

I. INTRODUCTION AND SUMMARY

A. Introduction

BAAQMD application 27215 for authority to construct the Metcalf Energy Center (MEC) along with CEC 99-AFC-3 is the latest in a series of applications to build large new gas-fired combined cycle power plants which have come before the California Energy Commission (CEC) and various California air quality management districts (AQMDs). Within the last year intervenors CARE and CURE, have pointed out that some of these projects are quite deficient in their BACT and other air quality analyses.¹ CARE has participated as an intervenor in the Delta Energy Center. CARE has filed a complaint with the EPA Office of Civil Rights over the disparate impacts of air pollutants associated with this project. With these comments, CARE has identified a similar lengthy list of inadequacies in the PDOC for the Metcalf proposal. CARE expects that the BAAQMD and the CEC will give serious attention to these inadequacies. Given the extensive scope of our comments, CARE calls upon the BAAQMD to re-circulate the PDOC for further comment after responding to our comments. To go directly to an FDOC and FSA at this stage would deny the public any substantive opportunity to comment on the many issues, which are inadequately addressed in this PDOC and the PSA, or not addressed at all.

¹ CURE is the acronym for the California Unions for Reliable Energy. CURE is not opposing the Metcalf project. However, the comments below on the Metcalf project draw on various public documents filed by CURE in the Elk Hills, Sunrise, and Three Mountain siting cases. These documents include:

- a. Letter from Lizanne Reynolds, Adams Broadwell Joseph & Cardozo, Re: Comments on Draft PDOC for the Elk Hills Power Project (ATC #990210), January 17, 2000.
- b. Elk Hills, CEC Docket No. 99-AFC-1, Exhibit 44, Testimony of J. Phyllis Fox, Ph.D. on Behalf of the California Unions for Reliable Energy on Air Quality Impacts of the Elk Hills Power Project, May 8, 2000.
- c. Letter from Katherine S. Poole, Adams Broadwell Joseph & Cardozo, Re: Comments on Preliminary Determination of Compliance for the Sunrise Cogeneration and Power Project, August 28, 1999.
- d. Letter from Katherine S. Poole, Adams Broadwell Joseph & Cardozo, Re: Comments on PSD Permits SJ 99-01, SJ 78-16 and SJ 78-17 (Sunrise), January 7, 2000.
- e. Letter from Lizanne Reynolds, Adams Broadwell Joseph & Cardozo, Re: Comments on the Draft PSD ATC/PDOC for the Three Mountain Power Project (ATC #99-PQ-01), February 3, 2000.
- f. Letter from Mark R. Wolfe, Adams Broadwell Joseph & Cardozo, Re: PSD/ATC/FDOC for the Three Mountain Power Plant Project -- Supplemental BACT Analysis for SCONOX, May 28, 2000.

B. Summary of CARE's comments

CARE's comments have been grouped into a dozen main areas, which CARE summarized here. Within each area CARE have attempted to not only identify omissions or errors in the PDOC (e.g., the absence of a CO catalyst requirement) but also identify the position, which CARE believe the BAAQMD should adopt, and the facts supporting that position. CARE have also identified counter-arguments which the Applicant might make, or has already made elsewhere, and supplied the District with a response to those arguments.

The key deficiencies in the PDOC and PSA are errors of omission. The PDOC does not contain a serious top-down BACT analysis (Section II, below). As a result it fails to correctly identify BACT for NO_x (Section III), for CO (Section IV), for VOC (Section VII), and for startup emissions (Section VIII). Along the way, the PDOC omits any discussion of other air quality benefits of catalyst-based CO and NO_x control technologies (Section VI) and their lack of negative PM₁₀ impacts (Section V).

The PDOC and PSA relies on Applicant data, which is either wrong or misleading, leading to inaccurate conclusions regarding PM₁₀ emissions and offset requirements (Section IX).

The PDOC and PSA also lacks an adequate analysis of the toxics MEC would emit, emissions whose health consequences would easily exceed the CEC and BAAQMD thresholds for further analysis and mitigation (Section X).

Finally, CARE has commented on a variety of other matters ranging from the meteorological modeling in the PDOC to the treatment of the proposed on-site internal combustion engines to the proposed condition regarding overlapping startups of the two proposed MEC turbines (Section XI).

II. THE PDOC DOES NOT INCLUDE A TOP-DOWN BACT ANALYSIS

The project is a major source whose emissions trigger PSD requirements for NO_x and CO. (PDOC, Table 3.) Any major modification subject to PSD must conduct an analysis to ensure that best available control technology ("BACT") is used. This requirement is set forth in section 165(a)(4) of the federal Clean Air Act, in federal PSD regulations at 40 C.F.R. § 52.21(j), and in federal regulations providing the requirements for State implementation plan (SIP) approval of a State PSD program, at 40 C.F.R. § 51.166(j). For PSD purposes, BACT is "an emissions limitation... based on the maximum degree of reduction for each pollutant subject to regulation under [the] Act which would be emitted from any proposed major stationary source...." (40 CFR § 52.21(b)(12).)

PSD regulations require the District, as EPA's delegate, to perform and document an analysis to ensure that federal BACT is used. (CAA, § 165(a)(4); 40 CFR 52.21(j).) This obligation is fulfilled by conducting what is known as a "top-down BACT analysis" as outlined in EPA's

NSR Manual. (NSR Manual,² Chapter B.) The NSR Manual and the top down procedure have been accepted by EPA's Environmental Appeals Board ("EAB") "as the most current statement of the Agency's thinking on BACT issues" and are routinely used to decide cases involving matters of federal law. (See, e.g., Masonite Corporation, 5 E.A.D. 558 (EAB 1994); Inter-Power of New York, Inc.; 5 E.A.D. 135 (EAB 1994); Hawaiian Commercial & Sugar Company, 4 E.A.D. 99 (EAB 1992).)

The Environmental Appeals Board of the EPA has on several occasions stressed the primary importance of a complete and meaningful BACT analysis in the PSD program, stating most recently:

"The BACT analysis is one of the most critical elements of the PSD permitting process. As such, it should be well documented in the administrative record. A permitting authority's decision to eliminate potential control options as a matter of technical infeasibility, or due to collateral impacts, must be adequately explained and justified. See *In re Masonite Corp.*, 5 E.A.D. 551, 566 (EAB 1994) (remanding PSD permit decision in part because BACT determination for one emission source was based on an incomplete cost-effectiveness analysis); *In re Pennsauken County, N.J., Resource Recovery Facility*, 2 E.A.D. 667, 672 (Adm'r 1988) (remanding PSD permit decision because "the applicant's BACT analysis does not contain the level of detail and analysis necessary to satisfy the applicant's burden" of showing that a particular control technology is technically or economically unachievable); *Columbia Gulf*, 2 E.A.D. at 830 (permit applicant and permit issuer must provide substantiation when rejecting the most effective technology)." *In re Knauf Fiber Glass, GmbH*, PSD Appeal Nos. 98-3 through 98-20 (EAB, Feb. 4, 1999)."

The top-down BACT process consists of five steps that are discussed in detail in Section B of the NSR Manual. These steps are (NSR Manual, Table B-1):

1. Identify all control technologies (including lowest achievable emission rate or LAER)
2. Eliminate technically infeasible options
3. Rank remaining control technologies by control effectiveness
4. Evaluate the most effective control and document results
5. Select BACT

² U.S. EPA, *New Source Review Workshop Manual. Prevention of Significant Deterioration and Nonattainment Area Permitting*, Draft, October 1990.

In brief, the top-down process requires all available control technologies to be ranked in descending order of effectiveness. The PSD applicant first examines the most stringent – or “top” – alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not “achievable” in that case. (NSR Manual at p. B.2.)

The PDOC does not contain a responsive BACT analysis.³ Instead, the PDOC has leapt to step 5, selecting BACT from its outdated "Guidelines 89.2.1" for gas turbines (PDOC, pp. 9-10), without conducting the analyses required for any of the preceding steps. The BAAQMD's guideline for large gas turbines (>23 MMBtu/hr) was adopted on August 24, 1998, nearly two years ago. (Exhibit --: Guidelines 89.2.1.⁴) Two new technologies have been introduced into the marketplace since this guideline was adopted, SCONOX and XONON. Had the District performed a formal top-down analysis, it would have included these two new technologies which are technically feasible and achieve lower emissions limits than those proposed for Metcalf. The District has failed to identify BACT by failing to perform a top-down BACT analysis.

III. BACT HAS NOT BEEN REQUIRED FOR NOX

The PDOC concludes that BACT for nitrogen oxides ("NOx") is an emission limit of 2.5 ppm at 15% O₂ averaged over 1 hour, achieved using dry low NOx combustors ("DLN") and selective catalytic reduction ("SCR") technology, during all conditions except startups and shutdowns. (PDOC, p. 9.) Ammonia slip was separately limited to no more than 10 ppm. (PDOC, p. 28, Condition 20(e).) The Applicant and the District have made this determination without considering or evaluating two competing technologies, SCONOX and XONON. As described below, BACT for NOx is an emission limit of no more than 1.3 ppm at 15% O₂ averaged over 1 hour and no ammonia slip, which can be achieved by using SCONOX and other technologies.

A. SCONOX Should Have Been Considered In A Top-Down BACT Analysis

SCONOX is a catalytic system that simultaneously oxidizes carbon monoxide ("CO") to carbon dioxide ("CO₂"), hydrocarbons to CO₂ plus water ("H₂O"), and nitrogen oxide ("NO") to nitrogen dioxide ("NO₂"). The NO₂ is then absorbed onto a potassium carbonate-impregnated ceramic-based catalyst. Passing a dilute hydrogen reducing gas across the surface of the catalyst in the absence of oxygen continuously regenerates the catalyst. The hydrogen reacts with nitrites and nitrates to form water and elemental nitrogen. Carbon dioxide in the regeneration gas reacts

³ CVRP is not alone in making this point. The CEC staff in their PDOC comments has also called on the BAAQMD to perform a top-down BACT analysis. CEC, 5/16/2000, Therkelsen to Garvey letter re MEC PDOC.

⁴ BAAQMD, Best Available Control Technology (BACT) Guideline for Gas Turbines > 23 MMBtu/hr, Guideline 89.2.1, August 24, 1998.

with potassium salts to form potassium carbonate, which is the absorber coating that was on the surface of the catalyst before the oxidation/absorption cycle began.

There is no indication in the PDOC that any technology other than SCR was considered. This by itself is a clear violation of the PSD rules. The first step of the top-down process is to identify all available control options. (NSR Manual, pp. B.5, B.10-B.11, Table B-1.) SCONOx is clearly among the technologies available. EPA has stated, “SCONOx (and possibly in the near future XONON) should be included in a BACT/LAER analysis for proposed combined cycle gas turbine power plant projects in Region 9.” (Exhibit --: Haber 3/24/00.⁵) Furthermore, the South Coast Air Quality Management District (“SCAQMD”) has concluded that SCONOx achieves the Lowest Achievable Emission Rate (“LAER”) for NOx. (SCAQMD 5/98: Exhibit 3). Technologies that satisfy LAER “must also be included as control alternatives [for BACT purposes] and usually represent the top alternative.” (NSR Manual, p. B.5.) Therefore, SCONOx must be included in the District’s BACT analysis.

A proper top-down analysis would almost certainly conclude that SCONOx is BACT for this project, even if it achieved exactly the same emission limit as SCR, because it offers a number of important advantages over SCR alone, with no offsetting disadvantages. First, SCONOx uses a single catalyst to simultaneously remove NOx, CO, VOCs, and toxics. Second, it uses no ammonia or other hazardous materials and thus requires no ammonia slip, eliminating the many significant impacts associated with ammonia use (e.g., transportation accidents, unloading accidents, site releases, PM₁₀ generation). Third, the SCONOx system operates effectively at temperatures ranging from 300°F to 700°F, making it well suited for merchant operation and providing better control during startups and shutdowns than achieved with other competing catalytic technology (e.g., SCR, CO oxidation catalyst). Fourth, unlike other catalytic systems, the SCONOx catalyst is continuously regenerated, assuring continuous maximum catalyst effectiveness. Finally, notwithstanding the forgoing benefits, SCONOx has achieved much lower NOx and CO levels than other competing technologies and, therefore, is de facto BACT for this project. (See Comments below.)

There is no indication in the PDOC that SCONOx was even considered. The District appears simply to have adopted the Applicant’s choice of SCR without any scrutiny of any kind, relying only on its outdated guidelines. The District’s guidelines are no substitute for a formal top-down BACT analysis. Further, if SCONOx was in fact considered and rejected in favor of a less beneficial technology such as SCR, then the District must clearly justify its choice in the public view. (See *In re Columbia Gulf Transmission Co.*, 2 E.A.D. 824, 827 (Adm’r 1989) (detailed substantiation required when rejecting most effective technology).)

The District, as EPA’s delegate, has an affirmative duty under the Clean Air Act to promote the use of more environmentally protective technologies. (74 U.S.C. §§ 7475(a)(4), 7479(3).) Thus,

⁵ Letter from Matt Haber, Chief, Permits Office, to statewide air pollution control districts and others, March 24, 2000.

the District should have either required that the Applicant perform a proper BACT analysis, or conducted the analysis itself, since a permit decision must reflect a level of detail and analysis indicating that the permit issuer has reached a considered judgment. (In re: Knauf Fiber Glass, GmbH, PSD Appeal Nos. 98-3 through 98-20, slip op. at p. 15 (EAB, Feb. 4, 1999); In re Pennsauken Co., N.J., Resource Recovery Facility, 2 E.A.D. 662, 667 (Adm'r 1988); In re Ash Grove Cement Co., RCRA Appeal Nos. 96-4 & 96-5, slip op. at 41 (EAB, Nov. 14, 1997); In re Austin Powder Co., 6 E.A.D. 713, 720 (EAB 1997); In re Gennessee Power Station, L.P., 4 E.A.D. 832, 835 (EAB 1993); In re Pennsauken Co., N.J., Resource Recovery Facility, 2 E.A.D. 667, 672 (Adm'r 1988) (remanding a PSD permit because the record did not contain the level of detail and analysis required).)

As discussed below, SCONOX is BACT for NO_x for this project under PSD regulations because it achieves the "maximum degree of reduction" for NO_x and is additionally commercially available, technically feasible, environmentally superior, and cost effective. It has significant environmental advantages compared to its nearest competitor, SCR, because it eliminates the risks of handling ammonia and degradation of air quality from the generation of PM₁₀. In the following sections, CVRP first present the evidence that SCONOX has been demonstrated to achieve a lower NO_x limit than any other technology. CVRP then discuss the evidence that SCONOX is commercially available, technically feasible, cost-effective, and environmentally superior.

B. NO_x Emission Limit Of 2.5 ppmv Is Not BACT

The District concluded that BACT for NO_x is an emission limit of 2.5 ppmv @ 15% O₂ averaged over 1 hour. Lower NO_x levels have been required in permits and achieved in practice. These lower levels should have been included in the District's BACT analysis. The PDOC contains no evidence that the District considered any other emission limit. The NSR Manual requires that "the most effective control option not eliminated in step 4 is selected as BACT." (NSR Manual, p. B.53.) In this section, CVRP demonstrate that a lower NO_x limit than proposed by the District, 1.3 ppm, has been achieved in practice. In the next section, CVRP demonstrate that there is no ground for eliminating the technology, SCONOX that has achieved this lower limit.

In 1998, the U.S. EPA concluded, based on six months of Continuous Emission Monitoring ("CEM") data, that the Federal Facility had "demonstrated in practice" NO_x emissions rates that are consistently at or below 2.0 ppmvd based on a 3-hour rolling average. (Haber 3/23/98.⁶) The South Coast Air Quality Management District ("SCAQMD") subsequently independently concluded based on this same data that the Lowest Achievable Emission Rate ("LAER") for NO_x for gas turbines greater than 3 MW in rated capacity is 2 ppm based on a 3-hour average or

⁶ Letter from Matt Haber, Chief, Permits Office, U.S. EPA, to Robert Danziger, President, Goal Line Environmental Technologies (March 23, 1998).

2.5 ppm based on a 1-hour average. (SCAQMD 6/12/98.⁷) LAER emission limits are the top alternative in a BACT analysis and must be adopted as BACT unless eliminated based on economic or environmental factors. (NSR Manual,⁸ p. B.5.) An emission limit of 2.5 ppm averaged over 1 hour has been adopted as BACT for all large gas turbines permitted in California since, based on EPA's and the SCAQMD's determinations for the Federal Facility (e.g., Sutter Power Project, High Desert Power Project, La Paloma Generating Project, Los Medanos Energy Center, Delta Energy Center).

1. Federal CEMs Data Indicates BACT Is 1.3 ppm NOx

The Applicants argue that SCONOx does not offer any improved performance with respect to NOx control, compared with SCR (Metcalf Response to CVRP Data Request 8a) and the "unappealing characteristics of SCONOx are not offset by any significant improvement in overall NOx emission reduction performance." However, the most recent CEMs operating data from the Federal Facility demonstrate that they are wrong. Further, the vendors are willing to guarantee NOx emission limits of 1 ppm averaged over 1 hour. This is clear evidence of improved performance compared to SCR.

Since EPA and the SCAQMD made their BACT determinations based on the Federal Facility in 1998, the performance of the SCONOx unit at the Federal Facility has been improved by adding more catalyst⁹ so that it now consistently meets a lower NOx emission limit. Further, it has been converted from a base load facility to a merchant facility, which means that it is more representative of the Metcalf Project.

Other parties collected 9 months of CEMs data from the Federal Facility for the period April 1, 1999 through December 31, 1999 and analyzed it to establish the "maximum degree of reduction" or BACT for both NOx and CO.¹⁰ The continuous emission monitors at the Federal Facility are certified annually by the SCAQMD. In addition, Sunlaw conducts annual stratification source tests to verify that the location of the CEMs sampling point in the stack is

⁷ SCAQMD, Staff Report for Best Available Control Technology Guidelines Update (Phase IID), June 12, 1998.

⁸ U.S. EPA, New Source Review Workshop Manual. Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990.

⁹ Removal efficiency depends on temperature and space velocity. The space velocity was reduced from about 18,000 hr⁻¹ to 10,000 hr⁻¹ by adding more catalyst. The same performance could be achieved at Elk Hills with a space velocity of 22,000 hr⁻¹ because the catalyst would be located in the HRSG at a temperature of about 600 F, compared to 300 F at the Federal Facility, which was a retrofit application.

¹⁰ See CURE comments submitted to the U.S. EPA on the Sunrise Project, to the Shasta County Air Quality Management District on the Three Mountain Power Project, and to the San Joaquin Valley Unified Air Pollution Control District on the Elk Hills Project. These comments are items a and c-f in footnote 1, supra.

representative of the average exhaust gas concentration. The results of the stratification test conducted during this 9 month period shows that the CEMs sampling location was within 0.07 ppm or 8.1% of the measured average concentration.

It is important to note that this data is from the very same facility that was used by both the EPA and the SCAQMD to establish the 2.5 ppm BACT level that has been widely permitted in California and accepted by the District for other large combined cycle merchant plants. Thus, there can be no dispute that additional data from this same facility is relevant to this Project and is a reasonable basis to establish a lower BACT NOx level.

The 1-hour average NOx CEMs data for the modified Federal Facility are summarized in (05-31-00) CVRP comments on the MEC PDOC, Figure 1. This figure excludes excursions due to startup, shutdown, and non-SCONox operating problems (e.g., CEM failure, plant trips, operator error, condensation in gas generator), as allowed by the permit. Rolling averages were calculated from 15-minute data in the file in by eliminating all valid exceedances based on the operating log and averaging the remaining data in groups of four 15-minute segments. All such excursions are documented based on the plant-operating log.

The maximum reported NOx concentration is 1.275 ppm as a 1-hour rolling average, and 1.254 ppm as a 3-hour rolling average.¹¹ Figure 1 is based on 9,380 15-minute average NOx measurements out of a total possible of 25,595 because the plant was operated in merchant mode and only dispatched about 37% of the time due to mild weather conditions in 1999. These data demonstrate that BACT for NOx should be established at 1.3 ppm averaged over 1 hour.

2. Other Data Confirm That BACT For NOx Is Lower Than 2.5 ppm Averaged Over 1 Hour

Other information also confirms that BACT for NOx is lower than 2.5 ppm averaged over 1 hour required for this Project.

First, SCONox has been installed on a second power plant, at the Genetics Institute in Andover, Massachusetts, which is reportedly meeting a 1-ppm NOx limit when the turbine is functioning properly.

¹¹ A lower NOx limit could be readily achieved at the Federal Facility by increasing the frequency of catalyst washing. The peaks and valleys shown during sustained operation during the latter half of 1999 correspond to catalyst washing events. Sulfur combustion byproducts in the flue gas can deactivate the SCONox catalyst. This can be addressed in two ways. First, the catalyst can be periodically washed with water. This procedure is used at the Federal Facility. Second, a sulfur removal catalyst, SCOSOx, can be installed upstream of SCONox. SCOSOx is used at the Genetics Facility. The choice between catalyst washing and SCOSOx is a purely economic decision. Both are commercially available, and both can be designed to achieve a lower NOx limit than currently achieved at the Federal Facility.

Second, both Massachusetts and Connecticut have made BACT determinations and issued permits requiring that large gas turbines achieve a NO_x limit of 2 ppmv at 15% O₂ averaged over 1 hour. These permits are based on clock or block averages, identical to the averaging time proposed for Metcalf. This is a lower emission limit than 2.5 ppmv averaged over 1 hour.

Notwithstanding the CEMs data reviewed above, these permits alone establish a lower NO_x emission limit for Metcalf than that required in the PDOC and therefore should have been considered by the District. The lowest permit limit required in any construction permit which has been issued anywhere in the country in the time period up to and including the public comment period on a permit establishes BACT.¹² Hence, even if the CEMS data from the Federal Facility did not establish a new BACT level for this Project (which it does), the BACT determinations made in Massachusetts and Connecticut, which specify a NO_x limit of 2 ppmv averaged over 1 hour, would constitute a new BACT level for this Project. Thus, the District must include 2.0 ppm NO_x in its BACT analysis.

3. NO_x Levels Of 1 ppm Can Be Accurately Measured

In other forums, it has been argued that the NO_x BACT limit should not be lowered because NO_x cannot be accurately measured, even at 2.5 ppm. (CARB 9/99, pp. 24-25.) These and similar issues were also raised in the South Coast AQMD's proceedings in which the 2.5 ppmvd BACT level was originally adopted. The South Coast AQMD thoroughly evaluated and rejected all of these measurement issues as insignificant in its staff report (Ex. 7, South Coast AQMD Staff Report) and in correspondence. (Gangule 5/26/98.¹³)

NO_x levels can be accurately measured at 1.0 ppm. This has been demonstrated at the Sunlaw Federal Facility, where three separate monitoring systems were used there to measure NO_x: (1) the facility CEM, which is an API Series 200 CEM with a lower limit of detection and precision of 0.1 ppm; (2) South Coast AQMD Reference Method 100.1 by South Coast AQMD staff; and (3) in annual certification tests by an independent source testing firm using the RECLAIM Rule 2012 protocol.¹⁴ All three testing methods provided consistent measurement results.

Manufacturers of NO_x CEMs -- Rosemount Analytical, California Analytical Instruments, Thermo Analytical Instruments, and Advanced Pollution Instruments -- all offer CEMs that are

¹² Memorandum from John Seitz, Director, Stationary Source Compliance Division, Office of Air Quality, Planning and Standards, U.S. EPA, to David Kee, Director, Air and Radiation Division, U.S. EPA Region V, Subject: Cut-off Date for Determining LAER in Major New Source Permitting (February 24, 1989).

¹³ Letter from Anupom Gangule, Senior Manager, Stationary Source Compliance, South Coast AQMD, to Steve Weinman, Director, Standardization, ASME International, Subject: Lowest Achievable Emission Rate (LAER) for Gas Turbines, May 26, 1998.

¹⁴ Delta Air Quality Services, Inc., NO_x Stratification Test Report. Sunlaw Cogeneration partners I Federal Cold Storage Cogeneration Facility, June 29, 1998.

guaranteed to measure NO_x from 0 to 10 ppm with a lower limit of detection of 0.1 ppmv NO_x or 1% of full scale, and a precision of the greater of either 0.1 ppm or 1% of full scale or better. This is well below the BACT level of 1.3 ppm CVRP have proposed for TMPP, is consistent with the results of certification and inter-method comparison studies at the Sunlaw Federal Facility, and provides a comfortable margin of safety. Thus, CVRP believe that measurement issues should not limit the establishment of BACT for gas turbines at 1.3 ppm.

C. SCONO_x Is Technically Feasible Under PSD Regulations

The top-down BACT analysis process allows a control option to be eliminated if it is technically infeasible or results in adverse energy, environmental, or economic impacts. (NSR Manual, § B.) The NSR Manual clarifies when a technology is technically feasible: “[I]f the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible.” (NSR Manual, p. B.17.) SCONO_x meets this test, as demonstrated below.

1. SCONO_x Has Been Installed And Successfully Operated

The SCONO_x system has been demonstrated to achieve 2 ppmvd averaged over 3 hrs or 2.5 ppmvd averaged over 1 hr¹⁵ on the 32 MW combined cycle (25 MW LM2500 gas turbine plus 7 MW steam turbine) Federal Cogeneration facility in Vernon, California (“Federal Facility”). (South Coast AQMD Staff Report, p. 3-4.) The South Coast AQMD has concluded that SCONO_x/water injection is “achieved-in-practice” technology for natural gas-fired turbines with rated capacities of 3 MW or greater. EPA Region 9 has also concluded that the Federal Facility “has, based on data submitted to EPA for the six-month period from June 28, 1997 to December 28, 1997, ‘demonstrated in practice’ NO_x emissions rates that are consistently at or below 2.0 ppmvd based on a 3-hour rolling average.” (Haber 3/23/98.¹⁶) EPA has recently acknowledged that this same facility is currently meeting 1 ppm NO_x. In addition, SCONO_x has been operating on a 5-MW Solar Taurus 60 gas turbine at the Genetics Institute facility in Andover, Massachusetts since August 1999, likewise meeting 1 ppm.

Setting aside the more stringent technical feasibility demonstration discussed above, which SCONO_x meets, the NSR Manual alternatively defines a technology as technically feasible if it is both “available” and “applicable.” (NSR Manual, p. B.17.) A technology is considered “available” “if it has reached the licensing and commercial sales stage of development.” (Ibid, p. B.18.)

¹⁵ The South Coast AQMD concludes that 2 ppmvd averaged over 3 hrs is equivalent to 2.5 ppmvd averaged over 1 hr. (South Coast AQMD 5/12/98, p. 3-4).

¹⁶ Letter from Matt Haber, Chief, Permits Office, U.S. EPA, to Robert Danziger, President, Goal Line Environmental Technologies, March 23, 1998.

2. SCONOx Is Available

The Applicants have argued that SCONOx is not BACT because Massachusetts concluded in July 30, 1999, "the Department cannot conclude that SCONOx is the Best Available Control Technology for the control of NOx for turbines larger than 50 megawatts." (Metcalf Response to CVRP Data Request 7a, p. 6.) When this was written, ABB had not completed its evaluation and scale up program and was not commercially offering SCONOx. However, ABB Alstom Power announced on December 1, 1999 that SCONOx is commercially available for large gas-fired turbines. ABB Alstom Power has licensed SCONOx from Goal Line and is the exclusive licensee for power plants larger than 100 MW. Goal Line itself may sell the SCONOx system if ABB cannot or will not sell SCONOx to a given applicant. ABB Alstom Power has completed testing and scale-up of the technology and is now offering it for sale with performance guarantees, specifically targeting the largest gas turbines made (e.g., ABB GT-24, Westinghouse 501G) or announced (e.g., GE Frame 7H). The technology is fully described on ABB's website. (www.apcnnoxcontrol.com.)

The ABB announcement was based on the completion of scale-up testing by ABB, which was subsequently reviewed and confirmed by Stone & Webster. This work included a comprehensive review and analysis of design documents for a 270 MW reference plant consisting of one ABB GT-24 turbine, one HRSG, and one steam turbine. A full-scale prototype damper system for this plant was constructed and operated on a test rig for 101,000 cycles, equivalent to about 5 years of continuous operation. Regeneration gas flow distribution through the catalyst was investigated using both computer and physical model studies. A control system failure mode analysis was also performed.

In addition, Marsh USA Inc. conducted an insurance review and concluded that "CVRP did not discover any issues that cannot be readily addressed by ABB or which, in our opinion, make the SCONOx system uninsurable." They further concluded, "The underwriting community will positively embrace SCONOx as a viable product that reduces industry emissions. Realistically, due to the method in which pricing is determined, CVRP expect no additional premium credit being applied to project insurance if a SCONOx system is installed." (Marsh 10/6/99.¹⁷)

3. SCONOx Is Applicable

The NSR Manual additionally considers a technology to be "applicable" "if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type." (Ibid. p. B.18.) The San Joaquin Valley Air Pollution Control District has specified SCONOx in a permit on a 262-MW ABB GT-24 gas turbine issued to the La Paloma Generating Co. LLC in an authority to construct permit issued May 26, 1999,¹⁸ by the San Joaquin Valley AQMD.¹⁹) It has also been proposed for use on the 510-MW Otay Mesa Project at 2 ppm with a goal of 1 ppm,

¹⁷ Marsh USA Inc., ABB SCONOx System Insurance Review, Prepared for ABB Environmental Systems, October 6, 1999.

and on the 550-MW Nueva Azalea Project at 1 ppm NO_x and 0.5 ppm CO. Therefore, even if SCONOx had not been installed and successfully operated on two gas turbines representing the same “type” of source, it would still be judged to be technically feasible using EPA’s alternate criterion for situations where there is no actual operating experience.

4. EPA Has Concluded SCONOx Is Technically Feasible

Finally, the U.S. EPA has determined that SCONOx is technically feasible. EPA Region 1 recently concluded, based on correspondence with ABB Alstom Power, that “it is our view that SCONOx is a technically feasible control option for large combined cycle turbine project” and “the Region now considers SCONOx a technically feasible and commercially available air pollution control technology that is expected to obtain emission levels for criteria pollutants such as NO_x, CO and VOC comparable or superior to previously applied technologies for large combined cycle turbine applications.”²⁰ The EPA and ABB correspondence supporting this conclusion are included in (5-31-00 CVRP comments on MEC PDOC, Ex. 16: Region I letter).

5. There Is No Demonstration Of Technical Infeasibility

The NSR Manual notes “the control option is presumed to be technically feasible unless the source can present information to the contrary.” (NSR Manual, p. B.19.) The demonstration of technical infeasibility must be “based on a technical assessment considering physical, chemical and engineering principles, and/or empirical data showing that the technology would not work on the emission unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique.” (Id., p. B.20.) No such demonstration has been made in this case. However, the Applicants have argued in other fora that SCONOx is not technically feasible.

In material handed out in an Energy Commission air quality workshop on MEC, held in San Jose on April 5, 2000, the Applicant argues that SCONOx “is not feasible for the following reasons: 1) significant adverse impacts on plant reliability, 2) significant degradation of plant performance and output, 3) increase in the complexity of instrumentation and controls, 4) significant increases to plant capital and operating costs, 5) the reality that the system has never been proven, much less even test, on large gas turbine, and 6) satisfactory commercial

¹⁸ SCONOx was ultimately not installed on this Project because at the time construction commenced, in November 1999, because ABB had not completed their testing and scaleup program. This program has since been completed and, thus, there should be no commercial impediment to the future use of SCONOx.

¹⁹ San Joaquin Valley Unified Air Pollution Control District, Notice of Determination of Compliance for La Paloma Generating Company, LLC Project Number: 980654, May 26, 1999.

²⁰ Letter from John P. DeVillars, Regional Administrator, Region 1, U.S. EPA, to Robert Varney, Commissioner, Department of Environmental Services, New Hampshire, Subject: Recent SCONOx Pollution Prevention Control System Development, December 20, 1999.

performance guarantees are unlikely."²¹ All of these claims are false. The vendor, ABB, reviewed these claims and prepared a response, dismissing each allegation. (Oegema 4/14/00.²²)

In responses to data requests propounded by CVRP, the Applicants additionally argue that: 1) SCONOx is not commercially available for Otay Mesa and at any rate would not achieve lower emission limits; 2) that the Nueva Azalea proposal is irrelevant because Sunlaw, the proponent of Nueva Azalea, has a financial stake in SCONOx; 3) that SCONOx triples PM10 emissions; and 4) that Massachusetts has concluded that SCONOx is not BACT in certain cases, among others. (Metcalf Responses to CVRP Data Requests 6-9.²³) Many of these allegations are based on out of data information. All of them are incorrect.

The following subsections discuss each allegation made by Calpine/Bechtel Enterprises.

a. SCONOx Can Be Scaled Up

The Applicant argued that SCONOx "has never been proven, much less even tested, on large gas turbines" and "SCONOx technology to date has only been tested on two small gas turbines...more catalyst modules of the same size used at the test plant would be required if this technology is applied to a large industrial frame combustion gas turbine. Calpine/Bechtel have serious concerns about this unproven system and its impact on reliability, and more importantly, its ability to maintain compliance with all applicable emissions limits." This is incorrect.

The definition of BACT only requires that the technology be "achievable for such source or modification through application of production processes or available methods, systems, and techniques . . ." (40 CFR § 52.21(j) (emphasis added).) Restricting the application of new technologies to the exact type and size of unit initially tested would unnecessarily limit the transfer of technology and defeat the purpose of the Clean Air Act. In fact, the case-by-case approach selected by Congress to implement BACT was specifically designed to cause "the adoption of improvements in technology to become widespread far more rapidly than would occur with a uniform Federal standard."²⁴ The arguments advanced by the Applicants turns this goal on its head.

Nevertheless, there is no evidence that size and type of turbine affects the performance of SCONOx. EPA has unequivocally stated that SCONOx is technically feasible for large

²¹ Calpine/Bechtel Enterprises, 1/31/2000, Exhibit 5.

²² Letter from Gerald R. Oegema, Product Manager, ABB Alstom Power, Environmental Systems, to Matt Haber, Chief, Permits Office, Air Division, EPA Region 9, April 14, 2000.

²³ Metcalf Energy Center, Data Requests and Responses (99-AFC-3), Coyote Valley Set 1, Responses to Data Requests: 1 through 12, May 8, 2000.

²⁴ S. Rep. No. 95-127, 95th Cong., 1st Sess., p. 31 (1977) (Report of the Senate Committee on Environment and Public Works re Clean Air Act Amendments of 1977).

combined cycle projects such as this one. EPA Region I recently concluded, based on correspondence with ABB Alstom Power, that “it is our view that SCONOx is a technically feasible control option for large combined cycle turbine project” and “the Region now considers SCONOx a technically feasible and commercially available air pollution control technology that is expected to obtain emission levels for criteria pollutants such as NOx, CO and VOC comparable or superior to previously applied technologies for large combined cycle turbine applications.”²⁵

In addition, both EPA and other regulatory agencies that have considered scale-up of SCONOx to larger size turbines have concluded that scale-up is not a concern. As far back as 1998, EPA Region 9 concluded there are no scale-up issues. “In June 1998, Region 9 informed the South Coast Air Quality Management District (AQMD) that CVRP were not aware of any technical problems associated with scale-up of the SCONOx technology to larger turbines.” In 1999, EPA Region 1 reiterated, “there are no known scale-up concerns with SCONOx. Consequently, it is our view that SCONOx is a technically feasible control option for large combined cycle turbine projects.”

The SCAQMD rigorously evaluated the scale-up issue in its BACT/LAER determination and concluded that:

It is the staff’s technical finding that the SCONOx control technology can be scaled up in comparison to the 32 MW demonstration plant since the exhaust characteristics of the turbines are similar. Based on staff review of AQMD source test reports for different turbines, staff finds that the NOx reduction process and the characteristics of the exhaust gases from natural gas fired turbines are similar regardless of size above 3 MW. Therefore, the identified emission rate of 2.5 ppm NOx at 1-hour average constitute BACT/LAER for gas turbines with rated capacities of 3 MW or larger. U.S. EPA staff also has the same technical judgment concerning this issue. (BACT Guidelines Update 6/12/98, p. 4.)

This position is echoed throughout the documentation supporting the SCAQMD’s BACT/LAER determination that is currently used throughout California, including statements that: “[t]here is no known technical limitation that would render the exhaust flue gas of a large industrial turbine to have different characteristics than exhaust from a 30 MW aero derivative turbines” (id., p. 3-4); and “[s]ince there is no known technical reason that will render the exhaust flue gas from a large gas-fired turbine to have different characteristics than exhaust from a 30 MW turbine, AQMD staff has concluded that LAER, as presented in the Staff Report, must apply to gas turbines over 3 MW size.”

²⁵ Letter from John P. DeVillars, Regional Administrator, Region 1, U.S. EPA, to Robert Varney, Commissioner, Department of Environmental Services, New Hampshire, Subject: Recent SCONOx Pollution Prevention Control System Development (December 20, 1999).

This position makes sense because catalyst systems are designed based on desired removal efficiency, space velocity, exhaust gas flow rate, and operating temperature. The basic principles of catalyst design apply regardless of the specific type of catalyst or the size of the catalyst system. (Heck and Farrauto 1995.²⁶) The size of the system only affects the size and number of components (e.g., dampers, module), the volume of catalyst, and amount of chemicals, not the fundamental design. The operating temperature in the HRSG where a SCONOx system would be installed is identical for Metcalf's Westinghouse 501F turbines and the Solar Taurus on which SCONOx has been demonstrated. For identical temperatures, the amount of catalyst is directly proportional to the amount of exhaust gas. Therefore, the amount of catalyst would be greater for a Westinghouse 501F than for the Taurus on which SCONOx has been demonstrated. However, the engineering principles that apply are the same, regardless of the scale of the installation.

Further, SCONOx and other catalyst systems, including SCR, are designed in standard module sizes of similar geometry allowing for unlimited scale-up. This is accomplished by putting standard modules together as building blocks to obtain a desired configuration.

Successful scale-up has already been demonstrated for SCONOx, which has more than 10 years of operating history, much more than many of the new turbines being put into service. SCONOx was originally scaled up from a laboratory "plug" catalyst the size of a small carrot to slip-stream testing the size of two cement bricks, to full-scale testing 100 times bigger than the slip-stream catalyst, to commercial operation at the Federal Facility, to scale-up testing to >100 MW by ABB, who has licensed the technology for gas turbines rated 100 MW and larger. (Stone & Webster 2/22/00.)

Otay Mesa, a project similar to Metcalf located in the San Diego area, has proposed to use SCONOx. The Applicants suggest that as of January 5, 2000, Otay Mesa was uncertain whether SCONOx was commercially available. (Metcalf Response to CVRP Data Request 6d.) However, much has changed since then. Otay Mesa is currently permitting SCONOx. Bob Hilton, Vice President, and Rick Oegema, SCONOx Product Manager, for ABB appeared at the March 2, 2000 Otay Mesa status conference before the Energy Commission and presented testimony on the status of SCONOx. The transcript reveals that ABB is the largest vendor of pollution control systems in the world (3/2/00 RT 23:3-7) and is "extremely good" at scaling up technologies and developing them into full commercial application. (3/2/00 RT 23:15-18.) Mr. Hilton testified that "CVRP know the system works. It's been in operation. We've gone through a scale-up program. And to verify our scaled-up design we've actually gone through a secondary verification program." (3/2/00 RT 28:21-24.) The scale-up of SCONOx "is a routine process with virtually every technology we've taken to market for the last 40 years... And what you're seeing is not a new process. This is a developmental process that we've done for years where we've just literally scaled things up in roughly the same order of magnitude that we're talking

²⁶ R.M. Heck and R.J. Farrauto, Catalytic Air Pollution Control, Van Nostrand Reinhold, 1995.

here.” (3/2/00 RT 29:6-14.) Mr. Hilton concluded that the scale-up program that ABB has completed for SCONOx “has basically satisfied us.” (3/2/00 RT 39:20-21.)

Scale-up is simply not an issue for monolithic modular catalyst systems, such as SCONOx and SCR. There is nothing anywhere in the technical literature to the contrary. No party has provided any evidence to the contrary. Further, regulatory agencies that have reviewed the issue have concluded there is no scale up issue.

b. Dampers Are Reliable

The Applicant argues that “[t]he SCONOx process uses a set of dampers to isolate the regeneration process from exhaust gases. The power industry normally avoids the installation of any moving parts in the exhaust stream of combustion devices due to the high potential for warping, jamming, corrosion, and ultimate failure of the devices.” This is simply not true and is refuted by actual operating experience, scale-up testing performed by ABB, the vendor's comments, and actual experience in the power and other industries.

The SCONOx system is shown schematically in the figures on the vendor's website (www.apcnnoxcontrol.com). The catalyst system consists of 10 to 15 vertically stacked rows of catalyst. Pollutant removal and catalyst regeneration occur in cycles. Dampers isolate the catalyst rows so that 20% of the rows are being regenerated while 80% are actively removing pollutants. These dampers open and close once every 15 to 40 minutes on a continuous basis between major shutdowns. (Id., p. 4-12.)

SCONOx dampers have been in continuous operation on the Federal Facility since 1996 and on the Genetics Facility since July 1999. These dampers have not caused plant shutdowns. Maintenance has been minimal, performed with the plant on line. In addition, Mader Dampers, a Division of Mader Machine Company Inc. of LaGrange, Ohio built a full-scale test rig to verify the performance and reliability of the damper louvers, seals, seal design and actuators. Complete, full-size dampers (30 ft x 3 ft 7-1/2 in with a total seal length of 292 feet), including seals and actuators, were tested at normal HRSG operating conditions. The test rig was maintained at 610 F by circulating hot flue gas from an external combustor. No attempt was made to simulate the flow or emissions as these were evaluated and deemed to have no impact on the test as designed. The dampers were cycled at an accelerated rate through 101,000 cycles to simulate five years of continuous operation in four months of testing, representing more severe service than would be experienced in practice.

These tests demonstrated that the system performed without much problem up to 60,000 cycles, which is equivalent to about 3 years of continuous operation. The typical failure rate of wearable components throughout the power island is 1 to 3 years. Thus, this is typical performance, consistent with industry-wide standards.

The only damper issues identified after 3-years of continuous operation were with the actuators and shaft-seal interface. The limit switches within the actuators control the damper sequencing. The original Auma limit switches were inadequate for the proposed service and thus replaced by external mechanically actuated limit switches, which resolved the problem. Regardless, these switches costs about \$500 and can be replaced in about half an hour without taking the system offline. Similarly the shaft design was modified to eliminate shaft-seal leakage. Thus, the modified damper system currently offered by ABB and Goal Line has none of the problems identified after 5 years of continuous operation on the test rig. The vendor concluded that “no known maintenance issues have been identified as part of this design verification” and “the expected maintenance...can be reasonably performed with typical plant outage schedules required to service boiler systems and the turbine and should not impact reliability”, consistent with actual operating experience at the Federal Facility. The dampers themselves are designed for 30 years of operation, subject to regular maintenance, inspection and repair, excluding wear components such as bearings, seals, actuators, or similar wearable components.²⁷

There is simply no evidence that the dampers would cause reliability, maintenance, and scale-up problems as alleged by the Applicants. Similar dampers are widely used throughout the power industry in air pollution control applications with minimal operational problems as well as in other industries under conditions far more severe than those that would be experienced by the SCONOx dampers. (Makansi 1993.²⁸) They are also used in bypass applications in the power industry, when more than one turbine, stack, or other equipment is present, and are used to isolate equipment from exhaust gases to allow man-safe access to perform maintenance while the balance of plant remains in operation. In fact, the original SCONOx damper design was scaled down from large coal plant designs. Dampers are also widely used in the steel industry in applications that involve higher temperatures, more corrosive environments, and similar duty cycles. The dampers used in the SCONOx process have the added benefit, compared to these other applications, of cycling full stroke at regular intervals, open to close. The full stroke ensures even wear, and the regular interval of actuation prevent binding and corrosion due to extended periods of inactivity that occur in some other applications.

c. The Control System Is Reliable

The dampers are operated by an electronic control system. The Applicants allege that SCONOx "will require a significant addition to the plant control system and field instrumentation." This is incorrect. The control system has been in operation at the Federal Facility since 1996 and at the Genetics Facility since July 1999, and no problems have been encountered. The vendors provide the SCONOx instrumentation and control system as a package with a dedicated PLC controller. This can be simply connected to the existing plant distributed control system through “PC Highway” connections. The vendor for their ruggedness and known reliability selected Field instrumentation and supporting devices used in this system.

²⁷ www.apcnnoxcontrol.com/category.asp?catg_name=Maintenance.

²⁸ J. Makansi, Reducing NOx Emissions from Today's Power Plants, *Power*, pp. 11-28 (May, 1993).

d. Catalyst Regeneration Will Not Cause An Explosion Hazard

Passing a controlled mixture of regeneration gases across the surface of the catalyst in the absence of oxygen continuously regenerates the SCONOx catalyst. The regeneration gases consist of steam with small amounts (2%-4%) hydrogen and natural gas, depending upon system design. The hydrogen is required to convert nitrites and nitrates to water and inert nitrogen gas, not to avoid an "explosion caused by hydrogen inside the SCONOx modules" as alleged by the Applicants. The vendor has corrected most of the Applicants' incorrect statements about the hydrogen regeneration process.

There is simply no explosion hazard. Goal Line conducted a safety evaluation of hydrogen use in the SCONOx process and concluded that "The use of hydrogen as a regeneration gas does not result in an unsafe operating conditions for unlikely but possible anomalies that could result during the operation of the SCONOx system."²⁹

The SCONOx system is designed to prevent explosions. Hydrogen (and natural gas) is only explosive in the presence of oxygen and an ignition source and then only if its concentration exceeds the lower flammable limit ("LFL"), which is 4%. (NFPA 1991, p. 325M-59.³⁰) The concentration of hydrogen in the regeneration gas is typically 2%, half of the LEL. Therefore, even if oxygen and an ignition source was present, which they are not, or even if hydrogen leaked out of the catalyst modules, the concentration of hydrogen is too low to cause an explosion.

The hydrogen is only used for regeneration, which occurs in an inert atmosphere. Oxygen is absent in an inert atmosphere. The purpose of the dampers that isolate the catalyst modules, discussed above in Section III.C.5, is to isolate the section of catalyst being regenerated, specifically to exclude oxygen. Therefore, explosions are not chemically or physically feasible within the modules.

Even if the right concentration of hydrogen and oxygen were present, an explosion still would only occur if an ignition source were present. There is none for SCONOx because the hydrogen is isolated from the duct burners by the dampers, which seal off the area where the hydrogen is used. Even if leakage occurred, the concentration of hydrogen (and natural gas, depending upon system design) is far below the LFL of 4% for hydrogen and natural gas. The total regeneration gas volume represents only 1% of the turbine exhaust gas volume. Therefore, under worst-case conditions, if leakage occurred, the hydrogen and natural gas concentrations in the flue gas

²⁹ Goal Line Environmental Technologies, Safety Evaluation of Hydrogen Used in the SCONOx Process, Report GL-R-03-01, August 13, 1999.

³⁰ National Fire Protection Association (NFPA), Fire Protection Guide on Hazardous Materials, 10th Ed., 1991.

outside of the SCONOx modules, would be no more than 0.04%, which is substantially less than the LFL of 4%. Therefore, this does not pose any flammability or explosion hazards.

In fact, anhydrous ammonia, which is used in much larger amounts by the proposed SCR installation, also forms explosive mixtures with air and can ignite in the presence of a combustion source. (NFPA 1991, p. 325M-14.) The explosion risk is similarly managed by keeping the maximum concentration of ammonia below the LFL. However, the explosion danger is far smaller for SCONOx than for SCR because in the SCONOx system, the hydrogen is isolated from the ignition source and is used in an inert atmosphere with no oxygen, unlike the ammonia in an SCR system. The Applicant has not expressed any concerns about the explosion hazards of the aqueous ammonia system required by its SCR.

The Applicant also asserts that the reforming process used to generate hydrogen "has never been successfully tested." This is not true. There are two hydrogen production processes that are used with SCONOx. The first has been in operation since December 1996 at the Federal Facility. The second has been in operation since July 1999 at the Genetics Institute Facility. Further, the steam reforming process used in both of these processes has been widely used throughout the refining, petrochemical industries, and other industries for decades³¹.

Finally, it is important to note that hydrogen is already widely used in the power industry to purge the generators. Hydrogen use statistics have not been reported for Metcalf. However, other similar facilities typically store about 175,000 cubic feet of compressed hydrogen on site and another 55,000 cubic feet inside generators and distribution piping. (e.g., see Elk Hills AFC, p. 5.12-2.) The Applicants have not expressed any concerns about either leakage or explosion hazards of this hydrogen.

e. SCONOx Does Not Increase Back Pressure

The Applicants allege that the "pressure drop across the SCONOx catalyst is twice that of a conventional SCR." SCONOx simultaneously removes both CO and NO_x and is therefore equivalent to a conventional SCR and oxidation catalyst. Although the PDOC does not recommend an oxidation catalyst as BACT for CO and VOCs, an oxidation catalyst is clearly BACT for Metcalf, as discussed below in Comment --. Further, the Energy Commission has recommended an oxidation catalyst in the Preliminary Staff Assessment. (PSA, p. 41.)

Vendor quotes indicate that the backpressure created by SCONOx is about the same to slightly lower than that created by an SCR and oxidation catalyst combo. The backpressure for SCONOx quoted by ABB for similar applications is 4.0 inches of water. A similarly sized SCR would create 3.5 inches and an oxidation catalyst would create 0.8 inches of backpressure. Therefore, the total backpressure for the conventional system, 4.3 inches of water, is greater than the backpressure created by SCONOx, the reverse of what is alleged. Further, broadening the area of the catalyst bed to reduce the backpressure can configure the housing configuration for

³¹ George T. Austin, *Shreve's Chemical Process Industries*, Fifth Edition, McGraw-Hill Book Co., New York, 1984

SCONOx, as well as other catalytic systems. Therefore, SCONOx does not cause a 1.2 MW reduction in electrical output due to changed backpressure, as alleged by the Applicant.

f. SCONOx Steam Consumption Is Minor

The Applicants allege that 40,000 lb/hr of superheated steam must be extracted from the supply to the steam turbine, which would be lost out of the HRSG stacks, reducing output by about 4.5 MW. This is incorrect.

The regeneration of the SCONOx catalyst requires about 20,000 lb/hr of 600 F, low-pressure steam, which is taken from the steam turbine exhaust where the impact of steam demand on turbine operations would be minimal. GT PRO simulations indicate that this would reduce output by 1 Mw, a minimal amount on a 600 Mw project

g. Commercial Warranties

The Applicant "believes that the SCONOx system is not commercially available for the turbines proposed at MEC with commercial performance guarantees adequate to ensure safe and reliable operation, and continuous compliance with all applicable emission limits, at the present time." (Metcalf Response to CVRP Data Request 8.) No evidence is presented to support this position, which is pure speculation.

The vendors are actively quoting and providing commercial guarantees for SCONOx. ABB is currently working with two serious purchasers for large Frame 7 engines -- Nueva Azalea and Otay Mesa. The guarantees currently being offered by ABB are consistent with the NOx and CO limits that have been demonstrated at the Federal and Genetics Facilities.

Nueva Azalea has been guaranteed by ABB and is currently being permitted at 1 ppm NOx and 0.5 ppm CO averaged over 1 hour. The Applicants argue that this is irrelevant because "the Nueva Azalea project is being developed by Sunlaw Energy, which has a financial stake in the marketing of the SCONOx system. For these reasons, we do not find the Nueva Azalea Project to be similar to MEC for purposes of determining the commercial availability of the SCONOx system." (Metcalf Response to CVRP Data Request 6d.) However, ABB has stated that it will offer the same guarantee and terms to other applicants, including Metcalf.

The Applicants also argue that Otay Mesa is not relevant because "in the case of the Otay Mesa Generating Project, identical emission limits for all pollutants are proposed for all criteria pollutants regardless of whether SCONOx is used." (Metcalf Response to CVRP Data Request 8a.) This is not true. The Otay Mesa Project will achieve lower emission limits than those currently proposed for Metcalf. The Project is being permitted at 2 ppm NO_x averaged over three hours with a goal of 1 ppm NO_x (3/2/00 RT 19:10-12, 46:16-18) and 100 ton/yr of NO_x. (3/2/00 RT 43:19-20.) The 100 ton/yr limit would require year-round operation below 2 ppm. (3/2/00 RT 46:23-25, 47:1-3, 48:12-17.) Recent conversations with PG&E Generating indicate

that 100 ton/yr actually corresponds to a concentration limit between 1 ppm and less than 2 ppm NO_x, depending upon the number of startups and shutdowns and actual hours of operation. Further, the 100 ton/yr limit proposed for Otay Mesa is substantially lower than the 185 ton/yr proposed for Metcalf. (PDOC, Condition 25.)

A guarantee is an opening offer, i.e., ABB's opening position in what would ordinarily be a negotiation between a serious buyer and seller. ABB's standard warranty for SCONOx is 1 year for equipment and 3 years for catalyst, which is consistent with industry standards for SCR and other catalytic systems. A 10-year warranty is also available, contingent upon the owner entering into a long-term service agreement for maintenance of the catalyst.

h. Financing

The Applicants argue that "financial institutions will be reluctant to provide financing to the MEC project utilizing SCONOx. Proving project viability to these institutions would be difficult, if not insurmountable task. Performance guarantees supplied by the EPC contractor would be another likely point of contention.." This is demonstrably false.

The Genetics Facility in Andover, Massachusetts, and the Federal Facility in Vernon, California both include SCONOx and both have been financed and are operating. Further, the La Paloma Project was permitted and financed with SCONOx and is currently under construction.

Both Otay Mesa, proposed by PG&E Generating, and Nueva Azalea, proposed by Sunlaw, has been proposed with SCONOx. Obviously, both project proponents are confident they will obtain financing or they would not have proposed SCONOx. Although PG&E Generating decided not to build La Paloma with SCONOx due to a timing issue (see footnote --), clearly, SCONOx posed no financial or other obstacle as PG&E Generating has again proposed to use SCONOx on a second project, Otay Mesa.

i. SCONOx Is Cost Effective

The Applicants argue that the installed capital cost of SCONOx is three to four times higher and the operating costs two to three times higher than a conventional SCR system. This is irrelevant and incorrect.

First, it is simply irrelevant whether one technology which achieves much higher emission reductions (SCONOx) costs more than another with lower emission reductions. The key question is whether the more expensive technology is cost-effective, regardless of how much more it may cost than a cheaper and less effective technology. Cost effectiveness is an economic criterion used to assess the potential for achieving a control objective at the lowest cost. Cost is measured in terms of annualized control costs, and effectiveness is measured in terms of tons of pollutants removed per year. Therefore, cost effectiveness is the total annualized costs of control divided by annual emission reductions. (NSR Manual, p. B.36.) The EPA has developed

guidelines for determining cost-effectiveness (NSR Manual, § IV.D.2.b) and procedures to perform the requisite calculations. (OAQPS Manual.³²)

Second, vendor cost data indicates that while installed capital costs for SCONOx are about twice as high as an SCR/oxidation catalyst, the annual operating costs for SCONOx are lower than the conventional system. The overall cost effectiveness of SCONOx well within BAAQMD and other agency guidelines.

Specifically, recent independent cost-effectiveness analyses based on EPA guidelines and procedures indicate that SCONOx costs \$6,270 per ton of NO_x (“\$/ton”) to reduce NO_x from 25 ppm to 2 ppm on a GE Frame 7 machine. (OnSite Sycom 10/15/99, Table A-7.³³) Cost estimates prepared by CURE for Elk Hills indicate that SCONOx costs \$7,360/ton to reduce NO_x from 9 ppm to 2.5 ppm on a GE Frame 7 machine.³⁴

We prepared a cost effectiveness analysis for the Metcalf Project that assumes BACT emission limits of 2.5 ppm NO_x and 6 ppm CO. Our calculations, summarized in Table 1, are based on vendor-supplied costs and emissions from the PDOC, assuming inlet concentrations of 25 ppm NO_x and 10-ppm CO. (PDOC, pp. A-2 to A-3.) Our calculations give no credit for emission reductions during startup, and thus overstate the cost per ton of emissions reductions using SCONOx. Nevertheless, these calculations indicate that SCONOx costs between \$5,651 and \$6,028 per ton of NO_x removed. The cost effectiveness drops to \$4,601 to \$5,440 per ton when both nonattainment pollutants are included in the calculation. This is reasonable here and has been requested by EPA for other facilities³⁵ because SCONOx controls both pollutants simultaneously.

³² U.S. EPA, OAQPS Control Cost Manual, 5th Ed., Report EPA 453/B-96-001, February 1996.

³³ ONSITE SYCOM Energy Corporation, Cost Analysis of NO_x Control Alternatives for Stationary Gas Turbines, Report Prepared for U.S. Department of Energy, October 15, 1999.

³⁴ Elk Hills, Docket No. 99-AFC-1, Exhibit 44, May 8, 2000, Table 1.

³⁵ Letter from Matt Haber, Chief, Permits Office, EPA Region 9, to Dennis J. Champion, Project Permitting Manager, Elk Hills Power, Re: Prevention of Significant Deterioration (PSD) Application for Elk Hills Power, LLC, 500 MW Power Plant, February 10, 2000.

TABLE I
Cost-Effectiveness Analysis for SCONox
Metcalfe Energy Center

	Cost	Notes
Direct Capital Costs		
Capital	13,000,000	ABB
Installation	1,475,000	Average of ABB and Goal Line estimates
Indirect Capital Costs		
Engineering	187,500	Average of ABB and Goal Line estimates
Contingency	250,000	Average of ABB and Goal Line estimates
TOTAL CAPITAL INVESTMENT	14,912,500	
Direct Annual Costs		
Maintenance	250,000	ABB
Steam/Natural Gas	300,000	ABB, based on 2400 scf/hr of natural gas with a heat content of 1000 Btu/scf at \$2.50/MMBtu and 20,000 lb/hr of steam at 500 Kw per 10,000 lb/yr for 8300 hr/yr of baseload operation
Pressure Drop	213,000	ABB, based on 4" water and \$0.03/Kwh
Catalyst Replacement	340,000	1 layer every 10 years
Catalyst Disposal	(60,300)	Average of ABB and Goal Line estimate for residual value of Pt
Total Direct Annual Costs	1,042,700	
Indirect Annual Costs		
Administrative, Tax & Insurance	225,000	ABB
Total Indirect Annual Costs	225,000	
TOTAL ANNUAL INVESTMENT	1,267,700	
Capital Recovery Factor	0.0806	7% interest for 30 years
TOTAL ANNUALIZED COSTS	1,736,188	^a
Annual Tons of Pollutant Removed		
NOx	478	Assumes NOx reduced 75%, from 10 ppm to 2.5 ppm for 8300 hr/yr
CO	155	Assumes CO reduced 60%, from 10 ppm to 6 ppm for 8300 hr/yr
COST EFFECTIVENESS		
(\$/ton NOx Removed)	3,632	
(\$/ton NOx and CO Removed)	2,743	

a Capital recovery costs adjusted for replacement parts per OAQPS Manual, Eq. 2.9, assuming replacement costs are 70%

All of the SCONox costs discussed above, ranging from \$4,601 per ton of CO or NOx to \$7,360 per ton of NOx alone, are well within the BAAQMD's cost-effectiveness criterion. In the Bay Area Air Quality Management District, the maximum cost per ton of NOx controlled that is considered cost-effective is \$17,500. Therefore, SCONox is cost-effective.

³⁶ San Joaquin Valley Unified Air Pollution Control District ("SJVUAPCD"), Best Available Control Technology (BACT) Policy, November 9, 1999, p. BACT 1-2.

³⁷ Bay Area Air Quality Management District ("BAAQMD"), BACT/TBACT Workbook. Guidelines for Best Available Control Technology, June 30, 1995, p. 9.

D. OTHER BENEFITS OF SCONOX NEED TO BE CONSIDERED IN DETERMINING BACT

The SCR system proposed for use by the Applicants results in a number of environmental problems that are reduced or eliminated with the use of SCONOX. These problems include: (1) hazards from accidental releases of the ammonia used in the SCR system during its transportation and handling; (2) the formation of particulate matter from the oxidation of SO₂ in the SCR catalyst; (3) the formation of particulate matter from reactions between ammonia and SO₂; (4) generation and disposal of the hazardous SCR catalyst at the end of its useful life; (5) inability to control NO_x and CO emissions during startups and shutdowns; (6) increase in NO₂ from the use of dry low NO_x combustor.

SCONOX and SCR are compared in Table 2. SCONOX offers a number of important advantages over a conventional SCR, with no known disadvantages. First, SCONOX uses a single catalyst to simultaneously remove NO_x, CO, and VOCs. A conventional system requires two separate catalyst systems. Second, SCONOX uses no ammonia or other hazardous materials and thus requires no ammonia slip, eliminating the many significant impacts associated with ammonia use (e.g., transportation accidents, unloading accidents, accidental releases of ammonia, PM₁₀ generation). Third, the SCONOX system operates effectively at temperatures ranging from 300°F to 700°F, making it well suited for merchant power plant operation and providing better control during startups, shutdowns, and load swings than achieved with other competing catalytic technology. Fourth, unlike other catalytic systems, the SCONOX catalyst is continuously regenerated, assuring continuous maximum catalyst effectiveness. The performance of a conventional catalyst system, on the other hand, degrades with use. Fifth, SCONOX has been demonstrated to achieve much lower NO_x and CO levels than other competing technologies, at lower overall costs. Finally, the SCONOX catalyst contains precious metals, which can be reclaimed by smelting, reducing overall operating costs. The SCR catalyst must be disposed as a hazardous waste at the end of its useful life. The ammonia impacts and startup/shutdown emissions are discussed further below.

³⁸ South Coast Air Quality Management District (“South Coast AQMD”), Draft Best Available Control Technology Guidelines, September 11, 1995, p. 33, Table 4.

³⁹ South Coast AQMD, Best Available Control Technology Guidelines, Part A: Policy and Procedures, May 21, 1999, p. 10.

Table 2
Comparison of SCONOx and SCR

Issue	SCONOx	SCR/Oxidation Catalyst
Air Quality/Public Health	No ammonia. Achieves higher VOCs and toxic emission reductions. No PM10 formation. Lower emissions during startup, shutdown, and load fluctuations	Ammonia slip of 10ppm. Increase in stack PM10 emissions from oxidation of SO2 to SO3. Secondary PM10 emissions from reaction of ammonia with nitrate and sulfate.
Waste Water	No increase if vendor maintenance purchased. Otherwise, 50,000 gal/yr of 8.5% potassium carbonate solution.	Periodic washwaters if vendor recommended maintenance is performed.
Water Supply Solid/Hazardous Waste	<1% increase in demand. Catalyst can be reclaimed to recover platinum. Catalyst lifetime is 10 yrs for leading row (30%) and 30 yrs for balance of catalyst, resulting in lower volumes of wastes than SCR/oxidation catalyst.	No impact SCR catalyst is a hazardous waste due to vanadium. Platinum can be recovered from oxidation catalyst. Catalyst lifetime is 3 yrs.
Hazardous Materials	Small amounts of hydrogen and natural gas are used to regenerate catalyst. (Insignificant compared to quantities otherwise handled.)	Requires delivery and storage of ammonia, which poses security risk and danger to public health.
Maintenance	Annual catalyst washing and regeneration with 8.5% potassium carbonate.	Ammonium sulfate deposits in low pressure boiler tubes. This reduces heat transfer, corrodes tubes, and requires periodic tube cleaning and/or replacement. Pressure drop increases over catalyst life from deposition.
Economics	For BACT levels of 2.5 ppm Nox and 6.0 ppm CO, <\$5,440/ton. For BACT levels of 1 ppm Nox and 1 ppm CO, <\$4,600/ton.	Typically lower for BACT levels of 2.5 ppm Nox and 6 ppm CO and higher.

1. SCONOx Eliminates Ammonia Impacts

The District selected SCR with an ammonia slip of 10 ppm as BACT for NOx without performing a proper environmental analysis as required by the top-down BACT process. (See NSR Manual at B.6.) PM₁₀ is formed from two sources in an SCR system -- ammonia slip and oxidation of SO₂ to sulfur trioxide (SO₃) by the SCR catalyst. Ammonia and sulfur trioxide form particulate matter within the stack and secondary PM₁₀ downwind in the atmosphere. This PM₁₀ can cause health impacts, visibility impairment impacts, contribute to existing exceedances of the California ambient PM₁₀ standard, and impact listed and protected species. These collateral increases in PM₁₀ have not been evaluated. Further, ammonia is a hazardous substance, and the transportation and handling of ammonia can result in accidental releases that adversely impact the public.

2. Ammonia Impacts Must Be Considered

The top-down BACT process and the federal law it implements require that the environmental impacts of selected technologies be considered as part of the BACT determination. The federal Clean Air Act defines BACT as an “emission limitation” that is set “on a case-by-case basis . . . taking into account energy, environmental, and economic impacts and other costs.” (42 USC § 7479(3), (emphasis added).) The Environmental Appeals Board has provided the following interpretation of the emphasized portion:

[I]f application of a control system results directly in the release (or removal) of pollutants that are not currently regulated under the Act, the net environmental impact of such emissions is eligible for consideration in making the BACT determination. [As a result of the analysis], the control system proposed as BACT may have to be modified or be rejected in favor of another system. In other words, EPA may ultimately choose more stringent emission limitations for a regulated pollutant than it would otherwise have chosen if setting such limitations would have the incidental benefit of restricting a hazardous but, as yet, unregulated pollutant. (North County Resource Recovery Associates, 2 E.A.D. 230 (EAB 1986).)

The U.S. EPA has similarly interpreted this requirement to mean that, where two technology choices provide equivalent control for a regulated pollutant, but one would also control pollutants not directly regulated by the PSD Program, such as PM₁₀ and NH₃ in this case, the one controlling the unregulated pollutants should be chosen as BACT.⁴⁰ Moreover, EPA is

⁴⁰ Memorandum from Gerald A. Emison, Director, Office of Air Quality Planning and Standards, Subject: Implementation of North County Resource Recovery PSD Remand, September 29, 1987; Memorandum from Gerald A. Emison, Re: Supplemental Guidance on Implementing the North County PSD Remand, July 28, 1988.

seeking to integrate pollution prevention as an ethic throughout its activities. (Habicht 5/28/92.⁴¹)

The NSR Manual itself is clear that the environmental analysis should also include a consideration of "...visibility impacts, or emissions of unregulated pollutants." (NSR Manual, p. B.46.) Thus, even if SCONOX did not achieve lower NO_x limits than other technologies, SCONOX should have been deemed BACT on the basis that it eliminates ammonia emissions.

6. a. PM₁₀ Formation From Oxidation Of SO₂ And Ammonia Slip

The SCR catalyst oxidizes SO₂ to SO₃. The excess residual ammonia downstream of the SCR system (i.e., the slip) reacts with this SO₃ as well as NO₂ and water vapor in the stack gases and downwind in the atmosphere to form ammonium sulfate, ammonium bisulfate, and ammonium nitrate according to the following reactions. (Seinfeld and Pandis 1998, pp. 529-534;⁴² South Coast AQMD 6/12/98, p. 3-3; Matsuda et al. 1982;⁴³ Burke and Johnson 1982.⁴⁴)



The resulting salts form particulate matter, which contributes to ambient PM₁₀, causes maintenance problems in the HRSG, contributes to visibility impairment, and impacts protected species. These salts cause a number of environmental problems, which are addressed below.

i. PM₁₀ Formation Contributes To Existing Violations Of State Standards

The reactions between SO₃, NH₃, and NO₂ form salts, some of which are emitted to the atmosphere and some of which deposit within the HRSG. The above equations can be used to estimate a portion of the secondary PM₁₀ that is formed from ammonia slip. Secondary PM₁₀ can be formed by reaction of ammonia with SO₃ and NO₂ emitted by the gas turbines and present in the stack gases and plume as well as additional SO₃ and NO₂ that are present downwind in the atmosphere.

⁴¹ Memorandum from F. Henry Habicht II, Deputy Administrator, Subject: EPA Definition of "Pollution Prevention," May 28, 1999.

⁴² John H. Seinfeld and Spyros N. Pandis, Atmospheric Chemistry and Physics, John Wiley & Sons, Inc., New York, 1998.

⁴³ S. Matsuda, T. Kamo, A. Kato, and F. Nakajima, Deposition of Ammonium Bisulfate in the Selective Catalytic Reduction of Nitrogen Oxides with Ammonia, Ind. Eng. Chem. Prod. Res. Dev., v. 21, 1982, pp. 48-52.

⁴⁴ J.M. Burke and K.L. Johnson, Ammonium Sulfate and Bisulfate Formation in Air Preheaters, Report EPA-600/7-82-025a, April 1982.

TABLE 3
Calculation of PM-10 Emissions From
Ammonia Slip in Turbine Exhaust ((NH₄)₂SO₄)

Molecular Weights		
S	32.06	
SO ₂	64.06	
SO ₃	80.06	
SO ₄	96.06	
(NH ₄) ₂ SO ₄	132.16	
	Maximum Hourly	Average Hourly
Natural Gas Usage (scf/hr) ^a	2,062,136	1,917,786
Assumed Sulfur Content (grains/100scf) ^b	0.24	0.24
Exhaust S Flow (lbs/hr) per turbine	0.71	0.66
Conversion % (S to SO ₂)	100%	100%
SO ₂ emissions (lbs/hr) per turbine	1.41	1.31
Conversion % (SO ₂ to SO ₃)	3%	3%
SO ₃ emissions (lbs/hr) per turbine	0.05	0.05
Conversion % (SO ₃ to SO ₄)	100%	100%
SO ₄ emissions (lbs/hr) per turbine	0.06	0.06
Conversion % (SO ₄ to (NH ₄) ₂ SO ₄)	100%	100%
(NH ₄) ₂ SO ₄ emissions (lbs/hr) per turbine	0.09	0.08
Fraction of (NH ₄) ₂ SO ₄ that is PM-10	100%	100%
PM-10 emissions (lbs/hr) per turbine	0.09	0.08
PM-10 emissions (tpv) per turbine	n/a	0.36
Fraction of PM-10 that is PM-2.5	100%	100%
PM-2.5 emissions (lbs/hr) per turbine	0.09	0.08
PM-2.5 emissions (tpy) per turbine	n/a	0.36
Results for Two Turbines:		
PM-10 emissions (lbs/hr), two turbines	0.17	0.16
PM-2.5/PM-10 emissions (tpy), two turbines	n/a	0.71

a Based on 4 ppmv (PDOC, p. A-7).

b Based on maximum fuel flow of 2,124 MMBtu/hr with a HHV of 1030 Btu/scf (PDOC, pp. A-1 to A-2). The ratio of the maximum to hourly fuel use is assumed to be 0.9, based on other similar projects.

CVRP calculated the amount of secondary PM10 that could form from the reaction of ammonia slip with NO₂ and SO₃ in the turbine exhaust. The calculations in Table 3 show that Equation (1) would produce up to 3.9 ton/yr of ammonium sulfate secondary PM₁₀ from reaction of ammonia only with combustion byproducts. Additional ammonium sulfate would form from reaction of SO₃ in the atmosphere with any emitted ammonia. Table 4 shows that Equation (3) would produce up to 105.8 ton/yr of ammonium nitrate secondary PM₁₀ from reaction of ammonia only with combustion byproducts. Some this PM10 would be deposited within the HRSG and the balance emitted. Additional ammonium nitrate could form from the reaction of NO₂ in the atmosphere with any emitted ammonia. This additional PM₁₀ was not included in the Project's emissions estimates. The PDOC's conclusion that the Project will not trigger an emissions offset requirement is thus false.

The CEC has made the same point in its PDOC comments. The CEC staff concludes that "the ammonia slip from the proposed MEC is 118.6 tons per year....The direct PM10 from the proposed MEC is 98.6 tons per year which is close to the District's mitigation threshold [of] 100 tons per year. Considering the formation of secondary PM10, ammonia nitrate, from the proposed project, the combined PM10 emissions will be more than the District's threshold and qualify MEC to mitigate PM10."⁴⁵

ii. PM₁₀ Formation Causes SCR Maintenance Problems

Some of these salts estimated in Tables 3 and 4 deposits in the low-pressure tube sections of the HRSG. According to GE, "[a]ctual operating experience indicates that ammonium-sulfur salt formation and boiler damage occur without exception, when ANY sulfur bearing fuel is fired in the gas turbine and SCR is used for NO_x control. This is not usually accounted for in BACT determinations, but adds significant cost, and should be considered." These salts build up, decreasing heat transfer and increasing operating costs. They also corrode the boiler tubes, requiring periodic cleaning and periodic replacement of the low-pressure tube sections of the HRSG. (Id., pp. 1, 3.) This affects the reliability and maintenance costs of SCR and thus must be considered in the BACT analysis. The salt deposition problem will be aggravated by the use of dry low NO_x combustors, which increase the amount of NO₂ in turbine exhaust gases, and hence the amount of ammonium nitrate that may form in the HRSG. (ASME 1/1/99.⁴⁶)

⁴⁵ CEC staff, 516/2000, Therkelsen to Garvey letter re Metcalf PDOC.

⁴⁶ ASME, Low NO_x Measurement: Gas Turbine Plants. Final Report on Review of Current Measuring and Monitoring Practices, Report CRTD Vol. 52, January 11, 1999.

TABLE 4
Calculation of PM-10 Emissions From
Ammonia Slip in Turbine Exhaust ((NH₄)NO₃)

Molecular Weights	
H	1.01
N	14.01
(NH ₄)NO ₃	80.06
NO ₂	46.01
O	16.0
	Maximum Hourly
Exhaust NOx flow (lbs/hr) per turbine (W/DB) ^a	19.2
Conversion % (NO to NO ₂) ^b	40%
NO ₂ emissions (lbs/hr) per turbine	7.68
Conversion % (NO ₂ to (NH ₄)NO ₃)	100%
(NH ₄)NO ₃ emissions (lbs/hr) per turbine	13.36
Fraction of (NH ₄)NO ₃ that is PM-10	100%
PM-10 emissions (lbs/hr) per turbine	13.36
PM-10 emissions (tpy) per turbine	58.53
Results for Two Turbines:	
PM-10 emissions (lbs/hr), two turbines	26.73
PM-2.5/PM-10 emissions (tpy), two turbines	117.07

a PDOC, p. A-2.

b ASME, Low NOx Measurement: Gas Turbine Plants,

iii. PM₁₀ Formation Causes Visibility Reduction

The fact that these reactions actually occur and cause visibility impacts is well documented in the technical literature. A noted atmospheric textbook, for example, contains this vivid description of the problem (Pitts and Pitts, 1999,⁴⁷ p. 284):

"The formation of ammonium nitrate has some interesting implications for visibility reduction. In the Los Angeles air basin, for example, the major NOx

⁴⁷ Barbara J. Finlayson-Pitts and James N. Pitts, Jr., Chemistry of the Upper and Lower Atmosphere. Theory, Experiments, and Applications, Academic Press, San Diego, 1999.

sources are at the western, upwind end of the air basin. Approximately 40 miles east in the vicinity of the city of Chino, there is a large agricultural areas that has significant emissions of ammonia...under typical meteorological conditions, air is carried inland during the day, with NO_x being oxidized to HNO₃ as the air mass

moves downwind. When it reaches the agricultural area, the HNO₃ reacts with gaseous NH₃ to form ammonium nitrate, the particles formed by such gas-to-particle conversion processes are in the size range where they scatter light efficiently, giving the appearance of a very hazy or smoggy atmosphere even though other manifestations of smog such as ozone levels may not be highly elevated."

iv. PM₁₀ Formation Endangers Endemic Biota

The majority of the ammonia slip reacts with NO_x to form ammonium nitrate, which is PM₁₀. (Table 4.) This PM₁₀ can be deposited on surrounding hills, including Coyote Ridge to the east, Santa Teresa Hills to the west, and Tulare Hill, located immediately adjacent to the site. These hills contain soils derived from serpentine rock that support serpentine grasslands, considered a sensitive habitat by the California Department of Fish and Game. These soils also support a high number of rare and/or endemic plant species as well as endemic invertebrates such as the federally threatened bay checkerspot butterfly. (PSA, pp. 361-362.)

Serpentine soils are low in nitrogen, which restricts the growth of invasive non-native plant species. The soils are currently over-saturated with nitrogen and exceed levels known to alter serpentine ecosystems. (PSA, p. 378.) Although the Applicant modeled the impact of the Project on these soils and concluded that the increase in nitrogen would be small, 1.56% of existing background (PSA, p. 378), the Applicant's analysis apparently failed to include secondary PM₁₀, most of which is ammonium nitrate. This additional PM₁₀ would nearly double the Project's reported contribution to soil nitrogen. The impact of this additional ammonium nitrate has not been evaluated and must be to fully evaluate the environmental impacts of SCR.

E. ALTERNATIVES TO SCONOX TO ACHIEVE A NO_x BACT OF 1.3 PPM

There are alternatives to SCONOX that achieve 1.3 ppm NO_x averaged over 1 hour with very low ammonia slip. A standard SCR can be designed to achieve a NO_x level of 1 ppm, comparable to SCONOX, by simply adding more catalyst and increasing the catalyst change out efficiency. The ammonia slip can be reduced or eliminated by using this standard system by either designing the SCR to achieve a lower ammonia slip and by following the SCR with a CatCO oxidation catalyst to remove ammonia. These two options are discussed below.

1. Standard SCR Designed For A Lower NH₃ Slip

Lower slip levels can be readily and inexpensively achieved using a standard SCR system designed to meet a lower slip. The CARB Guidance Document⁴⁸ recommends a slip of less than 5 ppm and acknowledges that slips as low as 2 ppm can be achieved using standard technology. (CARB 9/99,⁴⁹ pp. 25-26.)

Very low slips have been achieved in practice at large natural gas-fired turbines that comply with vendor-recommended maintenance (e.g., annual catalyst washing.) The Hitachi NO_x guarantee letter in Appendix D of the CARB Guidance Document, for example, identifies a 1400-MW plant consisting of four GE Frame 9 gas turbines that is currently operating at a NO_x level of 3 ppmvd with a 3-ppmvd ammonia slip in Japan.

Both Massachusetts and Rhode Island have established 2-ppm ammonia slip BACT limits for new power plants. Rhode Island requires all power plant permit applicants to justify why they cannot achieve a 2ppm ammonia slip for SCR as part of their BACT analysis. The Massachusetts Department of the Environmental Protection ("MDEP") has established a "Zero Ammonia Technology" BACT standard for gas turbines larger than 50 MW. (Struhs 1/29/99.⁵⁰) Three large projects in the Massachusetts market, the 350-MW Cabot Power Island End Project, the 420-MW American National Power Blackstone Project, and 1,550-MW Sithe Mystic Development have been issued PSD permits specifying a NO_x limit of 2 ppm achieved with a 2 ppm ammonia slip, demonstrated using ammonia CEMs and both averaged over 1 hour. Their permits further require that they retrofit with zero ammonia technology at the end of five years.

All of the major SCR vendors will guarantee ammonia slips substantially below 10 ppm. Attachment D to the CARB Guidance Document includes performance guarantees from four of the major SCR vendors for a 5-ppmv slip, the only level requested. A slip level of 5 ppm is currently proposed for the Moss Landing Project.⁵¹ The CEC staff has preliminarily called for a 5-ppmv ammonia slip limit for MEC.⁵² In addition, all of the major vendors are currently offering performance guarantees of 2 ppmvd to compete in the New England market.

⁴⁸ CARB, Guidance for Power Plant Siting and Best Available Control Technology. As Approved by the Air Resources Board on July 22, 1999, September 1999.

⁴⁹ California Air Resources Board (CARB), Guidance for Power Plant Siting and Best Available Control Technology, September 1999.

⁵⁰ Memorandum from David B. Struhs, Commissioner, Massachusetts Department of Environmental Protection, to Ed Kunch, Re: Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) for Electric Power Generators, January 29, 1999.

⁵¹ Monterey Bay Unified Air Pollution Control District, Preliminary Determination for Duke Energy Moss Landing LLC, January 7, 2000.

⁵² CEC staff, Metcalf PSA, 5/15/2000, p. 41, item 7.

Finally, the CARB Guidance Document recommends “that districts consider establishing ammonia slip levels below 5 ppmvd at 15 percent oxygen in light of the fact that control equipment vendors have openly guaranteed single-digit levels for ammonia slip.” (CARB 9/99, p. 26.)

2. SCR Plus Downstream Oxidizing Catalyst

A standard SCR system can be designed to include an oxidizing layer downstream of the SCR catalyst. The oxidizing layer would oxidize ammonia to nitrogen gas and water. However, depending on the temperature in the oxidation zone, some NO_x could be created, requiring an increase in the volume of the SCR catalyst to achieve equivalent NO_x without the oxidation zone. Near-zero slip levels can be readily and inexpensively achieved using this system. This approach is routinely used to control unburned hydrocarbons and CO from diesel engines (Durilla 5/99⁵⁴) and represents standard practice in Europe for engines. This technique was also employed in Grace Dual Function catalysts, which are currently operating on many large natural gas fired turbines.

The Applicants' consultant has argued that "if the oxidation catalyst were located downstream of the SCR catalyst, you run the risk of converting the ammonia slip back to NO_x. Even typical ammonia slip levels of 1-2 ppm from a new SCR catalyst would increase NO_x levels by 50%-100% from new generation facilities that are equipped with dry low-NO_x combustors and high efficiency (90%) SCR systems." (Rubenstein 6/8/99.⁵⁵) However, according to Englehard research engineers, this is incorrect. The maximum conversion of ammonia to NO_x that could occur in the region where the downstream Camet catalyst would be located is 20% and actual values would be substantially smaller. Assuming a typical slip level of 2 ppm, the maximum increase in NO_x would be 0.4 ppm, which would increase NO_x from 2.5 ppm at the outlet of the SCR to 2.9 ppm or by about 20%. This increase in NO_x could be readily addressed by simply increasing the volume of SCR catalyst.

IV. BACT HAS NOT BEEN REQUIRED FOR CO – LOWER CO LEVELS HAVE BEEN ACHIEVED

The PDOC concludes that BACT for carbon monoxide (“CO”) is an emission limit of 10 ppm at 15% O₂ averaged over 3 hours achieved without an oxidation catalyst. However, the District failed to perform a top-down BACT analysis, as discussed above. Further, it made several errors in applying its own BACT guidelines. The District argues that its BACT determination for gas turbines larger than 23 MMBtu/hr (Guideline 89.2.1) does not apply to Metcalf because Crockett

⁵⁴ Mike Durilla, Engelhard, “Using Oxidation Catalysts To Improve SCR Performance,” 1999 CAPCOA Engineers’ Symposium, May 1999.

⁵⁵ Memorandum from Gary Rubenstein, Sierra Research, to Bob Giorgis, CARB, Re: Conversion of Fuel Sulfur to Particulate Sulfates.

has not achieved its permit limit and lower limits recently permitted for other similar projects have not yet been achieved in practice. The District's arguments are technically incorrect, violate federal BACT guidance, and ignore significant data to the contrary. As a result, the District has failed to establish the proper BACT level for CO. The proposed 10-ppm limit is much higher than CO concentrations that are routinely achieved on similar plants and, thus, is not BACT.

The District's BACT Guideline 89.2.1 establishes a BACT limit of < 6 ppm or 90% CO reduction as technologically feasible and cost effective and 10 ppm as achieved in practice, both achieved with an oxidation catalyst.⁵⁶ The District has declined to adopt the <6 ppm limit or an oxidation catalyst, contrary to its own guidance.⁵⁷

First, the District argues that Los Medanos, which was permitted by the District at 6 ppm CO, is not relevant to Metcalf because it has not yet been demonstrated consistently under actual operating conditions. (PDOC, p. 10.) This is inconsistent with U.S. EPA guidance, which only requires that a limit be specified in a permit to be selected as the top technology in the top-down BACT process. Other recently permitted projects in California, outside of the District, have been permitted at 6 ppm (e.g., La Paloma, Sunrise, Elk Hills). Further, other states have required much lower CO limits (2 ppmv averaged over 1 hour) in recently issued PSD permits. These lower limits, which have been established in valid PSD permits, should have been included in a proper top-down BACT analysis. There is no obligation under federal law to constrain a BACT determination to the boundaries of the permitting agency, as done here. BACT knows no boundaries, and, in fact, EPA acknowledges foreign experience as relevant.

Second, the District argues that a limit lower than 10 ppm has not been achieved for the type of project (power augmentation, duct burners, merchant operation) proposed by Metcalf, specifically citing the compliance problems at Crockett. (PDOC, p. 10.) However, the Crockett experience is irrelevant as discussed below. Further, CO levels much lower than 10-ppm have been achieved in practice elsewhere, as also demonstrated below. Finally, the specifics (e.g., duct burners, steam injection, merchant mode) of the Metcalf Project do not affect the performance of catalytic systems. In these processes, simply adding more catalyst to reduce space velocities can increase removal efficiencies. Therefore, even if duct burners and steam injection for power augmentation appreciably increased CO levels, which they apparently do not, it would not affect the performance of a properly designed catalytic process. The increase in CO, if any, could be removed by simply designing the system to include the proper amount of catalyst require to achieve the target emission limit.

Under the PSD program, BACT is “an emissions limitation . . . based on the maximum degree of reduction for each pollutant subject to regulation under [the] Act which would be emitted from any proposed major stationary source” (40 CFR § 52.21(b)(12), emphasis added.) The

⁵⁶ www.baaqmd.gov/permit/bactworkbook/89-2-1.htm.

⁵⁷ This failure of the District to abide by its own BACT guidelines has also been noted by the CEC. See Therkelsen to Garvey comment letter on the PDOC, 5/16/2000, p. 1.

information reviewed below indicates that 0.5-ppm CO averaged over 3 hours is achieved in practice. Therefore, the District has failed to specify BACT for this Project.

A. Crockett Experience Is Irrelevant

The Crockett facility has been unable to meet its 5.9-ppm CO limit during minimum load under ambient conditions of low temperature and high relative humidity and during peak load under ambient conditions of high temperature and moderate to high relative humidity. The District uses the experience at Crockett to argue that its BACT guideline is not relevant. (PDOC, p. 10.) However, the gas turbine at Crockett is recognized by CARB “as being somewhat unique, since it is an early version of the General Electric Frame 7FA” which has since been discontinued. The rotor was recently replaced due to vibration and blade erosion problems. The combustor has also been replaced, with subsequent CO emissions below 10 ppmv.⁵⁸ In CARB’s opinion, the compliance problems at Crockett “appear to be related specifically to this gas turbine or overall system and not necessarily to the oxidation catalyst.” CARB specifically cautioned that this experience is unique and should not be applied to other projects, as advocated here by the District. (Menebroker 9/1/99.⁵⁹)

Further, Engelhard, the vendor of the oxidation catalyst, has conducted extensive investigations into the possible causes of the CO compliance problems at Crockett. Contrary to the District's claims, it has concluded that the compliance problems are unlikely to be related to either the weather or the catalyst itself (plug samples consistently showed the catalyst was good), a similar catalyst at the same site was operating properly, and numerous similar facilities are in successful operation worldwide. (Mack 7/19/99.⁶⁰) There are other, more plausible explanations, not related to the efficacy of the catalyst itself. These include sugar deposits (from the adjacent C&H sugar plant), catalyst plugging from internal insulation sloughing,⁶¹ and turbine problems. Therefore, the District has inappropriately used the Crockett experience to establish a CO BACT limit for Metcalf that is higher than CO levels achieved in practice at other power plants.

B. Source Tests Support A CO Limit <1 ppm

The information compiled in the CARB Guidance Document supports a much lower BACT level than 6 ppm averaged over 3 hours. For combined-cycle plants, the most stringent emission limit for CO required in a construction permit is 1.8 ppmvd at 15%O₂ averaged over 1 hour at the

⁵⁸ Letter from Robert L. Therkelsen, Deputy Director, Energy Facilities Siting and Environmental Protection, CEC, to Ellen Garvey, Air Pollution Control Officer, BAAQMD, May 16, 2000.

⁵⁹ Letter from Raymond E. Menebroker, Chief Project Assessment Branch, CARB, to Ellen Garvey, Air Pollution Control Officer, BAAQMD, September 1, 1999.

⁶⁰ Letter from Stan Mack, Sales Manager, Engelhard, to Bob Giorgis, CARB, July 19, 1999.

⁶¹ Silencing baffles in the gas stream were insulated. Some of the insulation was pulled out by the gas flow and plugged the CatCO catalyst. In one case, the maximum allowed backpressure was exceeded, shutting down the unit and damaging the frame.

Newark Bay Cogeneration facility. (CARB 9/99, Table C-6.) Compliance with this limit was demonstrated in a source test. (Id., Appx. C, p. 26.) Moreover, the actual CO concentrations measured in all nine of the CO source tests summarized in the Guidance Document are at or below 2.0 ppmvd at 15% O₂. (Id., Table C-8.) These data support a BACT level for CO for combined-cycle plants of 2.0 ppmvd @ 15% O₂ averaged over 1 hour.

In addition, source test data for four additional combined cycle and cogeneration gas turbines equipped with oxidation catalysts (Table 5) support a CO BACT level of less than 1 ppm. Table 5 includes six sets of source tests that were performed at loads ranging from 50% to 100%. These partial load data are representative of merchant operation and indicate that CO (and VOC – see Table 5) levels during partial load operation are comparable to those during full load operation. Most of the CO measurements, irrespective of load, are much less than 1 ppm. These data confirm that BACT for CO for large combined cycle gas turbines in merchant operation is no more than 2.0 ppmvd @ 15% O₂ averaged over 1 hour and support a BACT CO level of less than 1 ppm.

C. SCONOx Achieves 0.7 ppm CO

SCONOx simultaneously removes NO_x, CO, and VOCs. The nine months of recent CEMs data discussed above in Comment III.B.1 indicate that the Federal Facility routinely achieves a CO limit of 1.0 ppm averaged over 1 hour, and 0.7 ppm averaged over 3 hours. Similar performance has been demonstrated at the Genetics facility. The 1-hour average CO data are summarized in Figure 2, and the 3-hour average data in Figure 3. These figures exclude excursions due to startup, shutdown, and non-SCONOx operating problems (e.g., CEM failures, plant trips, operator error, condensation in gas generator).

The Applicants have argued that duct firing would somehow limit SCONOx's ability to control CO. (Metcalf Response to CVRP Data Request 8e.) This is erroneous. SCONOx has been operating for nearly a year at the Genetics Institute in Andover, Massachusetts, which employs a duct-fired heat recovery steam generator (“HRSG”). Because both the turbine and the duct burners burn natural gas, the emission characteristics are very similar. In any event, the duct burner emissions comprise only a small fraction of the total exhaust gases, 7% in the case of Metcalf that would have to be treated by a SCONOx system. This small increase would not alter the system’s fundamental design. Finally, the vendors of SCONOx have confirmed these facts and have further noted, based on experimental tests, that duct firing actually improves the performance of SCONOx, not reduces it as alleged by the Applicants.

The Applicants have also argued that "the Applicant is not aware of the performance of the SCONOx system in combination with the inherently low levels associated with the advanced combustors proposed for use at MEC." (Metcalf Response to CVRP Data Request 8a, p. 9.) The type of combustor is irrelevant to the performance of SCONOx. The only important variable is inlet CO concentration. ABB guarantees a CO reduction of 90%, irrespective of the inlet

concentration. Therefore, for Metcalf, SCONO_x could be designed to achieve 1.0 ppm CO, not 2 ppm as alleged by the Applicants. (Id., p. 10.)

D. An Oxidation Catalyst Achieves 0.5 ppm

Continuous Emission Monitoring (“CEM”) data from the Southwest Air Pollution Control Agency (“SAPCA”) in Washington for the River Road Generating Project indicates that this facility, which is a large Frame 7, meets a CO limit of 0.5 ppm averaged over 3 hours. The facility is a 248-MW natural gas fired, combined-cycle plant consisting of a GE 7231 FA gas turbine equipped with GE dry low-NO_x combustors (DLN III), an unfired HRSG, and a steam turbine. Control equipment includes an SCR system permitted at 4 ppmvd NO_x at 15% O₂ averaged over 24 hours, and a CO oxidation catalyst guaranteed by the vendor at 3 ppmvd at 15% O₂ and permitted at 6.0 ppmvd at 15% O₂ averaged over 3 hour. The unit operates at loads from 75% to 100%, and experiences frequent shutdowns and startups.

The 1-hour averaged CEM data for the last four quarters of operation are included in (05-31-00 CVRP comments on MEC PDOC: Exhibit 16). These data indicate that the River Road Generating Station routinely achieves a CO limit of 1.2 ppm averaged over 1 hour and 0.5 ppm averaged over 3 hours. The 1-hour average data are shown in Figure 4 and the 3-hour average data in Figure 5. All exceedances of these limits were due to startups, shutdowns, operator error, or equipment malfunctions reported to the SAPCA, with the exception of a single event on 12/20/98 from 12:00 PM to 1:00 PM. Although not of a Westinghouse 501 F equipped with dry low NO_x combustors can meet 10 ppm CO for all operating conditions proposed by Metcalf. In fact, Metcalf has agreed to 10 ppm for all operating conditions. (PDOC, p. 11.) Oxidation catalysts can be readily designed to remove 90% or more of the CO. (Mack 7/19/99.⁶²) Therefore, it is clearly feasible to meet a CO limit of 1.2 ppm averaged over 1 hour or 0.5 ppm averaged over 3 hours, consistent with the River Road data.

V. CATALYTIC CONTROLS DO NOT SIGNIFICANTLY INCREASE PM10

The Applicants argue that both SCONO_x and oxidation catalysts significantly increase PM10 emissions, thus offsetting the benefits of CO reduction because CO is attainment and is therefore safe, and PM₁₀ is nonattainment in the District. This is untrue with regard to both SCONO_x and oxidation catalysts, as discussed below.

A. An Oxidation Catalyst Does Not Increase PM10

The Applicant, in response to District inquiry, argues that an oxidation catalyst should not be used because 80% of the SO₂ is oxidized to sulfate, increasing PM10 emissions. (Rubenstein

⁶² Letter from Stan Mack, Sales Manager, Engelhard, to Bob Giorgis, CARB, July 19, 1999.

6/14/00.⁶³) The Applicant supports its argument by attaching a memorandum from its consultant to CARB. (Rubenstein 6/8/99.⁶⁴)

The Applicant's consultant has made this argument elsewhere, where it has been repeatedly rejected. The proffered letter was originally submitted to CARB during development of the Power Plant Guidance Document in an attempt to persuade CARB not to endorse oxidation catalysts.⁶⁵ CARB rejected these arguments, concluding that "[f]rom the perspective of staff, there is not enough evidence indicating any significant increase PM10 emission caused by oxidation catalysts." (CARB 9/99, Appx. C, p. 29.) Engelhard, the largest manufacturer of oxidation catalysts, also previously rebutted these claims. (Mack 6/1/99.⁶⁶)

In response to comments filed by others, the Applicant's consultant subsequently claimed that a "confidential" source test supported his position that oxidation catalysts generate PM₁₀.⁶⁷ These subsequent claims were likewise rebutted by both CARB (Menebroker 1/7/00⁶⁸) and Engelhard. (Mack 12/22/99.⁶⁹) CARB, for example, concluded: "[w]e do not believe that there is adequate evidence proving that oxidation catalysts contribute to PM10 emissions from gas turbines," confirming their original conclusion in the Guidance Document. Engelhard concurred: "the challenges against CO oxidation catalysts raised in the Sierra Environmental letter regarding PM₁₀ are inaccurate and unsubstantiated," pointing out that if the "confidential" source test actually does support PM₁₀ generation, the PM₁₀ is likely from the SCR system, which is a well known source of PM₁₀ caused by the oxidation of sulfur across the SCR catalyst.

In fact, the claims made in the June 8, 1999 Rubenstein letter submitted to the District are incorrect.

First, they are based on a 1993 engineering estimate, which is not provided. The catalyst industry has changed dramatically since 1993 and even if the analysis were then accurate (for which there is not evidence), it would not be accurate today.

⁶³ Letter from Gary Rubenstein, Sierra Research, to Dennis Jang, BAAQMD, Re: Application No. 27215, June 14, 1999.

⁶⁴ Memorandum from Gary Rubenstein, Sierra Research, to Bob Giorgis, CARB, Re: Conversion of Fuel Sulfur to Particulate Sulfate, June 8, 1999.

⁶⁵ See discussion of this letter in the Power Plant Guidance Document, p. 27 and note 7.

⁶⁶ Letter from Stan Mack, Sales Manager, Engelhard, to Magdy Badr, CEC, June 1, 1999.

⁶⁷ Letter from Gary Rubenstein, Sierra Research, to Mike Sewell, MBUAPCD, November 22, 1999.

⁶⁸ Letter from Raymond E. Menebroker, Chief, Project Assessment Branch, to Mike Sewell, MBUAPCD, January 7, 2000.

⁶⁹ Letter from Stan Mack, Sales Manager, Stationary Source Group, Engelhard, to Bob Giorgis, Engelhard, December 22, 1999.

TABLE 5
CO BACT Source Test Results for Combined Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Method of Control	Permit Limit	Turbine	Load	SOURCE TEST RESULTS		Date
					Emissions (lb/hr)	Concentration (ppm @ 15% O2)	
River Road Generating Project 248-MW GE 7231 FA gas turbine	Engelhard oxidation catalyst	6 ppm		100%	1.36	0.4	10/97
Procter & Gamble Cogen 2 GE LM6000 raked at 421.4 MMBtu/hr and generating 42 MW and 75.39 MMBtu/hr duct burners	Engelhard oxidation catalyst	3.6 lb/hr 4.2 lb/hr 3.6 lb/hr 4.2 lb/hr	A B A B	50% 100% 50% 100% 50% 100%	0.25 0.36 0.84 0.68 0.07 0.14 0.05 0.58	0.31 0.30 1.06 0.59 0.13 0.12 0.09 0.53	3/98 3/98 3/98 3/98 2/97 2/97 2/97 2/97
Harbor Cogen GE 80-MW Frame 7	Camet oxidation catalyst	10ppm 101lb/day	1 2	50-100% 50-100%	ND ND	0.2 0.2	11/95 11/95
Watson Cogen 4 82.75-MW GE 7EAs producing 405 MW and duct burners	Hitachi oxidation catalyst	82 lb/day	1 2 3 4		ND ND ND ND	2 2 2 2	11/98 11/98 11/98 11/98

VOC Source Test Results for Combined Cycle and Cogeneration Gas Turbines

Facility and Gas Turbine Description	Method of Control	Permit Limit	Turbine	Load	SOURCE TEST RESULTS		Date
					Emissions (lb/hr)	Concentration (ppm @ 15% O2)	
River Road Generating Project 248-MW GE 7231 FA gas turbine	Engelhard oxidation catalyst	6.6 lb/hr		100%	0.0*	0.0*	10/97
Procter & Gamble Cogen 2 GE LM6000 raked at 421.4 MMBtu/hr and generating 42 MW and 75.39 MMBtu/hr duct burners	Engelhard oxidation catalyst	1.1 lb/hr 1.8 lb/hr 1.1 lb/hr 1.8 lb/hr	A B A B	50% 100% 50% 100% 50% 100%	0.18 0.46 0.00 0.00 0.76* 0.76* 0.68*	0.39 0.67 0.00 0.00 1.77* 1.2* 1.59*	3/98 3/98 3/98 3/98 2/97 2/97 2/97
Harbor Cogen GE 80-MW Frame 7	Camet oxidation catalyst		1	50-100%	22	1.6	11/95
Watson Cogen 4 82.75-MW GE 7EAs producing 405 MW and duct burners	Hitachi oxidation catalyst	108 lb/day	1 2 3 4		1.79 1.59 2.43 1.66	1.30 1.13 1.75 1.27	11/98 11/98 11/98 11/98

* Total Hydrocarbons

Second, the letter claims conversion of SO₂ to particulate sulfate (SO₄), based on an attached Grace curve. However, the curve is for conversion of SO₂ to SO₃ as a function of gas temperature, not of SO₂ to SO₄. To form particulate matter, any SO₃ that is formed across the catalyst would have to combine with moisture in the stack gas to form H₂SO₄ and then with ammonia to form ammonium sulfite and ammonium bisulfite to form particulate. Third, the proffered curve is for a space velocity of 108,000 per hour. Catalyst removal efficiency is directly proportional to space velocity, which is the ratio of exhaust gas flow rate through the catalyst to catalyst volume, while SO₂ oxidation is inversely proportional to space velocity. Oxidation catalysts today are designed to operate at a space velocity of 200,000 per hour, not 108,000 per hour. The conversion of SO₂ to SO₃ increases as the space velocity decreases. Therefore, the proffered curve, even if it were relevant, overstates the conversion, if any. Third, the letter claims 80% conversion based on the Grace curve. An inspection of this curve indicates that 80% conversion corresponds to a temperature of about 1000 F. However, oxidation catalysts are typically installed in the HRSG where the temperature is 600 to 650 F, not at 1000 F.

Similar curves, supplied by the largest manufacturer of oxidation catalysts in the world, indicate that the conversion of SO₂ to SO₃ at a space velocity of 200,000 per hour at 650 F, the highest temperature likely to be experienced, would be about 5%, not 80% as claimed by the Applicant. To contribute to particulate matter in the stack, this SO₃ would have to react with ammonia and condense. Condensation would only occur if the dew point of the ammonia reaction products is above the exhaust temperature at the stack. The dew point of sulfate reaction products is about 120 F, well below the stack temperature of combined cycle plants, including the Metcalf facility. Therefore, the oxidation of SO₂ to SO₃ will not form particulate matter. Further, even if condensation occurred, the presence of ammonia from the SCR system is the culprit, not oxidation of SO₂ to SO₃ across the oxidation catalyst. Ammonia can be substantially reduced by using lower the slip or eliminated using a downstream ammonia oxidation step, as discussed in Comment --.

Finally, we note that the Applicant has argued that oxidation catalysts increase PM₁₀ while ignoring the identical problem for the SCR. However, in the case of NO_x, which is also an attainment pollutant, the Applicant has advocated an SCR system without any concern for the very same PM₁₀ issue. SCR systems generate substantial amounts of PM₁₀ from oxidation of SO₂ to SO₃ and from secondary PM₁₀ formation from the ammonia, as discussed above in Comment --.

In sum, there is no credible evidence that oxidation catalysts generate PM₁₀. This is a non-issue, which should not be considered in the District's BACT analyses.

B. IF AN OXIDATION CATALYST WOULD INCREASE PM10, THEN MEC REQUIRES PM10 OFFSETS

The PDOC states that a CO catalyst will not be part of the initial control technologies employed. But if the system does not achieve the CO emissions requirement (which is 10 ppm in proposed Condition 20(d) of the PDOC, but which we argue in our comments should be much lower), then MEC would be required to install an oxidation catalyst according to permit condition 23. However, according to Calpine consultants, the use of an oxidation catalyst may well increase the PM10 emissions significantly, and to the point where the emissions would exceed the 100-tpy threshold. Because offsets would then be required, and because offsets are difficult to obtain, this contingency must be addressed up-front, at the permitting stage. The District must either explicitly reject the argument that CO catalysts increase PM10 emissions, or if it does not it must require that PM10 offsets be acquired because of the PM10 emissions implications of licensing condition 23.

References provided are from submissions made by Calpine to the Connecticut DEP for the Towantic Energy Project.) The PDOC states that a CO catalyst will not be part of the initial control technologies employed. The statement is that the MEC will attempt to achieve a stack gas concentration of 10 ppm of CO without the use of a catalyst. If the system does not achieve the 10ppm requirement, the MEC would install an oxidation catalyst according to permit condition 23. However, the use of an oxidation catalyst may well increase the PM emissions significantly, and to the point where the emissions would exceed the 100-tpy threshold. Because offsets may then be required, and because offsets are difficult to obtain, this contingency must be addressed up-front, at the permitting stage. Therefore, the projected increase of PM emissions associated with the potential use of an oxidation catalyst needs to be accounted in the estimate of total PM emissions. As is discussed elsewhere, the emissions of PM have been already underestimated by a factor of two because of the omission of the condensable fraction of PM in the emission calculations. The use of the catalyst in the secondary formation of particulates will further increase the total emissions of particulates.

Attached are tabulated values of the PM emissions estimated by R.W.Beck, the air quality consultant to Calpine's Towantic Energy Project in Oxford, CT. Table 6-6, dated 12/22/1998 shows that the PM emissions were originally in the range of 2.6 g/s for natural gas combustion for a GE 7241 (FA) combustion turbine with HSRG. Table 6-6 (Revised), dated 10/25/1999 shows that when an oxidation catalyst is employed to reduce CO emissions, the PM emissions associated with natural gas firing increase to about 4.4 g/s. This is a 50 % increase. The excerpt from the enclosed transmittal letter to Mr. Sinclair and footnote 6 to the revised table document the association of the increases to the use of the CO catalyst.

When the increase of emissions of PM10 is calculated, it will be necessary to recalculate the Significant Impact Area surrounding the site. Emissions from other sources within this area will have to account for directly in the ambient air quality compliance computations. It is certain that an increase of PM10 emissions from the proper estimate of the formation of condensable

particulates will push the present peak prediction of 9.3ug/m³ well over the monitoring significance level of 10ug/m³ for PM₁₀.

C. SCONOx Does Not Increase PM₁₀

The Applicant has also claimed in the Energy Commission proceedings that Nueva Azalea, which is using SCONOx to control CO and NOx, would emit "32.8 lbs/hr during base load operation, more than three times the comparable figure for MEC...We believe that it would be a poor trade-off indeed to reduce CO levels (which are already safe) and nearly triple PM₁₀ emission rates for the sake of "matching the performance" of another project." (Metcalf Response to CVRP Data Request 8e.) This is unsupported and incorrect.

The PM₁₀ emission rate that is being permitted in the Nueva Azalea case is 13.6 lb/hr per turbine, not 32.8 lb/hr as claimed by the Applicants. (Nueva Azalea AFC,⁷⁰ Table 5.2-22.) This rate is only 13% higher than the PM₁₀ emissions being permitted by the Applicant. However, this comparison is irrelevant for three reasons.

First, Nueva Azalea is using AB24 gas turbines, while the Applicants are using Westinghouse 501F turbines. These two turbines have different exhaust PM₁₀ emission rates, totally independent of installed controls. Thus, they cannot be directly compared to evaluate the contribution of SCONOx as advocated by the Applicants.

Second, as discussed in Comment --, the Applicants have understated their PM₁₀ emissions. Actual vendor-guaranteed emissions for the Applicants' Westinghouse 501F turbines are 22 lb/hr, not the 12 lb/hr that is being permitted.

Third, it is chemically and physically impossible for SCONOx to generate substantial amounts of PM₁₀. First, SCONOx in some applications uses an upstream SCOSOx catalyst, which removes over 95% of the SO₂ from the gas stream. The SO₂ is subsequently stripped from the SCOSOx catalyst during catalyst regeneration and is either removed by a solid scrubber or routed around the SCONOx catalyst, thus eliminating any possibility of oxidizing over 95% of the SO₂ to SO₃. Second, SCONOx uses no ammonia, and, as discussed above, ammonia is necessary to convert any SO₃ to particulate. Thus, even if small amounts of SO₃ formed, it would not react with ammonia to form particulate.

Finally, actual source tests on the Federal facility demonstrate that SCONOx (in this case without use of SCOSOx) does not increase PM₁₀. (Delta 2/9/98.⁷¹) Two identical LM2500 turbines, one with (Federal) and one without SCONOx (Growers), were tested. The PM₁₀ emissions from the SCONOx facility (0.0003 g/dscf or 0.28 lb/hr) are half of those from the non-

⁷⁰ Application for Certification, Nueva Azalea Project, March 2000.

⁷¹ Delta, January 1998 Particulate Emissions From Federal Cold Storage and Growers Cold Storage Cogeneration Facilities, February 9, 1998.

SCONOx facility (0.0006 gr/dscf or 0.60 lb/hr). Further, the PM10 concentration achieved in the SCONOx test (0.000038 lb/MMBtu) is substantially smaller than the PM10 limit proposed by Metcalf (0.00565 lb/MMBtu). Therefore, the claim that SCONOx increases PM10 is wrong.

VI. OTHER AIR QUALITY BENEFITS OF CO CONTROL

The Applicant's consultant has argued that CO should not be controlled because stack concentrations are lower than ambient air quality standards and hence safe. This argument turns the PSD program on its head by advocating for no CO control when an area is in attainment. Further, the NSR Manual explicitly requires that the environmental tradeoffs of control technologies be evaluated. In this case, the failure to control CO has the very real potential of increasing ozone, which would aggravate the Bay Area's existing ozone compliance problems. Two significant benefits of controlling CO using either an oxidation catalyst or SCONOx are discussed below.

A. CO Control Simultaneously Removes VOCs, Which Are Ozone Precursors

The SCONOx and CO catalysts both consist of a ceramic substrate impregnated with platinum and is essentially oxidation catalysts. The SCONOx system achieves higher CO removal efficiencies because it operates at much lower space velocities, typically 22,000 per hour compared to 200,000 per hour for an oxidation catalyst. Therefore, some collateral VOC (and toxics) reduction occurs across both catalysts, depending upon their operating temperature, which are determined by their placement in the HSRG.

The collateral VOC (and toxics) reduction for a conventional CO catalyst could be as high as 50% of the quoted CO reduction, depending upon catalyst operating temperature and the composition of the exhaust gas stream. (Heck and Farrauto 1995, Chapter 11.) Aldehydes, alkanes, alkenes higher than butane, and aromatics, such as benzene, are readily oxidized across Engelhard's CO catalyst. Most of the specific organic compounds found in turbine exhaust fall into these classes.⁷² Reported removal efficiencies range from 71% for toluene to 86% for acetylene. (Heck and Farrauto 1995, Table 11.1.) Similarly, source tests at the Federal Facility, a low-temperature retrofit application, indicate that SCONOx reduces formaldehyde by 97% and acetaldehyde by 94%. (Delta 4/2/97;⁷³ Delta 4/00.)

⁷² California Air Resources Board, *Identification of Volatile Organic Compound Species Profiles*, ARB Speciation Manual, 2nd Ed., vol. 1, August 1991 plus updates available from Paul Allen, CARB; U.S. EPA, *Air Emissions Species Manual. Volume I. Volatile Organic Compound Species Profiles*, 2nd Ed., PB90-185844, 1990.

⁷³ Delta, Formaldehyde, Acetaldehyde and Benzene Control Efficiency at Federal Cold Storage March 14, 1997, April 2, 1997.

Generally, the higher the temperature, the higher the collateral VOC reduction. For example, the vendor guaranteed a 30% non-methane, non-ethane hydrocarbon⁷⁴ reduction and 80% CO reduction for the Tenaska 248 MW GE Frame 7FA combined cycle plant with the catalyst located in a high temperature zone of 1000 to 1100°F. The guarantee letter is attached in (05-31-00 CVRP comments on MEC PDOC: Exhibit 39).⁷⁵ Although we do not know the precise location and hence gas temperature where catalyst would be located in the Metcalf HRSG, it likely would be located in the high temperature zone of the HRSG where the temperature is 600-650 F. Therefore, high collateral VOC reductions of at least 30% and perhaps as high as 50% could be readily achieved for Metcalf using a conventional oxidation catalyst and substantially higher for SCONox.

B. CO Itself Is An Ozone Precursor

CARB and EPA Region 9 have historically declined to establish a lower CO BACT level than 6 ppm averaged over 3 hours because CO is attainment in most of California, most of the ambient CO is caused by motor vehicles, and the current BACT level is less than the ambient air quality standard on CO (see CARB 9/99, p. 29). However, these are not valid reasons under the federal definition of BACT to decline to establish a valid BACT limit.

Carbon monoxide is oxidized in the atmosphere to ozone.⁷⁶ Generally, the ozone formation potential of CO compared to most VOCs is quite low, but varies with atmospheric composition.⁷⁷ The ozone formation potential of CO is only 5% to 20% of that of poorly reactive alkanes (ethane, propane) and alcohols, and substantially less for more reactive compounds such as aromatics and highly reactive alkanes. Because CO has a low ozone formation potential on a per weight basis, EPA and other regulatory agencies do not consider CO to be an ozone precursor and have exempted it from ozone precursor status. However, ambient CO concentrations in much of California are typically several parts per million – considerably higher than precursor VOCs, which are collectively present at several hundred parts per billion of carbon. Consequently, despite its low specific reactivity, CO may still contribute significantly to the formation of ozone. This is a particularly important issue in the Bay Area, which was recently re-designated by EPA as nonattainment for ozone. Further, the NSR Manual requires that ozone precursors be evaluated in the environmental analysis required under the top-down BACT analysis.

⁷⁴ The vast majority of the organics in turbine exhaust are methane and ethane, which are not ozone precursors and, therefore, not included in ROC.

⁷⁵ Letter from Abe Rosenstein, Englehard Corp., to Chuck Eliason, Tenaska, Re: Tenaska Frederickson Washington Project, December 2, 1992.

⁷⁶ John H. Seinfeld and Spyros N. Pandis, Atmospheric Chemistry and Physics, John Wiley & Sons, Inc., New York, 1998, at p. 241; Peter Warneck, Chemistry of the Natural Atmosphere, 2nd Ed., International Geophysics Series, Volume 71, 1999, at p. 256.

⁷⁷ W. Carter, Development of Ozone Reactivity Scales for VOC, Journal of the Air and Waste Management Association, v. 44, 1994, pp. 881 *et seq.*

Two studies have modeled the contribution of VOCs and CO to ozone formation at various VOC/NO_x ratios.⁷⁸ The results are summarized in Table 5.

In the Los Angeles study, the initial composition of the atmosphere was selected to represent summertime conditions in Los Angeles -- 1,100 ppb of nonmethane hydrocarbons (“NMHC”) and 1,500 ppm of CO expressed as carbon. The results indicate that CO contributes 5% to ozone formed under conditions representative of the Los Angeles Basin. (Exhibit 40.)⁷⁹

In a similar study in Atlanta, initial conditions were selected to represent typical center city values -- 816 ppb of VOCs and 1,200 ppb of CO expressed as carbon. CO contributed 17.5% to the 209 ppb ozone peak. (Exhibit 41.)⁸⁰ The considerably larger contribution of CO to ozone in Atlanta compared to Los Angeles is likely due to several reasons: First, the initial CO/NMHC ratio was higher in Atlanta (1.47 vs. 1.36). Therefore, CO accounted for a somewhat larger fraction of total carbon in Atlanta than in Los Angeles. Second, the Atlanta model included a gradual increase in mixing height during the day, as well as the presence of 500 ppb of CO aloft, compared to 30 ppb of VOC aloft. Thus, mixing caused greater dilution of VOC than CO. Third, the VOC composition in Atlanta contained lower fractions of highly reactive species, particularly of alkenes. This would tend to reduce overall ozone production, and also increase the relative importance of less reactive species, such as CO, methane, and alkenes.

Thus, while CO is a relatively weak ozone precursor compared to many organic compounds such as alkenes, the concentration of CO is substantially higher than other precursor compounds. Therefore, as demonstrated by the two studies summarized in Table 5, CO can contribute substantially to atmospheric ozone.

The relative ozone formation potential of CO from Metcalf can be estimated and compared to that of VOC emissions using the relative reactivity scale developed and routinely updated by Carter. (Exhibit 42.)⁸¹ The “incremental reactivity” of a VOC (grams of ozone per gram of VOC) has become an established method of quantifying and comparing ozone formation potential under specific atmospheric conditions. Thus, the VOC equivalents of CO emissions can be conservatively estimated from the incremental reactivity of CO relative to propane, the least reactive compound considered a VOC by EPA.

⁷⁸ The atmospheric chemistry of NO_x and VOC exhibits significant non-linearity. Thus, modeling is required for a more quantitative assessment of these factors.

⁷⁹ F. Bowman and J. Seinfeld, Ozone Productivity of Atmospheric Organics, Journal of Geophysical Research, v. 99, 1994, pp. 5309 *et seq.*

⁸⁰ Harvey E. Jeffries, Photochemical Air Pollution, In: H.B. Singh (Ed.), Composition, Chemistry, and Climate of the Atmosphere, Van Nostrand Reinhold, New York, 1995, § 9.4.1.

⁸¹ W. Carter, Documentation of the SAPRC-99 Chemical Mechanism for VOC Reactivity Assessment, CARB Report, Draft, September 1999.

Most recent reactivity data (Exhibit 42) indicate that the mass-based reactivity of propane exceeds that of CO by a factor of 9 to 10. The ratio of reactivity of two different ozone precursors varies with atmospheric conditions, particularly the VOC/ NO_x ratio.⁸² However, the relative reactivity of poorly reactive compounds, such as CO and lighter alkanes, such as propane, are not very sensitive to atmospheric composition.⁸³ Thus, using a VOC-equivalency factor of 0.1 for CO represents the most conservative choice for assessing the relative ozone formation potential of CO emissions because it is based on propane. Consequently, the ozone-forming potential of permitted CO emissions from Metcalf of 735.1 ton/yr (PDOC, Condition 25, p. 29) corresponds to about 74 ton/yr of VOC emissions or nearly 1.5 times more VOCs than the Project would emit directly (49 ton/yr).

The actual contribution of CO to ozone formation, compared to more reactive VOCs, could be larger because the reactivity scales do not consider the fact that poorly reactive compounds such as CO have a longer effective residence time in the atmosphere, compared to more reactive species which are more rapidly converted, which may increase their total yield compared to more reactive compounds. Thus, during inversions and other conditions when atmospheric dispersion is poor, CO and alkanes will contribute, on a per mass basis, more to ozone formation than projected from their incremental reactivity. An assessment of the impact of such conditions on the relative ozone formation potential of CO can only be evaluated by modeling on a case-by-case basis. However, the above discussion suggests that CO emissions from Metcalf would contribute emissions of VOC equivalents of at least 74 ton/yr.

The formation of ozone precursors must be considered in the environmental analysis required as part of the top-down process. In fact, the NSR Manual specifically contemplates that precursor compounds be considered in the BACT analysis, as is demonstrated by the following statement:

“For example, the use of certain volatile organic compound (VOC) control technologies can increase nitrogen oxides (NO_x) emissions. In this instance, the reviewing authority may want to give consideration to any relevant local air quality concern relative to the secondary pollutant (in this case NO_x in favor of one having less of an impact on ambient NO_x concentrations.” (NSR Manual, p. B.49.)

In sum, Metcalf’s CO emissions would result in the formation of about 79 ton/yr of ozone in an area that currently violates the federal and California ozone standard. Thus, a CO BACT limit more stringent than 10 ppm is warranted.

⁸² Federal Register, Revision to Definition of Volatile Organic Compounds - Exclusion of Acetone, v. 60, p. 31633, June 16, 1995.

⁸³ Personal communication, J. Phyllis Fox, Ph.D. with William Carter, University of California at Riverside, Air Pollution Research Center (909-781-5797), December 1999.

VII. VOC LIMIT IS NOT BACT

The District established BACT for POCs as 2 ppmvd @ 15% O₂ averaged over 1 hour based on CARB's Guidance Document. In making this determination, the District erroneously eliminated from consideration or overlooked source tests that suggest that BACT for POCs is lower. (PDOC, p. 11.) Substantial evidence, not considered by the District, demonstrates that 2 ppmv is not BACT for the Project's POC emissions. The evidence reviewed below collectively indicates that BACT for POCs is a limit of no more than 0.1 ppmv based on the Crockett and River Road source tests.

In spite of its CO compliance problems, the Crockett facility achieved 0.007 ppm in one test and 0.041 in the other (CARB 9/99, Table C-12). These source tests show that emission levels are much lower than the BACT level of 2 ppm selected by the District as BACT for POC. The low POC emission levels achieved at Crockett were confirmed at the River Road Generating Project, a 248-MW GE Frame 7FA turbine that source tested at 0.0 ppm [sic] at 15% O₂. (Ex. 25.) These two units are comparable to Metcalf with respect to size, operation mode, and fuel composition. Thus, the District should have selected a much lower POC limit than 2 ppm as BACT for Metcalf.

The CARB Guidance Document also reports much lower achieved in practice POC limits including <0.8 ppmv at Bear Mountain and <0.67 to <0.71 ppmv at Brooklyn Navy Yard. Although the turbines are smaller than proposed by Metcalf, the size and load of the turbine do not affect the ability of an oxidation catalyst to control either CO or POCs. This is demonstrated by four sets of source tests in Exhibit 25, which were conducted at both 50% and 100% loads. These tests show comparable POC levels and performance of the oxidation catalyst at both loads. The POC (and CO) limit that can be achieved by an oxidation catalyst depends on the stack gas composition and the design of the oxidation system, not on the size of the turbine or its operating mode. The operating mode is normally accommodated in the design of the oxidation catalyst by simply increasing the volume of catalyst to control potential excursions during low load operation.

Similarly, the District ignored the lower POC BACT limits that have been established for Calpine's Sutter Power Project (1.0 ppmv) and for La Paloma Generating Company (1.1 ppmv). As discussed above, to qualify for inclusion in the top down process, an emission limit need only be specified in a permit, not demonstrated in practice. Therefore, the District should have explicitly considered these lower permit limits in its BACT decision.

VIII. STARTUP AND SHUTDOWN EMISSIONS ARE IMPROPERLY PERMITTED

The District did not consider startup and shutdown emissions in its BACT analysis. Further, the proposed limits are inconsistent with vendor data. These two issues are discussed below.

A. BACT Has Not Been Required For Startup And Shutdown Emissions

During startups and shutdowns, combustion temperatures and pressures change rapidly, resulting in inefficient combustion and higher emissions of NO_x, CO, and VOCs than during steady state operation. Further, during much of this transient period, the flue gas temperatures are lower than the design temperature of the SCR and oxidation catalysts, reducing their removal efficiency and further increasing emissions.

The U.S. EPA has consistently defined startup and shutdown to be part of the normal operation of a source. (Bennett 9/28/82,⁸⁴ 2/15/83.⁸⁵) The U.S. EPA has also consistently concluded that these emissions “should be accounted for in the design and implementation or the operating procedure for the process and control equipment. Accordingly, it is reasonable to expect that careful planning will eliminate violations on emission limitations during such periods.” (Ibid.) Furthermore, the new source performance regulations under the Clean Air Act provide as follows:

At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. (40 CFR § 60.11(d).)

CARB has also stated that “the BACT decision should consider control of emissions during such periods of operation.” (CARB 9/99, p. 34.) Hence, the Project’s startup and shutdown emissions should be considered in the BACT analysis, and all reasonable measures should be taken to minimize these emissions. (Rasnic 1/28/93.⁸⁶)

The draft permit in the PDOC includes separate limits for NO_x and CO for hours in which startups and shutdowns occur. (Draft Permit, Condition 21.) The EPA does not generally concur with this method of limiting startup and shutdown emissions. (Rasnic 1/28/93, p. 2.) The record contains no evidence that the Project’s startup and shutdown emissions were evaluated in the BACT analysis, or that efforts would be made to assure that these emissions are appropriately controlled.

⁸⁴ Letter from Kathleen M. Bennett, Office of Air, Noise and Radiation, to Assistant Administrator for Air, Noise and Radiation Regional Administrators, Regions I-X, Subject: Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions, September 28, 1982.

⁸⁵ Letter from Kathleen M. Bennett, Assistant Administrator for Air, Noise and Radiation, to Regional Administrators, Regions I-X, Subject: Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions, February 15, 1983.

⁸⁶ Letter from John B. Rasnic, Director, Stationary Source Compliance Division, Office of Air Quality Planning and Standards, to Linda M. Murphy, Director, Air, Pesticides and Toxics Management Division, Region 1, Subject: Automatic or Blanket Exemptions for Excess Emissions During Startup and Shutdowns Under PSD, January 28, 1993.

The proposed permit limits for the Project’s startup and shutdown emissions are much higher than levels that are routinely achieved using SCONOx. SCONOx is capable of achieving much lower emissions during startup and shutdown because it is fully operational at much lower temperatures, typically 300°F, than other catalytic-based systems.

The Applicant's turbine vendor could optimize the startup/shutdown process to reduce the Project’s startup and shutdown emissions. In addition, there are a number of controls available to the Applicant that could be used to satisfy BACT and reduce startup and shutdown emissions. These include the following:

- Use of an auxiliary boiler or other source of sealing steam to reduce startup time.
- Use of a stack damper to keep the HRSG hot during shutdown;
- Early injection of NH₃ into the SCR;
- Use of alternatives to low-NO_x combustor technology, such as XONON, which can achieve 3 ppm NO_x at 15% O₂ as currently proposed by Pastoria;
- Use of more efficient primary control technologies, such as SCONOx; and/or
- Use of other methods to more quickly heat up the catalysts in the control technologies. (CARB 9/99, p. 35)
-

B. Startup And Shutdown Emissions Are Inconsistent With Vendor Data

The District established startup and shutdown emissions in draft Permit Condition 21, apparently calculated by multiplying the hourly startup emission rate by the estimated startup time. (AFC, Supplement C, Table 8.1A-2.) However, the Applicant's data that the District relied on is inconsistent with vendor data submitted in other cases. The following table compares the proposed permit limits with data supplied by Westinghouse for its 501F machine in other cases:

	EMISSIONS (lbs per event per turbine)					
	NOx		CO		POC	
	Cold	Hot	Cold	Hot	Cold	Hot
TMP	556	153	1163	853	146	115
Sutter	306	170	1466	902	-	-
MSEP	350	120	1825	970	200	120
MEC	240	80	2514	902	48	16

These data indicate that the proposed permit limits for NOx and POCs are substantially lower than vendor-supplied data while the CO cold start limit is substantially higher. Therefore, the District should request supporting vendor data and verify that the proposed permit limits are reasonable. The District should also require that the continuous emissions monitoring cover startup and shutdown periods, and require the Applicant to use a CEM system, which is capable

of producing accurate measurements during the varying conditions, which will exist during startups and shutdowns.

IX. PM10 EMISSIONS ARE IMPROPERLY ESTIMATED AND PERMITTED

A. The Level of PM10 Emissions is Understated in the PDOC

1. PM10 emissions from the gas turbine and duct burners

The PDOC is based on a PM₁₀ emission rate of 12 lb/hr (PDOC, p. 27, Condition 20(h)), broken down as 10 lb/hr for the gas turbine and 2 lb/hr for duct firing and steam injection for power augmentation. This emission rate is used to determine the need for PM10 offsets and PSD review, both of which are triggered if emissions exceed 100 ton/yr. The total PM10 emissions, based on this limit, are 90.6 ton/yr without standby engines or cooling towers and 98.55 ton/yr with cooling towers and standby engines (PDOC, Table 3), allowing the Project to escape offsetting its PM10 emissions and going through PSD review for PM10. Although the PDOC claims that this emission rate is based on a vendor guarantee (PDOC, pp. A-4, A-5), the guarantee is not provided and the rate itself is inconsistent with emission rates quoted by Westinghouse for other similar sized projects.

Vendor-guaranteed emissions for Westinghouse 501F engines for other similar projects are included here and compared to the emissions claimed by Metcalf in the following table (the two lines for Metcalf are without and with duct burners, respectively):

Project	Fuel MMBtu/hr LHV	Vendor PM10 lb/hr	Adjusted PM10 lb/hr
New Milford	1875	8.45	16.2
Three Mountain	1689	16.4	17.4
Midway-Sunset	1704	19.2	20.2
Elk Hills	1728	17.3	18.8
Sutter	1705	30.3	31.9
Metcalf	1794	10	
Metcalf	1914	12	
AVERAGE			20.1

The emissions in this table were adjusted to a Metcalf basis (last column) to account for difference in fuel flow. The New Milford, Connecticut PM10 data were also doubled to account for the fact that only front half (filterable) PM10 is included in the vendor estimate. The vendor-

guaranteed PM10 emissions range from 17.9 lb/hr per turbine to 30.3 lb/hr per turbine, with the highest value for the nearly identical Calpine Sutter Project with duct burners and steam injection. These emissions are substantially higher than the 12 lb/hr claimed in the PDOC for Metcalf. Therefore, the District should support the PM10 emissions with a valid vendor quote.

Normally, a vendor guarantee is required to confirm that a proposed BACT limit is technically feasible. (NSR Manual, p. B.20.) There is no evidence here that a vendor guarantee for the 12 lb/hr has been obtained. The magnitude of the proposed limit suggests that it is based only on front half or so-called filterable PM10. Federal regulations require that permits be based on total PM10.

A number of power plant applicants have recently proposed similarly low PM10 limits based only on the filterable fraction to reduce PM10 offset liability (e.g., Sunrise, Moss Landing), assuming that the condensable fraction of PM₁₀ is negligible. They are gambling that exceedances will not be detected because only annual or less frequent source testing is required, during which operations are typically optimized to minimize emissions immediately prior to a source test.

We reviewed source tests of similar facilities to determine whether the proposed limit could reasonably be expected to be met (see Table 6). This review demonstrates that the PDOC's limit is unrealistically low, unlikely to be achieved in practice, and, if based only on the filterable or front-half portion of PM10, which is about 50% of the total, is based on a faulty assumption. (Table 6.) Based on these source tests, it is likely that the proposed limit will be exceeded.

However, it is unlikely that the exceedances will be detected, unless a continuous emission monitor is used. It is well known that “[m]annual stack tests are generally performed under optimum operating conditions, and as such, do not reflect the full-time emission conditions from a source.” (40 FR 46241 10/6/75.) A widely used handbook on CEMs notes, with respect to PM₁₀ source tests, that: Due to the planning and preparations necessary for these manual methods, the source is usually notified prior to the actual testing. This lead time allows the source to optimize both operations and control equipment performance in order to pass the tests.”⁸⁷ Therefore, it is unlikely that violations of the proposed 12-lb/hr limit would be detected.

The NSR Manual requires that “BACT emission limits or conditions must be met on a continual basis at all levels of operation...and be enforceable as a practical matter.” (NSR Manual, p. B.56.) PM₁₀ is routinely continuously monitored in Europe. The EPA has required continuous PM₁₀ monitoring on incinerators and has proposed Performance Specification 11 for their certification.⁸⁸ Therefore, we recommend that the District either require continuous monitoring for PM10, or require the Applicant to produce a valid vendor guarantee that demonstrates that 12

⁸⁷ James A. Jahnke, Continuous Emission Monitoring, 2nd Ed., John Wiley & Sons, Inc., New York, 2000, at p. 241.

⁸⁸ *Id.* at 241-242.

lb/hr represents the maximum front and back half PM10 emissions from its turbines. Source test data suggest that the proposed PM10 limit in the PDOC will be exceeded.

2. PM10 emissions from the cooling towers due to inadequate cooling tower permit conditions

The PM emissions from the 10 cooling towers contribute significantly to the ambient air concentrations of PM₁₀ concentrations. The effluents have low exit temperatures, low exit velocities and correspondingly are low in momentum and buoyancy. When ISC 3 is used to model the impact of these emissions as point sources, as was done in the applicant's submission, ISC3 models these as point sources and the Briggs plume rise equations are used. The plumes are predicted to have significant plume rise and the ground level concentrations are predicted accordingly. Observing that the releases often show little buoyancy, an alternative method of modeling the emissions is to assume they emanate from a series of volume sources based upon the dimensions of the individual cooling towers. This method better simulates the observation that there is little plume rise. When volume source configurations replace the point source approximations in ISC3, the predicted concentrations increase substantially, from a maximum value of about 8ug/m³ on a 24-hour basis to a value of 61 ug/m³. A value of 61 ug/m³ would constitute an exceedance of the Federal PSD increment of 30 ug/m³ for PM10. Because of the sensitivity of the predicted concentrations to the way that the cooling tower emissions are modeled, the applicant should attempt to demonstrate through alternative approaches, that the cooling towers would not cause an exceedance of a PSD increment

The cooling tower would emit 7.95 ton/yr of PM10, calculated assuming a cooling tower circulation rate of 133,378 gpm, a maximum total dissolved solids ("TDS") of 5,438 mg/L, and a drift rate of 0.0005%. (PDOC, p. B-7.) Proposed Condition 46 establishes a drift rate of 0.0005% and a TDS of 5,438 mg/L in the blow down to control PM10 emissions from the cooling tower. However, this condition is not sufficient to limit PM10 emissions to 7.95 ton/yr because it does not limit the circulation rate to 133,378 gpm. Further, it is not enforceable as a practical matter because it does not specify the method that would be use to measure TDS and it does not require any demonstration that the drift rate is actually met.

B. The PDOC understates the PM10 increment consumption by MEC

1. Corrected emissions factors

The PDOC concludes that the maximum increase in 24-hour PM10 concentrations due to MEC would be 9.3 µg/m³, compared to an allowable Class II area increment of 30 µg/m³ (PDOC, Table E-8). As discussed in the preceding sections, the PDOC appears to substantially understate the PM10 emissions associated with the MEC turbines and duct burners, based on data for other projects using Westinghouse 501 turbines. The PDOC may also have underestimated the PM10 emissions associated with the cooling tower, since it relies on an unverified drift fraction. And of course the PDOC makes no allowance at all for PM10 due to ammonium nitrate formed from

TABLE 6
PM10 Emissions from Gas Turbines

	Power Output (MW)	Sample Duration (min)	Analytical Method	PM10 (lb/hr)			Percent Condensible	Emission Rate Adjusted to 200 MW/turbine (lb/hr)	Source Test Firm	
				Filterable	Condensible	Total				
IE FRAME 7										
Watson Cogen (4 82.75-MW GE 7EAs 405 MW) (SCR and CO Catalyst)										
1/31/98	Unit 9100	83	72	SCAQMD	2.97	1.39	4.36	32%	10.5	Air Quality Engineering
	Unit 9200	84	72	Method 5.2	2.10	1.11	3.21	35%	7.6	Air Quality Engineering
	Unit 9300	81	72		5.23	1.15	6.38	18%	15.8	Air Quality Engineering
	Unit 9400	84	72		3.66	1.14	4.80	24%	11.4	Air Quality Engineering
Yamcamore Cogen (4 75-MW GE Frame 7s) (DLN, Water Injection)										
5/19-20/97	Unit 1 (100% load)	80	120	EPA Method 201A	2.11	1.74	3.85	45%	9.6	Parsons Engineering
5/19-20/97	Unit 1 (85% load)	64.5	120	EPA Method 201A	3.16	1.14	4.30	27%	13.3	Parsons Engineering
12/9/97	Unit 2 (100% load)	88	120	EPA Method 201A	-	-	2.72	-	6.2	Parsons Engineering
11/12-13/96	Unit 3 (100% load)	82.3	240	EPA Method 201A	1.03	2.98	4.01	74%	9.7	Parsons Engineering
11/12-13/96	Unit 3 (85% load)	69.2	240	EPA Method 201A	0.72	2.53	3.25	78%	9.4	Parsons Engineering
5/28-29/97	Unit 4 (100% load)	80.1	120	EPA Method 201A	2.72	2.05	4.77	43%	11.9	Parsons Engineering
5/28-29/97	Unit 4 (85% load)	70.6	120	EPA Method 201A	2.70	1.54	4.24	36%	12.0	Parsons Engineering
Western River Cogen (4 75-MW GE Frame 7s) (DLN, Water Injection)										
7/6-7/95	Unit 1 (100% load)	75	240	EPA Method 201	-	-	2.06	-	5.5	Parsons Engineering
5/17/95	Unit 1 (100% load)	73.3	45	EPA Method 5	4.39	1.47	5.86	25%	16.0	Parsons Engineering
5/17/95	Unit 1 (75% load)	55.5	45	EPA Method 5	3.46	0.47	3.93	12%	14.2	Parsons Engineering
11/14/95	Unit 2 (100% load)	75	240	EPA Method 201A	0.29	0.78	1.07	73%	2.9	Parsons Engineering
11/16/95	Unit 2 (75% load)	56	240	EPA Method 201A	0.18	0.06	0.24	23%	0.8	Parsons Engineering
5/6/98	Unit 4 (100% load)	71.5	120	EPA Method 201A	-	-	2.03	-	5.7	Parsons Engineering
5/7/98	Unit 4 (85% load)	83.7	120	EPA Method 201A	-	-	1.45	-	3.5	Parsons Engineering
Imperial Irrigation (1 GE 82.99-MW 7EA) (SCR and Steam Injection)										
7/8/97	Unit 2	83	110	EPA Method 5	0.72	2.37	3.09	77%	7.4	Steiner Environmental
Imperial River Road Generating Project (1 GE 231 FA 248-MW Turbine) (DLN, SCR and CO Catalyst)										
9/11/97		248	120	EPA Method 5	3.74	6.13	9.87	62%	8.0	Am-Test Air Quality
Imperial Rockett Cogen (1 160-MW GE 7FA) (DLN, SCR, and CO Catalyst)										
5/96	0% Load, No Duct Burn	160	120	EPA Method 5	2.29	-	-	-	-	Carnot
5/96	100% Load, With Duct Burr	160	120	EPA Method 5	1.03	-	-	-	-	Carnot
6/97	100% Load, With Duct Burr	160	120	EPA Method 5	0.78	-	-	-	-	Carnot
6/98	100% Load	160	120	EPA Method 5	2.82	-	-	-	-	Avogadro
	Average							43%	9.1	
Imperial Thermal & G Cogen (2 GE LM 6000 45 MW ea) (SCR and CO Catalyst)										
2/4/97	Turbine A/HRSG on	43		CARB Method 5	1.44	2.89	4.33	67%	20.1	SCEC
3/19/97	Turbine A/HRSG off	44.3		CARB Method 5	3.70	1.07	4.77	22%	21.5	SCEC
2/6/97	Turbine B/HRSG on	43		CARB Method 5	2.04	1.70	3.74	45%	17.4	SCEC
2/18/97	Turbine B/HRSG off	43.9		CARB Method 5	3.99	2.11	6.10	35%	27.8	SCEC
3/19/97	Turbine A/HRSG on	43		EPA Method 201	0.130	0.075	0.205	37%	1.0	SCEC
3/20/97	Turbine A/HRSG off	43		EPA Method 201	0.231	0.662	0.893	74%	4.2	SCEC
3/17/97	Turbine B/HRSG on	43		EPA Method 201	0.167	1.043	1.21	86%	5.6	SCEC
3/18/97	Turbine B/HRSG off	43		EPA Method 201	0.21	1.08	1.29	84%	6.0	SCEC
3/11/98	Turbine A/HRSG on	44.1	120	EPA Method 5/8	1.26	0.38	1.64	23%	7.4	Steiner Environmental
3/12/98	Turbine B/HRSG on	43.6	60	EPA Method 5/8	1.87	0.767	2.64	29%	12.1	Steiner Environmental
Imperial Ironstone Ice-Gen (2 GE LM 6000) (SCR + Water Inj; Peaker has CO Catalyst)										
9/95	Peaking Unit	42.1	240	EPA Meth. 201/202	0.45	0.18	0.63	29%	3.0	Carnot
10/95	Combined Cycle (Mixed Fu)	43.6	240	EPA Meth. 201/202	0.40	0.61	1.01	60%	4.6	Carnot
11/96	Peaking Unit CTG2	44	120	EPA Meth. 201/202	0.364	0.518	0.882	59%	4.0	Carnot
	Peaking Unit CTG2 ^a	44	120	EPA Meth. 201/202	1.94	4.11	6.05	68%	27.5	Carnot
11/96	Combined Cycle (Mixed Fu)	44	120	EPA Meth. 201/202	< 0.149	1.93	2.08	93%	9.5	Carnot
Imperial ISCO/SPA Cogen (Siemens V84.2 102 MW) (SCR and CO Catalyst)										
11/24/97		102		CARB Method 5	1.15	0.78	1.93	40%	3.8	Best Environmental
10/28/97		102	45	CARB Method 5	5.55	2.80	8.35	34%	16.4	Best Environmental
	Average							52%	11.7	

^a = 16.4 lb/hr and filterable = 5.10 lb/yr included.

ammonia slip due to use of SCR for NO_x control. After making the appropriate corrections, the District should recompute the incremental increase in maximum PM₁₀ concentrations due to MEC.

2. Alternative modeling approaches

The PM emissions from the 10 cooling towers contribute significantly to the ambient air concentrations of PM₁₀ concentrations. The effluents have low exit temperatures, low exit velocities and correspondingly are low in momentum and buoyancy. When ISC3 is used to model the impact of these emissions as point sources, as was done in the Applicant's submission, ISC3 models these as point sources and the Briggs plume rise equations are used. The plumes are predicted to have significant plume rise and the ground level concentrations are predicted accordingly. Observing that the releases often show little buoyancy, an alternative method of modeling the emissions is to assume they emanate from a series of volume sources based upon the dimensions of the individual cooling towers. This method better simulates the observation that there is little plume rise. When volume source configurations replace the point source approximations in ISC3, the predicted concentrations increase substantially, from a maximum value of about 8 µg/m³ on a 24-hour basis to a value of 61 µg/m³. A value of 61 µg/m³ would constitute an exceedance of the Federal PSD increment of 30 µg/m³ for PM₁₀. Because of the sensitivity of the predicted concentrations to the way that the cooling tower emissions are modeled, the District should attempt to use alternative approaches to test whether the cooling towers would cause an exceedance of a PSD increment.

X. THE HEALTH RISKS OF MEC ARE SIGNIFICANT

The Applicant evaluated the public health impacts of the Project to comply with the District's "Toxic Risk Management Policy" ("TRMP") and to satisfy its AB2588 LORS obligation under the Warren Alquist Act. The District's policy requires the installation of Toxics Best Available Control Technology ("TBACT") if the cancer risk is greater than one in one million or if the chronic hazard index is greater than one.

The most recent version of the Applicant's analyses are contained in Supplement C to the AFC and in responses to data requests in the CEC proceeding, which have been adopted in the PDOC as complying with the District TRMP. (PDOC, pp. 16-17, Appx. D.) These analyses underestimate health risks. When the errors and omissions discussed below are corrected, the Project is found to result in significant cancer, chronic, and acute health impacts, requiring additional mitigation and/or denial of the Project.

A. Cancer Impacts From The Turbine Are Significant

The Applicant estimated incremental cancer risk (number of additional cancers per million people exposed) using the CAPCOA Risk Assessment Guidelines.⁸⁹ (AFC, § 8.6.) Incremental cancer risk is calculated by estimating toxic emissions, modeling these emissions to estimate corresponding ambient concentrations, multiplying the modeled ambient concentration by a cancer unit risk factor, and summing over all compounds. A cancer unit risk factor expresses an individual's risk of contracting cancer for a given amount of pollutant breathed. It is expressed as the cancer risk per amount of a pollutant in a volume of air (i.e., risk per $\mu\text{g}/\text{m}^3$). Risk factors are published on the Office of Environmental Health Hazard Assessment's ("OEHHA's") website.⁹⁰

1. Partial Load Operation

The Applicant's calculations, summarized in the PDOC, suggest that the total cancer risk is 0.2 in one million, which is less than the significance threshold of one in one million. These calculations assume that both turbines are operating simultaneously at full load with the duct burners firing. However, emissions of some toxic compounds are substantially higher during reduced loads, such as occur during startup, shutdown, and partial load operation, than during routine operation.

The Gas Research Institute ("GRI") investigated the effect of load on criteria and toxic pollutant emissions from nine gas turbines including a large Frame 7 turbine. This study found that emissions of benzene, toluene, formaldehyde, methane, and total nonmethane hydrocarbons increase with load. Emissions of formaldehyde, a carcinogen, increased dramatically, by up to a factor of 343 when the load was reduced from 100% to 20%. For the 750 MW GE Frame 7, the formaldehyde emission factor increased from 15 $\text{lb}/10^{12}$ Btu to 7,539 $\text{lb}/10^{12}$ Btu, or by a factor of 503, and the formaldehyde emissions increased from 0.11 to 16.08 tons/yr or by factor of 146, when the load was reduced from 100% to 30%. (GRI 8/96,⁹¹ Table S-5.) This substantial increase in formaldehyde emissions during reduced load operation was not taken into account in the Applicant's risk calculations.

The maximum annual emission calculations in the PDOC are based on 520 1-hour hot startups per year and 104 3-hour cold startups per year. (PDOC, p. B-5.) Therefore, the facility will be operating at reduced load during startups for up to 832 hours per year, or perhaps even more.⁹²

⁸⁹ California Air Pollution Control Officers Association (CAPCOA), Air Toxics "Hot Spots" Program Revised 1992 Risk Assessment Guidelines, October 1993.

⁹⁰ www.oehha.ca.gov.

⁹¹ Gas Research Institute (GRI), Gas-Fired Boiler and Turbine Air Toxics Summary Report, Final Report, August 1996.

⁹² There is no actual condition in the PDOC limiting startups to the levels shown in Table B-5. Proposed condition 24 sets maximum daily emissions limits, which are calculated in Table B-13. Table B-13 is based

One or both turbines may also operate at reduced load for additional hours during non-startup periods, which are ignored here, but which would generally increase formaldehyde emissions beyond those claimed below. Using the Applicant's formaldehyde emission factor of 0.11 lb/MMscf (PDOC, Table B-8) for 7,928 hour per year (8,760 hr - 832 hr = 7,928 hrs) and an emission factor that is 146⁹³ times higher for the 832 hours of partial load operation results in annual load-weighted formaldehyde emissions that are 14.8 times higher than those evaluated by the Applicant in the cancer risk analysis.⁹⁴ This increases the cancer risk due to formaldehyde alone from 6.30×10^{-8} to 9.3×10^{-7} .⁹⁵

The change in formaldehyde risk alone would increase the total cancer risk of the Project from 0.2 in one million (0.20×10^{-6}) assumed in the PDOC (Table 7) to slightly over one in one million (1.07×10^{-6}). Acetaldehyde is an aldehyde that is chemically similar to formaldehyde. Assuming that it increases in like fashion, the cancer risk from acetaldehyde alone would increase from 1.76×10^{-8} to 1.99×10^{-7} . Benzene and possibly other toxics would also increase, further increasing cancer risk. This exceeds the significance threshold of one in one million and requires that TBACT be installed. At a minimum, TBACT would be either an oxidation catalyst or SCONOX, both of which have been demonstrated to reduce aldehydes. (Comment --.)

We note here that the PDOC condition purporting to eliminate formaldehyde emissions to 1898 pounds per year (proposed condition 26) is no substitute for TBACT. Compliance with proposed condition 26 is to be done by calculating formaldehyde emissions based on “the highest emission factor determined by any source test” of the turbines and HRSGs (proposed PDOC condition 29). Unless the source testing is done during startup or low-load conditions it will not reveal the high formaldehyde emission rates identified by GRI. A refinement to condition 29 requiring source testing at low load and/or start-up conditions should be an additional MEC condition, in addition to requiring TBACT for aldehydes.

on 2 cold starts and two hot starts (one each per turbine) in a single day. If market conditions reduce the number of hours of full load operation or duct burner operation, MEC could operate with more than 832 hours per year being startup hours and not be in violation of any proposed permit condition. To avoid the negative implications of repeated startups for toxics emissions, CVRP recommends that the assumed limits of one hot and one cold start per day (Table B-13) and 260 hot starts and 52 cold starts per year per turbine (Table B-5) be made into permit conditions.

⁹³ The factor of 146, which is based on annual emissions, takes into account reduced fuel use during partial load operation.

⁹⁴ Formaldehyde emissions adjusted to account for partial load operation = $[(0.11)(832 \text{ hr})(146) + (0.11)(7928)]/8760 = 1.625$. The increase in emissions is $1.625/0.11 = 14.77$.

⁹⁵ Increase in formaldehyde cancer risk due to partial load operation = $(1.05 \times 10^{-2} \text{ ug/m}^3)(6.0 \times 10^{-6})(11.3) = 9.31 \times 10^{-7}$.

2. Dry Low NOx Combustors

The Applicants used CARB's CATEF database to estimate toxic emissions of all chemicals except acrolein (which is discussed in Comment --). We suspect that the combustors on the turbines used to develop these emission factors were based on the diffusion-flame principle and were not equipped with pre-mixed, dry low NOx combustors, which are now widely used to control NOx. The CATEF database is based on measurements that were made between 1988 and 1992, when steam injection was predominately used to control NOx rather than pre-mixed combustors.

The GRI study included in Exhibit 44 indicates that pre-mixed low NOx combustors increase emissions of formaldehyde by about a factor of 6.6 during full load and by a factor of 11.4 during reduced load, compared to the same turbine without a low-NOx combustor. (Ex. 44 Table S-5, p. 8.) Benzene emissions are almost 40 times greater during reduced load operation for a turbine with low-NOx combustors as for the same kind of turbine without them, and are over twice as great during full-load operation when a low-NOx combustor is used (ex. 44, Table S-5, p.8)

The Project proposes to use a dry low NOx combustor to control NOx. Therefore adjustment factors have been included in Table 8 to account for increased emission associated with turbines using low-NOx combustors.

3. Other Carcinogens

The Applicant's analysis only considers five carcinogens: acetaldehyde, benzene, 1,3-butadiene, formaldehyde, and PAHs. However, dioxins, furans, hexavalent chromium, lead, and nickel are

present in the emissions from Frame 7 machines. (ESI 6/30/92.⁹⁶) We did not include them in our analysis because cancer risks exceed significance thresholds without them. However, the Applicant should be required to revise its risk calculations to include these additional substances, because they may make a significant contribution when considering controls to reduce risks from

TABLE 7
Revised Health Risk Assessment for Gas Turbines

Compound	Emission Factor lb/MMscf	EMISSION RATES (each turbine)		MODELED CONCENTRATION ^a ($\mu\text{g}/\text{m}^3$)		RISK FACTORS			CALCULATED RISK		
		One-hour Impacts, g/s	Annual Impacts, g/s	One-hour Impacts	Annual Impacts	Cancer Unit Risk Factor ($\mu\text{g}/\text{m}^3\text{-}1$)	Acute REL ($\mu\text{g}/\text{m}^3$)	Chronic REL ($\mu\text{g}/\text{m}^3$)	Cancer Risk	Acute Hazard Index	Chronic Hazard Index
Acetaldehyde ^b	6.86E-02	3.00E+01	2.07E+01	9.57E+02	8.41E-01	2.70E-06		9	2.27E-06		9.35E-02
Acrolein ^c	2.37E-02	1.03E+02	7.60E+00	3.31E+03	2.90E+00		1.90E-01	0.02		1.74E+04	1.45E+02
Ammonia		3.58E+00	3.41E+00	1.15E+02	1.31E+00		3.20E+03	200		3.59E-02	6.55E-03
Benzene ^d	1.36E-02	7.83E-02	4.06E-02	2.51E+00	1.55E-02	2.90E-05	1.30E+03	60	4.49E-07	1.93E-03	2.58E-04
1,3-Butadiene	1.27E-04	3.33E-05	3.15E-05	1.07E-03	1.21E-05	1.70E-04			2.06E-09		
Ethylbenzene	1.79E-02	4.69E-03	4.44E-03	1.50E-01	1.70E-03			2000			8.50E-07
Formaldehyde ^b	1.10E-01	4.79E+01	3.52E+00	1.54E+03	1.35E+00	6.00E-06	9.40E+01	3	8.13E-06	1.63E+01	4.52E-01
Hexane	2.59E-01	6.78E-02	6.43E-02	2.17E+00	2.46E-02			7000			3.51E-06
Naphthalene	1.66E-03	4.35E-04	4.12E-04	1.39E-02	1.58E-04			9			1.76E-05
PAHs	6.60E-04	1.73E-04	1.64E-04	5.54E-03	6.28E-05	1.70E-03			1.07E-07		
Propylene	7.71E-01	2.02E-01	1.91E-01	6.46E+00	7.32E-02			3000			2.44E-05
Propylene oxide	4.78E-02	1.25E-02	1.19E-02	4.01E-01	4.55E-03	3.70E-06	3.10E+03	30	1.68E-08	1.29E-04	1.52E-04
Toluene	7.10E-02	1.86E-02	1.76E-02	5.95E-01	6.75E-03		3.70E+04	300		1.61E-05	2.25E-05
Xylene	2.61E-02	6.83E-03	6.48E-03	2.19E-01	2.48E-03		2.20E+04	700		9.95E-06	3.54E-06
TOTAL									1.10E-05	1.74E+04	1.46E+02

a Modeled unit impacts: 16.01339 $\mu\text{g}/\text{m}^3$ per g/s, 1-hour average; 0.19153 $\mu\text{g}/\text{m}^3$ per g/s, annual average; except ammonia modeled at actual emission rates.

b Applicant's annual emissions and concentrations increased by a factor of 129 to account for partial load operation (x 11.3) and use of DLN combustor (x 11.4). Applicant's one-hour emissions and concentrations increased by a factor of 1664 to account for partial load operation (x 146) and DLN combustor (x 11.4)

c Applicant's annual emissions and concentrations increased by a factor of 4753 to account for partial load operation (x 11.3), use of DLN combustor (x 11.4), analytical problem (x 10), and use of wrong emission factor (3.69). Applicant's one-hour emissions and concentrations increased by a factor of 61,416 to account for partial load operation (x 146), DLN combustor (x 11.4), analytical problem (x 10), and use of wrong emission factor (3.69).

d Applicant's annual emissions and concentrations increased by a factor of 12 to account for partial load operation (x 1.1) and use of DLN combustor (x 11). Applicant's one-hour emissions increased by a factor of 22 to account for partial load operation (x 2) and DLN

⁹⁶ Engineering-Science, Inc., Air Toxic Emissions Testing of a Natural Gas Fired Turbine at Sycamore Cogeneration Company, Bakersfield, California, June 30, 1992.

the volatile organic compounds discussed above.

B. Cancer And Noncancer Impacts From Emergency Diesel Engines Are Significant

The CEC and the District required the Applicant to evaluate the health impacts of diesel exhaust particulates from the standby fire pump diesel engine in anticipation of pending amendments to District Regulation 2, Rules 1 and 2. (PDOC, p. D-1.) The firewater pump is a 300-hp Cummins engine that would be tested for about 30 minutes each week, up to 100 hours per year. The Applicant's risk calculations are included in its response to CEC data request PH-2 and indicate that the total cancer risk is 0.89 in one million, which is less than the significance threshold of one in one million. The Applicant's calculations also indicate that the 1-hour concentration of diesel exhaust is 12 ug/m^3 , which is less than the acute reference exposure level of 50 ug/m^3 and the annual average concentration of 2.98×10^{-3} is less than the chronic reference exposure level of 5 ug/m^3 . (Metcalf Response to CEC Data Request PH-3, 4/7/00, p. 5.) Therefore, according to the Applicant, diesel exhaust from the fire pump engine would not cause significant health impacts. (PDOC, pp. 16, D-2.) However, there are two problems with the Applicant's analysis, which substantially underestimate cancer risk.

First, the Applicant performed its calculations for the nearest residence. Health risks are usually calculated at the point of maximum impact. (CAPCOA 11/93.) This is particularly critical in a rapidly growing area where land use is changing, such as the Project site. Therefore, we remodeled the fire pump using the Applicant's emissions and stack parameters to determine the point of maximum impact and corresponding concentrations of diesel exhaust. This analysis shows that the 1-hour concentration of diesel exhaust increases from 12 ug/m^3 at the nearest residence to 52.5 ug/m^3 at the point of maximum impact (UTM 611400, 4119720). Similarly, the annual concentration increases from $2.98 \times 10^{-3} \text{ ug/m}^3$ at the nearest residence to $9.29 \times 10^{-3} \text{ ug/m}^3$ at the point of maximum impact (UTM 611400, 4119720).

Assuming the point of maximum impact is developed for commercial use in the future, which cannot be precluded given growth in the area, the cancer risk increases from 0.89×10^{-6} claimed by the Applicant to 2.79×10^{-6} ,⁹⁷ which exceeds the significance threshold of one in one million. Similarly, the maximum 1-hour concentration of 52.5 ug/m^3 exceeds the acute REL of 50 ug/m^3 . The corresponding hazard index ($52.5/50 = 1.05$) exceeds the significance threshold of one. Therefore, acute and cancer impacts from the firewater pump are significant, requiring mitigation. Installing Engelhard or equivalent soot filters can control Diesel exhaust from firewater pumps.

Second, the Applicant modeled the subject pump assuming a 35 ft high vertical stack. The pump is located within a 24-foot high building. (AFC, Figs. 2.2-1 and 2.2-2.) Typically, pump stacks

⁹⁷ Revised cancer risk due to firewater pump = $(9.29 \times 10^{-3} \text{ ug/m}^3)(3 \times 10^{-4} (\text{ug/m}^3)^{-1}) = 2.79 \times 10^{-6}$. This value does not need to be adjusted for a shorter exposure period for workers because it is addressed in the calculation of the annual emission rate of $2.38 \times 10^{-4} \text{ g/sec}$.

that are vented out of a building are run up the side of the building to about 5 feet above roof level. Therefore, the 35-ft high stack modeled by the Applicant is on the high side, underestimating ambient concentrations. Further, the exits of these types of stacks are conventionally outfitted with a rain hat or a gooseneck to keep out rain. Emissions from rain-hooded and gooseneck vents would be deflected downward towards the roof. Therefore, they have no vertical buoyancy and are normally modeled with an exit velocity of zero or as a fugitive volume source.

We remodeled the firewater pump with an exit velocity of zero. This increased the maximum annual concentration to $1.23 \times 10^{-2} \text{ ug/m}^3$ and the corresponding cancer risk to 3.68×10^{-6} .

Therefore, the Applicant has substantially underestimated health impacts of diesel exhaust from the emergency pumps. Diesel exhaust particulate concentrations exceed significance thresholds, which require that the District require controls.

C. Noncancer Health Impacts From Turbines Are Significant

The Applicant estimated Noncancer health impacts using the hazard index approach. A hazard index is the ratio of the ambient concentration, estimated by modeling, to the reference exposure level or REL, which is the concentration deemed by OEHHA as being safe.⁹⁸ The total hazard index is the sum of the indices for individual compounds. If the chronic hazard index exceeds one, impacts are significant and TBACT is required. The District does not evaluate the acute hazard index, but the Energy Commission typically considers an acute hazard index greater than one as significant. The Applicant estimated a chronic hazard index of 0.06. (AFC, p. 3-4; PDOC, Table D-2.) As discussed above, this index is underestimated because the Applicant's calculations do not take into account-increased emissions during partial load operation and the use of a DLN combustor. In addition, the Applicant made a questionable adjustment to the acrolein emission factor.

1. Acrolein Emission Factor

The Applicant originally estimated acrolein emissions using the CARB emission factor of 2.37×10^{-2} pounds per million standard cubic feet of gas combusted ("lb/MMscf"). However, these original calculations were based on outdated acute reference exposure levels ("acute RELs"). Thus, the Energy Commission directed the Applicant to revise their health risk assessment to use current acute RELs. (CEC Data Request 63, 8/23/99, p. 62.) This increased the acute hazard index from 0.16 (AFC, Table 8.6-6) to 1.05,⁹⁹ exceeding the significance level

⁹⁸ Acute RELs are found at www.oehha.ca.gov/air/acute_rels/allAcRELS.html. Chronic RELs are found at www.oehha.ca.gov/air/chronic_rels/AllChrels.html.

⁹⁹ The Applicant argues that this change "would not affect the determination that the acute hazard index is well below 1.0." (Metcalf Response to Staff Data Request PH-1, 4/7/00, p. 2). However, this does not appear to be correct. The revised acute REL is given by: $0.33 - 0.284 + 0.284(2.37 \times 10^{-2} / 6.43 \times 10^{-3}) = 1.05$.

of one. Therefore, the Applicant apparently reduced the acrolein emission factor from 2.37×10^{-2} to 6.43×10^{-3} to reduce acute health impacts below the significance level of one. (AFC, Supplement C, Table 8.1A-3.) This adjustment is wholly unsupported.

Both the Energy Commission Staff (CEC Data Request PH-1, April 7, 2000) and the District (Jang 3/2/00¹⁰⁰) requested a clarification of this change. The Applicant explained that the original emission factor was based on four source tests, only one of which was conducted on a Frame 7 machine. Therefore, the Applicant used the single source test on the Frame 7, which lowered the acrolein emission factor from 2.37×10^{-2} to 6.43×10^{-3} lb/MMscf. This is not justified as explained below.

Acrolein is the most toxic compound emitted by the gas turbines. It is a double-bonded aldehyde which causes eye, nose and throat irritation. It has the lowest acute and chronic reference exposure level among all of the substances emitted by the turbine. Therefore, very small concentrations of acrolein, much smaller than any other compound emitted by the Project, will result in significant health impacts.

The Applicant's risk assessment relied on a revision to the acrolein emission factors reported in CARB's CATEF database. However, the acrolein emission factor in this database was based on source tests in which acrolein was measured by CARB Method 430. (CARB 4/96.¹⁰¹) CARB has recently published an advisory that states: "any data or results, based on the use of M430 to determine acrolein...are suspect and should be flagged as nonquantitative wherever they appear." (CARB 4/28/00.¹⁰²) This method has been validated for only formaldehyde and acetaldehyde and substantially underestimates acrolein concentrations.

CARB Method 430 measures acrolein by reacting it with 2,4-dinitrophenylhydrazine ("DNPH") acidified with hydrochloric acid, which converts the acrolein into its hydrazone derivative. The hydrazone derivative is then analyzed by high performance liquid chromatography. However, the hydrazone derivatives of double-bonded aldehydes such as acrolein are not stable under acidic conditions and rapidly degrade. The acrolein hydrazone derivative begins to degrade almost immediately. After 30 minutes, 60% is degraded, after 1 hour, 70% is degraded, and after 48 hours, 93% is degraded. (Exhibit --: Freeman 1993.¹⁰³) Typically, it takes four hours to collect a sample. One to two weeks typically elapse between sample collection and analysis. Therefore, well over 90% of the acrolein is lost before the sample is analyzed.

¹⁰⁰ Letter from Dennis Jang, BAAQMD, to Ken Abreu, March 2, 2000.

¹⁰¹ California Air Resources Board, Development of Toxics Emission Factors from Source Test Data Collected under the Air Toxics Hot Spots Program: Volume 1, Final Report, April 1996.

¹⁰² Letter from William V. Loscutt, Chief, Monitoring and Laboratory Division, to All Air Pollution Control Officers/Executive Officers, Re: Advisories to Limit the Use of ARB Method 430 (M430) Determination of Formaldehyde and Acetaldehyde in Emissions from Stationary Sources, April 28, 2000.

¹⁰³ R.R. Freeman, (Air Toxics Ltd, 916-985-1000), The Analysis of Acrolein Using CARB Method 430: What Works and What Doesn't Work, A&WMA Proceedings, 1993.

The Applicant justifies using the Frame 7 emission factor "[b]ecause of the differences in combustion and control technology between the frame turbines and other turbines tested, there is no reason to believe that the test results from the other turbines are more representative than the test results from the frame turbine." (Metcalf Response to Staff Data Request PH-1, 4/7/00, pp. 1-2.) However, differences in the elapsed time between sample collection and extraction among the four source tests creates far more variability among acrolein emissions than turbine type. Thus, it is impossible, given this situation, to conclude that any one of the four measurements is any more representative of Frame 7 machines than any other. In fact, it is a fair bet that none are representative and all are underestimates. Therefore, none of the data should have been discarded. To address these analytical problems, we multiplied the acrolein emission factor by ten to adjust for the degradation that occurs between sample collection and extraction. We believe that this is conservative and underestimates actual acrolein emissions.

Using the average CATEF emission factor (2.37×10^{-2} lb/MMscf) as required by CARB¹⁰⁴ and increasing it by a factor of ten increases the acute hazard index from 0.33 reported in the PDOC to 1.7, which is significant. Likewise, these same two changes (CATEF data instead of the Applicant's unilateral adjustment of it; factor of ten increase to reflect CARB 430 under measurement of acrolein) increase the chronic hazard index from 0.06 reported in the PDOC to 0.93.

In addition to using the wrong emission factor and failing to adjust it to account for acrolein degradation, the Applicant also failed to consider startup and shutdown conditions and the use of DLN combustors, as discussed above. Each of these factors further increases the chronic and acute hazard indices. Incorporating all of these factors, as explained in Table 8, increases the acrolein hazard index values in Table 7, which are far above the permissible level of 2. Even if acrolein emissions are overestimated by factors of ten to one hundred, these hazard indices would still exceed the significance threshold of one by a large margin, requiring the use of TBACT. Put another way, if any of several acrolein emissions adjustment factors listed in Table 8 are appropriate, then acrolein emission adjustment factors listed in Table 8 are appropriate, then acrolein will have an acute hazard index greater than one.

¹⁰⁴ CARB, Emission Inventory Criteria and Guidelines Report for the Air Toxics "Hot Spots" Program, May 15, 1999, p. 56.

Adjustments Factors for Health Risk Assessment Table 8

Compound	Increased emissions at low loads (Frame 7 data) (Ex.48,p.5)	Increased emissions due to low-Nox combuster(Ex. 48, p.8)	Decreased emissions due to only 1 turbine at low loads ata time (PDOC condition 22)	Increased emissions due to failure to accurately measure emissions (exs. 50,51)	Total adjustment factor
Acetaldehyde					
One-hour	146.3	11.4	0.5		836
Annual	14.8	6.6	0.5		49
Acrolein					
One-hour	146.3	11.4	0.5	10	8362
Annual	14.8	6.6	0.5	10	491
Benzene					
One-hour	2.3	38.9	0.5		44
Annual	1.1	2.2	0.5		1.3
Formaldehyde					
One-hour	146.3	11.4	0.5		836
Annual	14.8	6.6	0.5		49

Assumes 832 hours per year of low turbine loads (520 1-hr hot starts plus 104 3-hr cold starts;PDOC, p.B-5)

2. The Acute Hazard Index for Fermaldehyde Also Exceeds One

Acrolein is not the only compound shown in Table 7 with a revised acute hazard index greater than one. The index for formaldehyde also exceeds one, providing yet another reason (besides its cancer risk) to require BACT for formaldehyde.

XI. THE PDOC’S ANALYSIS OF VISIBILITY IMPACTS IS INADEQUATE

The PDOC fails to satisfy the requirements of federal regulations regarding the protection of visibility. The PDOC states, with no factual or analytical support, that "....the proposed project will not cause any impairment of visibility at Pinnacles National Monument..." However, the District's own regulations, at Rule 2-2-309, state that a project must be denied "where it has been demonstrated by the Federal Land Manager that the permit would authorize emissions which would have an adverse impact on the air-quality-related values (including visibility) of a Class I area..." Nowhere in the District's PDOC is there any mention of input from the responsible Federal Land Manager, whose substantive input on this question is indispensable in order to adequately address the question of the potential impacts of a proposed project on air-quality-related values in a Class I area. EPA has designated the Pinnacles National Monument as a mandatory Class I area where visibility is an important value. See 40 CFR section 81.405. Pinnacles is 60 miles from, and is directly downwind from, the proposed Metcalf Energy Center. Under EPA's regulations, the agency reviewing the permit application, in this case, the District, must provide notification to the responsible Federal land manager responsible for a Class 1 area that might potentially be impacted by a project under review and that the reviewing agency must

consider any analysis performed by the Federal land manager on this issue. See 40 CFR section 51.27(d). At no point in the PDOC is there any indication that the District even consulted the Federal land manager for Pinnacles, much less than that any such comments from the Federal land manager were considered by the District as part of its air quality impacts analysis. The District's visibility analysis is therefore fatally flawed.

Furthermore, under EPA's rules, any person has the right, in connection with an application for a permit to construct a major stationary source (and the Metcalf project certainly qualifies under EPA's definition as a major stationary source, both for NO_x and PM₁₀) to request that the Administrator of EPA take responsibility from the state for conducting the required review of a proposed source's impact on visibility in any Federal Class I area, and that if so requested, the Administrator shall take such responsibility and conduct such review. See 40 CFR section 52.27(c). Given the proximity of Pinnacles to the proposed project location and the fact the proposed project location is directly upwind of Pinnacles, the District's apparent total failure to take seriously its responsibility to consult with the responsible Federal land manager for Pinnacles leaves a gaping hole in the required analysis for this project. In light of this failure, the Energy Commission staff should and must assert its right under section 52.27(c) and bring EPA in to conduct the very important consultation on visibility impacts of the Metcalf project with the Federal land manager for Pinnacles that the District has apparently failed to perform.

XII. OTHER ISSUES

A. EMERGENCY IC ENGINES NOT PROPERLY PERMITTED

The Project includes two emergency internal combustion ("IC") engines, a 300-hp, diesel-fired fired Cummins engine used in a fire-water pump and a 6.44 MMBtu/hr, natural gas-fired Caterpillar engine used in an emergency generator. These two emergency engines are exempt from District rules pursuant to Regulation 1-110.2. (PDOC, p. 2.) However, they are not exempt under federal PSD regulations at 40 CFR 52.21. The Draft Permit does not even mention these two engines, let alone establish BACT and enforceable permits limits as it must to comply with federal law.

The federal PSD program requires that BACT be applied to each emission unit at a major stationary source that would have the potential to emit in significant amounts. (40 CFR § 52.21.) The EPA as applying to "each individual new or modified affected emissions unit and pollutant emitting activity at which a net emissions increase would occur has interpreted the applicability of BACT. Consequently, the BACT determination must separately address, for each regulated pollutant with a significant emissions increase at the source, air pollution controls for each emissions unit or pollutant emitting activity subject to review." (NSR Manual, p. B.4 (emphasis added).)

The PDOC acknowledges that Metcalf's emissions exceed the significance thresholds in 40 CFR § 52.21(b)(23) for NO_x and CO. (PDOC, p. 7.) We believe the thresholds are also exceeded for

ozone and PM10, as discussed in Comment --. Thus, Metcalf is a major stationary source and BACT is required for each emission unit at Metcalf, including the two emergency IC engines. The District must perform a formal, top-down BACT analysis for these two engines, establish BACT emission limits,¹⁰⁵ and impose enforceable permit limits which limit both emissions and hours of operation. The resulting analyses and proposed permit limits must be circulated for public review. (NSR Manual, p. B.56.)

B. Source Testing Protocol Is Not Adequate

According to the NSR Manual, "[t]he construction permit should state how compliance with each limitation will be determined, and include, but not be limited to, the test method(s) approved for demonstrating compliance. These permit compliance conditions must be very clear and enforceable as a practical matter (see Appendix C). The conditions must specify:

- when and what tests should be performed;
- under what conditions tests should be performed;
- the frequency of testing;
- the responsibility for performing the test;
- that the source be constructed to accommodate such testing;
- procedures for establishing exact testing protocol; and
- requirements for regulatory personnel to witness the testing. (Id., p. H.6.)

Source testing requirements in Conditions 12, 30, and 31 do not specify the test methods, the conditions under which the tests would be performed (e.g., startup, shutdown, 50% load, duct burners on or off, steam injection for power augmentation), the responsibility for performing the test, procedures for establishing an exact testing protocol, and a requirement for regulatory personnel to witness the testing. Instead, the Draft Permit specifies "District-approved" methods (which are not identified specifically) and allows the development and approval of source test procedures prior to conducting any tests by the District, outside of the public view. In fact, Condition 39 allows the owner to contact BAAQMD "regarding requirements for the continuous monitors, sampling ports, platforms, and source tests required by conditions 32, 33, and 35." This information should all be in the Draft Permit and thus subject to public review.

Therefore, the Permit does not establish the conditions required to determine compliance, but rather leaves the establishment of such provisions to the future discretion of the District in approving a source test protocol. There is no assurance that the establishment of a future protocol would be subject to the public notice and review requirements of 40 CFR 52.21 & 124.

¹⁰⁵ We note that the PDOC includes emission calculations for the firewater pump engine (PDOC, Table B-6), but not the emergency generator.

Therefore, relying on a future source test protocol as advocated here is clearly erroneous as it allows for specification of the terms of the PSD permit outside of the PSD permitting process.

C. A CEMs Should Be Used To Assure Compliance With The SO₂ Limit

The EPA specifically requires that “[p]arameters which must be monitored continuously or continually are those used by inspectors to determine compliance on a real-time basis and by source personnel to maintain process operations in compliance with source emissions limits.” (NSR Manual, p. H.7.) The Draft Permit only requires that SO₂ be measured annually in a source test and otherwise, that fuel sulfur be analyzed monthly. (PDOC, p. 34, Condition 45.) It is well known that fuel sulfur content can be quite variable, and spikes are common. Therefore, this condition is not adequate to assure continuous compliance. The Permit should be modified to require SO₂ CEMs.

D. Use of 1 year of offsite meteorological data is inconsistent with Federal EPA guidance.

The air dispersion modeling performed to calculate the PSD increment consumption and air quality impact for comparison to the NAAQS and California AAQS is based upon the use of only one year of meteorological data obtained at a location (IBM site) nearly 5 kilometers from the proposed Metcalf Energy Center site. As discussed below, EPA will allow the use of a minimum of one year of data if the data is site-specific and representative. Otherwise, EPA requires that five years of “adequately representative” data be used. The reason for this difference in the required duration of measurements is that EPA recognizes the importance of site-specific meteorological data to the validity of model predictions and wanted to encourage sources to set up and collect on-site meteorological data collection systems for input to dispersion modeling for regulatory applications. To mandate a full five-year duration on-site program was deemed to cause an unacceptably long delay to the permitting process.

The use of meteorological data from the IBM site, however, does not pass the site-specific test as it is located in a very different and wider part of the Santa Clara Valley. As such, the meteorological data is not representative of the meteorological conditions affecting plume dispersion of effluent plumes at the proposed complex terrain site.

EPA’s current guidance on these issues are in two related documents: *Appendix W to Part 51-Guideline on Air Quality Models* (1999 Edition) and a related, referenced document EPA-450/4-87-013: *On-Site Meteorological Program Guidance For Regulatory Modeling Applications*. Appendix W Section 9.3.3.1 Discussion (under the heading of ‘Site-Specific Data’) states that “Spatial or geographic representative ness is best achieved by collection of all of the needed model input data at the actual location of the source(s)”. Section 1.2 of the ‘On-Site’ guidance document provides the following definition: “On-site refers to the collection of data at the actual site of a source that are representative, in a spatial and temporal sense, of the dispersion conditions for the source.” Both of the above quotations are in the context of any terrain situation (e.g. flat or complex). For complex terrain settings (The proposed MEC site is clearly complex

terrain with Tulare Hill to the west 150 feet above stack top and peaks 3 km to the east over 1100 feet above stack top.), the guidance is even more specific. Appendix W Section 9.3.3.2 (h) states that” For refined modeling applications in complex terrain, multiple level (typically three or more) measurements of wind speed and direction and turbulence (wind fluctuation statistics) are required. Such measurements should be obtained up to the representative plume heights of interest...” Similarly, the ‘On-site’ guidance Section 3.2 Complex Terrain Sites states “The ideal siting solution in complex terrain involves siting a tower between the source in question and the terrain obstacle of concern. The tower should be tall enough to produce measurements at the level of the plume, and should provide measurements of all variables at several levels.” Clearly, data from the 10-meter high anemometer at the IBM site does not meet the above proximity and representativeness criteria. It certainly does not provide measurements at the level of the expected plumes of concern.

We note that EPA, on April 21, 2000, proposed revisions to Appendix W, which, if adopted, would change the wording of some of the above. The revised Appendix W also references a new document: Site-Specific Meteorological Monitoring Guidance for Regulatory Applications (1999) (EPA –454/R-99-005). We discuss relevant word changes in these documents below. We do not believe that they alter the conclusion that the meteorological data utilized in the PDOC does not meet either present or proposed changes to their guidance criteria. The April 21, 2000 proposed revision to Appendix W to Part 51-Guideline on Air Quality Models pertaining to the length of Meteorological records states in Section 8.3.1.2 Recommendations (a) that “ Five years of representative meteorological data should be used when estimating concentrations with an air quality model. Consecutive years from the most recent, readily available 5-year period are preferred. The meteorological data should be adequately representative, and may be site specific or from a nearby NWS station.” Section (b) goes on to state that “The use of 5 years of NWS meteorological data or at least 1 year of site-specific data is required. If one year or more of, up to five years, of site-specific data is available, these data are preferred for use in air quality analyses.” Section 8.3.3.2 clarifies the meaning of ‘site-specific’: adding “As a minimum, site-specific measurements of ambient air temperature, transport wind speed and direction, and the variables necessary to estimate atmospheric dispersion should be available in meteorological data sets to be used in modeling. Care should be taken to ensure that meteorological instruments are located to provide representative characterization of pollutant transport between sources and receptors of interest.” We note that whereas in EPA’s current Appendix W, Section 9.3.3.1 defines the needed model input data “ at the actual site of the source(s)”, the proposed revision to the same section (renumbered to be 8.3.3.1) uses the phrase “in close proximity to the actual site of the source(s)” and goes on to state that “collection of meteorological data on property does not of itself guarantee adequate representativeness.” As discussed elsewhere, in the context of the needs for the present application, the IBM site is neither “on-site” nor “in close proximity”. In EPA’s new Meteorological Monitoring Guidance for Regulatory Modeling Applications (February, 2000), in Section 3.3 concerned with sources in complex or mountainous terrain, EPA discusses how “...measurements should be made at multiple levels in order to ensure data used for modeling are representative of conditions at plume level. The ideal arrangement in complex terrain involves siting a tall tower between the source and the terrain feature of concern.” The

messages are the same in both the present and potentially revised guidance: One needs to have very representative data for model inputs. The proximity issue for an anemometer in complex terrain focuses, in addition, also on the elevation of the measurements with respect to the range of plume heights of concern.

The rationale behind this guidance is the importance of measuring the wind speeds and directions that would affect plumes that would travel toward areas of high terrain, or in the case of terrain induced downwash, from high terrain areas toward the stack locations. The predicted concentrations are very sensitive to the very local meteorology in complex terrain settings. Tulare Hill is a significant local obstacle to the prevailing up and down valley flows expected in the Santa Clara Valley. It rises over 300 feet above the stack bases and about 150 feet above the tallest of the turbine stacks. The airflow between the MEC site and the hill will clearly be affected by the presence of Tulare Hill. The alterations of the flow patterns will, in turn, affect the dispersion of emissions from all the sources at the MEC site. In the narrow section of the Santa Clara Valley between closest to the proposed MEC, one would expect locally higher wind speeds during periods of general up or down valley flows. To the extent that these higher wind speeds affect the plumes from the MEC, we would expect to see a higher frequency of building induced downwash events affecting the air quality in the immediate vicinity of the site. Terrain induced downwash occurring when winds from the north and west flow over portions of Tulare Hill increase ground level concentrations to the east and south of the site. We note that the ambient air quality at the proposed development of the Cisco Systems Campus and associated day care and other populated areas is likely to be routinely adversely affected by these downwash conditions. It is important that winds at stack height be measured and that a longer database be developed. It is very important in complex terrain settings that the anemometer height be high enough to characterize the winds at stack top and above stack top. As noted above, EPA recommends that measurements be taken at multiple levels to achieve this requirement. The anemometer at the IBM site is at 10 meters above the surface. It cannot be relied upon to estimate winds at the 44-meter heights of the turbine exhausts or used to infer winds at the final rise heights. This is a clear case where a site-specific meteorological monitoring program that collects a year or more of data is required. The use of meteorological data from a site 5 km away cannot capture the site-specific flows of concern to the neighbors of the proposed MEC.

C. The use of 'Rural' dispersion coefficients needs to be re-examined for this application

The applicant has used the Auer method for determining that rural dispersion coefficients are appropriate for the modeling effort based upon present land use in a circle surrounding the proposed site. The ISC3 model forces a single choice for the use of Urban vs. Rural coefficients. Urban coefficients reflect greater surface roughness and result in more vigorous vertical mixing of pollutants emitted into the lower atmosphere. It is likely that a determination of urban would result in higher predicted concentrations in populated areas to the northwest and southeast of the

site because elevated plumes would rapidly mix downward to the ground. The Auer method simply requires an examination of land use within a 3-kilometer circle around the site. The determination of rural by the applicant is largely associated with the large areas of undeveloped land to the north east side of Route 101 and the undeveloped land of Tulare Hill. Winds flowing from the northeast and east across the areas to the northeast of Route 101 and toward the plant are relatively rare and the Auer method unfairly weights them for this setting. Although Tulare Hill has a relatively smooth surface, the hill itself causes increased turbulence in winds flowing from the north and northwest (also known as terrain-induced downwash) and in reality should not be contributing to the support of a rural dispersion coefficient determination.

In an area dominated by dominant and specific prevailing winds from two directions, a more realistic determination would weight the land uses by the percentage of the time that the winds transporting pollutants from the plant are along those wind directions. Those directions coincide with the directions of high population density. Note that the planned campus development in the area to the south of the proposed plant location would not only change the surface roughness by the construction of buildings but also greatly increase the population density of potentially exposed people. It is important to also observe that the US EPA is aware of the deficiencies of ISC3 and the Auer method in applications such as this one. EPA has recently proposed to replace the ISC3 model with an improved model, AERMOD. AERMOD's primary difference from ISC3 is the allowed and encouraged use of more site specific and detailed meteorological data as input to the model. For the present application, AERMOD will allow the use of direction specific roughness coefficients, which would in effect increase the vertical mixing of pollutants as the plumes passed over built-up or rougher terrain areas. The determination of direction specific roughness parameters would essentially eliminate the use of the Auer method and should yield more realistic predictions of air quality concentrations. With the mix of higher elevation and lower elevation sources at the MEC, the effects of an urban dispersion coefficient determination should be evaluated. Alternatively, the AERMOD model should be run after an assessment of present and future roughness lengths has been made.

D. Potential for simultaneous turbine start-up

PDOC proposed licensing condition 22 requires the two gas turbines at MEC not to be in start-up simultaneously. The PDOC indicates a 3-hour duration for cold start-ups (PDOC, p. B-5), and in Table B-13 assumes one gas turbine in start-up at the beginning of a 24-hour period, with the other starting up "at beginning of third hour of 24 hour period." Were the situation in Table B-13 to occur in real life, MEC would be in violation of proposed condition 22.

How likely is it that simultaneous turbine start-up could occur? Calpine/Bechtel Enterprises will have substantial financial incentives to start both turbines at once. The two turbines will be basically identical, with identical operating costs, and they will be operated as merchant facilities in response to market prices. So whenever market conditions justify operating one turbine, they will justify operating both, and whenever market prices justify shutting down a turbine they will justify shutting down both. Compliance with condition 22 therefore will require Calpine/Bechtel

to either start up the first turbine before it is cost-effective to do so, or delay starting up the second one until after it is cost-effective to do so.

California energy prices can change by many dollars per Mwh from one hour to another. For a 300 Mw turbine/HRSG train as proposed at Metcalf, that means the foregone profits from a delayed start-up of one turbine could easily run to thousands of dollars per hour. With the Applicant proposing up to 312 starts per year per turbine, the financial cost of complying with condition 22 will be substantial.

Nevertheless, compliance with condition 22 is essential. Many of the MEC emissions will be higher during startup than during normal operations, and allowing both units to be in startup at once would produce substantially greater one-hour emissions than the PDOC has assumed. Therefore the PDOC conditions must be modified to include a monitoring and enforcement provision for condition 22. The proposal made above that the CEMS for MEC be required to be operable and accurate during startups are one way that any violation of condition 22 would be detectable. In addition, we propose that the Applicant be required to keep a real-time log of unit output (e.g., the same sort of data it would report to the California Independent System Operator (CAISO) in the normal course of business as an ISO-interconnected facility) showing unit output for each turbine in intervals of no more than 10 minutes (the ISO already operates using 10-minute data). This data should then be provided to the District at least monthly to verify that at no time were both turbine units in startup (ramping up their output) or shutdown (ramping down their output).

E. Verification of ERCs

The PDOC asserts that Calpine/Bechtel have identified valid emission reduction credits (ERCs) of 356 tons/year of POC from banking certificate #625 belonging to Quebecor, Inc. of San Jose (PDOC, Table 4, p. 15). ERCs are required to be federally enforceable (PDOC, p. 13). Nowhere in the PDOC is there any analysis of the Quebecor ERCs to verify their validity. In particular, the PDOC should be amended to include a discussion of whether the Quebecor ERCs were properly issued and quantified, and whether an analysis of BARCT would reduce the size of the Quebecor ERCs. Since the Quebecor ERC certificate represents over 10 percent of all the POC ERC's in the BAAQMD bank, and is over twice as large as the next largest certificate in the bank, it is particularly important that the BAAQMD provide a close and public analysis of its size and validity.