlight, so all observed temperature-ozone correlations overestimate the magnitude of cause and effect.

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0094-8276/08/2007GL031101$05.00

[1]Auxiliary materials are available in the HTML. doi:10.1029/2007GL031101.

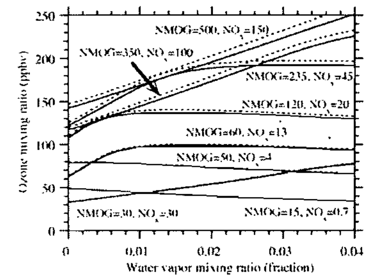

Figure 1. Mixing ratio of ozone and several other gases as a function of water vapor mixing ratio after 12 hours of a box-model chemistry-only simulation initialized at 0430 under several initial NO_x and nonmethane organic gas (NMOG) mixing ratio combinations (ppbv) (given in the figure) at 298.15 K (solid lines) and 299.15 K (dashed lines). The simulations assumed sinusoidally varying photolysis between 0600 and 1800.

3. Health Effects of CO_2 From Global-U.S. Simulations

[7] The chemistry used for Figure 1 was applied with emission, aerosol, cloud, meteorological, radiative, transport, and surface processes in the nested global-urban 3-D model, GATOR-GCMOM. The model (see auxiliary material) has been evaluated against U.S. gas, aerosol, meteorological, and radiative data extensively [e.g., *Jacobson*, 2001; *Jacobson et al.*, 2004, 2007; *Colella et al.*, 2005].

[8] Two global simulations (4°-SN × 5°-WE) were run under present-day conditions. In the second, fossil-fuel CO_2 (fCO_2) ambient mixing ratios and emissions were set to preindustrial values. When U.S. temperatures were about 1 K higher in the present minus preindustrial-CO_2 global simulations, the U.S. regional domain (0.5°S-N × 0.75°W-E) in each global simulation was turned on and initialized with global-domain data (including ambient CO_2). Global and regional domains were run another four months. Emissions of fCO_2 were included in the present-day but not preindustrial-CO_2 global- and U.S.-domain simulations.

[9] Figures 2 and S3 show differences between the present-day and preindustrial-CO_2 simulations. Figure 2a compares modeled with radiosonde (1958–2006) vertical temperature differences. The population-weighted near-surface temperature increase over land was 1.07 K (Table S4), which increased population-weighted H_2O by 1.28 ppthv (Table S4) and U.S.-averaged H_2O by 1.1 ppthv (Figure 2b). The observed 1961–1995 U.S. water vapor increase and positive correlation between temperature and H_2O [*Gaffen and Ross*, 1999] support the modeled H_2O increase with increasing temperatures.

[10] Figure 2c indicates that fCO_2 increased ozone by 0.12 ppbv in the U.S., 5 ppbv in Los Angeles, 1–5 ppbv in the southeast, and up to 2 ppbv along the northeast coast. In Los Angeles, the 0.75 K temperature increase (Figure 2a) and 1.3 ppthv water vapor increase increased ozone through chemistry (Figure 1).

[11] In the southeast, 0.5–1 K temperature increases increased isoprene and monoterpenes (Figure S3a), reducing the relative humidity (Figure S3c) and cloud optical depth (Figure S3d), increasing ultraviolet radiation (Figure S3e), and enhancing ozone. The 0.5–2 ppbv/K ozone increase in Tennessee is just below the correlated estimate of 2.4 ppbv/K from *Olszyna et al.* [1997] as expected (section 2). Averaged over the U.S. domain, higher temperatures from fCO_2 increased biogenic soil NO_x, isoprene, monoterpene, and other organic carbon emissions by 6% (0.01 Tg/yr), 9% (0.47), 9.8% (0.15), and 8.9% (0.14), respectively. In the northeast, higher ozone due to higher temperatures was offset partly by higher cloud optical depth (Figure S3d) and lower ultraviolet radiation (Figure S3e), modestly increasing ozone.

[12] The population-weighted 8-hr ozone increase due to fCO_2 was +0.72 ppbv (Table 1), suggesting a greater increase over populated than less-populated areas. FCO_2 increased particles in populated areas (Tables 1 and S4) by warming the air more than the ground, increasing stability (as with radiosonde data-Figure 2a, ii), decreasing turbulence, shearing stress, and surface wind speed (Table S4 and Figure S3), reducing dispersion. Reduced dispersion and wind speed are consistent with *Mickley et al.* [2004] who correlated warmer temperatures with reduced cyclone activity. FCO_2 also increased isoprene and monoterpene emissions, thus secondary organic matter (SOM) (Table S4, Figures S3a and S3b); and increased relative humidity (Table S4) by increasing H_2O, swelling aerosol particles, increasing nitric acid and ammonia dissolution and the surface area for sulfuric acid and organic condensation. FCO_2 increased land precipitation, consistent in direction with observed trends [*Intergovernmental Panel on Climate Change*, 2001], increasing aerosol removal, but less than other processes increased aerosol concentrations.

[13] Health effect changes (Δy) due to ozone and $PM_{2.5}$ changes in each model cell were determined from [e.g., *Ostro et al.*, 2006],

$$\Delta y = (1 - \exp[-\beta \Delta x])y_0 P \qquad (2)$$

where Δx is the simulation-averaged mixing ratio or concentration change in the cell, β is the fractional increase in risk per unit Δx, y_0 is the baseline health effect rate, and P is the cell population exposed to at least a minimum threshold. Table 1 and its footnote provide values of P, Δx, β, y_0, and thresholds. Changes were summed over all cells and adjusted from a four-month to an annual average (Table 1, footnote).

[14] With this method, mortality increases due to modeled ozone and $PM_{2.5}$ from fCO_2 were 415 (207–620)/yr and 640 (160–1280)/yr, respectively, per 1.07 K (Table 1) or a total of near 1000 (350–1800) per 1.00 K (a 1.1% increase relative to the baseline death rate - Table 1), with about 40% due to ozone. A simple extrapolation from U.S. to world population (301.5 to 6600 million) gives 21,600 (7400–39,000) deaths/yr worldwide per 1 K due to fCO_2 above the baseline air pollution death rate (2.2 million/yr). The ozone portion of this (8,500 deaths/yr) is conservative compared with 15,500 deaths/yr, calculated from *West et al.* [2006] (= 30,000 deaths/yr from 1 ppbv ozone multiplied by the 2006:2030 population ratio (66:92) and the ozone

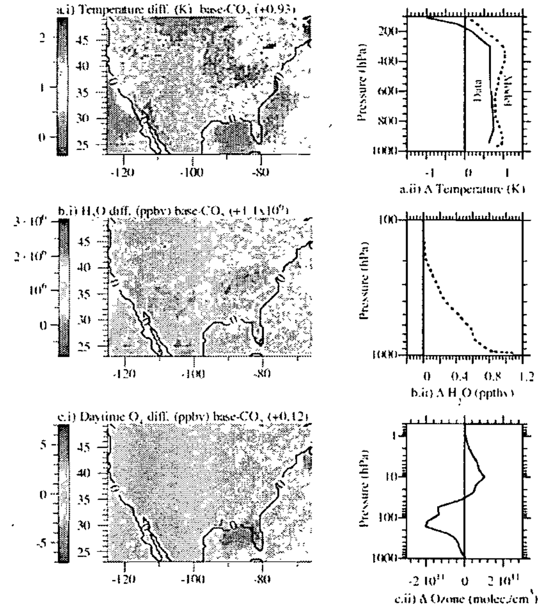

Figure 2. Four-month (mid-July to mid-November) domain-averaged near-surface and vertical-profile differences in (a) temperature, (b) water vapor, and (c) ozone between the present-day and preindustrial-CO_2 simulations. The domain-averaged (over land and water) change for each surface plot is given in parentheses. Also shown in Figure 2a (ii) is the 1958–2006 globally-averaged radiosonde temperature change [*Thorne et al.*, 2005], which is for reference only since the present simulations isolate the effects of CO_2 and do not examine all forcing agents.

change ratio (0.72:1.0). Remaining differences may be due to different thresholds used (35 ppbv here vs. 25 ppbv).

[15] One estimate of severe weather-related fatalities worldwide in the 1990s was 33,000/yr (Worldwatch Institute. Unnatural disaster: The lesson of Katrina, available at www.worldwatch.org/node/1822, 2005). A 1 K rise will increase this number, but less than 23,000/yr given that hurricane and tornado deaths have declined due to better warning systems (e.g., the deadliest hurricane since 1910 was over 30 years ago – Honduras, 1974, 10,000 deaths). Global warming will increase heat stress- and disease-related deaths as well, but by uncertain rates [e.g., *Medina-Ramon and Schwartz*, 2007].

[16] FCO_2 increased carcinogens, but the increase was small. Isoprene increases due to higher temperatures increased formaldehyde and acetaldehyde. Reduced dispersion increased exposure to these carcinogens and benzene and 1,3-butadiene.

[17] These simulations treated temperature effects on natural emissions but not power plant or vehicle emissions. A sensitivity test was run examining the impact of 1 K on power plant energy demand and emissions. The resulting ozone (Figure S4) may cause 80 more U.S. deaths/yr. However, warmer winter temperatures will also decrease natural gas and vehicle emissions, and warmer summers will increase vehicle emissions [*Rubin et al.*, 2006; N. Motallebi et al., manuscript in review, 2007]. The feedbacks of temperature to anthropogenic emissions must be studied more but are expected to be smaller than the other feedbacks examined here. Further uncertainties arise from model resolution, current and future emissions, numerical treatments, health data, and extrapolation of four-month results to a year, as detailed in the auxiliary material.

4. Effects of CO_2 on Stratospheric Ozone and UV Radiation

[18] Whereas, fCO_2 warms the surface and troposphere, it cools the stratosphere (Figure 2a, ii). Measurements indicate a 1%/yr (0.45 ppmv/decade) stratospheric water vapor

Table 1. Summary of CO_2's Effects on Cancer, Ozone Mortality, Ozone Hospitalization, Ozone Emergency Room Visits, and Particulate-Matter Mortality[a]

	Base	Base Minus No fCO_2
	Carcinogens	
Formaldehyde (ppbv)	3.61	+0.22
Acetaldehyde (ppbv)	2.28	+0.203
1,3-Butadiene (ppbv)	0.254	+0.00823
Benzene (ppbv)	0.479	+0.0207
USEPA cancers/yr[b]	389	+23
OEHHA cancers/yr[b]	789	+33
	Ozone	
8-hr ozone (ppbv) in areas ≥35 ppbv[c]	42.3	+0.724
Pop (mil.) exposed in areas ≥35 ppbv[d]	184.8	184.8
High ozone deaths/yr[e]	6230	620
Med. ozone deaths/yr[e]	4160	+415
Low ozone deaths/yr[e]	2080	+207
Ozone hospitalizations/yr[e]	24,100	+2400
Ozone ER visits/yr[e]	21,500	+2160
	Particulate matter	
PM2.5 ($\mu g/m^3$) in areas > 0 $\mu g/m^3$[f]	16.1	+0.065
Pop (mil.) exposed in areas ≥ 0 $\mu g/m^3$	301.5	301.5
High PM2.5 deaths/yr[g]	191,000	+1280
Medium PM2.5 deaths/yr[g]	97,000	+640
Low PM2.5 deaths/yr[g]	24,500	+160

[a]Results are shown for the present-day ("Base") and present-day minus preindustrial ("no-fCO_2") 3-D simulations. All mixing ratios and concentrations are near-surface values averaged over four months (mid-July to mid-November) and weighted by population (population-weighted value is defined in the footnote to Table S4). Divide the last column by 1.07 K (the population-weighted CO_2-induced temperature change from Table S4) to obtain the health effect per 1 K.

[b]USEPA and OEHHA cancers/yr were found by summing the product of individual CUREs (cancer unit risk estimates = increased 70-year cancer risk per $\mu g/m^3$ sustained concentration change) by the population-weighted mixing ratio or mixing ratio difference of a carcinogen, by the population, and air density, over all carcinogens, then dividing by 70 yr. USEPA CURES are 1.3×10^{-5} (formaldehyde), 2.2×10^{-6} (acetaldehyde), 3.0×10^{-5} (butadiene), 5.0×10^{-6} (= average of 2.2×10^{-6} and 7.8×10^{-6}) (benzene) (www.epa.gov/IRIS/). OEHHA CUREs are 6.0×10^{-6} (formaldehyde), 2.7×10^{-6} (acetaldehyde), 1.7×10^{-4} (butadiene), 2.9×10^{-5} (benzene) (www.oehha.ca.gov/risk/ChemicalDB/index.asp).

[c]8-hr ozone ≥35 ppbv is the highest 8-hour-averaged ozone during each day, averaged over all days of the four-month simulation in areas where this value ≥35 ppbv in the base case. When base $O_3 \geq 35$ ppbv and no-fCO_2 $O_3 < 35$ ppbv, the mixing ratio difference was base O_3 minus 35 ppbv.

[d]The 2007 population exposed to ≥35 ppbv O_3 is the population exposed to a four-month-averaged 8-hour averaged ozone mixing ratio above 35 ppbv and was determined from the base case.

[e]High, medium, and low deaths/yr, hospitalizations/yr, and emergency-room (ER) visits/yr due to short-term O_3 exposure were obtained from Equation 2 applied to each model cell, summed over all cells. The baseline 2003 U.S. death rate (y_0) was 833 deaths/yr per 100,000 [*Hoyert et al*, 2006]. The baseline 2002 hospitalization rate due to respiratory problems was 1189 per 100,000 [*Merrill and Elixhauser*, 2005]. The baseline 1999 all-age emergency-room visit rate for asthma was 732 per 100,000 [*Mannino et al.*, 2002]. These rates were assumed to be the same in each U.S. county, although they vary slightly by county. The fraction increases (β) in the number of deaths from all causes due to ozone were 0.006, 0.004, and 0.002 per 10 ppbv increase in daily 1-hr maximum ozone [*Ostro et al.*, 2006]. These were multiplied by 1.33 to convert the risk associated with 10 ppbv increase in 1-hr maximum O_3 to that associated with a 10 ppbv increase in 8-hour average O_3 [*Thurston and Ito*, 2001]. The central value of the increased risk of hospitalization due to respiratory disease was 1.65% per 10 ppbv increase in 1-hour maximum O_3 (2.19% per 10 ppbv increase in 8-hour average O_3), and that for all-age ER visits for asthma was 2.4% per 10 ppbv increase in 1-hour O_3 [*Ostro et al.*, 2006] (3.2% per 10 ppbv increase in 8-hour O_3). All values were reduced by 45% to account for the mid-July to mid-November and year-around $O_3 \geq 35$ ppbv ratio, obtained from detailed observations (H. Tran, personal communication, 2007).

[f]This is the simulated 24-hr $PM_{2.5}$, averaged over four months, in locations where $PM_{2.5} \geq 0$ $\mu g/m^3$.

[g]The death rate due to long-term $PM_{2.5}$ exposure was calculated from Equation 2. *Pope et al.* [2002] provide increased dearth risks to those ≥30 years of 0.008 (high), 0.004 (medium), and 0.001 (low) per 1 $\mu g/m^3$ $PM_{2.5}$ >8 $\mu g/m^3$ based on 1979–1983 data. From 0–8 $\mu g/m^3$, the increased risks were conservatively but arbitrarily assumed = $^1/_4$ those >8 $\mu g/m^3$ to account for reduced risk near zero $PM_{2.5}$. Assuming a higher risk would strengthen the conclusion found here. The all-cause 2003 U.S. death rate of those ≥30 years was 809.7 deaths/yr per 100,000 total population. No scaling of results from the 4-month model period to the annual average was performed to be conservative, since $PM_{2.5}$ concentrations from July–November are lower than in the annual average based on California data (H. Tran, personal communication, 2007).

increase from 1954–2000 [*Rosenlof et al.*, 2001], but a slight lower-stratospheric decrease from 2001–2005 [*Randel et al.*, 2006]. The simulations here, which accounted for chlorine and bromine gas and heterogeneous chemistry, found that the temperature and H_2O changes due to fCO_2 increased middle and upper-stratospheric ozone but decreased upper tropospheric and lower stratospheric (UTLS) ozone, where its column abundance is greater, causing a net U.S. column ozone loss of 2.7% (Figure 2c, ii, and Table S4). The UTLS ozone losses were due to increases in H_2O there (Figure 2b, ii), as indicated by Figure S2b and *Dvortsov and Solomon* [2001]. The upper- and middle-stratospheric gains can be explained by Figure S1, which shows that, at 25 km, stratospheric ozone decreases by 1.5% as H_2O increases by 1 ppmv. As temperature decreases by 1.5 K, though, ozone increases by 3.6%, suggesting an overall ozone increase from H_2O and cooling. The ozone increase upon stratospheric cooling is due to reduced loss from $O+O_3$ [*Evans et al.*, 1998]. Despite the column ozone loss due to fCO_2, surface UV hardly changed (Table S4) because fCO_2 increased cloud optical depth, offsetting UV increases from ozone loss.

5. Summary

[19] A climate-air pollution model showed by cause and effect that fossil-fuel CO_2 increases increase U.S. surface ozone, carcinogens, and particulate matter, thereby increasing death, asthma, hospitalization, and cancer rates. Increased water vapor and temperatures due to higher CO_2

each increase ozone increasingly with increasing ozone. At low ozone, more water vapor decreases ozone slightly but higher temperatures increase biogenic emission in many areas, offsetting ozone decreases in such areas. CO_2 increases stability, the relative humidity, and biogenic particle mass thus $PM_{2.5}$. Finally, CO_2 decreases column ozone over the U.S. by increasing upper tropospheric/lower stratospheric water vapor.

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ATTACHMENT H

The enhancement of local air pollution by urban CO_2 domes

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Data suggest that domes of high CO_2 levels form over cities[1-5]. Despite our knowledge of these domes for over a decade[1], no study has contemplated their effects on local temperature or water vapor or the resulting feedback to air pollution and health. In fact, all air pollution regulations worldwide assume arbitrarily that such domes have no local health impact[6] and carbon policy proposals, such as "cap and trade" implicitly assume that CO_2 impacts are the same regardless of where emissions occur. Here, it is found by cause and effect that local CO_2 emissions indeed increase local ozone, particulate matter, and mortality. As such, reducing locally-emitted CO_2 will reduce local air pollution mortality even if CO_2 in adjacent regions is not controlled. This result contradicts the basis for all air pollution regulations worldwide, none of which considers controlling local CO_2 based on its local health impacts. It also suggests that implementation of a "cap and trade" policy should consider the location of CO_2 emissions, as the underlying assumption of the policy is incorrect.

Although CO_2 is generally well-mixed in the atmosphere, data indicate that its mixing ratios are higher in urban than in background air, resulting in *urban CO_2 domes*[1-5]. Measurements in Phoenix, for example, indicate that peak and mean CO_2 in the city center are 75% and 38-43% higher, respectively, than in surrounding rural areas[2]. Many recent studies have examined the impact of global greenhouse gases on air pollution[7-14]. However, no study has isolated the impact of locally-emitted CO_2 on local air pollution, health, or climate. If locally-emitted CO_2 increases local air pollution, then cities, counties, states, and small countries can reduce air pollution health problems by reducing their own CO_2 emissions, regardless of whether other air pollutants are reduced locally or whether other locations reduce CO_2.

For this study, the nested global-through-urban 3-D model, GATOR-GCMOM[15-20] was use to examine the effects of locally-emitted CO_2 on local climate and air pollution on two scales, California as a whole and the Los Angeles basin. Three pairs of baseline and sensitivity simulations were run: one pair nested from the globe to California for one year and two pairs nested from the globe to California to Los Angeles, each for three months (Aug-Oct; Feb-Apr). In each sensitivity simulation, only anthropogenic CO_2 emissions ($emCO_2$) were removed from the finest domain. Initial ambient CO_2 was the same in all domains of both simulations and $emCO_2$ was the same in the parent domains of both. As such, all resulting differences were due solely to locally-emitted (in the finest domain) CO_2.

The model and comparisons with data have been described over 16 years, including recently[15-20]. Figure 1 further compares modeled O_3, PM_{10}, and CH_3CHO from August 1-7 of the baseline (with $emCO_2$) and sensitivity (no $emCO_2$) simulations from the Los Angeles domain with data. The comparisons indicate very good agreement with respect to ozone in particular and that $emCO_2$ increased O_3, PM_{10}, and CH_3CHO almost immediately, during day and night.

Figure 2a shows the modeled contribution to surface CO_2 of California's CO_2 emissions. The CO_2 domes over Los Angeles, the San Francisco Bay Area, and parts of the Central Valley are evident. The largest CO_2 increase (5%, or 17.5 ppmv) was lower than observed increases in cities (*1*) since the resolution of the California domain was coarser than the resolution of measurements. As shown for Los Angeles shortly, an increase in model resolution increases the magnitude of the CO_2 dome. Whereas the population-weighted (PW) and domain-averaged (DA) increases in surface CO_2 due to $emCO_2$ were 7.4 ppmv and 1.3 ppmv, respectively, the corresponding increases in column CO_2 were 6.0 g/m^2 and 1.53 g/m^2, respectively, indicating that changes in column CO_2 were spread horizontally more than were changes in surface CO_2. This is because local $emCO_2$ starts mixing with

the larger scale soon after emissions, but the losses are quickly replaced with more local CO_2 emissions.

The CO_2 increases in California increased the PW air temperature by about 0.0063 K, more than it changed the domain-averaged air temperature (+0.00046) (Fig. 2b). Thus, CO_2 domes had greater temperature impacts where the CO_2 was emitted and where people lived than they had in the domain average. This result holds for the effects of $emCO_2$ on column water vapor (Fig. 2c - PW: +4.3 g/m^2; DA: +0.88 g/m^2), ozone (Fig. 2d – PW: +0.06 ppbv; DA: +0.0043 ppbv), $PM_{2.5}$ (Fig. 2f – PW: +0.08 μg/m^3; DA: -0.0052 μg/m^3), PAN (Fig. 2h – PW: +0.002 ppbv; DA: -0.000005 ppbv) and particle nitrate (Fig. 2i – PW: +0.030 μg/m^3; DA: +0.00084 μg/m^3).

Figure 3 elucidates correlations between changes in local ambient CO_2 caused by $emCO_2$ and changes in other parameters. Modeled temperature, water vapor, ozone, and $PM_{2.5}$ increased more in grid cells with larger ambient CO_2 increases than in cells with smaller ambient CO_2 increases. In other words, increases in ozone and $PM_{2.5}$ correlated spatially with local CO_2 increases. Figure 2 shows further that ozone increases correlated spatially with temperature and water vapor increases, both of which increase ozone particularly at high ozone[15].

$PM_{2.5}$ correlated slightly negatively (R=0.017) with higher temperature but more strongly positively (R=0.23) with higher water vapor (Fig. 2). Higher temperature decreased $PM_{2.5}$ by increasing vapor pressures thus PM evaporation and by enhancing precipitation in some locations. Some $PM_{2.5}$ decreases from higher temperatures were offset by biogenic organic emission increases from higher temperatures followed by biogenic oxidation to organic PM. But in California, biogenic emissions are lower than in the southeast U.S. Some $PM_{2.5}$ decreases were also offset by slower winds caused by enhanced boundary-layer stability from CO_2. While higher temperatures slightly decreased $PM_{2.5}$, higher water vapor due to $emCO_2$ increased $PM_{2.5}$ by increasing aerosol water content, increasing nitric acid and ammonia gas dissolution, forming more particle nitrate (Fig. 2i) and ammonium. Higher ozone from higher water vapor also increased oxidation of organic gases to organic PM. Since $PM_{2.5}$ increased overall due to $emCO_2$, water vapor increases of PM exceeded temperature decreases.

Health effect rates (y) due to pollutants in each model domain were determined from

$$y = y_0 \sum_i \left\{ P_i \sum_t \left(1 - \exp\left[-\beta \times \max\left(x_{i,t} - x_{th}, 0\right)\right]\right) \right\} \quad (1)$$

where $x_{i,t}$ is the concentration in grid cell i at time t, x_{th} is the threshold concentration below which no health effect occurs, β is the fractional increase in risk per unit x, y_0 is the baseline health effect rate, and P_i is the grid cell population. Table 1 provides sums or values of P, β, y_0, and x_{th}.

California's local CO_2 resulted in ~13 (6-19) additional ozone-related deaths/year (Fig. 2e), or 0.3% above the baseline 4600 (2300-6900) deaths/year (Table 1). Higher $PM_{2.5}$ due to $emCO_2$ contributed another ~39 (13-60) deaths/year (Fig. 2g), 0.2% above the baseline death rate of 22,500 (5900-42,000) deaths/year. Changes in cancer due to $emCO_2$ were relatively small (Table 1).

Simulations for Los Angeles echo results for California but allowed for a higher-resolution, more accurate picture of the effects of $emCO_2$. Figure 4 (Feb-Apr) indicates that the CO_2 dome that formed over Los Angeles peaked at about 34 ppmv, twice that over the coarser California domain. The column difference indicates a spreading of the dome over a larger area than the surface dome. In Feb-Apr and Aug-Oct, $emCO_2$ enhanced PW ozone and $PM_{2.5}$, increasing mortality (Fig. 4, Table 1) and other health effects (Table 1). The causes of such increases, however, differed with season. From Feb-Apr, $emCO_2$ increased surface temperatures and water vapor over the Los Angeles basin (Fig. 4). This slightly enhanced ozone and $PM_{2.5}$, but the increase in the land-ocean temperature gradient also increased sea-breeze wind speeds, increasing resuspension of road and soil dust and moving particulate matter more to the eastern basin. From Aug-Oct, $emCO_2$ increased temperatures aloft, increasing the land-sea temperature gradient and wind speed aloft, increasing the flow of moisture from the ocean to land aloft, increasing water vapor and clouds over land, decreasing surface solar radiation, causing a net decrease in local ground temperatures and UV radiation but a net increase in water vapor at all altitudes due to the vertical diffusion of water vapor aloft to the surface. The higher water vapor triggered higher ozone and relative humidities, which increased

aerosol particle swelling, increasing gas growth onto aerosols, and reducing particle evaporation. In sum, $emCO_2$ increased ozone and $PM_{2.5}$ and their corresponding health effects in both seasons, increasing air pollution deaths in California and Los Angeles by about 50-100 per year (Fig. 4, Table 1). Death rates for Los Angeles were similar or higher than those for California due to the greater accuracy of higher resolution (Los Angeles) simulations, as shown in Table 2 of Ref 17; thus, these results are likely to be conservative for California as a whole.

The California mortality increase compares with a U.S. death rate increase of about 1000/yr per 1 K rise due to all globally-emitted anthropogenic CO_2, with about 300 deaths/yr occurring in California[15], which has 12% of the U.S. population. The greater death rates in California versus the rest of the U.S. are due to the fact that higher temperatures and water vapor due to CO_2 enhance air pollution the most where it is already high, and California has 6 of the top 10 polluted cities in the U.S.

Worldwide, emissions of many pollutants (e.g., NO_x, HCs, CO, PM) that cause local air pollution are regulated. The few CO_2 emission regulations proposed to date have been justified based on the large-scale climate effects and resulting feedbacks to sea levels, water supply, and global air pollution that such emissions cause. However, no proposed CO_2 regulation is based on the potential impact of locally-emitted CO_2 on local pollution as such effects have been assumed not to exist[6]. The result here suggests that reducing local CO_2 will reduce 50-100 California air pollution deaths/yr even if CO_2 in adjacent regions is not controlled. Thus, CO_2 emission controls are justified on the same grounds that NO_x, HC, CO, and PM emission regulations are justified. Results further imply that the assumption behind the "cap and trade" policy, namely that CO_2 emitted in one location has the same impact as CO_2 emitted in another, is incorrect, as CO_2 emissions in populated cities have larger health impacts than CO_2 emissions in unpopulated areas. As such, CO_2 cap and trade, if done, should consider the location of emissions to avoid additional health damage.

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Acknowledgements

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Figure Captions

Figure 1. (a) Paired-in-time-and-space comparisons of modeled baseline (solid lines), modeled no-emCO$_2$ (dashed lines), and data[21] (dots) for ozone, sub-10-μm particle mass, and acetaldehyde from the Los Angeles domain for August 1-7, 2006. The resolutions of the global, California, and Los Angeles domains were 4° SN x 5° WE, 0.20° SN x 0.15° WE, and 0.45° SN x 0.05° WE, respectively. The global domain included 47 sigma-pressure layers up to 0.22 hPa (≈60 km), with very high resolution (15 layers) in the bottom 1 km. The nested regional domains included 35 layers exactly matching the global layers up to 65 hPa (≈18 km). The model was run without data assimilation or model spinup.

Figure 2. Modeled annually averaged difference for several surface or column parameters when two simulations (with and without emCO$_2$) were run. The numbers in parentheses are population-weighted changes.

Figure 3. Scatter plots of paired-in-space one-year-averaged changes between several parameter pairs, obtained from all near-surface grid cells of the California domain. Also shown is an equation for the linear fit through the data points in each case.

Figure 4. Same as Fig. 2., but for the Los Angeles domain and for Feb-Apr and Aug-Oct. Also shown are scatter plots for Aug-Oct similar to those for Fig. 3.

Table 1. Summary of locally-emitted CO_2's ($emCO_2$) effects on cancer, ozone mortality, ozone hospitalization, ozone emergency-room (ER) visits, and particulate-matter mortality in California. Results are shown for the with-$emCO_2$ emissions simulation ("Base") and the difference between the base and no $emCO_2$ emissions simulations ("Base minus no-$emCO_2$") for California and Los Angeles. The domain summed populations in the Los Angeles and California domains were 17.268 million and 35.35 million, respectively. All concentrations are near-surface values weighted spatially by population. Los Angeles results were an average of Feb-Apr and Aug-Oct results.

	Annual base Calif.	Base minus no $emCO_2$ Calif.	Annual Base LA	Base minus no $emCO_2$ LA
Ozone ≥ 35 ppbv (ppbv)	47.4	+0.060	44.7	+0.12
$PM_{2.5}$ (μg/m^3)	50.0	+0.08	36	+0.29
Formaldehyde (ppbv)	4.43	+0.0030	4.1	+0.054
Acetaldehyde (ppbv)	1.35	+0.0017	1.3	+0.021
1,3-Butadiene (ppbv)	0.11	-0.00024	0.23	+0.0020
Benzene (ppbv)	0.30	-0.00009	0.37	+0.0041
Cancer				
USEPA cancers/yr⁺	44.1	0.016	22.0	+0.28
OEHHA cancers/yr⁺	54.4	-0.038	37.8	+0.39
Ozone health effects				
High O_3 deaths/yr*	6860	+19	2140	+20
Med. O_3 deaths/yr*	4600	+13	1430	+14
Low O_3 deaths/yr*	2300	+6	718	+7
O_3 hospitalizations/yr*	26,300	+65	8270	+75
Ozone ER visits/yr*	23,200	+56	7320	+66
PM health effects				
High $PM_{2.5}$ deaths/yr^	42,000	+60	16,220	+147
Medium $PM_{2.5}$ deaths/yr^	22,500	+39	8500	+81
Low $PM_{2.5}$ deaths/yr^	5900	+13	2200	+22

(+) USEPA and OEHHA cancers/yr were found by summing, over all model surface grid cells and the four carcinogens (formaldehyde, acetaldehyde, 1,3-butadiene, and benzene), the product of individual CUREs (cancer unit risk estimates=increased 70-year cancer risk per μg/m^3 sustained concentration change), the mass concentration (μg/m^3) (for baseline statistics) or mass concentration difference (for difference statistics) of the carcinogen, and the population in the cell, then dividing by the population of the model domain and by 70 yr. USEPA CURES are 1.3×10^{-5} (formaldehyde), 2.2×10^{-6} (acetaldehyde), 3.0×10^{-5} (butadiene), 5.0×10^{-6} (=average of 2.2×10^{-6} and 7.8×10^{-6}) (benzene) (www.epa.gov/IRIS/). OEHHA CUREs are 6.0×10^{-6} (formaldehyde), 2.7×10^{-6} (acetaldehyde), 1.7×10^{-4} (butadiene), 2.9×10^{-5} (benzene) (www.oehha.ca.gov/risk/ChemicalDB/index.asp).

(*) High, medium, and low deaths/yr, hospitalizations/yr, and emergency-room (ER) visits/yr due to short-term O_3 exposure were obtained from Equation 1, assuming a threshold of 35 ppbv[22] The baseline 2003 U.S. death rate (y_0) was 833 deaths/yr per 100,000[23]. The baseline 2002 hospitalization rate due to respiratory problems was 1189 per 100,000[24] The baseline 1999 all-age emergency-room visit rate for asthma was 732 per 100,000[25] The fractional increases (β) in the number of deaths from all causes due to ozone were 0.006, 0.004, and 0.002 per 10 ppbv increase in daily 1-hr maximum ozone[26] These were multiplied by 1.33 to convert the risk associated with a 10 ppbv increase in 1-hr maximum O_3 to that associated with a 10 ppbv increase in 8-hour average O_3[22] The central value of the increased risk of hospitalization due to respiratory disease was 1.65% per 10 ppbv increase in 1-hour maximum O_3 (2.19% per 10 ppbv increase in 8-hour average O_3), and that for all-age ER visits for asthma was 2.4% per 10 ppbv increase in 1-hour O_3 (3.2% per 10 ppbv increase in 8-hour O_3)[24,25]

(^) The death rate due to long-term $PM_{2.5}$ exposure was calculated from Equation 1. Increased death risks to those ≥30 years were 0.008 (high), 0.004 (medium), and 0.001 (low) per 1 μg/m^3 $PM_{2.5}$ >8 μg/m^3 based on 1979-1983 data[27]. From 0-8 μg/m^3, the increased risks here were assumed =¼ those >8 μg/m^3 to account for reduced risk near zero $PM_{2.5}$[15] The all-cause 2003 U.S. death rate of those ≥30 years was 809.7 deaths/yr per 100,000 total population.

Figure 1

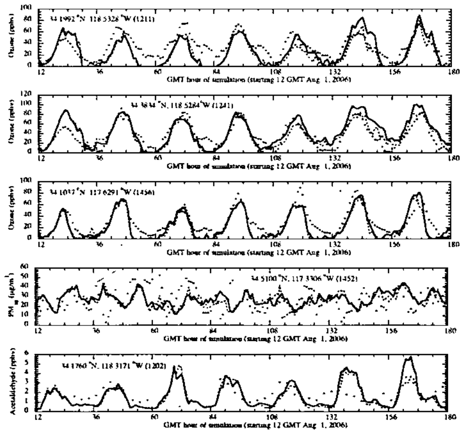


Figure 2

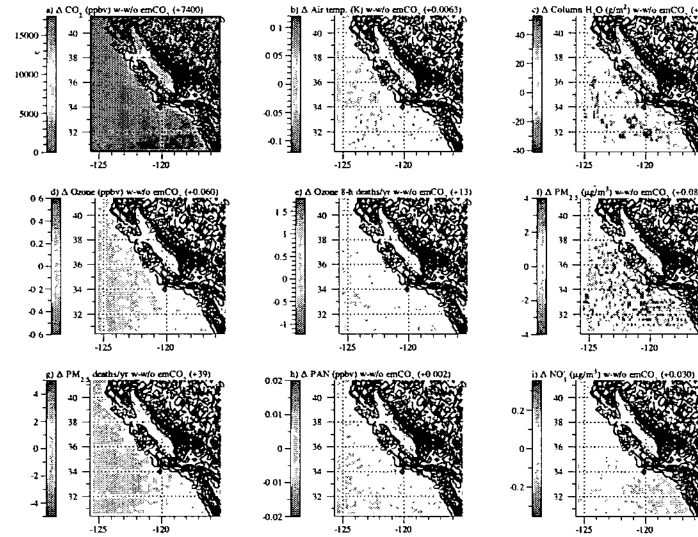


Figure 3

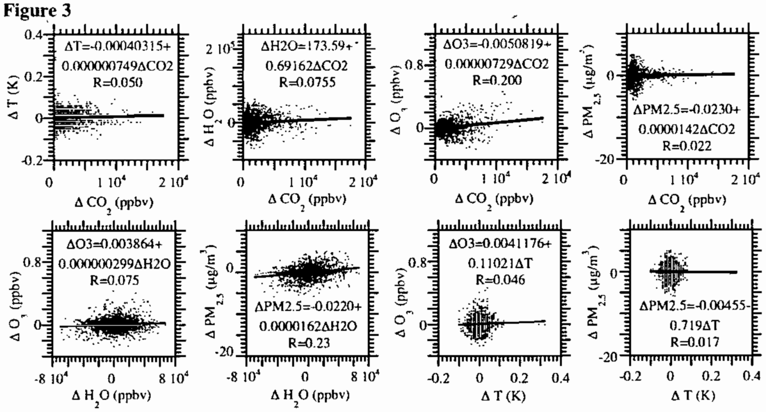
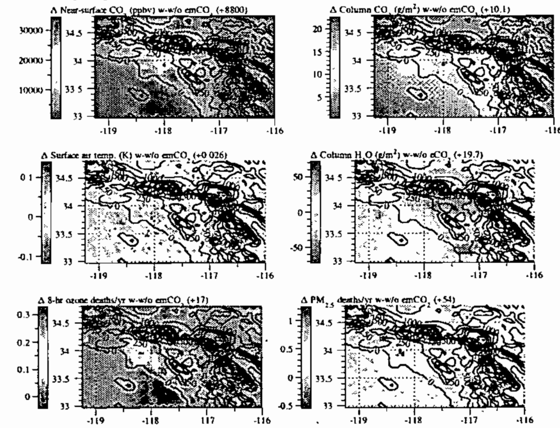
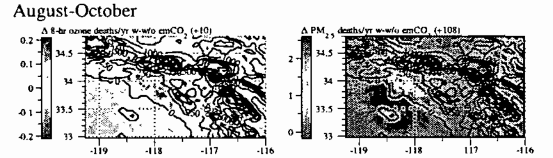


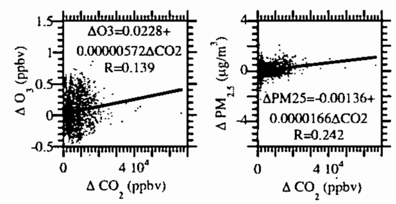
Figure 4

February-April



August-October





ATTACHMENT I

STATE OF CALIFORNIA – THE RESOURCES AGENCY — ARNOLD SCHWARZENEGGER, *Governor*

CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO, CA 95814-5512
www.energy.ca.gov

August 12, 2008

DOCKET
08-AFC-1
DATE AUG 12 2008
RECD. AUG 12 2008

Mr. David Warner
Director of Permit Services
San Joaquin Valley Unified Air Pollution Control District
1990 East Gettysburg Avenue
Fresno, CA 93726

Dear Mr. Warner:

AVENAL POWER CENTER (08-AFC-1)
PRELIMINARY DETERMINATION OF COMPLIANCE, PROJECT NO. C-1080386

Energy Commission staff appreciates the opportunity to provide written public comments on the Preliminary Determination of Compliance (PDOC) issued by the District on July 11, 2008, for the Avenal Energy project, proposed by Avenal Power Center, LLC.

Energy Commission staff, pursuant to both the Warren-Alquist Act and the California Environmental Quality Act (CEQA), must evaluate whether the facility is likely to conform with applicable laws, ordinances, regulations, and standards, and whether mitigation measures can be developed to lessen potential impacts to a less than significant level. These evaluations may be difficult without additional information from the San Joaquin Valley Air Pollution Control District (SJVAPCD or District) in support of the PDOC.

Equivalency of Emission Reductions

Energy Commission staff is concerned that the integrity of the proposed mitigation may be adversely affected by the annual equivalency demonstration required by SJVAPCD Rule 2201, Section 7. This rule requires the District to demonstrate that emission reduction credits (ERCs) used by the project as offsets are surplus at the time of use.

The applicant's proposed mitigation includes ERCs issued between 1991 and 2002, and some of the ERCs may be subject to discounting at the time of use under Rule 2201, Section 7. An SJVAPCD Draft Staff Report dated July 29, 2008, for revising Rule 2201 indicates that the District will likely fail to demonstrate equivalency for nitrogen oxides (NOx) this year because surplus NOx credits may make up less than 10 percent of the total banked credits. [1] If Rule 2201, Section 7 requires the applicant's ERCs to be

[1] SJVAPCD, Draft Staff Report, Draft Amendments to Rule 2201 (New and Modified Stationary Source Review Rule) and Rule 2530 (Federally Enforceable Potential to Emit). Prepared by Carlos Garcia, Senior Air Quality Engineer. Dated: July 29, 2008.

discounted, or if they are not representative of real or surplus reductions, then Energy Commission staff may need to identify additional mitigation for the project.

Please describe whether District compliance with Rule 2201, Section 7 would require any of the offsets to be subject to discounting. Please also confirm whether the offsets identified for the project (on PDOC p. 47) are representative of real and surplus reductions, taking into account possible discounting under Rule 2201, Section 7. Additionally, please identify the original emission reduction site and date, and the method of reduction, for the ERCs that would be used to offset this project.

Interpollutant Offsets and Particulate Matter Plans

Staff would like to verify that using offsets would not disrupt regional progress in attaining PM10 or PM2.5 standards. Our staff assessment needs to discuss the cumulative impacts of the project in the context of regional planning efforts, including the SJVAPCD 2008 PM2.5 Plan adopted April 30, 2008, and the 2007 PM10 Maintenance Plan. Emission reductions of NOx, directly emitted PM2.5, and sulfur dioxide (SO^2) are needed to demonstrate attainment of the PM2.5 NAAQS in the San Joaquin Valley (p. 6-1 of 2008 PM2.5 Plan), and the "reasonable further progress" calculations in the 2008 PM2.5 Plan shows that about ten times more tons of direct PM2.5 need to be reduced than SO^2 (see Table 8-2 of 2008 PM2.5 Plan).

SJVAPCD Rule 2201, Section 4.13.3 requires the District to conduct an air quality analysis to determine an adequate trading ratio for interpollutant trading. The 2007 PM10 Maintenance Plan (see Appendix E of the Maintenance Plan) indicates that the *minimum* ratio would be one-to-one, but the applicant relied on data from 1997 and 1998 to show that 1.4 tons of SOx reductions would be needed to offset each new ton of PM10 emissions. SJVAPCD in Attachment H of the PDOC incorrectly states that the applicant proposed a one-to-one ratio.

Please describe whether the one-to-one interpollutant trading ratio for SOx reductions-to-PM10 or PM2.5 increases would conform with the reductions specified in the 2008 PM2.5 Plan and the 2007 PM10 Maintenance Plan. Attachment H of the PDOC refers to a District analysis of the interpollutant ratio of one-to-one in an "Appendix A," but the copy of the PDOC provided to Energy Commission Dockets (08-AFC-1) dated July 11, 2008, did not include an "Appendix A" with the Attachment H of the PDOC. Please provide the District analysis that supports compliance with Rule 2201, Section 4.13.3.

NOx Emission Limits

Energy Commission staff concurs with the District that the NOx emission limits for the combustion turbines and duct burners should apply on one-hour rolling averages during all operating conditions, except startup and shutdown periods (as described in PDOC

p. 64 and PDOC Condition 26). However, the one-hour NOx emission limit is not consistently described in the PDOC. Please confirm that the value calculated by the District is 17.20 lb/hr (PDOC Condition 26), not 17.44 lb/hr (as shown on p. 64).

Ammonia Slip Levels

Energy Commission staff recommends limiting ammonia slip to the extent feasible. Although ammonia slip is intrinsic to operation of the selective catalytic reduction system, staff suggests that the District set a performance standard for ammonia slip. Guidance from CARB (Guidance for Power Plant Siting and Best Available Control Technology, September 1999) indicates that an ammonia slip limit of 5 parts per million by volume dry basis (ppmvd) should be achievable. The applicant proposed a condition in response to staff's data request on this issue (from Avenal Power Center LLC, dated June 20, 2008). Please consider revising the ammonia slip limits for the combustion turbines (PDOC Condition 31) with the following language that is similar to the applicant's proposal:

The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15 percent O_2 averaged over one hour. The selective catalytic reduction (SCR) system catalyst shall be replaced, repaired, or otherwise reconditioned within 12 months if the ammonia slip exceeds 5 ppmvd @ 15 percent O^2 over a 24 hour rolling average. The SCR ammonia injection grid replacement, repair, or reconditioning scheduled event may be cancelled if the owner or operator can demonstrate that, subsequent to the initial exceedance, the ammonia slip consistently remains below 5 ppmvd @ 15 percent O^2 averaged over 24 hours, and that the initial exceedance does not accurately indicate expected future operating conditions.

New Source Performance Standards (40 CFR Part 60)

The New Source Performance Standard (NSPS) Subpart KKKK applies to stationary combustion turbines and emissions from any associated duct burners, and it replaces earlier requirements in NSPS Subpart Db and Subpart GG. The PDOC (p. 55) shows requirements from NSPS Subpart Db, although the project appears to be exempt. Similarly, the PDOC (p. 63) states that the turbines meet the applicability requirements of Subpart GG when the project appears to be exempt. Please clarify whether the project is indeed exempt from NSPS Subparts Db and GG.

We appreciate the District working with Energy Commission staff on this licensing case. If you have any questions regarding our comments, please contact Keith Golden at (916) 653-1643. We look forward to discussing our comments in further detail with you.

Sincerely,

DALE EDWARDS, Manager
Environmental Protection Office

cc: Docket (08-AFC-1)
Proof of Service List
Mike Tollstrup, California Air Resources Board
Gerado Rios, US Environmental Protection Agency, Region IX

ATTACHMENT J

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

May 21, 2009

DOCKET	
08-AFC-7	
DATE	May 21 2009
RECD.	June 02 2009

David Warner
Director of Permit Services
San Joaquin Valley Air Pollution Control District
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244

Re: EPA Comments on Project Number N-1083212
Facility Name: GWF Energy, LLC – Tracy (N-4597)

Dear Mr. Warner:

Thank you for the opportunity to comment on San Joaquin Valley Air Pollution Control District's (District) Preliminary Determination of Compliance (PDOC) for Project Number N-1083212 at GWF Energy, LLC – Tracy (GWF Tracy) (N-4597). We understand that the project is a proposed Title V significant modification and the applicant has requested that a Certificate of Conformity (COC) be issued for this project.

Our comments provided in the enclosure are made in reference to the PDOC submitted to us on April 7, 2009. They address the PDOC evaluation and proposed permit conditions as they pertain to the federal New Source Review (NSR) program and title V program requirements. While this project does not trigger review under the requirements for Prevention of Significant Deterioration (PSD), it is subject to the requirements for a major modification under Non-attainment NSR review for NOx emissions.

Based on our review, we are concerned that several issues fail to meet federal requirements, such as the proposal to re-bank NOx offsets that have been surrendered previously and the proposal to use inter-pollutant offset ratios that EPA has not yet approved. Because these proposals are inconsistent with the requirements of the Clean Air Act, we recommend that the District work with the applicant to address these deficiencies.

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We look forward to working with you to address our comments prior to the issuance of the Final Determination of Compliance (FDOC). Please contact Andrew Chew at (415) 947-4197 or Laura Yannayon at (415) 972-3534 of my staff if you have any questions.

Sincerely,

for Gerardo C. Rios
Chief, Permits Office

Enclosure

cc: Keith Golden, California Energy Commission
Michael Tollstrup, California Air Resources Board

EPA Comments on the Preliminary Determination of Compliance (PDOC) for GWF Tracy Combined Cycle Power Plant (N-4597)

1. Offsets required for PM10 and VOC emissions

   GWF Tracy is required to provide offsets for the net emission increases of VOC and PM10 resulting from the project. To meet this requirement, GWF Tracy proposed (on page 49) to allocate any excess NOx emissions towards meeting the VOC and PM10 offset requirements by "re-bank[ing] the [NOx] ERCs that they originally provided." However, this type of "re-banking" does not comply with the Clean Air Act's requirement under Section 173(a) that the offsets be real emission reductions[1]. The ERCs that GWF Tracy surrendered to permit the original Tracy Peaker Project in 2003 were consumed by the original permitting action and cannot be re-banked as ERCs. Accordingly, GWF has no valid NOx ERCs to use as interpollutant offsets for VOC and PM10. Therefore the project does not meet the NSR requirements to provide offsets for increased VOC and PM10 emissions.

2. Inter-pollutant Offsetting

   Although the project relies on inter-pollutant offset ratios of 1:1 and 2.629:1 for NOx-to-VOC and NOx-to-PM10, respectively, the underlying methodology to determine the appropriate ratios for inter-pollutant offsets has not been approved by EPA as required by District Rule 2201. The burden in seeking approval for inter-pollutant offsets rests with GWF Tracy to demonstrate that the proposed inter-pollutant offsets will ensure a net benefit to air quality levels in the area of the proposed project. It is important to note that modeling is a critical component of an inter-pollutant offset analysis, and subsequent models are evaluated on a case-by-case basis. Any approach for inter-pollutant offsets, therefore, must be carefully considered by the agencies in the context of a thorough and descriptive protocol. EPA must concur with the assumptions and methodology before such ratios may be used in this project. Even though a proposed methodology has been presented in a District attainment plan, it should not be inferred that the methodology has been automatically approved for use in this project. Accordingly, GWF Tracy and SJVAPCD must work with EPA on such protocol to be reviewed in advance of an acceptable methodology. We are available to discuss the schedule for submission of such a protocol and its components. At a minimum, the protocol should include standard information, such as model choice, episode selection, emissions inventory parameters, and performance criteria.

3. BACT Evaluation for Startup and Shutdown Operating Scenarios

   We note that the District has included permit conditions for startup and shutdown (SU/SD) operating scenarios (e.g., mass limits, duration of startups and shutdowns, definitions of operating scenarios, etc.) for two combustion turbine generators in the PDOC. However we do not see a proper BACT analysis for operation during these periods. We are aware of several projects in California that are considering technologies and work practices that minimize duration and emissions during such operating scenarios from stationary combustion turbines in their BACT evaluations. Please provide an appropriate BACT analysis for operation during startup and shutdown periods.

   Although the District imposes the condition on the project to maintain the units in good operating condition and operate in a manner to minimize emissions, we request additional information be included in the District's evaluation that supports the proposed permit conditions (such as emission limits, durations, and definitions) for SU/SD operations.

   EPA requires that BACT apply not only during normal, steady-state operations but also during all transient operating periods such as SU/SD periods. Therefore, as part of the BACT evaluation, we expect applicants to consider operating approaches, operating controls, work practices, and equipment performance and design that would minimize SU/SD emissions. Please refer to the following two decisions from EPA's Environmental Appeals Board (EAB) that provide context in this matter. They are Rockgen Energy Center (PSD Appeal No. 99-1) (http://www.epa.gov/eab/disk11/rockgen.pdf) and Tallmadge Generating Station (PSD Appeal No. 02-12) (http://www.epa.gov/eab/orders/tallmadge.pdf).

4. Federally enforceable limits on PTE for stationary gas turbines and auxiliary boiler

   While the PDOC contains conditions for startup and shutdown (SU/SD) operating scenarios (e.g., mass limits, duration of startups and shutdowns, definitions of operating scenarios, etc.), it should also contain limits on the number of such events when operating under combined-cycle operation, since the evaluation is based on an assumed number of these events (page 26 and Attachment G of the PDOC). Likewise, the calculations were based on a total of 8,639 hours of operation per year rather than the maximum of 8,760 hours in a year. For these reasons, the proposed permit conditions must include limits on the capacity utilization and/or hours of operation to properly reflect the scenarios used in the emission calculations. Furthermore, the permit must include proper monitoring and recordkeeping conditions for such limits.

5. Limiting fuel usage and the PTE of HAPs

   Because the calculated PTEs of any individual HAP (e.g., formaldehyde) and of the total HAPs are within close to 6% of triggering the threshold for a major HAP source, the final DOC must include federally enforceable limits on the annual fuel usage rates for each emission unit at the source and the PTE for any individual HAP and for total HAPs. As calculated annual PTE's and fuel usage rates are indicated on pages 64-65, the PTE for formaldehyde is 9.4 tons per year and total HAPs of 23.3 tons per year. As such, the final DOC must include recordkeeping conditions that require the operator to calculate, on a monthly basis, the rolling 12-month averages of actual fuel usages for each emission unit and to comply with their associated conditions that limit the PTEs of any individual HAP and of the total HAPs.

   Furthermore, should the number of operating hours increase and/or, in turn, calculations of HAP emissions result in a finding that the source is a major source for HAPs, please evaluate

[1] While District Rule 2301 may allow a source to bank offsets that have been previously provided if its associated Permit to Operate has been voluntarily modified, that Rule has not been SIP-approved and is not consistent with the requirements of the Clean Air Act.

the applicability of NESHAPs/MACTs (including, but not limited to, CFR Subparts YYYY and DDDDD of Part 63 of title 40), identify the applicable requirements for this source, and include adequate permit conditions to assure compliance with them. While this is not necessary to address NSR requirements, the issuance of the COC is contingent upon the District adding the necessary conditions to the title V portion of the permit.

6. 40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ, and their applicable requirements

   Please indicate whether NSPS Subpart IIII and MACT Subpart ZZZZ apply to the project, identify the applicable requirements for this project, and include adequate permit conditions to assure compliance with them. While this is not necessary to address NSR requirements, the issuance of the COC is contingent upon the District adding the necessary conditions to the title V portion of the permit.

7. PDOC is not a written certificate of conformity (COC)

   Because the conditions under section 6.1 of District Rule 2201 have not been met, the PDOC does not serve as a written COC despite the proposed permit condition on page 61 stating otherwise. Section 6.0 (Certification of Conformity) of District Rule 2201 states that the COC may be issued only after all of the conditions under section 6.1.1 through 6.1.6 are met. Generally, some of these conditions include conformity with the Enhanced Administrative Requirements of District Rule 2201 and mandatory permit content for title V permits in District Rule 2520. Because the Authority to Construct has not been issued and will not be issued until our comments in this letter and comments from other agencies are resolved, the PDOC cannot serve as a written COC. Please make appropriate changes to reflect this in the FDOC.

8. SCR operation and startup and shutdown events

   It is unclear if the PDOC assumes operation of the SCR during startup and shutdown events. If it is the District's intention, as part of BACT that the SCR should be in operation as soon as technically feasible, please add conditions to both require its use and monitoring provisions to ensure the SCR unit is in operation during startup and shutdown events. Examples of such conditions could include: 1) require the installation and maintenance of a working temperature gauge at the inlet or the catalyst bed of the SCR system and 2) require the monitoring and recording of the temperature over which the control system ought to be operating.

9. Monitoring, recordkeeping, and recording for visible emissions

   Visible emissions from the electrical generator lube oil vents and from the exhaust of the diesel-fired internal combustion engine are subject to SIP-approved District Rule 4101. While subsection 6.1 of the rule identifies US EPA Method 9 for visual determination of the opacity, provisions for monitoring, recordkeeping, and recording should be considered and are required under title V (per section 9.0 of District Rule 2520). Examples of considerations include: 1) requirement to conduct periodic monitoring/inspection and to record the opacity readings (along with their times and dates); 2) requirement to conduct the monitoring while the equipment is operating and during daylight hours; 3) requirement to take corrective action that eliminates the visible emissions during X hours and report the visible emissions as a potential deviation in accordance with the permit's reporting requirements; 4) requirement to verify and certify within X hours that the equipment causing the visible emissions has been fixed; and 5) requirement that the operator maintain and make available upon request records of emission point(s), of descriptions of corrective actions taken, of date and time emissions were abated, and of records of emission readings. Please include these requirements as appropriate into the FDOC. Issuance of the COC is contingent upon the District adding the necessary conditions to the title V portion of the permit.

   In addition, please provide an evaluation whether compliance with District Rule 4101 would be expected of the two compression-ignited reciprocating internal combustion engines.

10. CEM during all startup, shutdown, and malfunction events

    Please propose a permit condition that requires the operator to keep the Continuous Emission Monitoring running during all startup, shutdown, and malfunction events provided that the CEM data is certifiable to determine compliance with startup and shutdown emission limits. Even though it may be implicit that CEM equipment is required to operate during all startup, shutdown, and malfunction events, it should be clarified to the operator through an explicit permit condition.

11. PM2.5 emissions from project

    Please provide actual calculations of PM2.5 emissions that would be expected from the project and perform an evaluation whether the amounts of emissions would trigger new source review. The PDOC (on page 119) has only an abbreviated discussion of PM2.5 emissions on the applicability of 40 CFR 51 Appendix S.

12. Fuel sulfur content limit (rolling 12-month average)

    Please provide an alternative calculation methodology to determine the rolling 12-month average fuel sulfur content contained in proposed Condition 50 in Attachment A-20. The currently proposed methodology can potentially bias the rolling average by allowing more than one data point in a month. Because of the potential for under-estimation of actual emissions, an alternative methodology should be proposed.

13. FGR control technology in auxiliary boiler

    Please propose a permit condition that requires the operator to properly operate and maintain the flue gas recirculation system since it is an important part of NOx control for the boiler.

14. CTG SOx emission limit during shutdown

Please correct the proposed permit condition containing the SOx emission limit for the CTG during shutdown (Condition 31 in Attachment A-5) to reflect the amount of 0.85 lb/event as indicated in the table titled "Shutdown Emission Factors, Per Turbine, Scenario 1," on page 18.

15. 40 CFR 60 Subpart Dc

a. Please edit proposed Condition 11 on Attachment A-28 to require the fuel flow meter to be calibrated and maintained properly.

b. Please propose a permit condition that requires the operator to conduct a performance test since section 60.8 in 40 CFR 60 requires one; as section 60.8 of part 60 applies, the operator must conduct a performance test according to the requirements in section 60.44c. Also, please consider re-evaluating the applicability of section 60.44c as it pertains to the auxiliary boiler.

c. Please clarify the applicability of subsections 60.47c(e) and 60.47c(f) as they pertain to the auxiliary boiler. Under those requirements, the operator may have to evaluate whether COMS would be required.

16. 40 CFR 60 Subpart KKKK

a. Subsection 60.4345(a). Please propose a condition that requires the RATA of the CEMS to be performed on a lb/MMBtu basis.

b. Subsection 60.4345(e) (CEM Quality Assurance Plan). Please propose conditions in the final Determination of Compliance (FDOC) that require the owner or operator to develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of subsection 60.4345.

c. Subsection 60.4350(b). Please propose conditions that 1) impose a maximum of 19% O2 diluent cap value and 2) calculate and record hourly NOx rate in ppm using Method 9 of 40 CFR 60, Appendix A. As currently proposed, the requirements contained in paragraphs 5.2 through 5.3.3 of Appendix P in 40 CFR 51 do not apply here as the project does not involve any nitric acid plants nor sulfuric acid plants.

d. Subsection 60.4350(h) (data calculation protocols). Please propose conditions in the FDOC that capture the applicable requirements contained in paragraph (h) of subsection 60.4350 after its evaluation has been performed.

e. Subsection 60.4380(b)(1). Please consider proposing conditions that reflect the applicable calculation methodologies in this subsection.

f. Subsection 60.4385(a) and (c). Please consider proposing conditions that indicate the sets of circumstances that would constitute excess emissions and downtime.

g. Subsection 60.4400(a). Please consider proposing conditions that reflect the applicable elements contained in paragraphs (a)(2), (a)(3), and (b).

17. Rule 4304

Please propose permit conditions that reflect the applicable requirements of District Rule 4304 as they pertain to equipment tuning procedures for boilers and steam generators.

18. Rule 4703

a. Subsection 6.2.6. Please propose a permit condition that includes the applicable elements in the operating log.