STATE OF CALIFORNIA
State Energy Resources
Conservation and Development Commission

In the Matter of:)) **Avenal Energy Power Plant**)		**Docket Number: 08-AFC-1** Appeal of Decision Rebuttal Testimony Request for new schedule By Rob Simpson

I thank the Commission for the opportunity to Intervene. However I hereby appeal the decision to Deny my request to Stay the proceedings.

In the June 11, 2009 COMMITTEE ORDER GRANTING AND DENYING PETITIONS TO INTERVENE

"The deadlines for conducting discovery in this case are past and other matters shall not be extended by the granting of these Petitions. Therefore, Petitioner Simpson's Request to Stay Proceeding is specifically **DENIED**."

I have reviewed the scheduling orders for this proceeding and found no indication of deadlines for conducting discovery. So I do not know when the purported deadline was. I don't know if it was before the the Commission Posted the Notice of Final Determination of Compliance. On June 9, 2009. This was after my intervention/testimony stated "**The California Energy Commission has not posted the Air District Final Determination of Compliance in the Documents and Reports record of this proceeding.**"

I don't know if it was before the Air Districts "Inter Pollutant Offset Ratio Development" posted by the Commission on the Documents page June 3, 2009. I also questioned the Development in my testimony The Document was subsequently removed from the Documents page. I do not know if it was withdrawn or simply removed from the public view.

I don't know if the discovery deadline was before the applicant filed the amendment to the AFC titled "Change in Carbon Emissions with the Addition of Avenal Energy" posted May 14 2009.

I don't know if it was before my (unanswered by the commission) comments docketed April 29, 2009

I did find in the May 27, 2008 **COMMITTEE SCHEDULING ORDER**

"August 14, 2008 Local, State and Federal Agency draft
determinations, including air district's
Preliminary Determination of Compliance
(PDOC) filed"

“October 13, 2008 Local, State and Federal Agency final determinations filed”

I have found no evidence of “Federal Agency draft determinations” or “Federal Agency final determinations”

The Status Report #2 Dated August 29,2008

The United States Environmental Protection Agency (USEPA) submitted comments, dated July 10, 2008, to Mr. Peter Cross of the United States Fish and Wildlife Service (USFWS) requesting the initiation of a formal consultation under Section 7 of the federal Endangered Species Act. The primary purpose of the consultation is to ensure that the construction and operation of Avenal Energy would not jeopardize the continued existence of the San Joaquin kit fox or result in the adverse modification of kit fox critical habitat. In addition, the USEPA also requested the USFWS to prepare a Biological Opinion concurring that Avenal Energy is not likely to adversely affect other federally endangered plant and wildlife species including San Joaquin wollythreads, California jewel flower, blunt-nose leopard lizard, and tipton kangaroo rat. Staff will continue to monitor the USEPA consultation and expects to confer with the USFWS in early September.

Shirley F. Rivera U.S. EPA, Region 9, Air Permits Office informed me on June 3, 2009 that they had not yet issued even a draft PSD permit. The problems with the CEC licensing these facilities without compliance with Federal laws is clear enough in multiple venues.

The Russell City Energy Center permit Remand by the U.S. EPA

“The District’s almost complete reliance upon CEC’s certification related outreach procedures to satisfy the District’s notice obligations regarding the draft permit resulted in a fundamentally flawed notice process. By “piggybacking” upon the CEC’s outreach, the District failed to exercise sufficient supervision over the CEC to ensure that the latter adapted its outreach activities to meet specific section 124.10 mandates. The inadequacy of the notice lists used by the CEC, the handling of public comments by the CEC, and the conduct of a public workshop by CEC with likely District participation during the PSD comment period at which air quality issues were discussed but no record of public comments made all demonstrate that the CEC merely folded the PSD notice proceeding into its ongoing process without attempting to ensure that the part 124 requirements for public participation were met...

Pursuant to its broad mandate, the CEC must make a specific finding that a proposed facility conforms with relevant federal and local law. *See* Cal. Pub. Res. Code § 25523(d)(1). As the Warren-Alquist Act states, “the [CEC] may not certify a facility * * * when it finds * * * that the facility does not conform with any applicable federal, local, or regional standards, ordinances, or laws” and “[CEC] may not make a finding in conflict with applicable federal law or regulation.” *Id.* § 25525. As such, the certification process serves as a procedural umbrella under which the CEC coordinates and consults with multiple agencies in charge of enforcing relevant laws and standards to ensure that a facility, as proposed, will satisfy such mandates. *See* Cal. Code Regs. Tit. 20, § 1744...

With respect to CEC's conformity finding, the Warren-Alquist Act imposes, as a condition for certification, that the local air pollution control officer of the relevant air quality district (in this case, the District) makes a specific determination that the proposed power facility complies with state and federal air quality requirements, including NSR. *See id.* tit. 20, § 1744.5. In particular, the Warren-Alquist Act's implementing regulations provide that "[t]he local air pollution control officer shall conduct, for the [CEC's] certification process, a determination of compliance review of the application [for certification] in order to determine whether the proposed facility meets the requirements of the applicable [NSR] rule and all other applicable district regulations. If the proposed facility complies, the determination shall specify the conditions, including BACT and other mitigation measures, that are necessary for compliance." *Id*...

Additional evidence offered by Mr. Simpson regarding the District's notice to third persons fortifies our view that the District's reliance upon CEC's certification procedures resulted in a flawed notice process..

This is just one illustration of the nature of the confusion between the District PSD and broader CEC processes. In response to questions during the teleconference hearing, the CEC representative indicated that the public was entitled to comment, during the CEC process, on any air quality issues, including those covered by the PSD permit. However, he noted that the CEC was powerless to make any changes to the permit based on these public comments..."

Further damage by the CEC failure to exercise oversight of Federal Clean Air Act compliance in its certification process is epitomized in the new PG&E **Gateway Generating Station** presently operating, in violation, without required permits as admitted by the Bay Area Air Quality Management District in my EAB appeal of the permit.

"there is in fact no current, valid permit, a point there is now no disagreement among Petitioner, EPA region 9, and the District." BAAQMD counsel Alexander Crocket

This represents the complete failure of the Energy commission licensing process to allow polluters to be developed and operated without Clean Air Act concurrence, BACT or permits.

Please inform me on exactly what date "The deadlines for conducting discovery in this case" ended and under what authority. Please also indicate how the public was informed of this Deadline.

The June 10, 2009 **NOTICE OF AVAILABILITY FINAL STAFF ASSESSMENT FOR THE PROPOSED AVENAL ENERGY PROJECT** ***States***
"The workshop will provide an opportunity for agencies, the public and other interested parties to present questions and comments on the FSA." Is this a discovery opportunity or are we to present questions without the

reasonable expectation of receiving answers? I request that this “workshop be recorded to try and prevent a repeat of the type of scenario that caused the Russell City Remand.

The inadequacy of the notice lists used by the CEC, the handling of public comments by the CEC, and the conduct of a public workshop by CEC with likely District participation during the PSD comment period at which air quality issues were discussed but no record of public comments made all demonstrate that the CEC merely folded the PSD notice proceeding into its ongoing process without attempting to ensure that the part 124 requirements for public participation were met.
Remand

Should the Commission decide not to “stay the proceedings on this appeal a reasonable scheduling order should be adopted. The zeal to license this facility and set new greenhouse gas rules prior to providing notice to those that have participated in AB 32 and others who are trying to participate in Carlsbad Energy Center for exactly this reason (like Earthjustice) undermine California and Federal laws for informed participation.

It appears from the transcript of MONDAY, MARCH 23, 2009 COMMITTEE STATUS CONFERENCE BEFORE THE CALIFORNIA ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION that a more rational schedule was proposed by staff.

MS. DeCARLO: This schedule was mainly a
11 result of discussions internally that we've been
12 having regarding the outfall from the Eastshore
13 proceeding, and how to handle potentially
14 contentious proceedings, how best to go forward..

8 PRESIDING MEMBER BYRON: Would you
9 please remind me how much time staff is assuming
10 is necessary for them to prepare testimony based
11 on that report?
12 MS. DeCARLO: I've put a month. I
13 didn't want to give a date that we could not meet...

If the Commission Staff required a month to prepare testimony why is the public given 3 days?

Why is The Schedule for this proceeding so much shorter than Carlsbad and others. The Schedule prevents informed participation.

Today is the Scheduled date for all parties to file rebuttal testimony, Apparently on June 6, 2009 Applicant's Evidentiary Testimony and Exhibits totaling 1500 pages was posted in the Docket for this proceeding. It is not available on the Documents page. It was not sent to me and it is too large for the Docket unit to send to me electronically.

“We have it electronically but the document is too large to send electronically. I would need to put it on a cd for you.” Dockets Staff Siting / Dockets Unit June 15, 2009

My own testimony and petition for intervention is not posted on the docket log or document page.

Apparently there are Commission Staff Reports 3 and 4 that are not posted on the Documents page. Because status reports 1 and 2 are posted and typically these are all posted, it is reasonable for the public to expect that if there are additional staff reports they will be posted. It is also inherent upon the Commission to promote informed public participation.

Please provide a certified copy of the administrative record for this proceeding.

The analysis for this project does not adequately address alternative energy sources ability to meet demand. It does not adequately address the transmission capacity strain that this facility will effect possibly preventing renewables from being developed based upon insufficient transmission capacity as a direct result of this development. It does not adequately address the effects of line loss and associated greenhouse gas production from the facility being developed so far from load centers.

The PM_{10} Emission limit for the Avenal Project is not BACT.

The District's meager BACT analysis for PM_{10} was presumably based on the Applicant's equally short BACT analysis found in the AFC. Based on this scant data, the PDOC concluded that BACT for PM_{10} emissions from the CTGs is the use of natural gas fuel with a LPG backup. There is no support for this conclusion as the PDOC does not contain any discussion of achievable PM_{10} emission levels, permitted PM_{10} emission limits at similar facilities, or results of source tests. As such, the entire analysis is deficient and must be redone.

A number of natural gas-fired power plants with substantially similar turbines have been *permitted* and licensed with considerably lower PM_{10} emission limits for the CTGs and associated duct burners than those proposed here. In California, these facilities include the Blythe Energy Project Phase II, the Russell City Energy Center, and the Inland Empire Energy Center. Turbine and duct burner characteristics and permit limits for these facilities are summarized in attached Table A-2 and some facilities are discussed in more detail below.

Particularly noteworthy is the Blythe Energy Project Phase II, which employed Siemens Westinghouse F-class turbines. This facility was licensed by the Energy Commission in 2005 and permitted by the EPA in 2007 with an emission limit of 6.0 lb/hour of PM_{10} emissions per turbine with and without firing the duct burners and using natural gas. The Project's proposed PM_{10} emissions would be double that limit with duct burners firing and 50% more than the Blythe project without the duct burners. The SJVAPCD should explain why these lower emission levels cannot be achieved at this Project.

The Los Medanos Energy Center, which employed two GE S207FA turbines, was initially licensed with PM_{10} emission limits of 16.3 lb/hr per turbine train with and without duct burner operation. In 2006, the project owner requested lowering the PM_{10} permit limits to 9.0 lb/hr based on stack tests repeatedly demonstrating PM_{10} emissions considerably below 9.0 lb/hr. As a result, the Energy Commission approved revised turbine PM_{10} emission limits of 9.0 lb/hr or 0.0040 lb/MMBtu per turbine including when the 330 MMBtu/hr duct burner is firing. Again this is much lower than the Avenal Energy's proposed limit of 11.8 lbs/hr with the duct burners firing.

Due to a lack of time under the current scheduling order and the similarity to other archaic plants planned, the balance of my rebuttal testimony is in the following attachments.

A SCR ammonia supply without the headaches of hazardous chemical handling.

B ALAMEDA COUNTY HEALTH CARE SERVICES AGENCY David J. Kears, Director
PUBLIC HEALTH DEPARTMENT

C Maureen Barrett, P.E. AERO Engineering Services

D Diane Zuliani

E Audubon California

F Earthjustice

G Sierra Club

H Mathias van Thiel

I Debra Weiss

J Bayview Hunters Point Community Advocates

K Golden Gate University Environmental Law and Justice Clinic

L CARE and Rob Simpson

M Communities for a Better Environment

N Congressman Pete Stark

O Devine Family

P Robert Sarvey

Q Petition

R Ohlone Audubon

S California Native Plant Society

T Natural Resources Defense Council, and Sierra Club

U EPA response

V David Roland Holst

W inter pollutant trading

X Ernest Pacheco

Y Mark Z. Jacobson

Z Jacobson CO2

AA Reasons to Not Replace Aging Natural Gas Power Plants
Robert Freehling, CNRCC-ECC, Committee Member, January 21, 2009

BB Resolution Opposing New Large Natural Gas Power Plants.

CC Pacific Environment

DD Sierra Club PSD comments.

Respectfully Submitted By,

Rob Simpson
27126 Grandview Avenue
Hayward CA. 94542
510-909-1800

-----Original Message-----
From: Doug Kirk [mailto:DKirk@ftek.com]
Sent: Saturday, January 17, 2009 12:13 PM
To: Weyman Lee
Subject: Russell City Energy Project

Mr. Lee:

Please accept this comment on the Amended PSD permit.

The use of ammonia in either 19% or 29% solution, will indeed add an unnecessary risk element to this project, both in storage and in the frequent transport of the required reagent through the community. Fuel Tech has a cost effective and commercially established technology that converts urea solutions to ammonia reagents for use with SCRs.

Also your analysis of the EMx, SCONOx technology omits two very relevant and important facts: one, the technology may not use ammonia, but the technology makes ammonia, and two, the technology in net GHG emitter, for every pound of NOx reduced it generates 8 pounds of CO2 via the regeneration process. The regeneration process, which makes H2 and CO2 necessary for the conversion of the potassium to the carbonate state, is the source of both the ammonia and CO2.

The technology provider only indicates the process does not use ammonia, but fails to note that the process releases ammonia. The amount of ammonia released is a variable of the amount of nitrogen in the natural gas, and amount air leaks, which have been pervasive in existing operations. Moreover none of the existing operators test for ammonia or has ammonia been part any start up testing protocol that I am aware of. As result each system runs with an unknown, unmeasured and uncontrolled amount of ammonia slip.

This is a blaring omission from yours and other BACT analysis conducted on this technology.

I have attached a product bulletin on the urea to ammonia process.

Good luck with your hearing next week, and thank you for allowing me to comment, and I welcome the opportunity to respond to any question or the need for additional information.

Doug

Douglas W. Kirk │Regional Sales Manager │ Fuel Tech, Inc. www.ftek.com/

│ 310.405.1061 │ dkirk@ftek.com │

P Please consider the environment before printingthis e-mail.

NO$_x$OUT® ULTRA™
NO$_x$ Reduction Process

TECHNICAL BENEFITS

- Simplified process, highly efficient urea conversion
- Non-hazardous materials throughout
- Low pressure operation
- Process controls designed to follow load and provide easy shutdown
- Liquid reagent system easily modified for dry urea feedstock
- Backed by Fuel Tech's proven start-up, optimization, and service experience

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Technology for a renewed environment™

Smart, safe, and simple… NOxOUT® ULTRA™ provides SCR ammonia supply without the headaches of hazardous chemical handling.

Selective catalytic reduction (SCR) has become a standard for meeting the most stringent NOx reduction requirements from power generation systems. Requiring ammonia (NH_3) as the reducing agent, operators of these systems have had little choice but to accept the handling issues, potential liability, and associated costs in using a hazardous chemical supply.

Fuel Tech's NOxOUT® ULTRA™ system is a new alternative that offers an ammonia feed from a safe urea supply. Available for new SCR systems and as a retrofit to existing applications, NOxOUT® ULTRA™ is a cost-effective solution that simplifies SCR operation.

Urea vs. NH_3

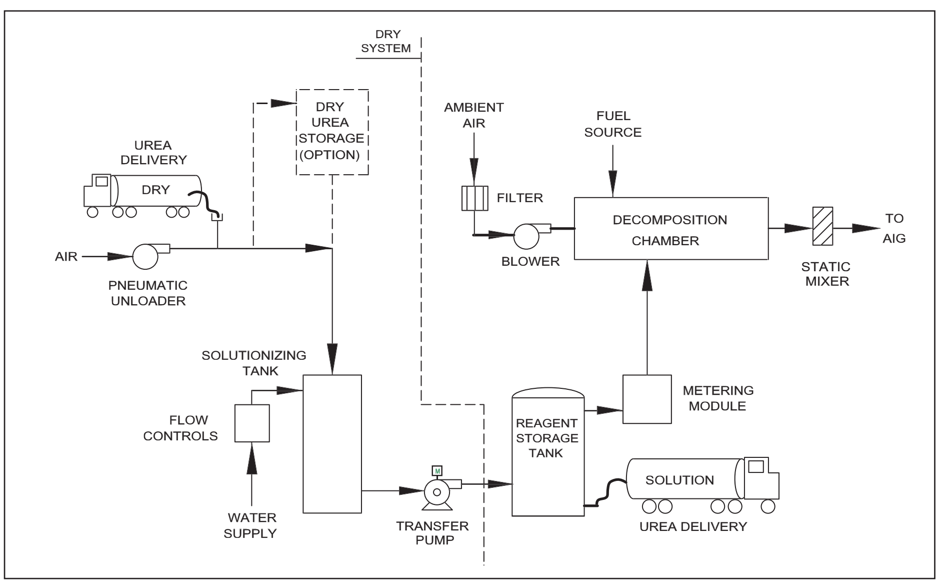
The advantages of a urea-based system over traditional anhydrous ammonia or aqueous supplies are clear. Anhydrous ammonia is classified as a hazardous chemical per CAA Section 112(r). As such, ammonia requires safety procedures to protect personnel, neighboring communities, and the environment from unforeseen chemical release. Reporting, record keeping, permitting, and emergency preparedness planning are generally all needed with on-site ammonia storage. Aqueous ammonia-based systems also require specialized equipment, including pressure vessels, a heated vaporizer, and other features, and have significantly higher operating costs than urea-based systems.

In contrast, urea products are non-hazardous sources of ammonia, so their transport, storage, and use are greatly simplified. Fuel Tech has extensive, proven experience with urea-based systems, and the NOxOUT® ULTRA™ system is built on that solid foundation.

Other urea-to-ammonia conversion systems on the market work by hydrolyzing urea on-site. These processes are complex, expensive, and include a high pressure vessel containing ammonia. NOxOUT® ULTRA™ is a more economical and easier way to generate ammonia.

Design Simplicity

The NOxOUT® ULTRA™ process provides ammonia for SCR systems by decomposing urea to feed the traditional ammonia injection grid (AIG). The process relies on post-combustion reactions in a chamber designed to

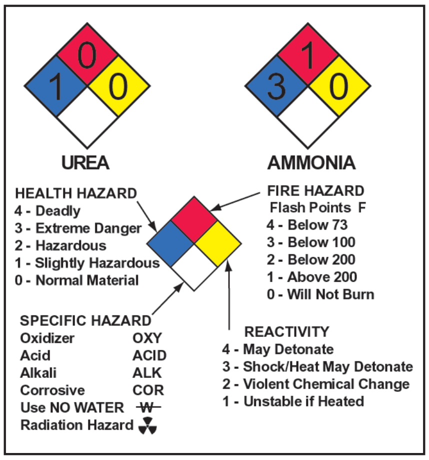


control urea decomposition in a specified temperature window (600-1000 °F). The NOxOUT® ULTRA™ system is simple, consisting of a blower, decomposition chamber, chemical pumping system, urea storage, and process controls.

Filtered ambient air is fed into the chamber through the use of a blower with automatic dampers to control discharge flow and pressure. A burner is fired downstream of the dampers, and an aqueous urea solution supplied by the storage and pumping system is sprayed into the post-combustion gases through the injectors. The urea is efficiently converted to ammonia in the decomposition chamber, and that ammonia feeds the AIG for a traditional SCR system.

System Options

The NOxOUT® ULTRA™ system can be customized for each application.



For larger systems, an in-duct gas-to-gas heat exchanger can be supplied to preheat the process air and minimize operating costs.

The liquid portion of the system can be supplied with dilution water capability to accommodate delivery of concentrated reagent solutions.

The dry urea system components can be supplied to provide flexibility for reagent selection.

New Process, Proven Technologies

The NOxOUT® ULTRA™ process incorporates commercially proven features of Fuel Tech's other NOx reduction products. Urea storage, pumping, metering, and injection are all standard to the NOxOUT® product line, first introduced in 1990. The NOxOUT CASCADE® process relies on careful duct and gas flow dynamics design. The NOxOUT SCR® system relies on the conversion of urea to ammonia for SCR reactions. So while NOxOUT® ULTRA™ is a new product to our mix of process solutions, the established technologies and know-how of Fuel Tech make it a uniquely reliable urea conversion system.

The NOxOUT® ULTRA™ system has all the benefits of direct ammonia supply for SCR without the cost, safety and environmental concerns associated with ammonia handling. More cost-effective than urea-hydrolyzing processes, NOxOUT® ULTRA™ from Fuel Tech is a smart choice for simplifying SCR operation with a urea-to-ammonia conversion process.

For more information on NOxOUT ULTRA™ programs available from Fuel Tech, call, fax, or write Fuel Tech at:

Fuel Tech, Inc. • 512 Kingsland Drive • Batavia, IL 60510
Phone 800.666.9688 • 630.845.4500 • Fax 630.845.4501
www.fueltechnv.com • webmaster@fueltechnv.com

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ALAMEDA COUNTY HEALTH CARE SERVICES AGENCY
PUBLIC HEALTH DEPARTMENT

David J. Kears, Director
Anthony Iton, Director & Health Officer

1000 Broadway, 5th Floor
Oakland, CA 94607

(510) 267-8000
(510) 267-3223

January 21, 2009

Weyman Lee, P.E., Senior Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Re: Proposed Air Quality Permit for the Russell City Energy Center
Alameda County Public Health Department Comments

Dear Mr. Lee,

There is a growing body of evidence suggesting that our citizens are more adversely affected by air pollution than the scientific community previously thought. A recent report published in October 2008 by the California Air Resources Board (CARB) provides evidence of premature mortality associated with exposure to fine particle pollution in concentrations as low as 5 micrograms per cubic meter of ambient air. Additionally, in December 2008, the Bay Area was determined to be in 'non-attainment' for PM2.5. This means that if Russell City Energy Center were to apply for permitting today, it would be subject to more stringent emissions impact assessments.

The standard Health Risk Assessments (HRA) that we have seen for both Eastshore Power Plant and Russell City estimate 1) the long term cancer risk, 2) the risk of other non-cancer, chronic illnesses such as heart disease and respiratory disease, and 3) the risk of acute illness, non-cancer-related, such as asthma and heart attacks. All of these take into account both long term and short term exposures and estimate hazard indices for each pollutant (ratios of expected exposures to acceptable exposures) that are then summed, assuming that the pollutant effects are additive rather than cumulative or synergistic.

In addition, the HRA "Surrogate" method allows for the amount of fine particulate matter, PM2.5, to be estimated from the known amount of larger particulate matter, PM10. The true amount of PM2.5 does not have to be known and may not be accurately estimated.

Thus the current practice of HRA appears to us to have three very significant but related gaps. First, the models estimate health impacts only in terms of morbidity, not mortality. They do not take into account the growing body of evidence that exposure to fine particulate matter contributes to premature death as well as illness. Second, they do not use an accurate estimate of PM2.5, and third, they do not consider that the health effects of multiple pollutants may be greater than the sum of the individual pollutants.

The recent CARB report, entitled *Methodology for Estimating Premature Deaths Associated with Long-term Exposure to Fine Airborne Particulate Matter in California*, concluded that fine particle emissions carry a much greater risk of premature death than they had previously estimated.

Two key findings from the CARB report were: 1) that PM2.5 exposure increases the risk of death in the population by 10% for every 10 microgram per cubic meter increase in concentration (an increase of 67% over the prior effect), and 2) that there is no evidence in the literature for a threshold below which exposure is safe. However, there is evidence of premature mortality associated with exposure to fine particle pollution in concentrations as low as 5 micrograms per cubic meter. In contrast, the prior threshold CARB used was the established state standard of 12 micrograms per cubic meter. This new threshold represents a 58% reduction in what exposure might be considered safe, if any.

CARB research staff, along with epidemiologists at many universities throughout the world, is on the cutting edge of studies to determine the true health effects of air pollution. CARB is currently developing criteria for conducting Health Impact Assessment at the small area level, looking at pollution from specific sources in small communities. The agency has an ongoing interest in refining the methods of this type of assessment in order to produce valid estimates of the health effects of pollution.

I urge you to consider the new scientific findings about the health impacts of air pollutants, as well as the Bay Area's new non-attainment status for PM2.5, when permitting Russell City Energy Center, or any future facilities. Please feel free to call me with any questions or comments at 510-267-8019.

Sincerely,

Anthony Iton, M.D., J.D., MPH
Director and Health Officer

-----Original Message-----
From: Maureen Barrett [mailto:maureen@aeroengineering.com]
Sent: Friday, January 09, 2009 8:08 AM
To: Weyman Lee
Cc: info@environmentcalifornia.org
Subject: Comments on Russell Energy Center Proposed PSD Permit

Mr. Weyman Lee:

Thank you for directing me to the correct location for the reporting of the air quality impacts analysis for the Russell Energy Center. My comments derive from very recent experience, including expert testimony and membership on a state PM2.5 implementation workgroup, relating to the modeling and permitting of PM2.5 impacts from electrical generating facilities.

On the basis of the impacts presented in Table III of Appendix C of the "Statement of Basis for Draft Amended Prevention of Significant Deterioration Permit" of the Russell Energy Center, the general thrust of my previous comments stand. More specifically, Table III shows that the facility's daily and annual maximum predicted PM2.5 impact exceed the most health-protective of the respective US EPA's proposed significant impact levels. Note that although only PM10 emissions are presented, as you are aware, the ratio of PM2.5 to PM10 emissions in the flue gas is likely on the order of 80% or greater, and without an emission limit that specifies this ratio or an explicit PM2.5 emission limit, the PM10 maximum impacts results must be assumed to be equivalent to the PM2.5 maximum impacts.

However, there is no supportable rationale for allowing the PM10 compliance assessment to serve as a surrogate for a PM2.5 compliance assessment. The health-based ambient air standards for these two pollutant classes are unique, reflecting that the health effects of each pollutant class are also unique. It is likely that if California allows the current approach whereby PM10 compliance alone is allowed to satisfy PM2.5 compliance, that the state will allow a permitted emission rate that will cause or contribute to a violation of the state and federal PM2.5 ambient air quality standards.

Note also that Table III presents the highest sixth-high daily concentration to assess against the SIL. This is an incorrect procedure, according to the NSR workshop manual, which in several areas makes it clear that for the purposes of assessment against significant impact levels, that the facility's highest impact should be used. Therefore, it is probable that this facilty's maximum PM2.5 impact not only exceeds the most health-protective of the proposed SILs, but also exceeds every one of the proposed SILs, for PM2.5.

Once a facility's maximum impact exceeds the SIL, it must include interactive sources within its modeling analysis, to ensure that its impacts do not cause or contribute to an exceedance of the PM2.5 standard. Therefore, the facility's ambient air quality analysis is incomplete as it stands now, because the applicant has not evaluated whether or not the proposed project will cause or contribute to an exceedance of the PM2.5 ambient air quality standard. The current amended permit has ignored this requirement, and therefore does not satisfy California air quality regulations for issuance of a permit.

Thank you very much.

Maureen Barrett, P.E.
AERO Engineering Services
978.443.7296

1/21/09

Statement to the Bay Area Air Quality Management District From Diane Zuliani, Chabot College Instructor:

The Russell City Energy Center stands to negatively impact the fertility of Chabot College's learning environment. It threatens to do so by introducing into our atmosphere several criteria pollutants, pollutants specifically identified by the EPA as harmful to human health, the environment, and property. By their power to harm human health, these pollutants have the potential to impede the ability of students to achieve their educational goals. They also threaten faculty retention, which in turn threatens student success. Yes, we understand that Calpine must legally seek mitigation of these pollutants, but we also understand that mitigation in the form of pollution credits and a fireplace retrofit will *not* decrease the toxicity of the actual criteria pollutants emitted, in the amount of hundreds of tons annually, from the Russell City Energy Center.

We have seen the California Energy Commission's Public Health map. Its isopleth indicates that the "maximally impacted receptor center" for cumulative acute hazards emitted by the Russell City Energy Center is Chabot College itself. We are stunned that anyone would seek to dump toxins on us or any other institution devoted to public service, and we are deeply alarmed by this potential breach of our educational environment. Yet unbelievably, while Chabot College is "ground zero" for this plant's falling pollutants, the impact assessments upon which you are relying inexcusably and completely ignore us. The impact of the Russell City Energy Center on "schools" was assessed, but the Center's impact on Chabot College was **not** assessed, because by the CEC's definition a "school" is a purveyor of K-12 education only. In other words, while Chabot College is this plant's maximally impacted receptor center, we are nowhere near adequately evaluated in the impact assessments. Again, we are deeply alarmed.

In your parlance, "significant risk" and "insignificant risk" are legal terms, but in ours they are relative terms, and when applied to human beings—our students—to whom we as Chabot faculty, staff and administrators are committed, your legalism offers insufficient reassurance. We members of the Chabot family have dedicated our lives to educating socially and economically overlooked people, people the impact reports call "sensitive receptors." The introduction of criteria pollutants into the teaching and learning environment where these sensitive receptors—that is, people, our students—are to learn, threatens Chabot's ability to meet its core mission, the mission for which our were created in the first place: to ensure our students' success, and thereby ensure the future success of the Bay Area and beyond.

We appreciate the difficulty of the decision before you. As you deliberate, we ask that you consider this: your organization will do a painful disservice to the Bay Area if your actions undercut Chabot's ability to meet it's educational mission. You, like us, have an obligation to improve the quality of life in the Bay Area. We ask that you take your obligation as seriously as we take ours. You are the Bay Area Air Quality Management District, after all. We urge you to follow the recommendations of the California Energy Commission's staff scientists and reject the Russell City Energy Center.

GEOPHYSICAL RESEARCH LETTERS, VOL. 35, L03809, doi:10.1029/2007GL031101, 2008

On the causal link between carbon dioxide and air pollution mortality

Mark Z. Jacobson[1]

Received 22 June 2007; revised 14 December 2007; accepted 3 January 2007; published 12 February 2008.

[1] Greenhouse gases and particle soot have been linked to enhanced sea-level, snowmelt, disease, heat stress, severe weather, and ocean acidification, but the effect of carbon dioxide (CO_2) on air pollution mortality has not been examined or quantified. Here, it is shown that increased water vapor and temperatures from higher CO_2 separately increase ozone more with higher ozone; thus, global warming may exacerbate ozone the most in already-polluted areas. A high-resolution global-regional model then found that CO_2 may increase U.S. annual air pollution deaths by about 1000 (350–1800) and cancers by 20–30 per 1 K rise in CO_2-induced temperature. About 40% of the additional deaths may be due to ozone and the rest, to particles, which increase due to CO_2-enhanced stability, humidity, and biogenic particle mass. An extrapolation by population could render 21,600 (7400–39,000) excess CO_2-caused annual pollution deaths worldwide, more than those from CO_2-enhanced storminess. **Citation:** Jacobson, M. Z. (2008), On the causal link between carbon dioxide and air pollution mortality, *Geophys. Res. Lett.*, *35*, L03809, doi:10.1029/2007GL031101.

1. Introduction

[2] Because carbon dioxide's (CO_2's) ambient mixing ratios are too low to affect human respiration directly, CO_2 has not been considered a classic air pollutant. Its effects on temperatures, though, affect meteorology, and both feed back to air pollution. Several studies have modeled the sensitivity of ozone to temperature [*Sillman and Samson*, 1995; *Zhang et al.*, 1998] and the regional or global effects of climate change from all greenhouse gases on ozone [*Thompson et al.*, 1989; *Evans et al.*, 1998; *Dvortsov and Solomon*, 2001; *Mickley et al.*, 2004; *Stevenson et al.*, 2005; *Brasseur et al.*, 2006; *Murazaki and Hess*, 2006; *Steiner et al.*, 2006; *Racherla and Adams*, 2006] and aerosol particles [*Aw and Kleeman*, 2003; *Liao et al.*, 2006; *Unger et al.*, 2006]. Some studies have highlighted the effect of water vapor on chemistry [*Evans et al.*, 1998; *Dvortsov and Solomon*, 2001; *Stevenson et al.*, 2005; *Steiner et al.*, 2006; *Racherla and Adams*, 2006; *Aw and Kleeman*, 2003]. However, none has isolated the effect of CO_2 alone on ozone, particles, or carcinogens, applied population and health data to the pollution changes, or examined the problem with a global-regional climate/air pollution model.

[3] Here, a box photochemistry calculation is first used to show how increases in water vapor and temperature independently increase ozone more with high than low ozone. This analysis helps to explain the causal link between CO_2 and health in areas where most people live, as subsequently found in 3-D global-regional simulations.

2. Chemical Effects of CO_2 on Ozone

[4] The SMVGEAR II chemical solver was used first in box mode, without dilution or entrainment, to solve chemistry for 12 hours among 128 gases and 395 inorganic, organic, sulfur, chlorine, and bromine reactions (including 57 photoprocesses) (mostly given by *Jacobson et al.* [2007], also see the supplementary material of *Jacobson* [2007]). Cases with different initial NO_x and organic gas were run.

[5] Figure 1 shows the water-vapor (H_2O) and temperature-dependence of ozone under several ozone precursor combinations. For initial NO_x < 8 ppbv, ozone decreased with increasing H_2O. For initial NO_x > 80 ppbv and moderate initial NO_x with low organics, though, ozone increased with increasing H_2O, by up to 2.8 ppbv-O_3 per 1 ppthv-H_2O. Between these extremes, ozone increased with increasing H_2O at low H_2O and stayed constant or slightly decreased at high H_2O (see the auxiliary material).[1] Figure 1 also shows that, generally (but not always), increasing water vapor increased ozone more with higher ozone.

[6] Further, the more ozone present, the more temperature-dependent chemistry increases ozone (Figure 1), consistent with *Sillman and Samson* [1995] and *Zhang et al.* [1998]. The ozone increase ($\Delta\chi$, ppbv) per 1 K change in temperature (ΔT) from all points in Figure 1 were fit to

$$\Delta\chi/\Delta T = -0.13034 - 0.0045585\chi + 0.00028643\chi^2 - 4.6893 \times 10^{-7}\chi^3 \quad (1)$$

where χ is ozone (ppbv) at 298.15 K (32–250 ppbv). A 1 K rise increased ozone by about 0.1 ppbv at 40 ppbv but 6.7 ppbv at 200 ppbv. *Olszyna et al.* [1997] reported an observed correlation in the rural southeast U.S. of 2.4 ppbv ozone per 1 K. If temperature-dependent chemistry alone were causing this increase, ozone would need to be about 115 ppbv (equation 1) in that study, but it was 30–90 ppbv. Thus, other factors not accounted for in Equation 1, such as H_2O increases (described above) and biogenic gas emission increases [e.g., *Guenther et al.*, 1995], due to higher temperatures, may have caused the larger observed temperature-ozone correlation. Also, both temperature and ozone increase with sunlight, so all observed temperature-ozone correlations overestimate the magnitude of cause and effect.

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0094-8276/08/2007GL031101$05.00

[1]Auxiliary materials are available in the HTML. doi:10.1029/2007GL031101.

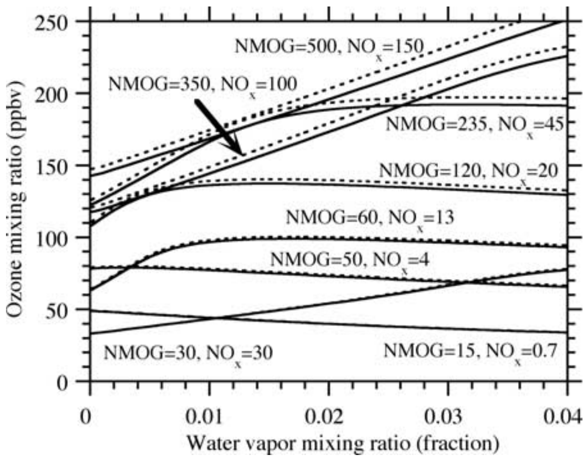

Figure 1. Mixing ratio of ozone and several other gases as a function of water vapor mixing ratio after 12 hours of a box-model chemistry-only simulation initialized at 0430 under several initial NO_x and nonmethane organic gas (NMOG) mixing ratio combinations (ppbv) (given in the figure) at 298.15 K (solid lines) and 299.15 K (dashed lines). The simulations assumed sinusoidally varying photolysis between 0600 and 1800.

3. Health Effects of CO_2 From Global-U.S. Simulations

[7] The chemistry used for Figure 1 was applied with emission, aerosol, cloud, meteorological, radiative, transport, and surface processes in the nested global-urban 3-D model, GATOR-GCMOM. The model (see auxiliary material) has been evaluated against U.S. gas, aerosol, meteorological, and radiative data extensively [e.g., *Jacobson*, 2001; *Jacobson et al.*, 2004, 2007; *Colella et al.*, 2005].

[8] Two global simulations (4°-SN × 5°-WE) were run under present-day conditions. In the second, fossil-fuel CO_2 (fCO_2) ambient mixing ratios and emissions were set to preindustrial values. When U.S. temperatures were about 1 K higher in the present minus preindustrial-CO_2 global simulations, the U.S. regional domain (0.5°S-N × 0.75°W-E) in each global simulation was turned on and initialized with global-domain data (including ambient CO_2). Global and regional domains were run another four months. Emissions of fCO_2 were included in the present-day but not preindustrial-CO_2 global- and U.S.-domain simulations.

[9] Figures 2 and S3 show differences between the present-day and preindustrial-CO_2 simulations. Figure 2a compares modeled with radiosonde (1958–2006) vertical temperature differences. The population-weighted near-surface temperature increase over land was 1.07 K (Table S4), which increased population-weighted H_2O by 1.28 ppthv (Table S4) and U.S.-averaged H_2O by 1.1 ppthv (Figure 2b). The observed 1961–1995 U.S. water vapor increase and positive correlation between temperature and H_2O [*Gaffen and Ross*, 1999] support the modeled H_2O increase with increasing temperatures.

[10] Figure 2c indicates that fCO_2 increased ozone by 0.12 ppbv in the U.S., 5 ppbv in Los Angeles, 1–5 ppbv in the southeast, and up to 2 ppbv along the northeast coast. In Los Angeles, the 0.75 K temperature increase (Figure 2a) and 1.3 ppthv water vapor increase increased ozone through chemistry (Figure 1).

[11] In the southeast, 0.5–1 K temperature increases increased isoprene and monoterpenes (Figure S3a), reducing the relative humidity (Figure S3c) and cloud optical depth (Figure S3d), increasing ultraviolet radiation (Figure S3e), and enhancing ozone. The 0.5–2 ppbv/K ozone increase in Tennessee is just below the correlated estimate of 2.4 ppbv/K from *Olszyna et al.* [1997] as expected (section 2). Averaged over the U.S. domain, higher temperatures from fCO_2 increased biogenic soil NO_x, isoprene, monoterpene, and other organic carbon emissions by 6% (0.01 Tg/yr), 9% (0.47), 9.8% (0.15), and 8.9% (0.14), respectively. In the northeast, higher ozone due to higher temperatures was offset partly by higher cloud optical depth (Figure S3d) and lower ultraviolet radiation (Figure S3e), modestly increasing ozone.

[12] The population-weighted 8-hr ozone increase due to fCO_2 was +0.72 ppbv (Table 1), suggesting a greater increase over populated than less-populated areas. FCO_2 increased particles in populated areas (Tables 1 and S4) by warming the air more than the ground, increasing stability (as with radiosonde data-Figure 2a, ii), decreasing turbulence, shearing stress, and surface wind speed (Table S4 and Figure S3), reducing dispersion. Reduced dispersion and wind speed are consistent with *Mickley et al.* [2004] who correlated warmer temperatures with reduced cyclone activity. FCO_2 also increased isoprene and monoterpene emissions, thus secondary organic matter (SOM) (Table S4, Figures S3a and S3b); and increased relative humidity (Table S4) by increasing H_2O, swelling aerosol particles, increasing nitric acid and ammonia dissolution and the surface area for sulfuric acid and organic condensation. FCO_2 increased land precipitation, consistent in direction with observed trends [*Intergovernmental Panel on Climate Change*, 2001], increasing aerosol removal, but less than other processes increased aerosol concentrations.

[13] Health effect changes (Δy) due to ozone and $PM_{2.5}$ changes in each model cell were determined from [e.g., *Ostro et al.*, 2006],

$$\Delta y = (1 - \exp[-\beta \Delta x]) y_0 P \tag{2}$$

where Δx is the simulation-averaged mixing ratio or concentration change in the cell, β is the fractional increase in risk per unit Δx, y_0 is the baseline health effect rate, and P is the cell population exposed to at least a minimum threshold. Table 1 and its footnote provide values of P, Δx, β, y_0, and thresholds. Changes were summed over all cells and adjusted from a four-month to an annual average (Table 1, footnote).

[14] With this method, mortality increases due to modeled ozone and $PM_{2.5}$ from fCO_2 were 415 (207–620)/yr and 640 (160–1280)/yr, respectively, per 1.07 K (Table 1) or a total of near 1000 (350–1800) per 1.00 K (a 1.1% increase relative to the baseline death rate - Table 1), with about 40% due to ozone. A simple extrapolation from U.S. to world population (301.5 to 6600 million) gives 21,600 (7400–39,000) deaths/yr worldwide per 1 K due to fCO_2 above the baseline air pollution death rate (2.2 million/yr). The ozone portion of this (8,500 deaths/yr) is conservative compared with 15,500 deaths/yr, calculated from *West et al.* [2006] (= 30,000 deaths/yr from 1 ppbv ozone multiplied by the 2006:2030 population ratio (66:92) and the ozone

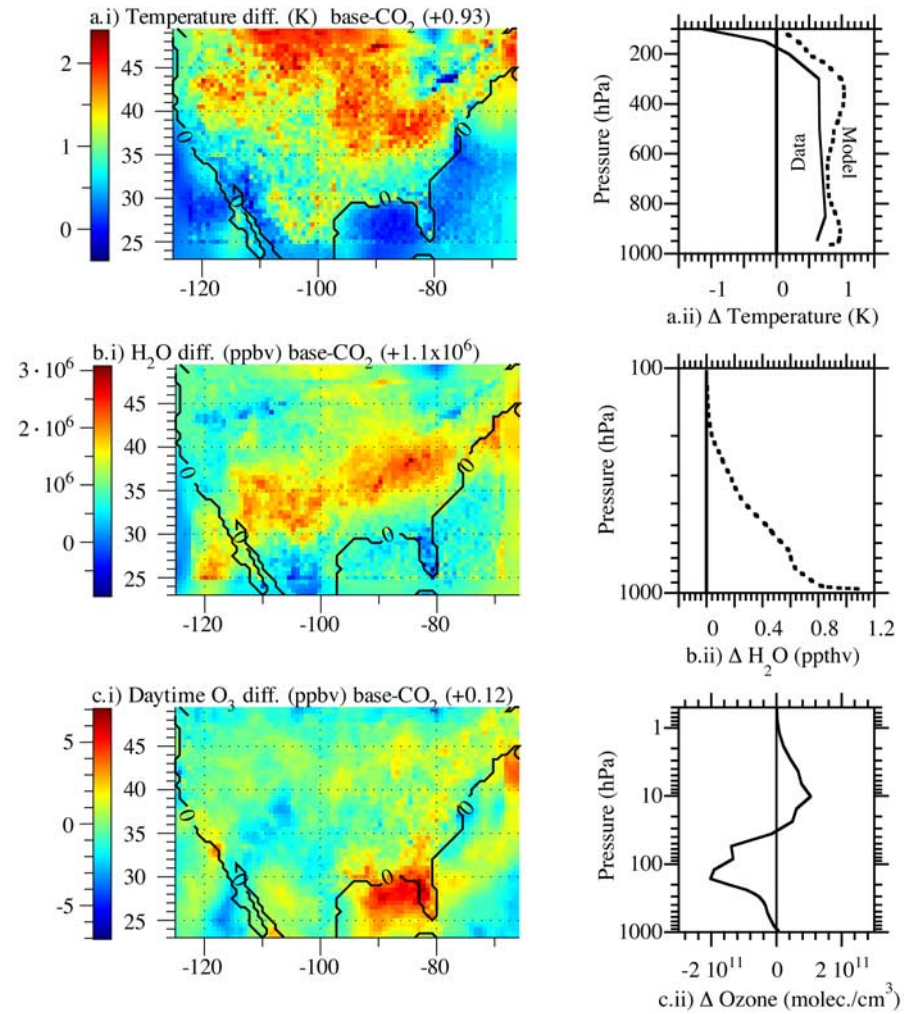

Figure 2. . Four-month (mid-July to mid-November) domain-averaged near-surface and vertical-profile differences in (a) temperature, (b) water vapor, and (c) ozone between the present-day and preindustrial-CO_2 simulations. The domain-averaged (over land and water) change for each surface plot is given in parentheses. Also shown in Figure 2a (ii) is the 1958–2006 globally-averaged radiosonde temperature change [*Thorne et al.*, 2005], which is for reference only since the present simulations isolate the effects of CO_2 and do not examine all forcing agents.

change ratio (0.72:1.0). Remaining differences may be due to different thresholds used (35 ppbv here vs. 25 ppbv).

[15] One estimate of severe weather-related fatalities worldwide in the 1990s was 33,000/yr (Worldwatch Institute, Unnatural disaster: The lesson of Katrina, available at www.worldwatch.org/node/1822, 2005). A 1 K rise will increase this number, but less than 23,000/yr given that hurricane and tornado deaths have declined due to better warning systems (e.g., the deadliest hurricane since 1910 was over 30 years ago – Honduras, 1974, 10,000 deaths). Global warming will increase heat stress- and disease-related deaths as well, but by uncertain rates [e.g., *Medina-Ramon and Schwartz*, 2007].

[16] FCO_2 increased carcinogens, but the increase was small. Isoprene increases due to higher temperatures increased formaldehyde and acetaldehyde. Reduced dispersion increased exposure to these carcinogens and benzene and 1,3-butadiene.

[17] These simulations treated temperature effects on natural emissions but not power plant or vehicle emissions. A sensitivity test was run examining the impact of 1 K on power plant energy demand and emissions. The resulting ozone (Figure S4) may cause 80 more U.S. deaths/yr. However, warmer winter temperatures will also decrease natural gas and vehicle emissions, and warmer summers will increase vehicle emissions [*Rubin et al.*, 2006; N. Motallebi et al., manuscript in review, 2007]. The feedbacks of temperature to anthropogenic emissions must be studied more but are expected to be smaller than the other feedbacks examined here. Further uncertainties arise from model resolution, current and future emissions, numerical treatments, health data, and extrapolation of four-month results to a year, as detailed in the auxiliary material.

4. Effects of CO_2 on Stratospheric Ozone and UV Radiation

[18] Whereas, fCO_2 warms the surface and troposphere, it cools the stratosphere (Figure 2a, ii). Measurements indicate a 1%/yr (0.45 ppmv/decade) stratospheric water vapor

Table 1. Summary of CO_2's Effects on Cancer, Ozone Mortality, Ozone Hospitalization, Ozone Emergency Room Visits, and Particulate-Matter Mortality[a]

	Base	Base Minus No fCO_2
	Carcinogens	
Formaldehyde (ppbv)	3.61	+0.22
Acetaldehyde (ppbv)	2.28	+0.203
1,3-Butadiene (ppbv)	0.254	+0.00823
Benzene (ppbv)	0.479	+0.0207
USEPA cancers/yr[b]	389	+23
OEHHA cancers/yr[b]	789	+33
	Ozone	
8-hr ozone (ppbv) in areas $\geq$35 ppbv[c]	42.3	+0.724
Pop (mil.) exposed in areas $\geq$35 ppbv[d]	184.8	184.8
High ozone deaths/yr[e]	6230	620
Med. ozone deaths/yr[e]	4160	+415
Low ozone deaths/yr[e]	2080	+207
Ozone hospitalizations/yr[e]	24,100	+2400
Ozone ER visits/yr[e]	21,500	+2160
	Particulate matter	
PM2.5 ($\mu g/m^3$) in areas > 0 $\mu g/m^3$[f]	16.1	+0.065
Pop (mil.) exposed in areas $\geq$ 0 $\mu g/m^3$	301.5	301.5
High PM2.5 deaths/yr[g]	191,000	+1280
Medium PM2.5 deaths/yr[g]	97,000	+640
Low PM2.5 deaths/yr[g]	24,500	+160

[a]Results are shown for the present-day ("Base") and present-day minus preindustrial ("no-fCO_2") 3-D simulations. All mixing ratios and concentrations are near-surface values averaged over four months (mid-July to mid-November) and weighted by population (population-weighted value is defined in the footnote to Table S4). Divide the last column by 1.07 K (the population-weighted CO_2-induced temperature change from Table S4) to obtain the health effect per 1 K.

[b]USEPA and OEHHA cancers/yr were found by summing the product of individual CUREs (cancer unit risk estimates = increased 70-year cancer risk per $\mu g/m^3$ sustained concentration change) by the population-weighted mixing ratio or mixing ratio difference of a carcinogen, by the population, and air density, over all carcinogens, then dividing by 70 yr. USEPA CURES are 1.3×10^{-5} (formaldehyde), 2.2×10^{-6} (acetaldehyde), $3.0x10^{-5}$ (butadiene), 5.0×10^{-6} (= average of 2.2×10^{-6} and 7.8×10^{-6}) (benzene) (www.epa.gov/IRIS/). OEHHA CUREs are 6.0×10^{-6} (formaldehyde), 2.7×10^{-6} (acetaldehyde), 1.7×10^{-4} (butadiene), 2.9×10^{-5} (benzene) (www.oehha.ca.gov/risk/ChemicalDB/index.asp).

[c]8-hr ozone $\geq$35 ppbv is the highest 8-hour-averaged ozone during each day, averaged over all days of the four-month simulation in areas where this value $\geq$35 ppbv in the base case. When base $O_3 \geq 35$ ppbv and no-fCO_2 $O_3 < 35$ ppbv, the mixing ratio difference was base O_3 minus 35 ppbv.

[d]The 2007 population exposed to $\geq$35 ppbv O_3 is the population exposed to a four-month-averaged 8-hour averaged ozone mixing ratio above 35 ppbv and was determined from the base case.

[e]High, medium, and low deaths/yr, hospitalizations/yr, and emergency-room (ER) visits/yr due to short-term O_3 exposure were obtained from Equation 2 applied to each model cell, summed over all cells. The baseline 2003 U.S. death rate (y_0) was 833 deaths/yr per 100,000 [*Hoyert et al.*, 2006]. The baseline 2002 hospitalization rate due to respiratory problems was 1189 per 100,000 [*Merrill and Elixhauser*, 2005]. The baseline 1999 all-age emergency-room visit rate for asthma was 732 per 100,000 [*Mannino et al.*, 2002]. These rates were assumed to be the same in each U.S. county, although they vary slightly by county. The fraction increases (β) in the number of deaths from all causes due to ozone were 0.006, 0.004, and 0.002 per 10 ppbv increase in daily 1-hr maximum ozone [*Ostro et al.*, 2006]. These were multiplied by 1.33 to convert the risk associated with 10 ppbv increase in 1-hr maximum O_3 to that associated with a 10 ppbv increase in 8-hour average O_3 [*Thurston and Ito*, 2001]. The central value of the increased risk of hospitalization due to respiratory disease was 1.65% per 10 ppbv increase in 1-hour maximum O_3 (2.19% per 10 ppbv increase in 8-hour average O_3), and that for all-age ER visits for asthma was 2.4% per 10 ppbv increase in 1-hour O_3 [*Ostro et al.*, 2006] (3.2% per 10 ppbv increase in 8-hour O_3). All values were reduced by 45% to account for the mid-July to mid-November and year-around $O_3 \geq 35$ ppbv ratio, obtained from detailed observations (H. Tran, personal communication, 2007).

[f]This is the simulated 24-hr $PM_{2.5}$, averaged over four months, in locations where $PM_{2.5} \geq 0$ $\mu g/m^3$.

[g]The death rate due to long-term $PM_{2.5}$ exposure was calculated from Equation 2. *Pope et al.* [2002] provide increased dearth risks to those $\geq$30 years of 0.008 (high), 0.004 (medium), and 0.001 (low) per 1 $\mu g/m^3$ $PM_{2.5}$ >8 $\mu g/m^3$ based on 1979–1983 data. From 0–8 $\mu g/m^3$, the increased risks were conservatively but arbitrarily assumed = $^1/_4$ those >8 $\mu g/m^3$ to account for reduced risk near zero $PM_{2.5}$. Assuming a higher risk would strengthen the conclusion found here. The all-cause 2003 U.S. death rate of those $\geq$30 years was 809.7 deaths/yr per 100,000 total population. No scaling of results from the 4-month model period to the annual average was performed to be conservative, since $PM_{2.5}$ concentrations from July–November are lower than in the annual average based on California data (H. Tran, personal communication, 2007).

increase from 1954–2000 [*Rosenlof et al.*, 2001], but a slight lower-stratospheric decrease from 2001–2005 [*Randel et al.*, 2006]. The simulations here, which accounted for chlorine and bromine gas and heterogeneous chemistry, found that the temperature and H_2O changes due to fCO_2 increased middle and upper-stratospheric ozone but decreased upper tropospheric and lower stratospheric (UTLS) ozone, where its column abundance is greater, causing a net U.S. column ozone loss of 2.7% (Figure 2c, ii, and Table S4). The UTLS ozone losses were due to increases in H_2O there (Figure 2b, ii), as indicated by Figure S2b and *Dvortsov and Solomon* [2001]. The upper- and middle-stratospheric gains can be explained by Figure S1, which shows that, at 25 km, stratospheric ozone decreases by 1.5% as H_2O increases by 1 ppmv. As temperature decreases by 1.5 K, though, ozone increases by 3.6%, suggesting an overall ozone increase from H_2O and cooling. The ozone increase upon stratospheric cooling is due to reduced loss from $O+O_3$ [*Evans et al.*, 1998]. Despite the column ozone loss due to fCO_2, surface UV hardly changed (Table S4) because fCO_2 increased cloud optical depth, offsetting UV increases from ozone loss.

5. Summary

[19] A climate-air pollution model showed by cause and effect that fossil-fuel CO_2 increases increase U.S. surface ozone, carcinogens, and particulate matter, thereby increasing death, asthma, hospitalization, and cancer rates. Increased water vapor and temperatures due to higher CO_2

each increase ozone increasingly with increasing ozone. At low ozone, more water vapor decreases ozone slightly but higher temperatures increase biogenic emission in many areas, offsetting ozone decreases in such areas. CO_2 increases stability, the relative humidity, and biogenic particle mass thus $PM_{2.5}$. Finally, CO_2 decreases column ozone over the U.S. by increasing upper tropospheric/lower stratospheric water vapor.

[20] **Acknowledgments.** NASA grants NNG04GE93G and NNG04GJ89G and U.S. Environmental Protection Agency grant RD-83337101-O. I thank Hien Tran of the California Air Resources Board for helpful health statistic comments.

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April 30, 2009

SUBMITTED BY E-MAIL
weyman@baaqmd.gov
Weyman Lee, P.E.
Senior Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Re: Draft PSD Permit for Russell City Energy Center

Dear Mr. Lee:

I am writing on behalf of Citizens Against Pollution to request the District to consider an April 3, 2009 paper by Dr. Jacobson called "The enhancement of local air pollution by urban CO2 domes." *See* http://www.stanford.edu/group/efmh/jacobson/PDF%20files/CO2loc0409.pdf. A related paper was cited in the initial comments. This April 3, 2009 paper concludes that "reducing locally-emitted CO2 will reduce local air pollution mortality even if CO2 in adjacent regions is not controlled." As part of this analysis, Dr. Jacobson models the increased local mortality due to locally emitted CO2.

We request that the District evaluate the Jacobson methodology as a method for estimating the increase in local mortality due to locally emitted CO2 when evaluating the Russell City Energy Center (RCEC) proposed permit. This methodology could be used to predict some of the effects the RCEC will have in Hayward and the surrounding communities during its proposed 30 year initial license, which would emit billions of pounds of greenhouse gases every year. In addition, this same methodology should be used to analyze the effects the RCEC will have on each of the listed endangered and threatened species. Since the physiology of the various listed species differ dramatically from species to species; respiration rate, body temperature regulation, kidney and liver function etc, a separate study must be done for the Salt Marsh Harvest Mouse (Reithrodontomys raviventris), Western Snowy Plover (Charadrius alexandrinus nivosus), California Black Rail (Laterallus jamaicensis coturniculus), Red Legged Frog (Rana aurora draytonii), etc.

We request the District not approve permits for the RCEC
or any other fossil fuel power plant adjacent to an endangered species preserve, and of a city of 149,000, until the completion of your evaluation and analysis of the Jacobson effect.

Sincerely,
Ernest A. Pacheco
Citizens Against Pollution
(510) 677 8452

CC:

Anita Lee
Gerardo Rios
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Avenal Testimony

Interpollutant Trade

The applicant proposes to offset the projects PM 2.5 emissions on a pound for pound basis with SOx offsets. Proposed interpollutant trading ratios are required to be scientifically justified with a site specific air quality analysis, as required by Rule 2201, Section 4.13.3. The PDOC attempts to establish an interpollutant[1] ratio based on modeling analyses performed in the Districts 2008 PM 2.5 plan. The EPA has commented in a letter to GWF Energy and the San jaoquin Valley Air Pollution control district that

"Although the project relies on inter-pollutant offset ratios of I: I and 2.629: 1 for NOx-toVOC and NOx:-to-PMIO, respectively, the underlying methodology to determine the appropriate ratios for inter-pollutant offsets has not been approved by EPA as required by District Rule'2201. The burden in seeking approval for inter-pollutant offsets rests with GWF Tracy to demonstrate that the proposed inter-pollutant offsets will ensure a net benefit to air quality levels in the area ofthe proposed project. It is important to note that modeling is a critical.component of an inter-pollutant offset analysis, and subsequent models are evaluated on a case-by-case basis. Any approach for inter-pollutant offsets, therefore, must be carefully considered by the agencies in the context of a thorough and descriptive protocol. EPA must concur with the assumptions and methodology before such ratios may be used in this project. Even though a proposed methodology has been presented in a District attainment plan, it should not be inferred that the methodology has been automatically approved for use in this project. Accordingly, GWF Tracy and SJVAPCD must work with EPA on such protocol to be reviewed in advance of an acceptable methodology. We are available to discuss the schedule for submission of such a protocol and its components. At a minimum, the protocol should include standard information, such as model choice, episode selection, emissions inventory parameters, and performance criteria."
[2]

The EPA has finalized its regulations to implement the New Source Review (NSR) program for fine particulate matter on July 15, 2008. Their recommended ratio of SOx offsets to PM 2.5 offsets is 40 tons of SOx for each ton of PM 2.5. The applicant is proposing a ratio that is 40 times less stringent than EPA has recommended.

In addition the CEC and the air district allow the project to emit 33,521 pounds of SO2 with no mitigation despite the alleged CEC policy to offset all PM2.5

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[1] "We have determined a nationwide preferred ratio of 40 to 1 (SO2 tons for PM2.5 tons) or 1 to 40 (PM2.5 tons for SO2) for trades between these pollutants. We recognize there is spatial variability here between urban and regionally located sources of these pollutants that can be addressed through a local demonstration to determine an area-specific relationship, as appropriate." http://www.epa.gov/fedrgstr/EPA-AIR/2008/May/Day-16/a10768.pdf page 28338

[2] http://www.energy.ca.gov/sitingcases/tracyexpansion/documents/others/2009-05-21_Comments_from_US_EPA_Regarding_San_Joaquin_Valley_Air_Pollution_Control%20District_PDOC.PDF

precursors. If one pound of SO2 offsets 1 pound of PM 2.5 the CEC and the Air District are allowing 33,521 pounds of SO2 to remain unmitigated. The new EPA rules on PM 2.5 require a pound for pound offset ratio for PM 2.5 precursors.[3] If the districts assumption that one pound of SOx offsets 1 pound of PM 2.5 as allowed in the interpollutant trade the district is allowing 33,521 pounds of SOx to remain unmitigated creating 33,521 pounds of PM 2.5 in violation of CEQA and EPA NSAR rules for PM 2.5.

Ammonia Emissions

The FDOC allows an ammonia slip of 10 ppm. The 5 ppm ammonia limit in combination with a 2 ppm NO limit has already been required for the following CEC licensed facilities: Malburg-Vernon (01-AFC-25), El Segundo (00-AFC-14), Inland Empire (01-AFC-17), Magnolia (01-AFC-6), Morro Bay (00-AFC-12), Palomar (01-AFC-24), and Tesla (01-AFC-21).

In the alternative the District could perform a site specific analysis that demonstrates that no particulate matter will be formed locally or district wide due to the ammonia slip emissions and require mitigation if the analysis demonstrates that there is significant secondary particulate matter formation from the ammonia emissions from the LGS. The district must also consider the transport of the ammonia emissions to regions that may not be ammonia rich outside of the San Joaquin Valley.

A second potential environmental impact that may result from the use of SCR involves ammonia transportation and storage. The proposed facility will utilize aqueous ammonia for SCR ammonia injection, which will be transported to the facility and stored onsite in tanks. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident. The project, if allowed to use SCR, can eliminate the impact from transportation accidents by utilizing a technology called NOxOUT ULTRA®. There are dozens of systems in service, one in Southern California at UC Irvine. Most of the UC campuses have decided not to risk bringing ammonia tankers through campus or having to offload or store ammonia. NOxOUT ULTRA is being specified for new units at UCSD, University of Texas and Harvard. The NOxOUT ULTRA system requires a tank for the urea. The urea is usually in a 50 to 32 % solution. Urea has no vapor pressure and no smell. If it spills, the evaporated water will leave behind a pile of crystal salts. There are no hazards to labeling or training required for the operator and absolutely no risk to adjacent facilities or neighbors. Like aqueous and anhydrous ammonia, NOxOUT ULTRA needs controls to manage the input from the power plant indicating how much reagent the SCR requires.

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[3] "As discussed previously, the Act requires that a source obtain offsets for emissions increases that occur in a nonattainment area. As with PM2.5 direct emissions, the minimum offset ratio permitted under subpart 1 of the Act is at least 1:1. Based on these requirements of the Act, we are finalizing our proposal that an offset ratio of at least 1:1 applies where a source seeks to offset an increase in emissions of a PM2.5 precursor with creditable reductions of the same precursor. This offset ratio applies for all pollutants that have been designated as PM2.5 precursors in a particular nonattainment area."
http://www.epa.gov/fedrgstr/EPA-AIR/2008/May/Day-16/a10768.pdf page 28338

Like aqueous ammonia, the system requires an air blower and heater to heat the air. The heated air goes to a decomposition chamber instead of a vaporizer. In the decomposition chamber, the urea solution is added. The water in the urea solution is vaporized and the additional heat required will then decompose the urea to ammonia. The gas/carrier air is then swept to the AIG and to the SCR. If the urea pump is stopped and air is left in service, the chamber is swept clear of ammonia in less than seven seconds. So in an emergency, there is very little, if any, ammonia exposure. Other than the seven seconds between the chamber and the AIG, the only exposure is the harmless urea.

Research Papers on Energy, Resources, and
Economic Sustainability

Energy Efficiency, Innovation, and Job Creation in California

David Roland-Holst

October 2008

CENTER FOR ENERGY, RESOURCES, AND ECONOMIC SUSTAINABILITY (CERES)

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Research Papers on Energy, Resources, and Economic Sustainability

This report studies the economic impacts of energy policies and climate adaptation generally, and particularly as this relates to employment and innovation. In addition to disseminating original research findings, this study is intended to contribute to policy dialogue and public awareness about environment-economy linkages and sustainable growth. All opinions expressed here are those of the authors and should not be attributed to their affiliated institutions.

For this project on Energy Efficiency, Innovation, and Job Creation in California, we express thanks to Next 10, who recognized the importance of this issue for California's economy and provided essential intellectual impetus and financial support. Thanks are also due for outstanding research assistance by Elliott Deal, Dave Graham-Squire, Maryam Kabiri, Fredrich Kahrl, Mehmet Seflek, and Tom Lueker.

F. Noel Perry, Morrow Cater, Sarah Henry, and Adam Rose offered many helpful insights and comments. Opinions expressed remain those of the author, however, and should not be attributed to his affiliated institutions.

Executive Summary

Global climate change poses significant risks to the California economy. Recognizing and responding to these threats, Governor Schwarzenegger signed Executive Order #S-3-05 (Schwarzenegger 2005) which called for a 30 percent reduction below business-as-usual of greenhouse gas emissions by 2020 and 80 percent below 1990 levels by 2050. In September 2006, the California legislature passed and Governor Schwarzenegger signed into law the historic Global Warming Solutions Act (AB 32), which mandates a first-in-the-nation limit on emissions that cause global warming. In June 2006, the California Air Resources Board (CARB) released a "Draft Scoping Plan" – the policy roadmap to meet the emissions reduction target of 169 Million Metric Tons of Carbon (MMTCO2) equivalent by 2020 to stabilize at 427 MMTCO2 overall. The CARB board will take up final adoption of this plan in December 2008.

During the months leading up to this decision, a financial crisis of global proportions is unfolding. The state, nation and world are caught in serial market failures sparked by the collapse of the housing credit market, and there is much speculation about the impact of declining capital gains revenue on the state budget.

Against this backdrop, *Energy Efficiency, Innovation, and Job Creation in California* analyses the economic impact of CARB's past and future policies to reduce fossil fuel generated energy demand. California's achievements in energy efficiency over the last generation are well known, but evidence about their deeper economic implications remains weak. This study examines the economy-wide employment effects of the state's landmark efficiency policies over the last thirty-five years, and forecasts the economic effects of significantly more aggressive policies proposed to reduce emissions to 1990 levels by 2020.

Part I: Economic Impact of California's Existing Energy Efficiency Policies

Over the last thirty-five years, as a result of landmark energy efficiency policies, California has de-coupled from national trends of electricity demand, reducing its per capita requirements to 40 percent below the national average. Using detailed data on the changing economic structure over the period 1972-2006, we examine one of the most potent catalysts of efficiency-based economic growth, household reductions in per capita electricity demand. Because it represents over 70 percent of Gross State Product (GSP), household consumption is the most powerful driver of economic activity in the state, and household expenditure patterns are the leading determinant of state energy use.

Methodology

Producing detailed historical employment impact estimates involved a data intensive process including assembling a series of input-output tables, comprising inter-industry flows, value added, and final demand for about 500 activity and commodity categories over the period 1972-2006. The U.S. Bureau of Economic Analysis (BEA) maintains these accounts and updates them every five years. Each of the seven relevant national tables were obtained from BEA and aggregated up to the 50-sector framework reported in this paper. Also, comparable tables for California, estimated for 2002 and 2006, were aggregated to the same sector standard. In addition to data on economic structure for the last 35 years, detailed employment wage data were obtained by California Regional Economies Employment (CREE) Series. This source provides annual data on enterprises, jobs, and average wages for over 1,200 North American Industry Classification System (NAICS) sector categories across California.

To impute historical employment gains from California's energy efficiency measures, we pose a simple counterfactual question:

Given California's economic structure, how would employment growth have proceeded in the absence of household energy efficiency?

Answering this question requires three kinds of information:

1. Historical national and current California consumption patterns, which were obtained from BEA tables.

2. Historical economic structure for California, which is estimated using seven historical input-output tables for the national economy and one (2002) for California. In particular, we used a combination of national and state tables to approximate California's changing economic structure.

3. Employment by sector, which was provided by the CREE data set.

Part I Core Findings

- Energy efficiency measures have, enabled California households to redirect their expenditures toward other goods and services, creating about 1.5 million FTE jobs with a total payroll of $45 billion, driven by well-documented household energy savings of $56 billion from 1972-2006.

- As a result of energy efficiency, California reduced its energy import dependence and directed a greater percentage of its consumption to in-state, employment-intensive goods and services, whose supply chains also largely reside within the state, creating a “multiplier” effect of job generation.

- The same efficiency measures resulted in slower (but still positive) growth in energy supply chains, including oil, gas, and electric power. For every new job foregone in these sectors, however, more than 50 new jobs have been created across the state’s diverse economy.[1]

- Sectoral examination of these results indicate that job creation is in less energy intensive services and other categories, further compounding California’s aggregate efficiency improvements and facilitating the economy’s transition to a low carbon future.

Part II: Future Economic Impacts of California’s Proposed Policies

At this critical moment of economic distress, balanced policy dialogue requires a more complete assessment of both the potential benefits and costs of the options before the state. Because of its pioneering role in climate policy, California faces a significant degree of uncertainty about direct and indirect effects of the many possible approaches to its stated goals for emissions reduction. High standards for economic analysis are needed to anticipate the opportunities and adjustment challenges that lie ahead, and to design the right policies to meet them. Progress in this area can increase the likelihood of two essential results: 1) that California policies work effectively, and 2) that they achieve the right balance between public and private interest.

In this part of the analysis, we conduct a rigorous ex ante economic assessment of draft policies contained in the California Air Resources Board Draft Scoping Plan.

Impact of Technological Change and Innovation

An important limitation of most prior California economic modeling of climate policies is innovation or technological neutrality. This means that factor productivity, energy use intensities, and other innovation characteristics were held constant across policy scenarios. Energy use and pollution levels might change, but the prospect of innovation to reduce energy intensity was not considered.

[1] This comparison is for net combined job creation, meaning we count both cumulative effects of both job creation and job losses.

Inclusion of innovation is important for two main reasons. First, technological change in favor of energy efficiency has been a hallmark of California's economic growth experience over the last four decades. As the earlier estimates show, the resultant energy savings have been an important growth and employment stimulus to the state economy. Second, most observers credit this technological progress to California's energy/climate policy combinations of mandates and incentives. And as discussed in Part I, California has reduced its aggregate energy intensity steadily over this period, attaining levels that today are 40 percent below the national average. Importantly, reductions in energy use were not flat across the last thirty-five years; instead energy efficiency grew at exponential rates.

In the present analysis, we factor in the prospect of innovation to reduce energy intensity by projecting a rate of energy efficiency gains that better reflects historical achievements, as well as the impact of significantly more aggressive policies aimed to reduce energy use. It is reasonable to assume that new climate polices will create new incentives for innovation. This is particularly true for policies like "cap and trade" which is included in the state's Draft Scoping Plan and will put an explicit price on carbon externalities that did not exist before. When firms are faced with new costs from emissions and energy use, they can be expected to make investments in technology that reduces these costs.

To capture this innovation, we assume that, subject to the implementation of the recommended measures, California is able to increase its energy efficiency by one additional percent per year, on an average basis, across the economy. This conservative estimate may be below the state's innovation potential in such circumstances, given that much lower energy prices and less determined policies were in place for the long period of improvement before AB 32.

Recently, the Center for Energy, Resources, and Economic Sustainability (CERES) at the University of California Berkeley conducted scenario analysis for the California Air Resources Board, which is included as a supplement to their economic forecasts conducted using the E-DRAM model. While the policy scenario analyzed here is identical to that modeled for the state, this analysis includes the potential for innovation to reduce energy intensity. The state's official modeling assumes technology characteristics remain static and includes a flat rate of energy efficiency for the time period considered (2008-2020).

Methodology
For the last three years, CERES has been conducting independent research to inform public and private dialogue surrounding California climate policy. Among these efforts has been the development and implementation of a statewide economic model, the Berkeley Energy and Resources (BEAR) model, the most detailed and comprehensive forecasting tool of its kind.

The BEAR model's sectoral detail, model determined emissions, and dynamic innovation and forecasting capabilities enable it to capture a wide range of program characteristics and their role in economic adjustments to climate action. BEAR was designed to model cap and trade systems, and includes all the major design features such as variable auction allocation systems, market determined permit prices, banking options, safety valves, and fee/rebate systems for CO2 and up to thirteen other criteria pollutants. BEAR is a detailed, computable general equilibrium model of California's economy that simulates demand and supply relationships across many sectors of the economy, and tracks the linkages among them. It can thus be used to trace the ripple effects throughout the economy over time of new economic and technology policies.

To assess the future economic impacts of the state's package of proposed policies to reduce greenhouse gas emissions, we used BEAR to model a generic policy scenario, which faithfully represents policies currently in the CARB Draft Scoping Plan.

Part II Core Findings

- By including the potential for innovation, we find that the proposed package of policies in the state's Draft Scoping Plan achieves 100 percent of the greenhouse gas emissions reduction targets as mandated by AB 32, while increasing the Gross State Product (GSP) by about $76 billion, increasing real household incomes by up to $48 billion and creating as many as 403,000 new efficiency and climate action driven jobs.

- The economic benefits of energy efficiency innovation have a compounding effect. The first 1.4 percent of annual efficiency gain produced about 181,000 additional jobs, while <u>an additional one percent</u> yielded 222,000 more. It is reasonable to assume that the marginal efficiency gains will be more costly, but they have more intensive economic growth benefits.[2]

[2] Job creation in the second case is larger because we assume energy efficiency applies to electricity use by all sectors, while the 1.4 percent efficiency improvement in the baseline applies only to household electricity demand.

- Existing energy efficiency programs and proposed state climate policies will continue the structural shift in California's economy from carbon intensive industries to more job intensive industries. While job growth continues to be positive in the carbon fuel supply chain, it is less than it would be without implementation of these policies.

Summary

California's legacy of energy policies and resulting economic growth provides evidence that innovation and energy efficiency can make essential contributions to economic growth and stability. Had the state not embarked on its ambitious path to reduce emissions over three decades ago, the California economy would be in a significantly more vulnerable position today. Looking ahead, California's ambitious plan to reduce greenhouse gas emissions as mandated by the California Global Warming Solutions Act (AB 32) puts the state on a more stable economic path by encouraging even greater investment in energy saving innovation. The current financial crisis reminds us of the importance of responsible risk management. The results of this study remind us that, in addition to energy price vulnerability and climate damage, the risks of excessive energy dependence include lower long-term economic growth. A lower carbon future for California is a more prosperous and sustainable future.

CONTENTS

APPENDIX

Energy Efficiency, Innovation, and Job Creation in California

David Roland-Holst[3]

UC Berkeley

1. Introduction

As California looks to a future of ambitious climate action, it can reflect with confidence on its own legacy of energy efficiency improvements. Over the last generation, the state has established national and even global precedence with a proactive approach to more efficient energy use, building a solid foundation of experience to sustain progress toward to a lower carbon future. The state's reductions in energy use per capita and per dollar of income are well known, but evidence of the deeper economic implications of efficiency improvement remains weak. As California intensifies its commitments to reduce energy dependence, and as others look to the state for leadership, it is essential that stakeholders have reliable guidance regarding the broader effects of these policies. This report contributes to the policy dialogue by examining economy-wide employment effects of California's historical experience with energy efficiency policies, comparing this with forward looking projections of the economic impacts of new climate policy, as represented by the state's Global Warming Solutions Act (AB 32).

In this report, we conduct original estimates of the employment effects arising from the most potent source of economic stimulus in the state, household consumption. In particular, we find that household energy savings in California over the last thirty years have contributed over one million additional jobs to the state economy. Moreover, these additional jobs have been concentrated in less energy intensive service sectors, further reducing the state's carbon footprint and reinforcing its transition to a post-industrial, greener, and more sustainable future. Looking ahead,

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we estimate the impacts of the package of policies being considered to implement AB 32, and find that the state can reconcile its growth and environmental objectives, although detailed adjustment patterns suggest policies should be carefully designed.

Most prior California economic modeling of climate policies assumes technological neutrality. This means that factor productivity, energy use intensities, and other innovation characteristics were held constant across policy scenarios. Energy use and pollution levels might change, but the prospect of innovation to reduce energy intensity was not considered. Including innovation is important because technological change for energy efficiency has been a hallmark of California's economic growth experience and most observers credit this technological progress to California's energy/climate policy combinations of mandate and incentive. Innovation has been an indispensable part of the history of the state's economic growth and at the same time a consequence of its policies.

This report, for the first time, captures the impacts of innovation in response to state policies. Using the BEAR model, which has been developed with explicit capacity to examine the role of technological change and innovation as it relates to climate policy, we are able to study how incentive and market mechanisms can animate innovation to facilitate the state's adaptation to new climate policy priorities and maintain domestic and global competitiveness.

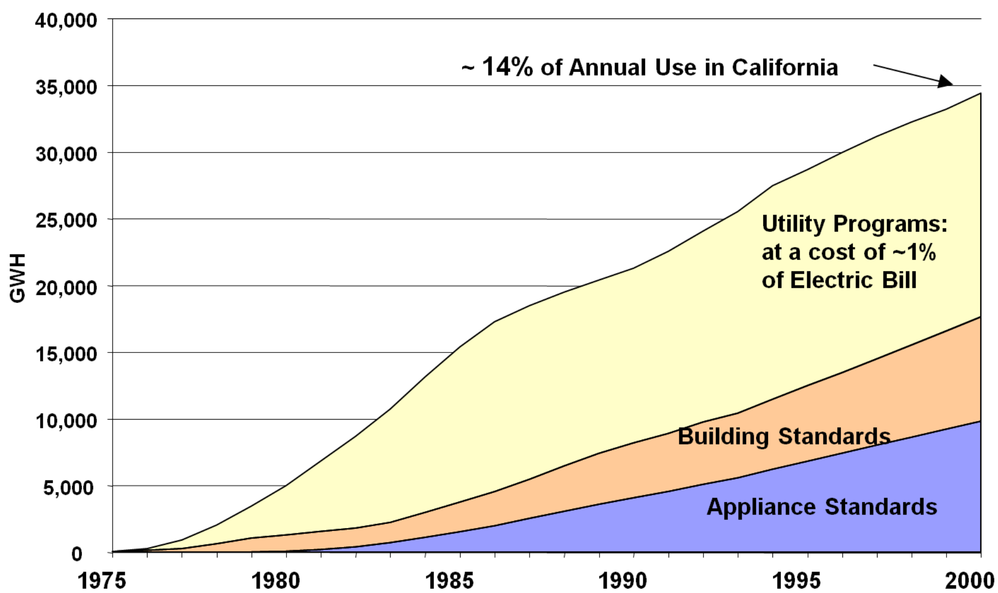
We begin this analysis of the economic impact of past and future energy and climate polices with a review of all of California's major energy efficiency initiatives and existing evidence of their economic impacts. From a very diverse array of research contributions on utilities, building standards, appliances, and transport, similar lessons are drawn. Energy efficiency not only saves money, it promotes demand that is less energy-intensive yet more job-intensive. This evidence contradicts the conventional notion of a trade-off between environmental policy and economic growth. Indeed, the growth-environment trade-off is based on a fallacy - that reduced emissions mean reduced economic activity. In California we can prove this.

2. Overview of Primary Sources of California's Energy Efficiency

Over the course of the last four decades, California and its first-in-the-nation California Public Utilities Commission (CPUC) and California Energy Commission

(CEC) have embarked on an ambitious path to decrease energy demand. Energy efficiency programs in the state focus on two major categories, electricity and fuels for heating and transportation. In the first category, a variety of programs and standards have been applied at various stages of the electricity supply chain, including efficiency standards for utilities (generation and distribution), buildings, and appliances. In the fuel category, utility and building standards are also relevant to natural gas, but another set of policies is targeted as transport fuel usage. In this section, we provide a general overview of these categories with a more detailed discussion of each provided in the Appendix.

Figure 1: Energy Efficiency Gain Impacts from Programs Begun Prior to 2001



Source: Rosenfeld (2008)

As Figure 1 vividly illustrates, California's investment in energy efficiency programs combined with appliance and building standards have played an important role in improving energy efficiency in California. Their combined impact resulted in a constant per capita electricity use in California over the past 30 years while nationwide use has increased by almost 50 percent.[4] The results included saving more than 12,000 MW of peak demand (equivalent to avoiding 24 giant power plants), and about 40,000 GWh each year (equivalent to 15 percent of California's energy consumption)[5].

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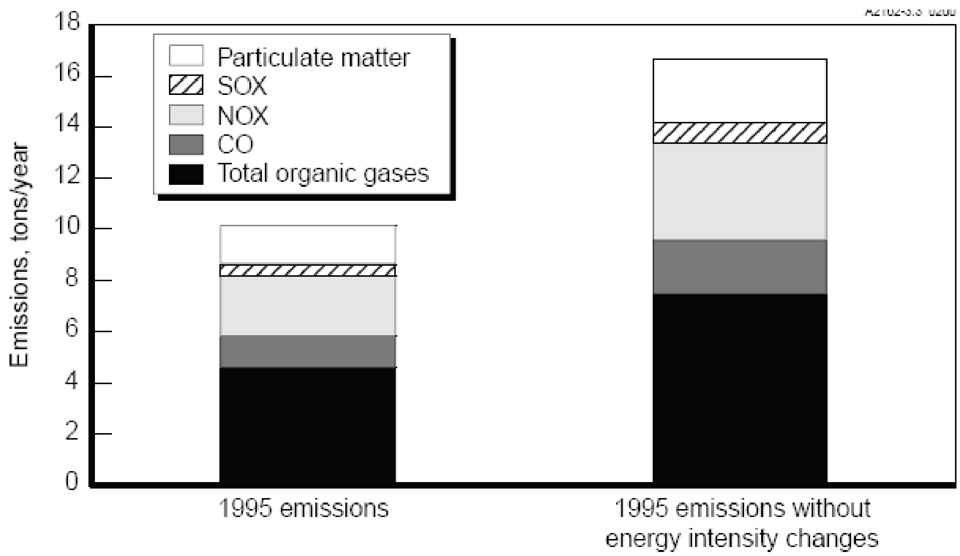
[4] CEC (California Energy Commission), 2005b, Options for energy efficiency in existing buildings. http://www.energy.ca.gov/2005publications/CEC-400-2005-039/CEC-400-2005-039-CMF.PDF

[5] CEC (Californian Energy Commission), 2005c, Pat McAuliffe

Energy consumption in California directly results in greenhouse gas emissions. Figure 2 compares California's actual 1995 emissions with estimated 1995 emissions if California had not improved upon 1977 efficiency levels. (Bernstein: 2001)

Figure 2: Estimated Pollutant Emissions from All Stationary Sources Excluding Waste Disposal



Utility Programs

Beginning in 1970, the CPUC has approved the use of ratepayer funds to promote energy efficiency activities, and authorized the major investor-owned utilities (IOUs) under its jurisdiction to administer a wide variety of energy efficiency programs. CPUC authorized programs to provide information services and financial assistance for consumers. CPUC also deployed a variety of strategies to assess the cost-effectiveness of energy efficiency. In the 1980s and early 1990s, California implemented programs for evaluation and measurement of utility Demand Side Management (DSM) and other publicly funded efficiency programs, which is currently being updated and expanded. The following is a simplified chronology of leading initiatives:

DATE	CPUC LEADING INITIATIVES
Late 1970s	The CPUC applied a least-cost planning strategy, whereby demand side reduction in energy usage was compared to supply additions.
Early 1980s	CPUC enacts policy to ensure that utilities' financial health is independent of their retail electricity sales. Sometimes referred to as "decoupling", this policy decision marked a radical shift in industry incentives, and opened the way for major investments in energy efficiency programs.

DATE	CPUC LEADING INITIATIVES
1983	The CPUC and CEC established the Standards Practice Manual, which provided several tests for evaluating the cost-effectiveness of publicly funded energy efficiency programs, including the Ratepayer Impact Measure Test, Utility Cost Test, Participant Test, Total Resource Cost Test, and Social Test. Most of the measures improved use monitoring and some included direct incentives for efficiency.
June 1990	The CPUC adopted shareholder incentives in order to increase energy efficiency program funding and established a more rigorous Mechanical & Electrical (M&E) infrastructure.
1995	Energy efficiency spending decreased because of the uncertainty in energy restricting.
1996	The state legislature passed AB 1890 to restructure the electricity industry, which required all publicly-owned utilities to invest in public benefit programs.
1996-1998	Regulators took steps to radically restructure the utility industry, including a temporary regulatory withdrawal of utility capacity to make long-term investment in resources of any kind (energy efficiency or generation).
1998	The CPUC changed the energy efficiency program goal and removed market barriers to energy efficiency so that the private sector would be able to provide energy efficiency services.
May 2001	Regulators set a goal of reaching 100 percent of low-income customers who want to participate in energy efficiency programs. The state's regulated utilities provided energy efficiency services to 845,000 low-income households between 2001 and 2005.[6]
2002	The state legislature restored utilities' resource investment responsibilities, including their mandate to pursue all cost-effective energy efficiency opportunities.
Spring 2003	CPUC, California Consumer Power and Conservation Financing Authority (California Power Authority) and California Energy Resources Conservation and Development Commission (California Energy Commission) adopt their *Energy Action Plan*, which establishes a "loading order" of preferred energy resources, placing energy efficiency as the state's top priority procurement resource, followed by renewable energy generation.[7]
Sept 2004	California regulators set the nation's most aggressive energy savings goals, to more than double the current level of savings over the next decade. Utilities are expected to invest nearly $6 billion over that period to reach the aggressive targets, projected to avoid the need to build ten new power plants (by saving nearly 5,000 MW) and provide approximately $10 billion in net benefits to state consumers over ten years.[8]

[6] Risser, Roland California Utility Low Income Energy Efficiency Program, Presentation given at the Low Income Energy Efficiency Symposium, Low Angeles, June 8 2006.
[7] California Consumer Power and Conservation Financing Authority, California Energy Resources Conservation and Development Commission and CPUC, Energy Action Plan, Adopted May 8, 2003 by CPUC, April 30 2003 by CEC and April 18, 2003 by CPA. Available online at www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.pdf.
[8] CPUC Decision 04-09-060 "Interim Opinion: Energy Savings Goals for Program Year 2006 and Beyond," September 23, 2004.

DATE	CPUC LEADING INITIATIVES
Dec 2004	Governor Schwarzenegger issues a green buildings Executive Order, requiring that all new and renovated state buildings achieve an environmental rating of LEED (Leadership in Energy and Environmental Design) of silver or higher, setting a goal for all state buildings to be 20 percent more efficient by 2015, and encouraging the private sector to do the same. [9]
Jan 2006	California utilities launch the most aggressive energy efficiency program in the nation, providing $2 billion in funding over three years. [10] This investment is projected to provide a return of nearly $3 billion in net benefits to California's economy, avert the need every year to build a new giant power plant and avoid over three million tons of CO2 emissions, equivalent to removing 650,000 cars from the roads.[11]
Sept 2006	Governor Schwarzenegger signed the landmark Global Warmings Solutions Act (AB 32) into law, making California the first state in the nation to cap its statewide greenhouse gas (GHG) emissions.[12] The Governor also signed a law establishing a GHG performance standard for power plants serving the state's customers. All new or renewed long-term financial commitments to baseload power must come from plants that have GHG emissions per megawatt-hour generated no higher than those of a combined-cycle natural gas plant.[13]
2006	AB 2021 is signed into law and requires municipal utilities (which account for approximately 1/4 of statewide electricity sales) to treat investments in energy efficiency as procurement investments and to set annual efficiency targets.
2007	By this time, CPUC has restored shareholder incentives linked to utilities' energy efficiency performance.
2008	Aggregate statewide utility investment in energy efficiency surpasses $1.2 billion annually.

Economic Impact of Utility Efficiency Programs

While there is a fairly extensive body of official data and analysis on California utilities, much of this information remains outside the public domain. In addition, accurately measuring the cost-effectiveness of utility energy efficiency programs is difficult because of their complexity. As a result, to date, the full economic impact of these programs has not been captured. Several studies reviewed below, however, provide evidence of the economic benefits of utility efficiency programs.

The California Climate Action Team (2007) collected data from the investor-owned utilities (IOU) to analyse and estimate the persistence of energy efficiency measures included in IOU energy efficiency portfolios (Table 1 below). They also

[9] Executive Order S-20-04, December 14, 2004

[10] CPUC, Decision 05-09-043, "Interim Opinion: Energy Efficiency Portfolio Plans and Program Funding Levels for 2006-08 – Phase I Issues," September 22, 2005

[11] Calculated from targets in CPUC Decision z04-09-060, September 23, 2004 and CEC, California Energy demand 2000-2016 Staff Energy Demand Forecast Publication #CEC-400-2005-034-SF-ED2, September 2005.

[12] Assembly Bill 32 (Nunez & Pavley, 2006)

[13] Senate Bill 1368 (Perata, 2006)

analysed the avoided costs of energy efficiency measures with respect to natural gas price forecasts (Table 2). The natural gas price forecast is from the CPUC and is known as the Market Price Referent. This forecast predicts that the price of natural gas will decline until 2020. In light of the current state of energy prices and also the large spike in petrol, the estimates of future pricing and avoided costs may prove to be significant underestimates. The CAT estimates, even under such optimistic energy price assumptions, imply that these avoided costs can create energy savings for both business and individuals, and can therefore stimulate the economy through spending on non-energy related goods and services.

Table 1: Estimated Persistence of Energy Efficiency Measures
(Based on Analysis of the IOU Program Portfolios)

Years Following Installation	*Remaining Energy Efficiency Impact*	
	Electric Measures	Gas Measures
1	99.69%	100.00%
2	95.97%	99.46%
3	89.59%	98.51%
4	85.14%	97.84%
5	84.02%	97.11%
6	78.32%	89.75%
7	78.24%	89.75%
8	78.22%	89.75%
9	74.58%	89.70%
10	66.73%	87.45%
11	51.71%	73.71%
12	34.56%	72.45%
13	33.13%	70.45%
14	32.88%	69.27%
15	32.51%	67.90%
16	17.12%	42.47%
17	4.56%	42.47%
18	4.56%	42.47%
19	4.03%	40.40%
20	3.89%	38.64%

Source: California Climate Action Team (2007)

Percentages reflect the portion of the first year energy savings that remains throughout the full 20-year lifetime of the energy efficiency measures. Estimated from the Investor Owned Utilities' energy efficiency portfolio plans for 2006-2008.

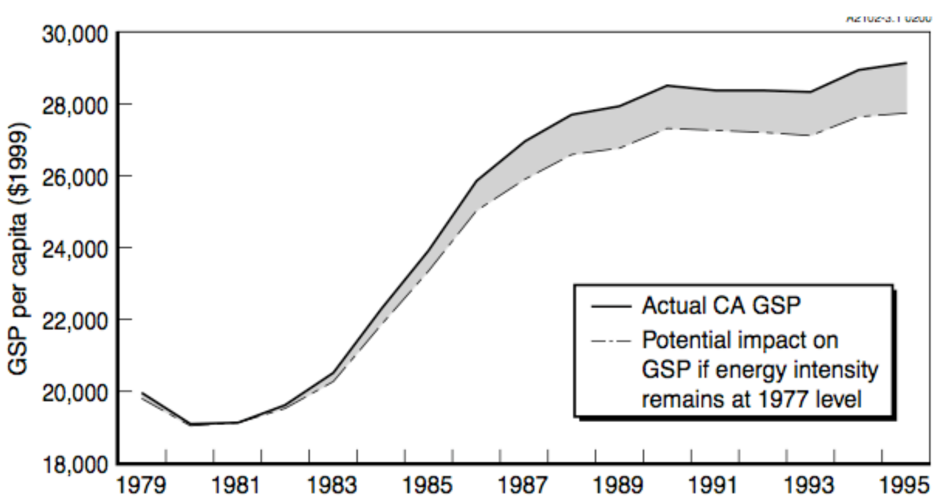
Table 2: Forecast of Annual Standardized Prices of Electricity Avoided Using the 2005 IEPR Natural Gas Price Forecast *(Price of Electricity ($/MWh)*

Year	Applied to Energy Efficiency Savings	Gas Price ($/MMBtu)
2007	$110.88	$8.17
2008	$99.85	$6.55
2009	$98.90	$6.45
2010	$87.14	$5.25
2011	$100.07	$6.56
2012	$95.49	$6.09
2013	$106.10	$7.15
2014	$99.01	$6.42
2015	$106.69	$7.20
2016	$106.12	$7.13
2017	$105.25	$7.03
2018	$108.55	$7.36
2019	$111.85	$7.69
2020	$111.82	$7.69

Source: California Climate Action Team (2007)

A RAND study prepared for the California Energy Commission estimated the historical impacts of energy efficiency investments in California from 1977 to 1995. They estimate that if energy efficiency had stayed constant at 1977 levels, GSP per capita would have been three percent less than its 1995 value (Figure 3). In a contrarian exercise, they find that reductions in energy intensity account for $875 of increased income per capita ($1998), though they do not directly attribute these gains to energy efficiency programs.

Figure 3: GDP Imputed at Higher Energy Dependence



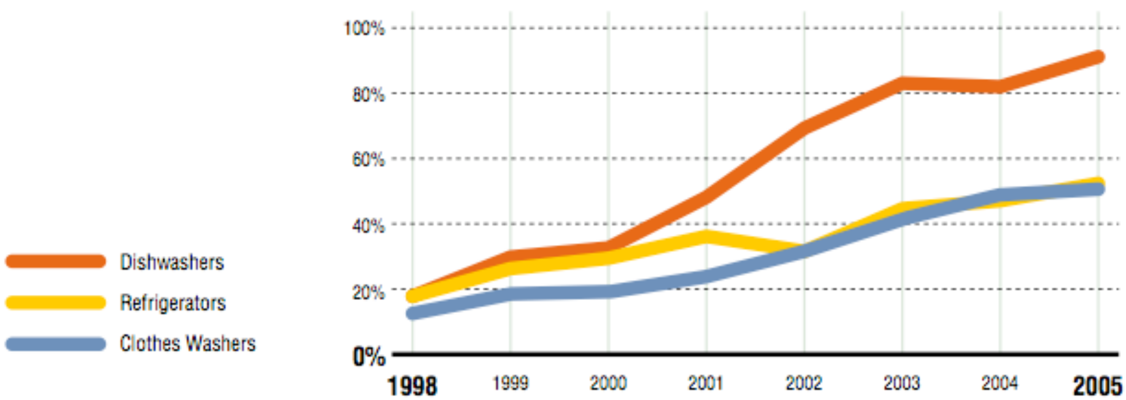
Source: Bernstein (2001)

Appliance and Building Standards

In 1978, California established the first building and appliance standards in the country. Title 24 building standards and Title 20 appliance standards require significant reductions in energy demand, and are revised upward every three years. It was estimated that the 2003 revisions of Title 24 will save 180MW/year[14], and Title 20 will save 100MW/year.[15] Further revisions in 2005 and 2008 are extending these gains and are estimated to produce another $23 billion in savings by 2013. Combing more stringent versions of existing standards with new initiative like outdoor lighting restrictions and reflective roof coatings, these will make important contributions to fulfilling our conjectural one percent annual efficiency gain.

Adoption of energy efficient appliances in California has been both rapid and sustained, as Figure 4 indicates. Nearly 85 percent of all dishwashers in California are Energy Star compliant, and 50 percent of both refrigerators and clothes washers also conform to these standards. What is even more impressive, however, is that this increase in market share occurred over only seven years.

Figure 4: California Market Share of Energy Star Appliances



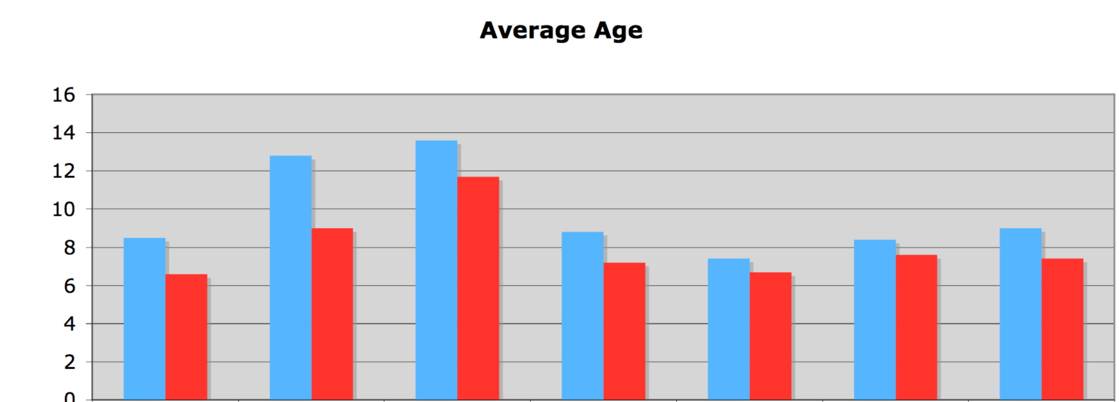
Source: Next 10's California Green Innovation Index

In a survey of 1,250 California households in 2000, and another 1,000 in 2005, Okura et al. (2006) found that appliance standards and energy efficiency programs have helped to decrease the use of older and outdated technologies (Figure 5) and

[14] California Energy Commission, "Energy Commission Approves New Building Standards to Help the State Cut Energy Use," Press Release, November 5, 2003.
[15] California Energy Commission, "Energy Commission Approves New Energy-Saving Rules for Appliances," Press Release, December 15, 2004.

on average lead to the decrease of more than 200 KWhr per year for primary refrigerators (Figure 6).

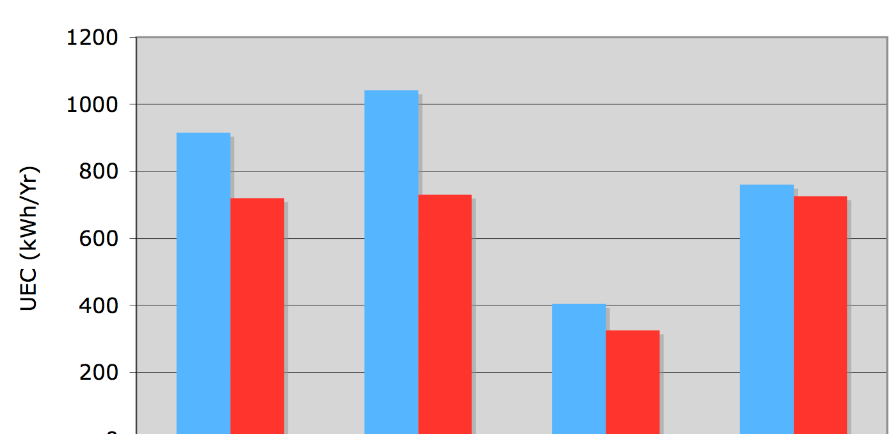
Figure 5: Appliance Renewal Cycles



	Primary Refrigerators	Secondary Refrigerartors	Freezers	Hot Water Heaters	Washers	Dryers	Dishwashers
2000	8.5	12.8	13.6	8.8	7.4	8.4	9
2005	6.6	9	11.7	7.2	6.7	7.6	7.4

Source: Okura et al (2006)

Figure 6: Appliance Average Efficiency

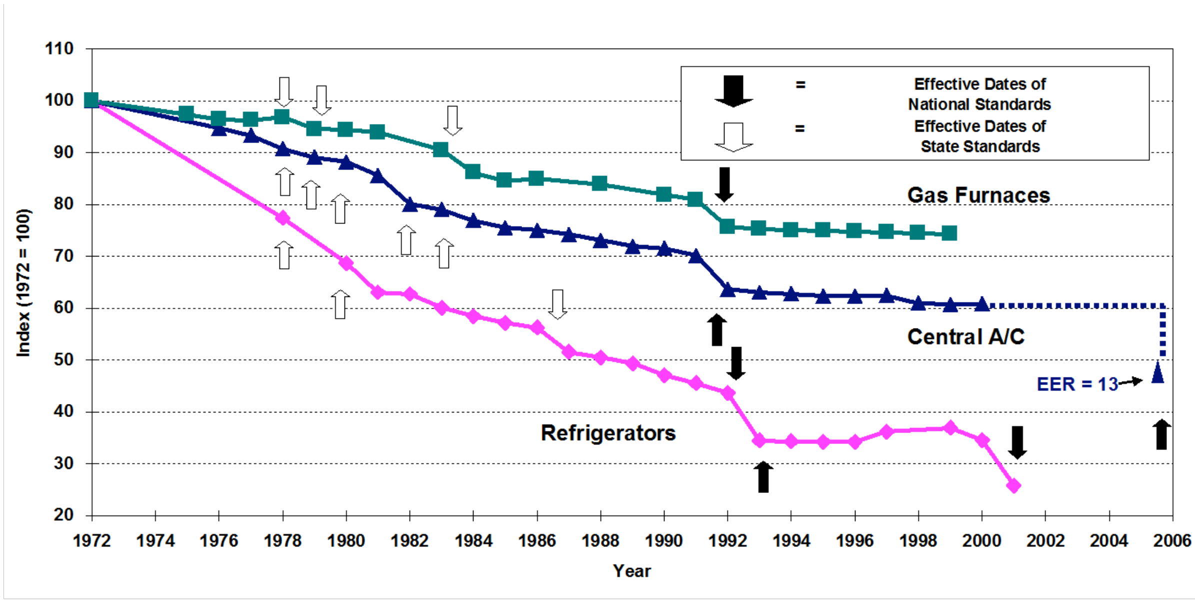


	Primary Refrigerators	Secondary Refrigerartors	Freezers-Chest	Freezers-Upright
2000	914.7	1041.3	403.6	760.4
2005	720.7	730.6	325.3	726.4

Source: Okura et al (2006)

Further, appliance standards targeting central air conditioners and gas furnaces have a notable impact on efficiency. As Figure 7 illustrates, over the past three decades, the implementation of California's Title 24, combined with federal standards, have decreased energy use by furnaces and air conditioners about 25 and 40 percent, respectively, with continued improvements in efficiency expected to continue.

Figure 7: Impact of Standards on Efficiency of Three Appliances



Source: Rosenfeld (2008)

Like appliance standards, building standards have been an essential source of energy savings for California. By 2003, building standards were saving about 10,000 GWh per year, which is about one-fourth of the over 40,000 GWh saved annually through a combination of utility efficiency programs and building and appliance standards. (See Appendix for additional information on building standards.)

Economic Impacts of Building and Appliance Standards

The California Energy Commission estimates that building and appliance efficiency standards combined have saved a total of more than $56 billion in electricity and natural gas costs, the equivalent to a net savings of more than $1,000 per household, and is money that then goes back into California's economy[16]. By 2013, they are expected to save an additional $23 billion.

[16] Bernstein,M., R. Lempert, D. Lougharn, and D. Oritz. 2000. The public benefit of California's investments in energy efficiency. Prepared for the California in Energy Commission. RAND Monograph Report MR-1212.0-CEC.
http://www.rand.org/pubs/monograph_reports/MR1212.0/index.html

In a retrospective examination of appliances in the year 2000, Gillingham et al (2004) show that appliance standards yield positive net benefits to US consumers on average. The average electricity price in 2000 was $6.3 billion ($2002) per quad of primary energy, while the cost of residential appliance standards was under $3.3 billion per quad. Gillingham notes that even if unaccounted for, costs of appliance standards are so large as to be almost equal to those included in the study, or if actual energy savings were half of what is estimated, the appliance standards studied would still yield positive net benefits on average. He adds that including the positive environmental externalities of reduced electricity consumption would further strengthen the argument that the benefits of appliance standards were worth the cost.

For California and the greater United States, the establishment of appliance efficiency standards has had a positive net employment impact on jobs created directly in the appliance manufacturing industry. A report prepared for the Regional Greenhouse Gas Initiative found efficiency standards among household appliances produced an estimated .8 percent increase in private-sector job growth by 2021 (Prindle: 2006). For manufacturers, appliance efficiency standards spur job creation because producers of standardized technologies must increase employment to meet increased demand for energy efficient technologies. Established standards make the markets for these technologies more secure and reduce uncertainties that often limit voluntary adoption. Furthermore, new efficiency standards increase innovation incentives for producers, reducing marketing risks, creating more jobs and leading to the development of better appliances, some of which are today 75 percent more efficient than their 1970 counterparts. The development of new more efficient appliances also stimulates market demand and producer profits. When these standards are adopted by an interstate agreement the standard becomes more universal, yielding another benefit for manufacturers (Hildt: 2001). As an early adopter, California producers have a better chance of internalizing these innovations and capturing future market advantages.

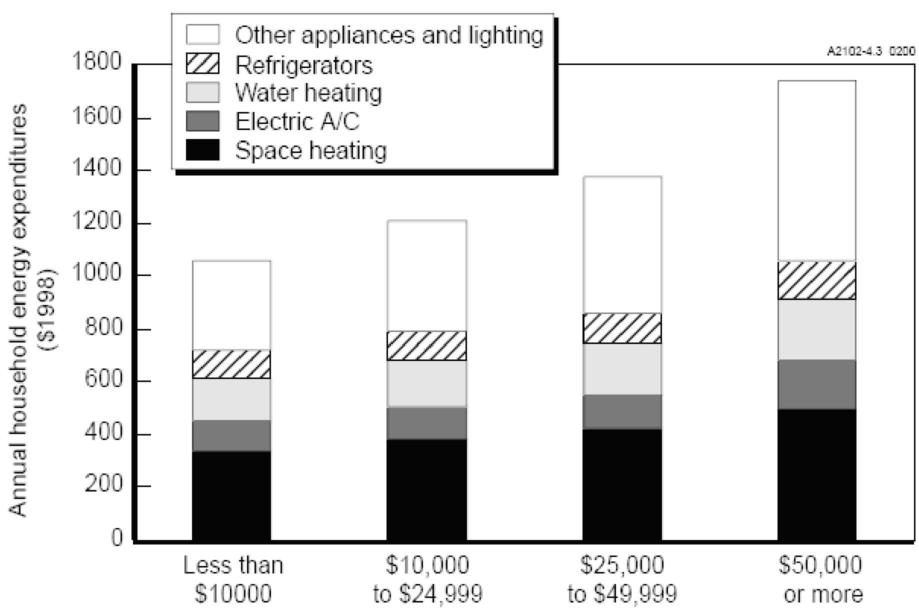
Like appliance standards, building standards have also been an important source of direct employment growth. While standards to promote more energy efficient buildings create new up-front costs and long-term savings, as is usual for California's efficiency policies, the latter far outweigh the former, but even the costs have a silver lining. Most independent studies indicate that the kind of technology adoption needed for building standard conformity is unusually employment intensive, and promotes job creation among relatively high wage, diverse groups of semi-skilled and unskilled workers. For this reason, building standards represent not just economic growth, but more inclusive growth.

Economic Impact on Low Income Families

Though low-income families spend less on energy on average than high-income families, a much larger portion of their lower incomes are spent on energy. The 1997 Residential Energy Consumption Survey (RECS) reported that the average annual energy expenditure for the $5,000-$9,999 income bracket was $985, compared to the average energy expenditure for the $75,000+ income bracket which was $1,835. High-income households spend approximately twice as much on energy as low-income households, but their incomes are over seven-and-a-half times greater. When looked at in terms of end-use, regardless of income, up to two-thirds of household energy use is for space heating, water heating, and refrigeration (Figure 8). These services can be considered essential, for they are shared across all income brackets. In 1997, the average expenditure for these services for households in the $10,000 and below bracket was $714, versus $863 for households between $25,000 and $49,999; only a 20 percent increase though incomes are two to five times greater. Clearly, efficiency increases in essential services provide a substantial benefit for low-income households.

Of course, the state is well aware of these social benefits, and has for decades encouraged utilities to invest in Low Income Energy Efficiency (LIEE) programs. These schemes, including a range of insulation and appliance maintenance services, have been offered by the California Public Utilities Commission and individual utilities for most of the period under discussion (1972-2006).

Figure 8: Annual Energy Expenditures by End Use and Household Income



Source: Bernstein (2001)

Table 3: Annual Household Energy Expenditure by End Use ($1993)

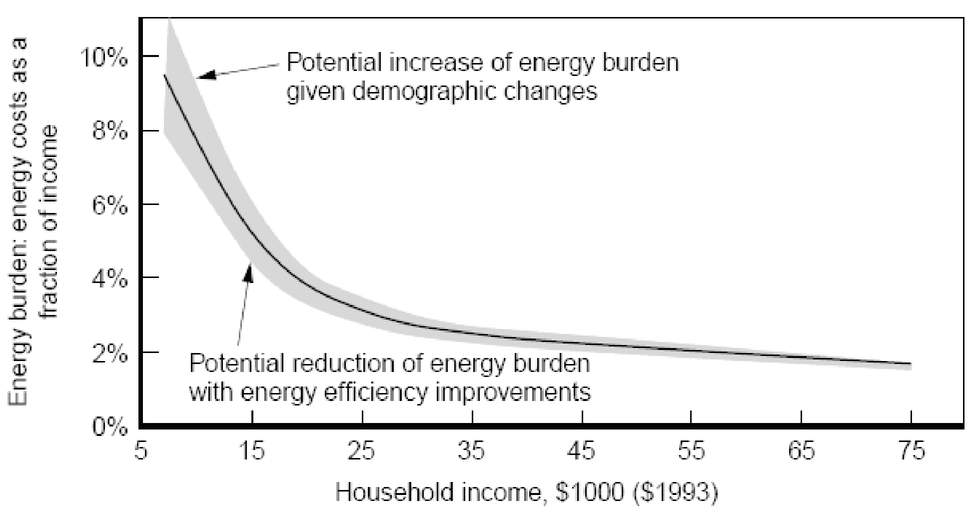
Income Level	Space Heating	Air Conditioning	Water Heating	Refrigeration	Appliances
Low-income	163	88	162	92	351
Median-income	193	137	138	139	519

Source: Bernstein (2001)

Low-income families benefit substantially from appliance efficiency standards not only because of their disproportionate energy expenditures, but also because these families tend to occupy older houses and own older appliances. A study on low-income housing found that only 64 percent of families in the $5,000- annual income bracket have ceiling insulation, versus 91 percent for families in the $50,000+ income bracket. Table 3 illustrates how inefficient housing impacts low-income end use energy consumption. Low-income households spend nearly as much on space heating as median income families, because even though their homes are smaller, the homes are older and less efficient to heat. More startling perhaps is the statistic that low-income households on average spend more than median-income households on water heating, likely due to the prevalence of less efficient electric water heaters and fewer numbers of dishwashers.

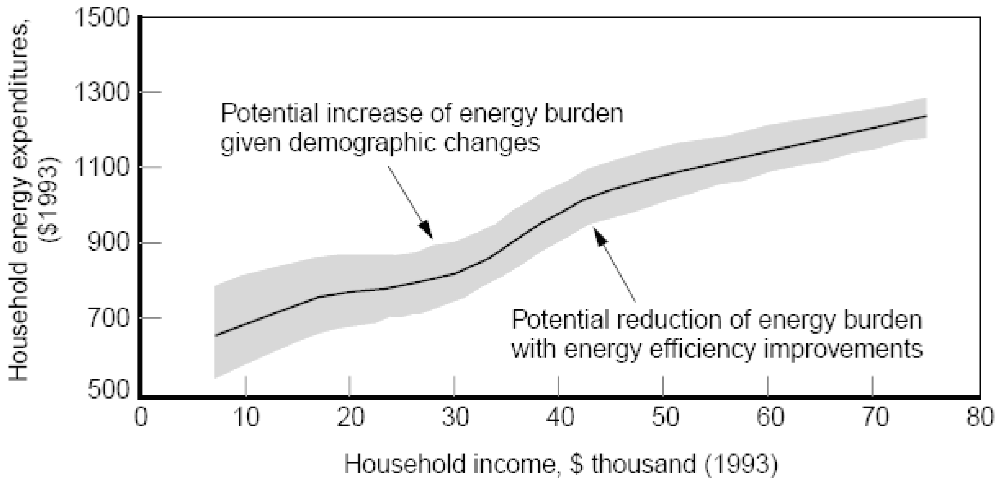
Clearly, low-income families stand to benefit most from the expansion of appliance efficiency standards and the continuing support of LIEE. Figure 9 shows the potential gains from efficiency across income brackets as a fraction of income, and Figure 10 the potential gains in terms of absolute energy expenditure. The broader benefits resultant from efficiency gains include "increased comfort and health, safety, reduced loss of service from termination, and increased housing development and property values." (Bernstein: 2001)

Figure 9: California Household Energy Expenditure as a Percentage of Income



Source: Bernstein (2001)

Figure 10: California Household Energy Expenditure



Source: Bernstein (2001)

Transportation

Fuel economy standards are federally regulated and California does not have the same discretion in transport fuel policy that it has used to establish national leadership with building and appliance efficiency. The state has benefited somewhat from Federal Corporate Average Fuel Economy (CAFE) standards, however, as they have increased on-road fuel economy of cars and light-duty trucks from 12.6 miles per gallon (mpg) in 1970 to 20.7 in 1985 in California. Although these standards have not changed substantially in the last 22 years, in 2004 alone the state's combined fleet's fuel economy increased by about two mpg. This improvement was due to a decrease in light truck sales, especially sports utility vehicles (SUVs), which conform to a lower mile-per-gallon fuel economy standard. In 2005, Governor Schwarzenegger appealed to the United States House of Representatives to establish new fuel economy standards that doubled the fuel efficiency of new cars, light trucks, and SUVs.

In January 2008, the United States Congress passed the Energy Independence and Security Act (EISA), which increased the national fleet wide fuel economy standards for cars and trucks to 35 mpg by 2020. A study by the Union of Concerned Scientists (UCS) estimated that a fleet wide average of 35 mpg by 2018 would increase employment by 241,000 across country by 2020 – including 23,900 job opportunities in automotive sector – and consumers would save $61 billion dollars in gasoline in the year 2020. In California, UCS estimated the program would save $8,407 million and create several thousand new jobs by 2020.

In 2008, a provision in a 2003 California law required that all replacement automobile tires sold in California are, on average, as fuel efficient as the original tires of new vehicles sold in the state.[17] The law is expected to increase the statewide fuel economy of cars and trucks by three percent, save over 545 million gallons of gasoline, over $1 billion in fuel costs and 4.8 million metric tons of CO_2.[18]

Conclusion

California's leadership in energy efficiency, from utility programs to standards, has put the state on an energy consumption path that has diverged greatly from the nation's path. While the dramatic reductions in energy consumption are well documented, the economic impacts are less well known. We have reviewed existing studies extensively (here and in the Appendix), which provide evidence of positive net economic benefits and job creation directly in the appliance and building sectors.

While multiple studies have recognized the positive economic benefits of energy efficiency programs, none have analyzed the economy-wide impacts of innovation associated with the consumer savings resulting from these efficiency improvements.

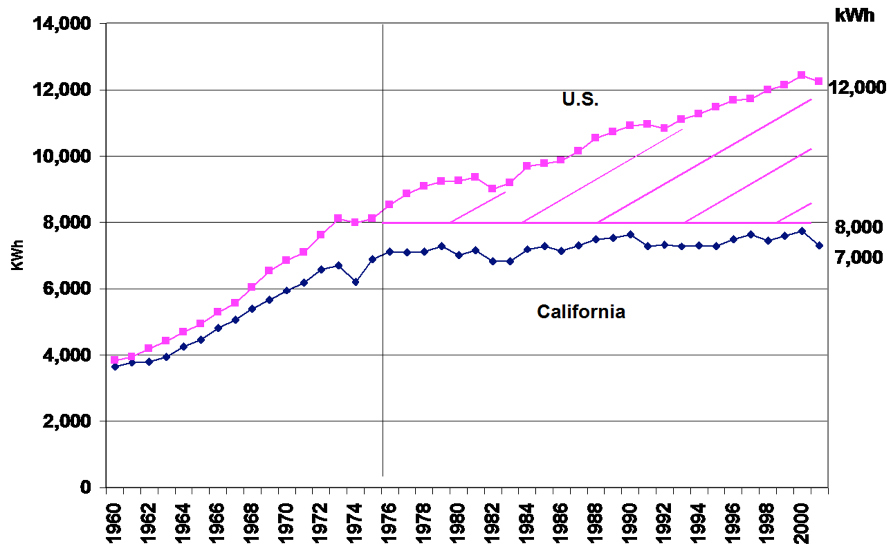
In the next section, we will present the first comprehensive economy-wide analysis of the impacts of California's history of energy efficiency and innovation.

3. Economic Impact of California's Legacy of Energy Efficiency

Because it represents over 70 percent of GSP, household consumption is the most important driver of economic activity in the state. For the same reason, household expenditure patterns are the leading determinant of state energy use. This includes direct energy use, for residential electricity and transport fuels, as well as an extensive web of indirect energy demand, embodied in all the other goods and services consumers purchase. Because of its significance, household energy demand was selected for detailed analysis in the employment context. In this work, we focus on electricity demand because California has a much longer history of promoting efficiency in this area.

[17] AB 844 (Nation: 2003)
[18] California State Fuel-Efficient Tire Report: Volume II, Consultant Report 600-03-001CR Vol. II, January 2003

Figure 11: Total Electricity Use, per capita, 1960-2001



Source: Rosenfeld (2008)

Deeper insight into the economy-wide effects of energy efficiency can be gained by detailed demand analysis. This approach is described in technical detail the Appendix, but for the present we describe it heuristically. As Figure 11 illustrates, over the last generation, California has de-coupled from national trends of electricity demand, reducing its per capita requirements to 40 percent below the national average. If this trend had not been established, the state would have been obliged to build over 24 additional power plants and statewide emissions would have increased accordingly. This is only the direct effect of averted energy use, however, and captures just a fraction of the economic impact of efficiency measures. Consumers were able to reduce energy spending vis-à-vis a no-efficiency baseline, and these savings were diverted to other demand. The stimulus thus provided by energy savings increased employment across a broad spectrum of consumer goods, services, and the activities in all their supply chains.

The estimates presented here take fuller account of these extensive indirect growth linkages (what economists call multiplier) effects. As many authors have already observed, energy supply chains are not job intensive, and for California they mainly include capital intensive refining, conveyance, and electric power generation. Other consumer spending is concentrated mainly on job intensive services, retail consumer goods, and foodstuffs. Thus expenditure diversion from energy to other consumption results in net job creation. The extent of this depends on specific characteristics of consumption patterns and linkages to upstream supply chains. These are captured in detailed industry accounts of the Bureau of Economic

Analysis, including 500 sector input-output tables estimated every five years from 1972 to the present. For the current estimates, we exhaustively researched these tables, aggregating them to fifty sectors and calculating multipliers for each of seven semi-decadal accounting systems (described in more detail in the Appendix). Using this information and detailed historical demand patterns for both California and the United States as a whole, we then calculated the contribution to total state employment resulting from reducing household energy expenditure over the 35 year period 1972-2006. The results, in terms of net job creation, are presented in Table 4 (sectors are defined in the Appendix). These estimates strongly support the argument that energy efficiency stimulates net job creation. Although energy sector industries may be adversely affected, efficiency saves households money. The resulting expenditure shifting leads to demand driven job growth that far exceeds the losses to the carbon fuel supply chain, and 1,463,611 net new jobs created over the period considered. Moreover, sectoral examination of these results indicate that job creation is in less energy intensive services and other categories, further compounding California's aggregate efficiency improvements and facilitating the economy's transition to a low carbon future.

More specifically, the results in Table 4 can be interpreted as estimates of the cumulative employment effects that have resulted because California households broke away from national trends in electricity consumption. These are calculated at each five-year milestone in the table, with the fairly conservative assumption that the attendant multiplier effects would take five years to run their course. In fact, the savings from additional efficiency are realized every year over the period considered, so our estimates may be significantly below the actual values. Having said this, it should be noted that we do not incorporate adoption costs, which beyond renewal and replacement might reduce net savings somewhat. Taking account of this and the degree to which five-year calculations underestimate the savings, we believe the results are robust indicators of net job creation from electricity efficiency. Table 5 translates efficiency-induced job growth into incomes. These estimates are based the detailed historical average wage data from the California Regional Economies Employment dataset (CREE, see the Appendix), and indicate that induced job growth has contributed approximately $45 billion to the California economy since 1972.

Table 4: Job Creation from Household Energy Efficiency

	1972	1977	1982	1987	1992	1997	2002	2007	Total
Agriculture	-	36	112	204	266	631	849	869	2,967
EnergyRes	-	(0)	(1)	(1)	(0)	(1)	(1)	(1)	(5)
ElectPwr	-	(266)	(1,140)	(2,236)	(3,405)	(4,720)	(5,809)	(5,944)	(23,520)
OthUtl	-	(12)	(78)	(2)	13	71	77	79	149
Construction	-	-	-	-	-	-	-	-	-
Light Industr	-	821	2,688	4,593	6,095	8,392	9,247	9,463	41,300
OilRef	-	(14)	(6)	(9)	(10)	(14)	(24)	(25)	(102)
Chemica	-	48	190	448	764	555	2,234	2,287	6,526
Cement	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Metals	-	2	1	4	(5)	(16)	(16)	(16)	(46)
Machinery	-	14	26	54	44	(38)	(51)	(52)	(2)
Semicon	-	0	0	3	8	176	318	325	830
Vehicles	-	20	38	133	133	240	427	437	1,428
OthInd	-	37	125	265	397	1,136	1,770	1,811	5,541
WhlRetTr	-	4,740	15,254	32,236	46,139	83,118	136,402	139,587	457,475
VehSales	-	-	-	-	-	215	0	0	215
Transport	-	9	31	(211)	76	202	305	312	724
FinInsREst	-	1,191	5,340	15,075	30,808	21,500	34,201	35,000	143,114
OthPrServ	-	3,063	11,456	25,848	45,596	64,397	96,352	98,602	345,313
PubServ	-	74	3,360	22,488	56,060	98,866	148,691	152,163	481,703
	-	9,763	37,396	98,892	182,977	274,710	424,974	434,898	1,463,611

Table 5: Employee Compensation Gains from Household Energy Efficiency
(millions of 2000 US dollars)

	1972	1977	1982	1987	1992	1997	2002	2007	Total
Agriculture	-	0	2	3	4	9	16	17	52
EnergyRes	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
ElectPwr	-	(10)	(50)	(111)	(190)	(303)	(441)	(546)	(1,652)
OthUtl	-	(1)	(4)	(0)	0	4	5	6	10
Construction	-	-	-	-	-	-	-	-	-
LightIndustr	-	20	70	117	162	214	284	323	1,190
OilRef	-	(1)	(0)	(0)	(1)	(1)	(2)	(3)	(8)
Chemica	-	2	7	16	27	23	87	97	258
Cement	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Metals	-	0	0	0	(0)	(1)	(1)	(1)	(2)
Machinery	-	0	1	2	2	(1)	(2)	(2)	(2)
Semicon	-	0	0	0	0	11	25	32	69
Vehicles	-	1	2	7	7	11	22	22	72
OthInd	-	1	3	7	12	36	67	82	208
WhlRetTr	-	105	336	707	1,026	1,859	3,530	3,647	11,211
VehSales	-	-	-	-	-	7	0	0	7
Transport	-	0	1	(8)	3	8	14	13	32
FinInsREst	-	31	158	512	1,207	971	2,036	2,415	7,329
OthPrServ	-	76	209	438	824	1,356	2,440	2,679	8,022
PubServ	-	2	107	730	1,866	3,160	5,526	6,422	17,814
	-	227	840	2,420	4,950	7,363	13,605	15,205	44,611

Source: Author's estimates

Unlike previous studies that estimate direct job creation as a result of energy efficiency programs and standards, our data-intensive multiplier analysis takes fuller account of the indirect effects of expenditure shifting. When consumers shift one dollar of demand from electricity to groceries, for example, one dollar is removed from a relatively simple, capital intensive supply chain dominated by electric power generation and carbon fuel delivery. When the dollar goes to groceries, it animates much more job intensive expenditure chains including retailers, wholesalers, food processors, transport, and farming. Moreover, a larger proportion of these supply chains (and particularly services that are the dominant part of expenditure) resides within the state, capturing more job creation from Californians for California. Moreover, the state reduced its energy import dependence, while directing a greater percent of its consumption to in-state economic activities.[19]

It should be noted that construction employment effects are omitted from this analysis because this is not classified as household (but investment) demand. Independent evidence (See Appendix) indicates, however, that construction has benefited significantly from building standards and expenditure diversion to housing and real estate. Other forces are at work over this period that can move our results in both directions. Significantly, aggregate energy demand in California has continued to rise, meaning some of the job losses estimated for energy sectors have probably been mitigated.

4. Future Economic Impacts of California Energy Efficiency and Climate Policies

After reviewing the economic impact of California's past achievements in energy efficiency, we turn to the future to evaluate the economic costs and benefits of the state's energy efficiency and climate polices. Because the state has recently redoubled its commitment to climate action, reducing energy dependence and global warming pollution (GWP) emissions, it is reasonable to expect increased structural change and job growth of the kind observed since the 1970s. For the last two years, we have been conducting independent research to inform public and private dialogue surrounding California climate policy. Among these efforts has been the development and implementation of a statewide economic model, the Berkeley Energy and Resources (BEAR) model, the most detailed and comprehensive forecasting tool of its kind. (See Appendix for technical

[19] There is a technical argument that reducing imported energy dependence might reduce California's export opportunities, but California exports are also less job-intensive than in-state goods and services. Thus the net employment gains remain positive.

discussion of BEAR model.) The BEAR model has been used in numerous instances to promote public awareness and improve visibility for policy makers and private stakeholders.[20] In the legislative process leading to the California Global Warming Solutions Act (AB 32), BEAR results figured prominently in public discussion and were quoted in the Governor's Executive Order establishing the 2020 and 2050 emissions reductions.

While researchers who developed and implement the BEAR model do not advocate particular climate policies, their primary objective is to promote evidence-based dialogue that can make public policies more effective and transparent. California's bold initiative in this area makes it an essential testing ground and precedent for climate policy in other states, nationally, and internationally. Because no other state has done this before, the state faces a significant degree of uncertainty about direct and indirect effects of the many possible approaches to its stated goals for emissions reduction. High standards for economic analysis are needed to anticipate the opportunities and adjustment challenges that lie ahead and to design the right policies to meet them. Progress in this area can increase the likelihood of two essential results: 1) that California policies work effectively, and 2) that they achieve the right balance between public and private interest.

The last round of BEAR analysis was broadly in accord with the state's findings and buttressed the public interest in legislative discussion of AB 32. In the next phase of climate action dialogue, more specific policies will be subjected to intensive public and private scrutiny. At this critical moment of policy debate, balanced policy dialogue requires a more complete assessment of both the potential benefits and costs of the options before the state. Here we continue to extend the scope and depth of these findings.

An essential characteristic of the BEAR approach to emissions modeling is endogeneity. Contrary to assertions made elsewhere (Stavins et al: 2007), the BEAR model permits emission rates by sector and input to be determined by the model itself or specified in advance, and in either case the level of emissions from the sector in question is model determined unless a cap is imposed. This feature is essential to capture structural adjustments arising from market based climate policies, as well as the effects of technological change. The BEAR model's sectoral detail, model determined emissions, and dynamic innovation and forecasting characteristics enable it to capture a wide range of program characteristics and their role in economic adjustments to climate action. BEAR was designed to model cap and trade systems, and includes all the major design

[20] See e.g. Roland-Holst (2006ab, 2007a)

features such as variable auction allocation systems, market determined permit prices, banking options, safety valves, and fee/rebate systems for CO2 and up to thirteen other criteria pollutants.

In this section, we use BEAR to provide independent economic assessment of California energy efficiency and climate action policies recommended for the implementation of AB 32 by CARB in its Draft Scoping Plan.

Scenario Discussion

To elucidate the economic effects of different combinations of mitigation strategies, we now examine California's climate action policies in more detail. In particular, we evaluate a policy scenario, which faithfully represent policies currently being evaluated for their potential to meet the state's 2020 target of 427 MMTCO2 equivalent overall emissions of greenhouse gases. In our scenario analysis, "RCT" refers to the entire set of Recommended Greenhouse Gas Reduction Measures (Table 6) with the cap and trade mechanism modeled without offsets (i.e. recognition of emission reduction outside the sectors covered by the mechanism) as delineated in the Draft Scoping Plan.

In the "cap and trade" (C&T) scenario modeled here, we assume that 100 percent of pollution permits are allocated by an efficient auction mechanism. This means the state realizes all the value of the permits in the first instance, and we assume this is rebated to taxpayers in a lump sum fashion. Permits are then re-allocated with a market mechanism between sectors, assuming all sectors are covered by the scheme and there are no offsets. This is similar to the California Air Resources Board's E-DRAM[21] model approach, which covers all carbon fuels and does not consider offsets, but BEAR explicitly models the sectoral adjustments and market costs of permits, as described earlier.[22]

[21] E-DRAM is the official macroeconomic assessment model used by the California Air Resources Board. It shares the same official baseline data with the BEAR model including, for example, an assumed gasoline price of $3.67/gallon.

[22] There have been several discussions of offset schemes for the 28 percent of estimated emissions mitigation committed to cap and trade (C&T) for the RCT policies, but none represent official policy. The WCI calls for 10 percent of total mitigation to be offset, but this is a different percent of targeted mitigation for the region and is not directly comparable.

Table 6: Recommended GWP Reduction Measures

Measure Description	Reduction (Mmtco$_2$e In 2020)	Cost $Million	Savings $Million
Transportation			
Pavley I Light-Duty Vehicle GHG Standards	31.7	1,372	11,142
Pavley II - Light-Duty Vehicle GHG Standards		594	1,609
Low Carbon Fuel Standard	16.5	(11,000)	(11,000)
Low Friction Oil	4.8	520	954
Tire Pressure Program		49	69
Tire Tread Program (Low resistance)		0.6	119.7
Other Efficiency (Cool Paints)		360	370
Ship Electrification at Ports	0.2	0	0
Goods Movement Efficiency Measures	3.5		
Vessel Speed Reduction		0	86
Other Efficiency Measures		0	0
Heavy-Duty Vehicle GHG Emission Reduction (Aerodynamic Efficiency)	1.4	1,136	973
Medium and Heavy-duty Vehicle Hybridization	0.5	93	163
Heavy-Duty Engine Efficiency	0.6	26	133
Local Government Actions and Targets	2.0	200	858
High Speed Rail	1.0	0	0
Building and Appliance Energy Efficiency and Conservation			
Electricity Reduction Program 32,000 GWH reduced	15.2	1,809	4,925
Utility Energy Efficiency Programs			
Building and Appliance Standards			
Additional Efficiency and Conservation			
Increase Combined Heat and Power Use by 30,000 GWh	6.9	362	1,673
Natural Gas Reduction Programs (800 Million Therms saved)	4.2	420	640
Utility Energy Efficiency Programs			
Building and Appliance Standards			
Additional Efficiency and Conservation			
Renewable Energy			
RPS (33%)	21.7	3,206	1,650
California Solar Programs (3000 MW Installation)	2.1	0	0
Solar Water Heaters (AB 1470 goal)	0.1	0	0
High GWP Measures			
MVACS: Reduction of Refrigerant from DIY Servicing	0.5	60.00	0.00
SF6 Limits in Non-Utility and Non-Semiconductor Applications	0.3	0.14	0.00
High GWP Reduction in Semiconductor Manufacturing	0.15	2.60	0.00

Measure Description	Reduction (Mmtco$_2$e In 2020)	Cost $Million	Savings $Million
Limit High GWP Use in Consumer Products	0.25	0.06	0.23
Low GWP Refrigerants for New Motor Vehicles AC Systems	3.3	15.80	0.00
AC Refrigerant Leak Test During SMOG Check		220.80	0.00
Refrigerant Recovery from Decommissioned Refrigerated Shipping Containers			
Enforcement of Federal Ban on Refrigerant Release During Service or Dismantling of MVACS			
High GWP Recycling and Deposit Program Specifications for Commercial and Industrial Refrigeration	11.6	1.24	0.66
Foam Recovery and Destruction Program		94.83	0.00
SF6 Leak Reduction and Recycling in Electrical Applications			
Alternative Suppressants in Fire Protection Systems		1.96	0.20
Gas Management for Stationary Sources--Tracking/Recovery/Deposit Programs		1.02	3.60
Residential Refrigeration Early Retirement Program		18.90	24.79
Others			
Landfill Methane Capture	1.0	0.5	0
Methane Capture at Large Dairies	1.0	156	0
Sustainable Forest Target	5.0	50	0
Water Use Efficiency	1.4	-	-
Water Recycling	0.3	-	-
Pumping and Treatment Efficiency	2.0	-	-
Reuse Urban Runoff	0.2	-	-
Increase Renewable Energy Production	0.9	-	-
Total Recommended Measures	*135.5*	*10,771*	*25,394*

Source: CARB Scoping Plan, Supplement

Taking Account of Innovation and Technological Change

Because innovation has been an indispensable part of the history of the state's economic growth and at the same time a consequence of its policies, the BEAR model has been developed with explicit capacity to examine the role of technological change and innovation as it relates to climate policy. The model includes features that allow for technological change with respect to every product/sector, factor of production, and pollutant category. Moreover, these detailed efficiency rates can be specified *a priori* or modeled, arising from other innovation processes such as induced R&D, technology transfer, and learning by doing. With these characteristics, BEAR is the most advanced decision tool of its kind for studying how incentive and market mechanisms can animate innovation to facilitate the state's adaptation to new climate policy priorities and maintain domestic and global competitiveness.

Since there is no agreement in economic theory or empirical work about how to model innovation processes, we can still elucidate this question, however, by posing a hypothetical scenario that provides a metric for the costs and benefits with enhanced efficiency. In the present analysis, we factor in the prospect of innovation to reduce energy intensity by projecting a rate of energy efficiency gains that better reflect historical achievements, as well as the impact of significantly more aggressive policies aimed to reduce energy use. It is reasonable to assume that new climate polices will create new incentives for innovation. This is particularly true for policies like "cap and trade" that put an explicit price on carbon externalities that did not exist before. When firms are faced with new costs from emissions and energy use, they can be expected to make investments in technology that reduces these costs. To capture this innovation, we assume that, subject to the implementation of the recommended measures, California is able to increase its energy efficiency by one additional percent per year, on an average basis, across the economy. This conservative estimate may be below the state's innovation potential in such circumstances, given that much lower energy prices and less determined policies were in place for the long period of improvement before AB 32.

Relationship to State Economic Analysis

Recently, we conducted scenario analysis for the California Air Resources Board, which is included as supplement to their economic forecasts conducted using the E-DRAM model (See Appendix). While the policy scenario analyzed here is identical to those modeled for the state, this analysis includes the potential for innovation to reduce energy intensity. The state's official modeling assumes technology characteristics remain static and includes a flat rate of energy efficiency for the time period considered (2008-2020).

Economic Impacts

Generally speaking, our results support the view that the state can reconcile its goals for economic growth and more sustainable climate policy. The policy choices informed by the scoping process will be more effective, however, if they are supported by rigorous *ex ante* assessment like that reported here. More evidence-based work of this kind will broaden the basis of stakeholder interest in the state's climate initiative and facilitate constructive policy dialogue.

When innovation is taken into account[23], our results show that the Draft Scoping Plan is a dynamic economic growth policy, significantly increasing aggregate mitigation, lowering adjustment cost, and contributing to dramatic job growth.

Assuming climate action measures intensify California's upward efficiency trend by one percentage point above the historic rate, we find:

- Existing efficiency programs combined with the proposed package of policies in the state's Draft Scoping Plan achieves 100 percent of the greenhouse gas emissions reduction targets as mandated by AB 32 while increasing the Gross State Product (GSP) by about $76 billion, increasing real household incomes by up to $48 billion and creating as many as 403,000 new efficiency driven jobs.

- The economic benefits of energy efficiency innovation have a compounding effect. The first 1.4 percent of annual efficiency gain produced about 181,000 additional jobs, while an additional one percent yielded 222,000 more. It is reasonable to assume that the marginal efficiency gains will be more costly, but they have more intensive economic growth benefits.

Table 7: Aggregate Results, Innovation Scenarios

	1	2	3
	Baseline	**Change Due to Existing Efficiency**	**Change due to RCT**
Real Output (2008$Billions)	**3,606**	**22**	**63**
Gross State Product	**2,598**	**37**	**39**
Personal Income	**2,096**	**31**	**17**
Employment (Thousands)	**18,410**	**181**	**222**
Emissions Total (MMTCO2e)	**596**	**N.A.[24]**	**-169**
Carbon Price (Dollars)	**0**	**0**	**12**

[23] We are not *estimating* the state's rate of energy efficiency improvement, but we are making reasonable assumptions in order to evaluate a calibrated scenario where the state improves energy efficiency by a single additional percentage point per year. This yields an elasticity type reference point for evaluating ex post efficiency contributions. If they achieve only 0.5% more efficiency, about half the estimated benefits can be expected to accrue to the state.

[24] Existing or assumed baseline efficiency measures (1.4%/yr) will reduce emissions 11.4% below what they would have been without any improvements. These reductions are included in the Baseline.

Percentage Changes

	1	2	3
	Baseline	Existing Efficiency	RCT
Real Output (2008$Billions)	3,606	.6	1.7
Gross State Product	2,598	1.4	1.5
Personal Income	2,096	1.5	.8
Employment	18,410	1.0	1.2
Emissions	596	N.A.	-28.3
Percent of Targeted Reduction		N.A.	100

The first column of Table 7 gives baseline or business-as-usual (BAU) values for macro variables in a scenario without AB 32 implementation. The second column, labeled Efficiency, measures changes in the same variables (in 2020), for the future impacts of existing energy efficiency programs[25], without AB 32 implementation. When actual abatement policies are implemented, adaptation costs will be set against these benefits, while other benefits will also come into play. RCT measures changes in the same variables (2020) with implementation of all policies contained in the Draft Scoping Plan including a "cap and trade" mechanism. While BAU contains the changes decomposed in the Efficiency column, RCT does not.

Job creation is robust in both existing efficiency and RCT scenarios because technological change permits the economy to reduce energy dependence more cost effectively. This compounds the benefits of the climate policies by either increasing the energy savings per dollar of adaptation cost or, for the same energy saving investment, freeing money for other demand. Both forces are at work, and over 400 thousand new jobs could be created in California by 2020, while the state attains its climate action objectives.

Employment Effects by Sector

We have seen that climate action can create jobs, and robustly so when the economy's innovation capacity is animated to improve efficiency in a context of rising energy costs. As is often the case with economic adjustment, however, small changes in aggregate variables can mask more dramatic structural change. In the following tables, we disaggregate the employment effects of existing efficiency measures, and the climate action policy scenario.

[25] The model assumes the state will continue its historical trend of 1.4% per capita energy efficiency gains without costs above normal renewal and replacement.

Existing efficiency programs and standards creates employment growth in every sector outside the carbon fuel supply chain, and significantly so, promising nearly 200,000 new jobs by 2020. While RCT affects jobs inside and outside the carbon fuel supply chain, RCT creates even greater employment, promising nearly 222,000 new jobs by 2020. The carbon fuel supply chain continues to experience positive job growth, albeit at a lower rate than the baseline.

Table 8: Sector Employment Effects, Innovation *(Thousands of FTE Jobs)*

	Sector	Baseline	Existing Efficiency	RCT
1	Agriculture	509	7	0
2	EnergyRes	29	0	-3
3	ElectPwr	27	-8	1
4	OthUtl	42	-8	6
5	Construction	1,351	6	37
6	Light Industr	501	6	-7
7	OilRef	20	0	-4
8	Chemica	187	3	-5
9	Cement	33	0	1
10	Metals	265	5	1
11	Machinery	127	0	-1
12	Semicon	471	7	7
13	Vehicles	170	1	2
14	OthInd	237	3	1
15	WhlRetTr	2,786	42	22
16	VehSales	287	5	7
17	Transport	413	2	12
18	FinInsREst	1,167	14	4
19	OthPrServ	6,998	84	123
20	PubServ	2,790	11	16
	Total	18,410	181	222

In response to the RCT measures, sectors with high levels of energy sector dependence experience modest job losses. Most of these are in the range of a few percentage points, and the state's aggregate job gains significantly outweigh these as households shift their expenditure away from the carbon fuel supply chain. Like the historical analysis that preceded this section, these prospective estimates reveal how energy efficiency liberates economic resources for job creation. By saving firms and households money, more expenditure can be channeled away from fuel imports and fuel services toward employment intensive, in-state goods and services. Overall, existing and recommended efficiency and climate action policies could generate over 400,000 new jobs by 2020, assuming the state only increases average efficiency by one percent annually.

Although these results are best interpreted as indicative, rather than precise forecasts, they have three important implications for the state's climate policy research agenda. Firstly, even the modest assumptions about innovation show it has significant potential to make climate action a dynamic growth experience for the state economy. Second, accelerating California's energy innovation may seem ambitious, but the added premium of steeply rising energy prices and the prospect of a price for carbon emissions should provide strong impetus for this. Third, the size and distribution of potential growth benefits is large enough to justify significant commitments to deeper empirical research on these questions.

If the state is to maintain its leadership as a dynamic and innovation oriented economy, it may be essential for climate policy to include explicit incentives for competitive innovation, investing in discovery and adoption of new technologies that offer win-win solutions to the challenge posed by climate change for the state's industries and for consumers. In this way, California can sustain its enormous economic potential and establish global leadership in the world's most promising new technology sector, energy efficiency, as it has done so successfully in ICT and biotechnology.

Thus, energy innovation has been part of the history of the state's economic growth and at the same time a consequence of its policies. For these reasons, it is important to consider the potential contribution of continued innovation to the economic effects of California climate policy. Modeling innovation processes, their spillovers and linkages, and their ultimate economic impacts is a very complex process.

Additional Observations

Aggregate Real Effects are Modest but Positive

Despite the political and environmental importance of the state's climate policy initiatives, the aggregate economic impact of the proposed policies is modest relative to the overall California economy. Although detailed sector adjustments may be more dramatic, the state largely remains on its long-term growth trajectory. To the extent that the sectoral adjustment costs are passed on, they would not significantly reduce aggregate state income and consumption. In particular, they are much smaller than most climate damage estimates (see e.g. Stern).

Individual Sector Demand, Output, and Employment can Change Significantly (Economic Structure Changes)

Energy fuel and carbon capped sectors can experience important adjustments, but these are offset by expansion elsewhere, including services, construction, and consumer goods. The California economy is seen undergoing an important structural adjustment, reducing aggregate energy intensity and increasing the labor-intensity of state demand and output. These shifts, masked at the aggregate level, may present opportunities for policymakers to mitigate adjustment costs.

In other words, the aggregate results indicate that the policies considered will pose no significant net cost to the California economy. They might raise costs for some firms and individuals, but as a whole the California economy will probably experience higher growth and create more jobs than it would have without this action (even before considering climate damage aversion). The task for California policymakers in the near term will be to design policies that fairly and efficiently distribute the costs of reducing Global Warming Pollution.

Employment Effects are Positive

The reason for this result, as in past BEAR estimates, is that energy efficiency saves money (relative to the baseline), and the resulting re-direction of consumer expenditure results in net job creation for the state. This is one of the most important economic effects of climate action policy, reducing import dependence on capital-intensive fuels and increasing spending on in-state goods and services. In the last round of estimates, the E-DRAM model revealed the same benefits, amplified by migration into California. The current BEAR scenarios do not allow for migration, but are otherwise qualitatively similar.

No Significant Leakage is Observed in the BEAR Scenarios

Import and export adjustments are significant in some sectors, but with no discernable interaction with the carbon constraint in the capped sectors. Imports of fuels fall sharply as the policies dictate, but there is negligible evidence of pollution outsourcing in targeted or energy dependent sectors.

No Forgone Damages, Including Local Pollution or Public Health Costs, are Taken into Account in these Results

Over a thirteen year time horizon, and considering the amount of pollution reduction, damages in the business-as-usual baseline could be significant. At present, no climate policy simulation models include such damages in the baseline. When interpreting the present results and comparing them to others, this fact must be considered. A number of studies have produced positive climate policy cost estimates without acknowledging that the cost of doing nothing might well exceed these.[26]

5. Conclusions and Extensions

This study presents original estimates and reviews other research on the employment effects of California's legacy of energy efficiency policies. Using detailed data on changing economic structure over the last four decades, we show that energy efficiency programs, by saving households money, have created more than one million new jobs since 1972. While employment in the carbon fuel supply chain has grown more slowly than it would without California's efficiency improvements, this is far outweighed by induced job creation across a broad spectrum of in-state goods and services activities. Over the intervening 35 years, households have saved more than $56 billion on energy by comparison to their national counterparts. These energy savings rendered unnecessary the capacity of 24 traditional coal fired power plants, and instead they were diverted to other expenditure, creating about 1.5 million new jobs with over $45 billion in payroll.

We then reverse perspective and assess the benefits of energy efficiency going forward, including proposed policies to implement California's AB 32 climate action initiative. Using a dynamic forecasting model and scenario for policies recommended in the state's Draft Scoping Plan, we find that existing energy efficiency programs and standards will contribute an additional 181,000 jobs from now until 2020, and the policies themselves could add 222,000 more when innovation is taken into account.

Evidence from a variety of officially sponsored and independent research supports these results, indicating that every significant efficiency measure has created more jobs than it might have displaced. Many estimates of net job creation are more moderate than ours because they measure only direct employment impacts on specific sectors while ours analyses impacts economy-wide, but all support the same fundamental message. Energy efficiency saves money, promotes more employment intensive demand and growth, and reinforces lower carbon growth patterns across the economy.

In other words, individual efficiency begets aggregate efficiency, and aggregate efficiency begets growth and sustainability. Adam Smith understood this fact two

[26] See e.g. CRA (2007), EPRI (2007) for Florida and California. The public health impacts of climate change are being activity studied in another component of this project, with findings to be disseminated by the end of the year.

hundred years ago, and today we are reminded of the fact that efficiency is a social good that, though long expenditure chains, compounds its benefits across the economy or over time. This is true whether regardless of whether efficiency is facilitated by private market forces or by public standards.

It should be recalled that aggregate benefits can often mask adjustment challenges. Given the magnitude of most of the benefits estimated here, however, there appears to be ample scope for supporting policies that target adjustment needs, particularly for job categories whose skills need reorientation to adapt to an innovating economy. The primary drivers of California's superior growth experience over the last generation were education and technology. This legacy can be extended with education and training programs targeted at climate adaptation.

An important next step for this work is deeper analysis of the qualitative characteristics of employment created by energy efficiency. Employment in the carbon fuel supply chain is relatively high wage, with average or above average education levels and relatively long job tenure. Even though job creation from energy efficiency far outweighs losses in these sectors, it is important that we better understand the same qualitative characteristics of these new opportunities.

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Appendix

1. Technical Overview of the BEAR Model

The Berkeley Energy and Resources (BEAR) model is a constellation of research tools designed to elucidate economy-environment linkages in California. The schematics in Figures A1 and A2 (below) describe the four generic components of the modeling facility and their interactions. This section provides a brief summary of the formal structure of the BEAR model.[27] For the purposes of this report, the 2003 California Social Accounting Matrix (SAM), was aggregated along certain dimensions. The current version of the model includes 50 activity sectors and ten households aggregated from the original California SAM. The equations of the model are completely documented elsewhere (Roland-Holst: 2005), and for the present we only discuss its salient structural components.

Technically, a Computable General Equilibrium (CGE) model is a system of simultaneous equations that simulate price-directed interactions between firms and households in commodity and factor markets. The role of government, capital markets, and other trading partners are also specified, with varying degrees of detail and passivity, to close the model and account for economy-wide resource allocation, production, and income determination.

The role of markets is to mediate exchange, usually with a flexible system of prices, the most important variables in a typical CGE model. As in a real market economy, commodity and factor price changes induce changes in the level and composition of supply and demand, production and income, and the remaining variables in the system. In CGE models, an equation system is solved for prices that correspond to equilibrium in markets and satisfy the accounting identities governing economic behavior. If such a system is precisely specified, equilibrium always exists and such a consistent model can be calibrated to a base period data set. The resulting calibrated general equilibrium model is then used to simulate the economy-wide (and regional) effects of alternative policies or external events.

[27] See Roland-Holst (2005) for a complete model description.

The distinguishing feature of a general equilibrium model, applied or theoretical, is its closed form specification of all activities in the economic system under study. This can be contrasted with more traditional partial equilibrium analysis, where linkages to other domestic markets and agents are deliberately excluded from consideration. A large and growing body of evidence suggests that indirect effects (e.g., upstream and downstream production linkages) arising from policy changes are not only substantial, but may in some cases even outweigh direct effects. Only a model that consistently specifies economy-wide interactions can fully assess the implications of economic policies or business strategies. In a multi-country model like the one used in this study, indirect effects include the trade linkages between countries and regions which themselves can have policy implications.

The model we use for this work has been constructed according to generally accepted specification standards, implemented in the GAMS programming language, and calibrated to the new California SAM estimated for the year 2003.[28] The result is a single economy model calibrated over the fifteen-year time path from 2005 to 2020.[29] Using the very detailed accounts of the California SAM, we include the following in the present model:

Production

All sectors are assumed to operate under constant returns to scale and cost optimization. Production technology is modeled by a nesting of Constant-Elasticity-of-Substitution (CES) functions, which are standard in the economic literature.

In each period, the supply of primary factors — capital, land, and labor — is usually predetermined.[30] The model includes adjustment rigidities. An important feature is the distinction between old and new capital goods. In addition, capital is assumed to be partially mobile, reflecting differences in the marketability of capital goods across sectors.[31]

Once the optimal combination of inputs is determined, sectoral output prices are calculated assuming competitive supply conditions in all markets.

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28 See e.g. Meeraus et al (1992) for GAMS. Berck et al (2004) for discussion of the California SAM.

29 The present specification is one of the most advanced examples of this empirical method, already applied to over 50 individual countries or combinations thereof.

30 Capital supply is to some extent influenced by the current period's level of investment.

31 For simplicity, it is assumed that old capital goods supplied in second-hand markets and new capital goods are homogeneous. This formulation makes it possible to introduce downward rigidities in the adjustment of capital without increasing excessively the number of equilibrium prices to be determined by the model.

Consumption and Closure Rule

All income generated by economic activity is assumed to be distributed to consumers. Each representative consumer allocates optimally his/her disposable income among the different commodities and saving. The consumption/saving decision is completely static: saving is treated as a "good" and its amount is determined simultaneously with the demand for the other commodities, the price of saving being set arbitrarily equal to the average price of consumer goods.

The government collects income taxes, indirect taxes on intermediate inputs, outputs and consumer expenditures. The default closure of the model assumes that the government deficit/saving is specified externally.[32] The indirect tax schedule will shift to accommodate any changes in the balance between government revenues and government expenditures.

The current account surplus (deficit) is fixed in nominal terms. The counterpart of this imbalance is a net outflow (inflow) of capital, which is subtracted (added to) the domestic flow of saving. In each period, the model equates gross investment to net saving (equal to the sum of saving by households, the net budget position of the government and foreign capital inflows). This particular closure rule implies that investment is driven by saving, with investment allocation going to capital according to the capital accumulation rules discussed below.

Trade

Goods are assumed to be differentiated by region of origin. In other words, goods classified in the same sector are different according to whether they are produced domestically or imported. This assumption is frequently known as the *Armington* assumption. The degree of substitutability, as well as the import of penetration shares, are allowed to vary across commodities. The model assumes a single Armington agent. This strong assumption implies that the propensity to import and the degree of substitutability between domestic and imported goods is uniform across economic agents. This assumption reduces tremendously the dimensionality of the model. In many cases this assumption is imposed by the data. A symmetric assumption is made on the export side where domestic producers are assumed to differentiate the domestic market and the export market. This is modeled using a Constant-Elasticity-of-Transformation (CET) function.

[32] In the reference simulation, the real government fiscal balance converges (linearly) towards 0 by the final period of the simulation.

Dynamic Features and Calibration

The current version of the model has a simple recursive dynamic structure as agents are assumed to be myopic and to base their decisions on static expectations about prices and quantities. Dynamics in the model originate in three sources: 1) accumulation of productive capital and labor growth, 2) shifts in production technology, and 3) the putty/semi-putty specification of technology discussed below.

Capital Accumulation

In the aggregate, the basic capital accumulation function equates the current capital stock to the depreciated stock inherited from the previous period plus gross investment. However, at the sectoral level, the specific accumulation functions may differ because the demand for (old and new) capital can be less than the depreciated stock of old capital. In this case, the sector contracts over time by releasing old capital goods. Consequently, in each period, the new capital vintage available to expanding industries is equal to the sum of disinvested capital in contracting industries plus total saving generated by the economy, consistent with the closure rule of the model.

The Putty/Semi-Putty Specification

The substitution possibilities among production factors are assumed to be higher with the new than the old capital vintages — technology has a putty/semi-putty specification. Hence, when a shock to relative prices occurs (e.g. the imposition of an emissions fee), the demands for production factors adjust gradually to the long-run optimum because the substitution effects are delayed over time. The adjustment path depends on the values of the short-run elasticities of substitution and the replacement rate of capital. As the latter determines the pace at which new vintages are installed, the larger is the volume of new investment, the greater the possibility to achieve the long-run total amount of substitution among production factors.

Dynamic Calibration

The model is calibrated to external data on growth rates of population, labor force, and GDP. In the so-called Baseline scenario, the dynamics are calibrated in each region by imposing the assumption of a balanced growth path. This implies that the ratio between labor and capital (in efficiency units) is held constant over time.[33] When alternative scenarios around the baseline are

[33]This involves computing in each period a measure of Harrod-neutral technical progress in the capital-labor bundle as a residual. This is a standard calibration procedure in dynamic CGE modeling.

simulated, the technical efficiency parameter is held constant, and the growth of capital is determined by the saving/investment relation.

Modeling Emissions

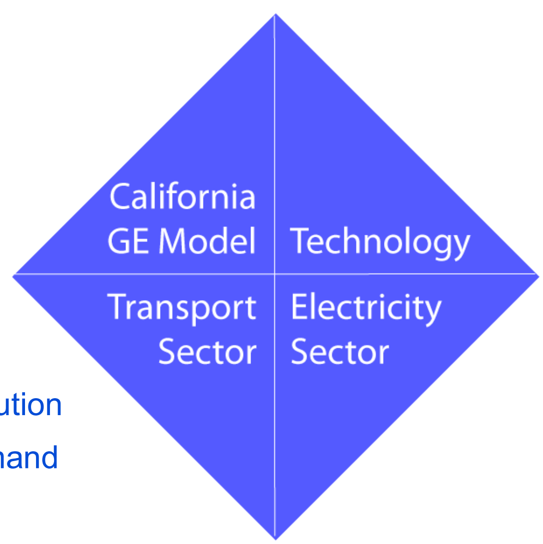
The BEAR model captures emissions from production activities in agriculture, industry, and services, as well as in final demand and use of final goods (e.g. appliances and autos). This is done by calibrating emission functions to each of these activities that vary depending upon the emission intensity of the inputs used for the activity in question. We model both CO2 and the other primary greenhouse gases, which are converted to CO2 equivalent. Following standards set in the research literature, emissions in production are modeled as factors inputs. The base version of the model does not have a full representation of emission reduction or abatement. Emissions abatement occurs by substituting additional labor or capital for emissions when an emissions tax is applied. This is an accepted modeling practice, although in specific instances it may either understate or overstate actual emissions reduction potential.[34] In this framework, emission levels have an underlying monotone relationship with production levels, but can be reduced by increasing use of other, productive factors such as capital and labor. The latter represent investments in lower intensity technologies, process cleaning activities, etc. An overall calibration procedure fits observed intensity levels to baseline activity and other factor/resource use levels.

Figure A1: Component Structure of the Modeling Facility

BEAR is being developed in four areas and implemented over two time horizons.

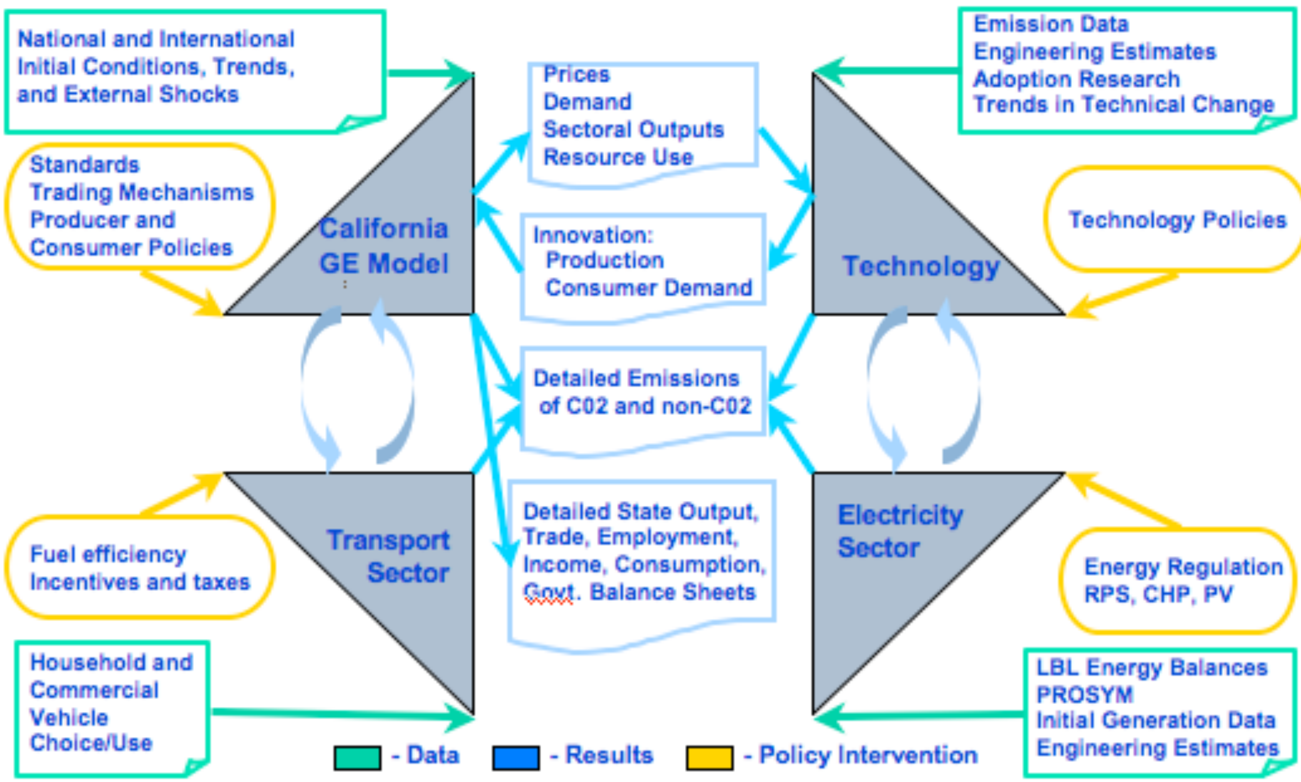
Components:

1. Core GE model
2. Technology module
3. Electricity generation/distribution
4. Transportation services/demand



[34] See e.g. Babiker et al (2001) for details on a standard implementation of this approach.

Figure A2: Schematic Linkage between Model Components



The model has the capacity to track 13 categories of individual pollutants and consolidated emission indexes, each of which is listed in Table A1. Our focus in the current study is the emission of CO2 and other greenhouse gases, but the other effluents are of relevance to a variety of environmental policy issues. For more detail, please consult the full model documentation.

Table A1: Emission Categories

Air Pollutants

1.	Suspended particulates	PART
2.	Sulfur dioxide (SO_2)	SO2
3.	Nitrogen dioxide (NO_2)	NO2
4.	Volatile organic compounds	VOC
5.	Carbon monoxide (CO)	CO
6.	Toxic air index	TOXAIR
7.	Biological air index	BIOAIR

Water Pollutants

8.	Biochemical oxygen demand	BOD
9.	Total suspended solids	TSS
10.	Toxic water index	TOXWAT
11.	Biological water index	BIOWAT

Land Pollutants

12.	Toxic land index	TOXSOL
13.	Biological land index	BIOSOL

2. Appliance Standards

Appliance Efficiency Standards are among the few government regulations that have net-negative costs for both consumers and businesses. By mandating levels of efficiency for various appliances, California has directly created jobs in manufacturing sectors related to appliances across the state. These policies have also indirectly created jobs by saving California residences and businesses hundreds of millions on their utility bills (see the results of Section 2 above). These impacts have been especially important for California's low-income populations, because they both spend a larger share of their income on energy, and benefit more (in terms of health and comfort) from improvements in appliance efficiency. These appliance efficiency standards have also helped California reduce emissions growth, put downward pressure on the cost of energy, and lessened peak electricity demand. Increasing the appliance efficiency will continue to be a cost effective way for California to simultaneously encourage economic growth and protect the environment.

With new household technology adoption has come substantial energy savings. Meier notes that there is uncertainty about energy consumption labels on appliances, as they can either underestimate, overestimate, or come close to actual energy consumption. Given that there is this uncertainty in labelling, it may create doubt as to whether it will be worth the upfront costs to upgrade appliances. Meier (1997) counters this argument by surveying a multitude of studies and national appliance standard experiences and concludes that the most convincing demonstrations of savings result from appliance standards occur in homes where an old model is replaced by a new model meeting the standards. Thus, there is a link between new standards and energy efficiency, and that these standards can create significant energy savings.

In his estimates the US energy savings and cost-to-benefits ratio of various new national appliance standards, Kuno (2002) finds that through 2020, the average benefit/cost ratio of the new national appliance standards is five, and the average national energy savings through 2020 is 1,800 trillion Btu. Nadel (2002) also analyzes the national historical experience with appliance standards and appliance efficiency. He finds that there have been significant energy efficiency improvements and that standards have driven efficiency.

National and state standards are already in place for most household appliances (air conditioners, refrigerators, shower heads, and space heaters just to name a few). Existing appliance standards in California are will save the average household $1,750 by 2020. Standards on the National level are expected to reduce national energy consumption by 341 billion kilowatt hours/year by 2020, over 7.5 percent of projected United States energy use. At that point, these standards will have already saved the equivalent annual energy use of about 23 million American households (Hildt: 2001), but these estimates only take account of current standards to predict future benefits. If California sustains its leadership in efficiency regulation, these savings will increase in proportion to the amount of energy they conserve. Table A2 illustrates the various savings projections from specific national appliance regulations, the most gains arising from showerhead standards.

Table A2: Summary of National Effects of Residential Efficiency standards in 2010

End-use	Fuel	Annual (in 2010)					Cumulative (1990–2010)				
		Primary energy savings (petajoules)	Carbon savings (MT-C)	Bill savings (M1995$/ year)	Incremental costs (M1995$/ year)	Net benefit (M1995$/ year)	Primary energy savings (petajoules)	Carbon savings (MT-C)	Bill savings (M1995$/ year)	Incremental costs (M1995$/ year)	Net PV benefit (M1995$/ year)
CAC	Electricity	0	0.00	0	0	0	112	1.70	536	379	157
Clothes washer	Electricity	52	0.75	390	5	385	721	10.37	3239	40	3198
Clothes dryer	Electricity	51	0.74	397	235	163	500	7.19	2148	1291	857
Dishwasher	Electricity	25	0.35	186	55	131	283	4.00	1238	360	878
Dishwasher motors	Electricity	20	0.28	150	62	88	228	3.22	998	407	592
Freezer 1990	Electricity	1	0.02	9	2	7	39	0.58	213	55	158
Freezer 1993	Electricity	6	0.08	42	26	16	106	1.57	541	338	203
Faucets	Electricity	19	0.27	153	25	128	207	2.85	894	152	743
HP	Electricity	0	0.00	1	0	0	46	0.67	262	129	133
Refrigerator 1990	Electricity	5	0.07	39	15	24	220	3.01	1228	507	720
Refrigerator 1993	Electricity	69	0.94	542	247	295	1348	18.57	6780	3229	3551
RAC	Electricity	1	0.02	12	1	10	214	3.12	1147	123	1024
Showers	Electricity	120	1.65	943	99	843	1278	17.62	5529	606	4922
Water heater	Electricity	6	0.08	43	8	36	724	10.32	4186	704	3446
Central heat	Natural gas	5	0.07	28	8	19	132	1.81	532	158	374
Clothes washer	Natural gas	31	0.42	181	7	174	427	5.85	1459	59	1400
Clothes dryer	Natural gas	10	0.14	59	60	− 1	100	1.38	330	340	− 10
Dishwasher	Natural gas	15	0.20	86	79	7	169	2.32	564	524	40
Faucets	Natural gas	12	0.16	73	38	35	128	1.76	415	227	188
Oven	Natural gas	18	0.25	111	57	54	237	3.25	840	454	386
Room heat	Natural gas	0	0.00	0	0	0	19	0.25	92	1	91
Range	Natural gas	27	0.37	163	65	98	350	4.80	1243	523	720
Showers	Natural gas	74	1.02	451	151	299	792	10.86	2566	908	1658
Water heater	Natural gas	42	0.58	250	45	205	2014	27.62	8268	1512	6756
Central heat	Distillate oil	0	0.00	0	0	0	0	0.00	0	0	0
Clothes washer	Distillate oil	2	0.04	15	0	15	31	0.59	123	4	118
Dishwasher	Distillate oil	1	0.02	7	6	2	12	0.23	47	38	9
Faucets	Distillate oil	1	0.02	7	4	4	12	0.23	45	21	23
Showers	Distillate oil	7	0.13	45	14	31	75	1.42	276	85	191
Water heater	Distillate oil	1	0.01	4	1	3	25	0.47	117	19	99
Total	Electricity	374	5.24	2906	780	2125	6026	84.8	28,938	8355	20,583
Total	Natural gas	234	3.21	1402	511	891	4368	59.9	16,309	4705	11,603
Total	Distillate oil	12	0.23	79	25	54	156	3.0	609	168	441
Total	All	620	8.68	4387	1316	3071	10,550	147.7	45,856	13,229	32,627

Electricity converted to primary energy at 11.4 MJ/kWh. Cumulative costs and benefits present-valued to 1995 at a 7% real discount rate.

Source: Koomey: 1997

Employment Impacts

While the job creation estimates of Section 2 are presented generally, the components of indirect consumption impacts play out among individual industries across the state and beyond. The United States Department of Energy predicts that new national standards for lamp ballasts, water heaters and clothes washers *alone* would create over 100,000 jobs by 2020 (Hildt: 2001). This economic stimulus is further amplified by multiplier effects like those discussed in Section 2.

Table A3: Job Impacts by State

	State	Net Job Gain 2010	Net Job Gain 2020
1	Alabama	13,100	22,600
2	Alaska	2,800	5,000
4	Arizona	11,200	19,900
5	Arkansas	7,500	13,200
6	California	77,400	141,400
8	Colorado	10,000	17,700
9	Connecticut	7,800	14,100
10	Delaware	2,200	3,800
11	District of Columbia	1,600	3,500
12	Florida	37,000	66,800
13	Georgia	21,300	38,300
15	Hawaii	2,700	5,000
16	Idaho	3,500	6,200
17	Illinois	31,900	56,400
18	Indiana	20,900	36,000
19	Iowa	8,300	14,700
20	Kansas	7,100	12,500
21	Kentucky	11,500	19,300
22	Louisiana	19,200	32,900
23	Maine	3,700	6,600
24	Maryland	12,500	22,000
25	Massachusetts	14,500	26,700
26	Michigan	29,800	51,000
27	Minnesota	13,400	24,000
28	Mississippi	7,200	12,600
29	Missouri	15,100	26,600
30	Montana	2,300	4,000
31	Nebraska	4,700	8,500
32	Nevada	5,300	9,100
33	New Hampshire	2,800	5,000
34	New Jersey	20,200	26,200
35	New Mexico	4,200	7,100
36	New York	38,000	68,200
37	North Carolina	22,400	38,900
38	North Dakota	1,900	3,300
39	Ohio	34,600	59,900
40	Oklahoma	8,200	13,700
41	Oregon	8,600	15,600
42	Pennsylvania	31,600	55,500
44	Rhode Island	2,100	3,900
45	South Carolina	11,500	20,000
46	South Dakota	2,000	3,500
47	Tennessee	17,100	29,800
48	Texas	71,500	123,400
49	Utah	5,700	10,300
50	Vermont	1,600	2,800
51	Virginia	18,500	32,100
53	Washington	16,600	29,700
54	West Virginia	3,800	6,000
55	Wisconsin	14,900	26,300
56	Wyoming	1,700	2,600
	TOTAL	**744,900**	**1,314,300**

Source: Hildt: 2001

Job creation would not be universal however, for an increase in energy efficiency would potentially lessen the demand for energy and reduce jobs in energy sectors. Those not benefited by the new standards may need adjustment assistance to ensure minimal frictional unemployment during the transition. However, this support could easily come from the gains in efficiency experienced in the larger economy, and could even come from the energy companies themselves should they choose to invest more heavily in energy efficient technologies. A proposal for a national Climate Protection Scenario, which includes new appliance efficiency standards along with building and transportation regulations, estimates that even with this initial friction, net job growth would be universal for the United States. Even more conservative estimates suggest that efficiency increases employment and income, but also has the potential to support for policies that recognise adjustment needs. The overall gains estimated in Section 2 could easily justify measures to facilitate transition toward greater statewide energy efficiency.

Other Advantages of Appliance Efficiency Standards

Cost Effectiveness

From a state perspective, Appliance Efficiency Standards are an incredibly low cost and efficient way to save energy, reduce emissions, and spur economic growth. [Hildt] They are relatively inexpensive to create and enforce because individuals and businesses have an incentive to comply to improve their own energy efficiency.

Peak Demand Reduction

Because California's energy is linked with Nevada, Arizona, and other members of the Western Systems Coordinating Council (WSCC) future heat waves are expected to demand more energy than the region can provide. Energy efficient appliances will directly reduce California's demand for energy during these times of peak demand. This will reduce the risk of power shortages during extreme weather across all states of the WSCC. (Bernstein: 2001)

Energy Security

National energy security is well served by increases in appliance efficiency, which reduce energy consumption and increase American energy independence. [Hildt]

Conclusion

The creation of appliance efficiency standards has been a highly successful program in California, both as a way to simultaneous promote economic growth and simultaneously promote environmental protection. New appliance efficiency standards will continue to create jobs in California and the greater United States, both for appliance manufactures and other economic sectors. These efficiency standards also present a direct way to provide assistance for low-income families. If expanded diligently, appliance efficiency standards will continue to reduce the cost of energy, producing a number of substantial benefits for California businesses and residences.

Utility Efficiency

Bernstein also approximates the demand-side management expenditures of utilities to be $4 billion ($1998), or $125 per capita. Although this may seem like a small amount compared the benefits, they also note that:

> "[T]here also exist indications that some of the drivers of lower energy intensity may reverse. It is widely believed that electricity industry restructuring will lead to lower energy prices: there may no longer be an economic motivation to encourage improvements in energy efficiency."

Thus Bernstein argued that government incentives to invest further in energy efficiency may be necessary as input prices decline. However, given the rising prices of energy globally, the market incentives may be reason enough to pursue energy efficiency. This does not mean, however, that government, especially California, does not have a role to play in these new investments in efficiency.

Bernstein also went further and estimated the future impact of improvements in energy efficiency in California. They estimated to 2010, and derived the following results:

Table A4: Estimates of future economic benefits of reductions in energy intensity to California in terms of per capita GSP ($1998)

Estimate of the effect of energy intensity on the CA economy	1995 Benefits	*2010 Changes in GSP per capita from 1995*		
		1986-1995 trend Increase in energy intensity	1977-1995 trend Moderate decrease in energy intensity	1977-1985 trend Large decrease in energy intensity
Higher Impact	$1,331	-$534	$1,112	$3,101
National Average	$876	-$302	$597	$1,622
Lower Impact	$470	-$68	$98	$226

Source: Bernstein: 2001

3. Building Standards

HVAC/Improved Efficiency in Heating and Cooling Buildings

There is a clear precedent for improvements in energy efficiency in buildings, particularly in their heating and cooling. A report given by the Commissioner of the California Energy Commission, Art Rosenfeld, proposes that due to efficiency improvements over the last 34 years, California saves $70 billion annually just from space heating and air conditioning. (Rosenfeld, 2008, pg. 5)

The Impact of 2004 Office of Energy Efficiency and Renewable Energy Buildings-Related Projects on United States Employment and Earned Income is an important report assessing the potential effects on employment and income due to projects. This report was generated by the Pacific Northwest National Laboratory for the US Department of Energy (DOE). The Office of Energy Efficiency and Renewable Energy (EERE), a division of the DOE, commissioned this study to examine 37 projects proposed or in progress. In the report, EERE projects are grouped into two categories, the Weatherization and Intergovernmental Program, and Building Technologies.

Two basic economic components characterize EERE projects, large investments and reduced expenditures on energy. There are three channels through which EERE projects can affect the economy. First, if any difference in the incremental cost exists between the new and old technologies, the manufacturing, distribution, and installation industries involved will be affected in terms of altered purchasing levels, as well as any firms linked to these original firms. Second, the investment in efficiency through the EERE projects can lead to a crowding out of domestic saving, investments, and consumer spending, decreasing some of the net positive impact due to energy savings. Third, expenditures on energy and other goods will be reduced because of the increase in efficiency. This decrease in expenditures will result in a smaller volume of sales for utility companies, as well as related manufacturing, distribution, and service sectors providing parts or labor for maintenance, operation, and general upkeep. However, this savings will also have the effect of increasing disposable income for households and businesses (including utilities, manufacturing, distribution, and service sectors), inspiring an increase in spending across all sectors.

Additionally, the report examines two scenarios. The energy savings stemming from EERE projects account for a large part of the effects on employment and income, but this neglects the effects caused by the large and continuous investment in new building practices and energy technology required by the projects. The Full Investment Scenario accounts for these investments. It is important to note that because some of the investment in the Weatherization and Intergovernmental Program falls within capitally-intense, high-wage industries, the full investment scenario predicts a slightly negative net change in employment and positive change in earnings.

The Weatherization and Intergovernmental division consists of three programs. The first is the Weatherization Assistance Program, dedicated to reduce energy losses through upgrades to building components such as insulation, air sealing, and windows. The other two components are the State Energy Program, which provides funds to states to improve the condition of buildings, and Gateway Development, which is an umbrella for programs such as Rebuild America, Information Outreach, and Energy Star, all of which focus on increases in energy efficiency. When the study was completed in 2003, the energy savings alone from the Weatherization and Intergovernmental Program was estimated to potentially create almost 133,000 jobs and about $1.61 billion earned income by the year 2030.

The second set of EERE programs are placed under the Building Technologies division. This includes Residential and Commercial Buildings Integration, Emerging Technologies, and Equipment Standards and Analysis. Not all of the divisions within the last two categories are directly applicable to buildings, as some appliances, such as refrigerators and lighting systems, are included. By 2030, the energy savings from this division was estimated to create almost 172,000 jobs and $2.18 billion in earned income.

The investment in energy technology would be in industries that are more capitally intense than the average investment. This is because most of the investment would be in the manufacturing industry, which is more capital-intense than the average industry. Assuming that the investment in the EERE programs is redirected evenly from other potential investments (which include labor-intense service industries), these investments will displace employment in the short run. Because the required investments, which initially increase, are diverting money away from other less capital-intense potential investments, the early net effect of investment in EERE projects will be lower rate of employment growth than under normal circumstances. It is not until the cumulative energy-saving effects become large enough to eclipse the massive investment, will the net effects on employment and income be clear.

It is important to note that the model used for this analysis operated under the assumption that these investments were on too small of a scale to impact prices in the energy market or production markets, or wages in the labor market. Similarly, changes in employment can be more realistically viewed as changes in demand, and changes in wages or labor supply could affect actual employment conditions.

Investment can be roughly divided into its effects on procurement, installation, and the investment that is saved. These effects cause increased growth of jobs and income in some industries, but divert investment from other industries. At the same time, increases in energy efficiency might negate the need for other construction or service provision (such as power plants), altering growth in those industries. Increases in energy efficiency will also require individual consumers or business to purchase less energy, and services related to energy consumption. As mentioned earlier, this will decrease sales of these to sectors, but provide businesses and consumers with increased disposable income to cycle through the economy.

California is at the forefront of energy efficiency and although it is difficult to determine what percent of the *Impact of 2004…* report applies directly to California, the “Building America” program might give some indication. Build America is a part of the Building Technologies segment of EERE, mainly concerned with creating public and private partnerships to implement new, efficient building innovations. To date, 40,748 houses have been built nationwide as a part of Build America. Nearly 30 percent, 12,169, of these houses have been built in California. Although this program is only a small fraction of the whole, if the other EERE projects are implemented in California on a similar scale, the impact on employment and income would be quite large.

Lastly, there are of course other effects that are not attributed monetary value in this examination, but are nonetheless valuable: Improved energy security, operational savings resulting from more efficient and durable equipment, improved quality of life stemming from decreased environmental degradation and increased liveability, and increases in property value are all examples.

One example of economic benefits from energy efficient building materials is illustrated in Figure 7 above, a chart from a report compiled by CEC Commissioner Art Rosenfeld, examining rewards derivable from new technologies. These results clearly reveal the potential savings for new technologies. Also, it is important to note that the energy efficiency improvements listed for the Low-E windows are only calculating an improvement from double-glazed windows. If single-pane windows are converted to Low-E windows or a more modern, more efficient type of window, an even greater amount of energy can be saved. Although some increase in employment would be generated in the retrofit of new windows, increased disposable income resulting from energy savings would indirectly increase employment more widely through increased consumption.

Similar solutions are available for other aspects of the house. The Heat Islands Research Project at Lawrence Berkeley National Laboratory found a massive potential for energy savings in the city of Los Angeles when they modeled a scenario implementing passive energy saving measures. In the scenario, houses in Los Angeles replaced traditional dark roofs with white roofs and planted trees alongside the houses. Direct air-conditioner savings to the buildings with lighter roofs and trees totaled $100 million. Indirect savings to the entire city resulting from a decrease in temperature of by about six degrees Fahrenheit came out to $70 million. Also, a decrease in health care costs and sick days because of reduced smog amounted to a savings of $360 million. Although this program might not yield as great a benefit in parts of Northern California, areas such as San Diego and the Central Valley could reap proportionate savings benefits.

4. Vehicle and Transportation Standards

Mobile emissions represent over 40 percent of California's greenhouse gas emissions, and fuel costs are an important and rapidly escalating share of household income. Like electricity, transport fuels thus offer an attractive opportunity for combining climate initiative with expenditure oriented economic stimulus. Although electricity efficiency has a much longer policy history in California, the state is moving quickly take advantage of these opportunities. In this section we review the leading policies and an emerging literature estimating its benefits. Although most of the potential remains to be realized, there is already evidence that transport standards save money and stimulate net employment growth.

In September 2004, the CARB staff released the results of an evaluation of vehicular GHG emissions and the technologies available to reduce them. Their primary focus was on technologies that were currently in use in some vehicle models or had been shown by auto companies and/or vehicle component supplies in at least prototype form. Auto manufactures were also allowed to use their own R&D to determine the most effective technology for their fleet, and were permitted the use of alternative methods of compliance such as reducing GHG emissions from their manufacturing facilities or by purchasing emissions-reducing credits from other sources. They did not consider hybrid gas-electric vehicles. The were two emissions standards for different classes of cars (one for cars and small trucks/SUVs, and the other for large trucks/SUVs) and they took the form of fleet average emissions per vehicle in grams of CO2 equivalent per mile driven, with a declining annual schedule for each model year between 2009 and 2016. The standards called for a reduction of GHG emissions by 22 percent compared to the 2002 fleet and by 30 percent by 2016.

The staff estimated that the 2016 standards would result in an average cost increase of $1064 for passenger cars and small trucks/SUVs, and $1029 for large trucks/SUVs. These costs were estimated to be paid back to the consumer through operating costs within five years, assuming a gasoline price of $1.74/gallon. They concluded that the net savings to vehicle operators would provide an overall benefit to the California economy in terms of GSP and statewide employment

The auto industry argued against the staff's predictions and noted that the upfront costs to consumers would be greater than the operating cost savings. They also argued that the total Vehicle Miles Traveled (VMT) would increase due to the impact of lower fuel costs per mile. Small and Van Dender (2005) analyzed this claim and found that California, due to its high average income and its culture of conservation, has one of the smallest elasticities of VMT with respect to fuel cost per mile (short-run -0.022 and long-run -0.113). Thus, if the operating costs were to decrease by 25 percent in 2009, the number of miles traveled would increase by about 0.6 percent in 2009 and 2.8 percent in 2020 (Hanemann, 2008).

The CARB staff's analysis of the costs savings attributed to decreased operating costs can today be considered quite conservative as gasoline prices were reported to be $4.01 in California for May, 2008 by the US Department of Energy. Thus, consumers would have recovered the up-front increased cost of the vehicle within less than three years (Hanemann, 2008).

Sperling et al. (2004) note that overall, vehicle prices in real dollars have increased significantly over the years due to both technology and quality changes in the vehicles, but consumers have continued to purchase the vehicles even at the higher prices. Thus consumers have been willing to pay more for cars for changes in technology and quality. Sperling continues by saying that about $1000 of today's retail vehicle price is incurred to meet emission standards. This is roughly the same cost that was incurred in the early 1980, when emission standards were far less stringent (Sperling et al. 2004). Sterling also notes that government regulations have accounted for about 1/3rd of overall vehicle price increases and that cost increases associated with regulations have been swamped by year-to-year variability in vehicle prices. The increase in the sticker price of a vehicle due to regulations should not decrease the quantity of cars demanded significantly for the reasons stated above (Sperling et al. 2004).

It is also argued by the motor vehicle industry within California that regulations such as AB 1493 and AB 32 impose significant competitive disadvantages to automobile manufacturers within the state. However, it is of value to note that Automobile manufacturing in California represents a small fraction of the state's economy, about 0.27 percent (CalEPA 2004). The California businesses impacted by regulations tend to be the affiliated businesses such as gasoline service stations, automobile dealers, and automobile repair shops. Affiliated businesses are mostly local businesses and compete within the state and generally are not subject to competition from out-of-state businesses. Therefore, the proposed regulations are not expected to impose significant competitive disadvantages on affiliated businesses (CalEPA 2004). Thus it is unlikely that large employment losses will occur either in California's Automobile sector or affiliated businesses due to inter-state competition.

CalEPA also addresses the job losses attributed to regulation by noting that according to their research (following tables) consumers would now spend more on the purchase of motor vehicles, thus having less money to spend on the purchase of other goods and services. Since most automobile manufacturing occurs outside of the state, the increased consumer expenditures on motor vehicles would be a drain on the California economy. The reduction in operating costs that results from improved vehicle technology would, however, reduce consumer expenditures and would therefore leave California consumers with more disposable income to spend on other goods and services. Businesses that serve local markets are most likely to benefit from the increase in consumer expenditures. Therefore, the California economy has to potential to grow from the increase in consumer expenditures and thereby cause the creation of additional jobs.

Table A5: California projected income and employment 2010 – 2030

Economic Impacts of the Proposed Climate Change Regulations on the California Economy in Fiscal Year 2010 (2003$)

California Economy	W/O Climate Change Regulations	With Climate Change Regulations	Difference	% of Total
Output (Billions)	$2,228.06	$2,227.97	- $0.09	- 0.004
Personal Income (Billions)	$1,451.01	$1,451.49	+ $0.48	+ 0.03
Employment (thousands)	16,354	16,362	+ $8	+ 0.05

Economic Impacts of the Proposed Climate Change Regulations on the California Economy in Fiscal Year 2020 (2003$)

California Economy	W/O Climate Change Regulations	With Climate Change Regulations	Difference	% of Total
Output (Billions)	$3,078.02	$3,075.44	- $2.58	- 0.08
Personal Income (Billions)	$2,003.54	$2,014.92	+ $5.38	+ 0.30
Employment (thousands)	18,661	18,718	+ 57	+ 0.30

Economic Impacts of the Proposed Climate Change Regulations on the California Economy in Fiscal Year 2030 (2003$)

California Economy	W/O Climate Change Regulations	With Climate Change Regulations	Difference	% of Total
Output (Billions)	$4,41.54	$4,236.83	- $4.71	- 0.1
Personal Income (Billions)	$2,781.44	$2,789.14	+ $7.71	+ 0.3
Employment (thousands)	21,763	21,839	+ 76	+ 0.4

Source: CalEPA (2005)

5. POLICIES UNDER EVALUATION

Feebates

Feebates is an incentive-based program for people to purchase more fuel efficient automobiles. It is self-funded and involves fees on vehicles above a size, weight, or fuel economy threshold, and a rebate for vehicles under that threshold. Feebates are designed such that consumers select smaller or more fuel efficient vehicles, and conversely, manufacturers produce the vehicles that provide them with the most profit, which, in this case, would be the more fuel efficient vehicles.

Although AB 1493 restricts the use of fees and thereby feebates, it is still an interesting policy tool to consider in order to better understand how much GHG can be reduced and at what cost/benefit. McManus (2006) analyzed the potential benefits of a feebates program using fuel prices of $1.74 per gallon, and a five percent discount rate to estimate the present value of future savings to consumers due to the technology investments by automobile manufacturers. Looking at the table below, we see in each scenario, there is a net increase in personal income for California residents. Also, retailers will also gain as their sales increase by up to six percent according to McManus. Thus, the increased personal income by consumers can greatly stimulate the California economy as they spend on other goods and services.

Table A6: Vehicle Lifetime Savings to Consumers

Scenario		Car	Van	Pickup	SUV	Market
Pavley Alone	Lifetime Fuel Cost Retail Price Total Change	($2,432) $1,253 ($1,178)	($3,090) $989 ($2,100)	($3,712) $1,367 ($2,344)	($3,786) $1,242 ($2,544)	($2,928) $1,275 ($1,652)
Feebates Alone ($18g per g/mi)	Lifetime Fuel Cost Retail Price Net Feebates Total Change	($1,428) $536 ($652) ($1,544)	($2,117) $743 $172 ($1,203)	($2,456) $959 $1,187 ($311)	($2,429) $920 $928 ($581)	($1,892) $658 $0 ($1,234)
Feebates Alone ($36g per g/mi)	Lifetime Fuel Cost Retail Price Net Feebates Total Change	($2,281) $979 ($877) ($2,179)	($3,254) $1,270 $235 ($1,748)	($3,812) $1,633 $1,444 ($735)	($3,817) $1,516 $1,353 ($948)	($2,957) $1,164 $0 ($1,793)
Pavley plus Feebates ($18g per g/mi)	Lifetime Fuel Cost Retail Price Net Feebates Total Change	($2,904) $2,618 ($541) ($287)	($3,949) $2,726 $280 ($1,222)	($4,817) $3,514 $966 ($1,303)	($4,770) $3,227 $673 ($1,543)	($3,670) $2,866 $0 ($804)

Source: McManus (2006)

CARB has previously (under AB 2076) investigated vehicle feebates as an option for reducing California's petroleum dependence, but AB 1493's prohibition on fees precludes the use of such feebates for greenhouse gas emissions control. If feebates are applied to a class of commodities that are relatively similar and interchangeable then they can be very effective in inducing a consumption shift toward low-emission technologies without forcing consumption restriction. (A good example of a successful feebate-type policy outside the automotive industry is the Swedish Nitrogen Oxide program, which induced power plants to reduce specific emissions of NOX by 60 percent between 1990 and 1995) However, vehicle feebates of the type investigated by CARB would not have this effect because fees would be levied primarily on heavy vehicles while rebates would accrue primarily to lightweight vehicles. The feebate would induce a weight-stratified cost and profitability imbalance whose primary effect would be to induce downweighting, which is a relatively inefficient way of inducing emissions reduction because heavy and lightweight vehicles are not functionally interchangeable. (Johnson, 2005)

Partial-Zero Emission Vehicles (PZEVs)

A RAND report by Dixon (2005) argues that automobile manufacturers will be producing large numbers of partial-zero emission vehicles (PZEVs) to satisfy part of California's Zero Emission Vehicle Program, which went into effect with model-year

2005 vehicles. The California Air Resources board requires that PZEVs must have a 15 year/150,000 mile extended exhaust system warranty in order to keep emissions low as the vehicle ages. These warranties will only be valid at dealer repair stations, and thus may adversely affect revenues of independent repair shops. Zero Emission Vehicles (ZEVs) are very expensive to produce, and thus automobile manufacturers are expected by RAND to fulfill as much of the California Zero Emission Vehicle program as possible with Partial Zero Emission Vehicles (so-called the “Maximum PZEV scenario”). They note that independent repair shop revenue will grow, but slower than if the warranty on PZEVs was not restricted to dealer repair shops (see the following tables and figures). RAND also predicts that there should be no need to lay off current workers at independent repair shops as a whole, because revenues at independent repair shops are projected to grow even with extended warranties. However, Dixon predicts that some independent repair shops may be more affected by extended emission warranties than others. Thus, they predict there may be some losses, but the impact of extended warranties are felt only gradually over time, and workforce reductions could be handled through normal attrition. Secondly, workers may be able to find employment at other independent repair shops, or at dealer repair shops.

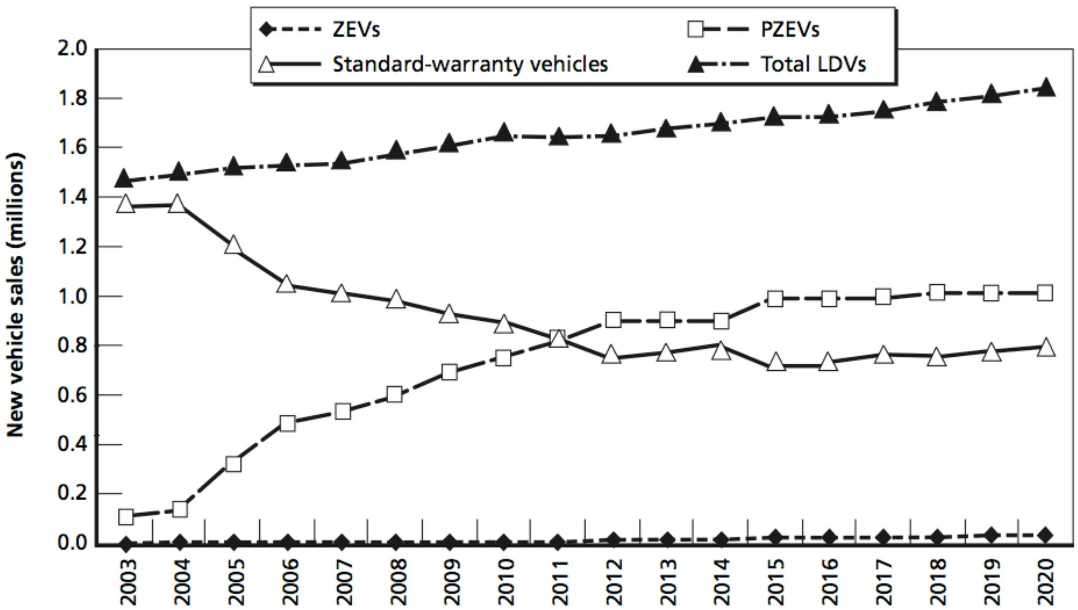
Dixon further notes that extended emission warranties will mean fewer opportunities for future workers in the independent-repair industry, but that these fewer opportunities may be offset by positions at dealer repair shops.

Table A7: Changes in Economic Welfare
(Percent Change Compared to Business-as-Usual)

Example	Sector	2012	2017	2022	2030	2050
Example 1: Ethanol and Hydrogen	State Output	0.06%	0.03%	0.08%	0.02%	0.14%
	Personal Income	0.01%	0.05%	0.13%	0.16%	0.05%
	Employment	0.06%	0.08%	0.14%	0.16%	0.14%
Example 2: Advanced Biofuel and PHEV	State Output	0.06%	0.11%	-0.11%	-0.04%	-0.24%
	Personal Income	0.02%	0.09%	0.01%	0.12%	-0.09%
	Employment	0.05%	0.09%	0.15%	15.00%	0.00%
Example 3: Advanced Biofuel and Hydrogen	State Output	0.08%	0.11%	-0.11%	-0.04%	0.21%
	Personal Income	0.01%	0.09%	0.01%	0.14%	0.08%
	Employment	0.06%	0.09%	0.15%	0.16%	0.15%

Source: Dixon (2005)

Figure A3: Sales of New Light-Duty Vehicles in California in the Maximum-PZEV Scenario



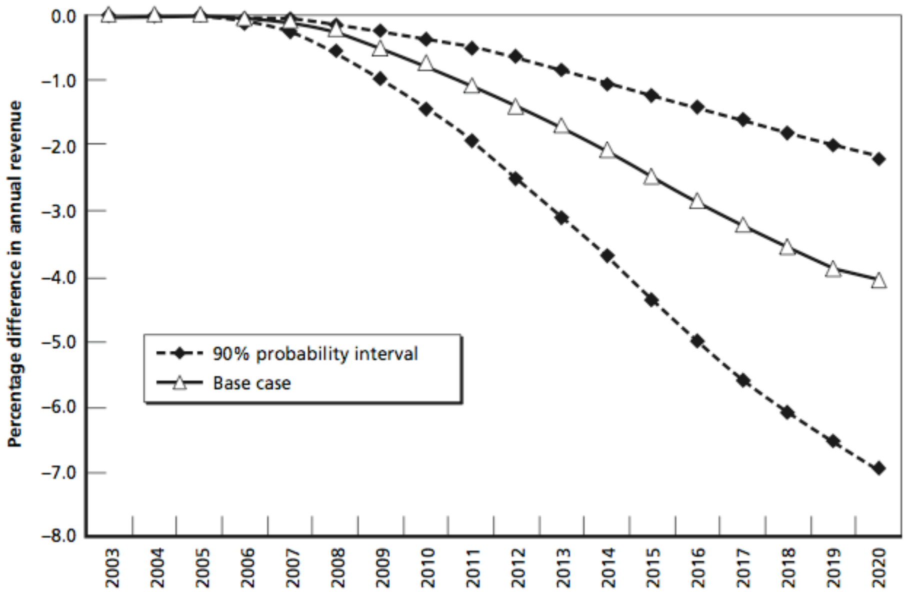
Source: Dixon (2005)

Table A8: Sales of New Light-Duty Vehicles Used in the Five PZEV Scenarios *(millions of vehicles)*

Scenario	PZEVs	Standard-Warranty Vehicles	Total LDVs
1. Maximum number of PZEVs that can be used to satisfy ZEV program requirements			
2003-2010	3.6	8.74	12.34
2011-2020	9.46	7.74	17.21
2. 75 percent of maximum number of PZEVs			
2003-2010	2.76	9.58	12.34
2011-2020	7.10	10.11	17.21
3. 50 percent of maximum number of PZEVs			
2003-2010	1.92	10.42	12.34
2011-2020	4.73	12.47	17.21
4. 25 percent of maximum number of PZEVs			
2003-2010	1.08	11.26	12.34
2011-2020	2.37	14.84	17.21
5. All new vehicles sold after 2008 are PZEVs			
2003-2010	6.58	5.76	12.34
2011-2020	17.21	0	17.21

Source: Dixon (2005)

Figure A4: Percentage Difference in Annual Revenue at Independent Repair Shops Due to Extended Warranties, 2003-2020, Maximum-PZEV Scenario



Source: Dixon (2005)

Alternative fuel strategies for California

The CEC (2007) in a report about alternative fuel strategies for California, make employment and growth predictions for California's economy (Table A7 above). They assume three different examples of fuel strategies:

> Example 1: Ethanol continues to be used as a gasoline blendstock. Lightduty fuel cell vehicles dominate the alternative vehicle market. Also includes natural gas, propane, and renewable diesel fuels, as well as plug-in hybrid electric vehicles.
>
> Example 2: Similar to example 1, except that hydrogen fuel cell vehicles do not achieve market success, and plug-in hybrid vehicles dominate the light-duty alternative vehicle market. Also, an advanced biofuel is developed and replaces ethanol as a gasoline blendstock.
>
> Example 3: Hybrid of examples 1 and 2. Assumes that both hydrogen vehicles and the advanced biofuel achieve market success.

Almost all examples until 2050 show significant employment increases. However, the various scenarios included in the examples are not completely available currently and are based on future availability of these technologies (eg. “an advanced biofuel”).

6. Energy Efficiency in the broader US context

A World Wildlife Fund (Bailie et al.) study in 2001 modelled the “Climate Protection Scenario”, a comprehensive environmental policy package, which included:

Buildings and Industry Sector

- Building Codes
- Appliance and Equipment Standards
- Tax Credits
- Public Benefits Fund
- Research and Development
- Voluntary Measures
- Cogeneration for Industrial and District Energy

Electric Sector

- Renewable Portfolio Standard
- NOx/SO2 cap and trade
- Carbon cap and trade

Transport Sector

- Automobile Efficiency Standard Improvements
- Promotion of Efficiency Improvements in Freight Trucks
- Aircraft Efficiency Improvements
- Greenhouse Gas Standards for Motor Fuels
- Travel Demand Reductions and High Speed Rail

The resulting estimated job creation would be quite substantial. As summarized in the following table, these estimates are qualitatively similar to our own estimates for California’s electricity measures, but to not take full account of stimulus from expenditure linkages.

Table A9: Net Changes in Jobs and GDP by Sector

	Net Change in Jobs	Net Change in Compensation *(Million 1998$)*	Net Change in GDP *(Million 1998$)*
Agriculture	63,100	$620	$2,120
Other Mining	11,200	$870	$1,830
Coal Mining	(23,900)	($2,340)	($4,940)
Oil/Gas Mining	(61,400)	($5,210)	($20,600)
Construction	340,300	$10,460	$15,030
Food Processing	16,100	$750	$1,380
Other Manufacturing	77,900	$9,360	$14,160
Pulp and Paper Mills	5,000	$570	$950
Oil Refining	(6,300)	($650)	($1,910)
Stone, Glass, and Clay	24,800	$1,630	$2,750
Primary Metals	18,600	$2,190	$3,180
Metal Durables	42,000	$4,670	$7,670
Motor Vehicles	54,300	$5,090	$8,350
Transportation, Communication, Utilities	50,500	$3,320	$6,750
Electric Utilities	(35,100)	($5,180)	($27,540)
Natural Gas Utilities	(26,200)	($3,080)	($11,180)
Wholesale Trade	12,400	$1,030	$1,890
Retail Trade	190,300	$4,410	$7,680
Finance	42,100	$4,570	$9,410
Insurance/Real Estate	11,900	$350	$2,420
Services	394,600	$13,080	$18,460
Education	33,200	$1,330	$1,340
Government	78,900	$3,550	$4,660
TOTAL	**1,314,300**	**$51,390**	**$43,860**

Source: Bailie et al (2001)

7. Energy Efficiency in the International Context

Although California is currently a pioneer in GHG reduction policy and technology, there have been other policies internationally that have led to changes in employment due to energy efficiency investments. Jochem/Hohmeyer (1992), for example, reported that the 4.1 exajoules per year of energy savings achieved in Western Germany between 1973 and 1990 alone created approximately 400,000 new jobs. Today, the net employment effect due to increased labour productivity since the 1980s and reduced energy prices between 1986 and 1999 found in

European and North American studies in the late 1990s is in the order of 40 to 60 new jobs per petajoule of primary energy saved (Laitner: 1998).

8. Technical Details

Data Resources

Producing the detailed employment impact estimates of Section 2 was a very data-intensive exercise. This process began with assembly of a series of input-output tables, comprising inter-industry flows, value added, and final demand for about 500 activity and commodity categories over the period 1972-2006. The U.S. Bureau of Economic Analysis maintains these accounts and updates them every five years. Each of the seven relevant national tables were obtained from BEA and aggregated up to the 50 sector framework reported in this paper. Also, comparable tables for California, estimated for 2002 and 2006, were aggregated to the same sector standard.

In addition to data on economic structure for the last 35 years, detailed employment wage data were obtained by California Regional Economies Employment (CREE) Series. This source provides annual data on enterprises, jobs, and average wages for over 1200 NAICS sector categories across California.

Estimation Technique

To impute historical employment gains from California's energy efficiency measures, we pose a simply counterfactual question: Given California's economic structure, how would employment growth have proceeded in the absence of household energy efficiency? Answering this question requires three kinds of information:

1. Historic National and current California consumption patterns
2. Historic economic structure for California
3. Employment by sector

The first item was obtained from the BEA tables, and third is provided by the CREE data set. To estimate California's historic economic structure, we use seven historic input-output tables for the national economy and one (2002) for California. In particular, we used a combination of national and state tables to approximate California's changing economic structure. Consider a series of tables representing intermediate expenditure shares $A_t = \hat{y}^{-1}T_t$, where y is a vector of total outputs (a caret denotes the corresponding diagonal matrix), and T_t is the input-output table for period t. These represent intermediate usage of goods and services, linking production activities across the economy through expenditure chains.

Now consider national expenditure share matrices A_t^N for period t=1972, 1977, 1982, 1987, 1992, 1997, 2002. The California counterpart data are A_t^C for t=2002. From this data, we construct a series of approximate California expenditure shares with an averaging procedure as follows:

$$E_t = A_t^N (2002 - t) / 30 + A_{2002}^C (t - 1972) / 30$$

Thus the estimated consumption shares represent national patterns in the initial year and converge to California consumption patterns by 2002. These matrices are then converted to multiplier matrices with the routine calculation $M_t = (I - E_t)^{-1}$. Multipliers in this matrix show how much an additional unit of demand for one good creates economy-wide demand for all other goods and services. Following the long expenditure chains of the A matrices, multipliers take account of all resource requirements and other induced demand. Next, we define the counterfactural consumption shares d_t defined as follows:

$$d_t(electricity) = (1 - .4(t - 1972) / 30) c_t^N (electricity)$$

and

$$d_t(other) = d_t(other) / (1 - (c_t(electricity) - d_t(electricity))$$

Intuitively, the vector d_t represents the difference in California household consumption patterns due to a transition from 1972 national norms to California's current consumption shares, including a 40 percent reduction in electricity consumption per capita.

The final estimation stage entails computing the economy-wide effects of expenditure shifting with the multiplier calculation, then rescaling for California consumption by commodity (C_t) and sectoral labor output ratios (J_t). This final expression (i.e. the estimated columns in Table 4) takes the form:

$$M_t d_t \widehat{C}_t \widehat{J}_t$$

This rather dense expression takes account of four factors. First is the structural multiplier matrix, which indicates how demand changes in one sector impact all others. Second is the d_t vector of estimated consumption changes, assuming California did and did not achieve its historic reductions in per capita electricity consumption. The C vector converts from US to California magnitudes, the last factor translates output into employment.

It should be noted that using national IO tables in our sample introduces some bias in the estimates for early years. Because state economies are generally more trade dependent than the nation as a whole, average intermediate consumption shares and in-state multipliers may be smaller. It should be noted, however, that most of the job creation for California arises in sectors providing non-tradable services, while estimated job losses are in energy and manufactures with significant trade shares. For these reasons, net state employment gains from energy efficiency are probably estimated with reasonable accuracy.

Table A10: Sector Definitions for the Current BEAR Aggregation

	Label	Description
1	A01Agric	Agriculture
2	A02Cattle	Cattle Production
3	A03Dairy	Dairy Production
4	A04Forest	Forestry, Fishery, Mining, Quarrying
5	A05OilGas	Oil and Gas Extraction
6	A06OthPrim	Other Primary Activities
7	A07DistElec	Generation and Distribution of Electricity
8	A08DistGas	Natural Gas Distribution
9	A09DistOth	Water, Sewage, Steam
10	A10ConRes	Residential Construction
11	A11ConNRes	Non-Residential Construction
12	A12Constr	Construction of Transport Infrastructure
13	A13FoodPrc	Food Processing
14	A14TxtAprl	Textiles and Apparel
15	A15WoodPlp	Wood, Pulp, and Paper
16	A16PapPrnt	Printing and Publishing
17	A17OilRef	Oil and Gas Refineries
18	A18Chemicl	Chemicals
19	A19Pharma	Pharmaceuticals
20	A20Cement	Cement
21	A21Metal	Metal Manufacture and Fabrication
22	A22Aluminm	Aluminium Production
23	A23Machnry	General Machinery
24	A24AirCon	Air Conditioner, Refridgerator, Manfacturing
25	A25SemiCon	Semiconductors
26	A26ElecApp	Electrical Appliances
27	A27Autos	Automobiles and Light Trucks
28	A28OthVeh	Other Vehicle Manufacturing
29	A29AeroMfg	Aeroplane and Aerospace Manufacturing
30	A30OthInd	Other Industry
31	A31WhlTrad	Wholesale Trade
32	A32RetVeh	Retail Vehicle Sales and Service
33	A33AirTrns	Air Transport Services
34	A34GndTrns	Ground Transport
35	A35WatTrns	Water Transport
36	A36TrkTrns	Truck Transport
37	A37PubTrns	Public Transport
38	A38RetAppl	Retail Appliances
39	A39RetGen	General Retail Services
40	A40InfCom	Information and Communication Services
41	A41FinServ	InfTel
42	A42OthProf	Other Professional Services
43	A43BusServ	Business Services
44	A44WstServ	Waste Services
45	A45LandFill	Landfill
46	A46Educatn	Educational Services
47	A47Medicin	Medical Services
48	A48Recratn	Recreation and Cultural Activity
49	A49HotRest	Hotel and Restaurant Services
50	A50OthPrSv	Other Private Services

9. BEAR Assessment of the Scoping Plan Scenarios

In this section, we provide a brief summary of the BEAR assessment for ARB climate action scenarios. For the purposes of this attachment, these results are preliminary and represent independent assessment. Analytical approaches, methodological assumptions, data, and evaluation discusses in this attachment represent the opinions of the author and should not be ascribed to the California Air Resources Board or any of their staff.[35]

Scenarios

For the purposes of policy comparison, BEAR was used to evaluate two representative scenarios that take account of Scoping Plan policy recommendations. These scenarios represent the primary policies currently being evaluated for their potential to meet the state's 2020 target of 427 MMTCO2 equivalent overall emissions of greenhouse gases, and are discussed in detail in the main body of the Plan.

The Preliminary Recommendation scenario, in Table III.2, represents the Preliminary Recommendation approach described in the Draft Scoping Plan. This scenario includes the recommended measures that provide the reductions of 169 MMTCO2e in emissions needed to meet the 2020 target.[36] These measure include both a broad-based cap and trade program and sector specific measures. In the same table, Sector Specific Measures scenario refers to a scenario that includes the measures other than the cap and trade program from the Preliminary Recommendation together with the measures listed as "other measures under evaluation" in the Draft Scoping Plan. Together, these are envisioned to achieve an estimated 169 MMTCO2e aggregate emission reduction all through developing measures other than the cap and trade program that apply to specific economic sectors.

Table A11: General Scenarios

Number	Label	Description
1	Preliminary Recommendation	Regulations and Standards Recommended in the Scoping Plan, plus cap and trade to Attain AB 32 Emission Goals for 2020
2	Sector Specific Measures	Sector-specific measures other than the cap and trade program included in the Preliminary Recommendation and 'Other Measures Under Evaluation' in the Draft Scoping Plan

[35] This Annex reproduces exactly the text of the Scoping Plan Supplement, written by the author.
[36] For full discussion of the Preliminary Recommendation, see 6/26/08 release of the Draft Scoping Plan.

Preliminary Recommendation Scenario

E-DRAM results have been discussed in the main body of this document as well as a separate appendix. In this section, we present independent results with general interpretation, offered from the perspective of current and previous research with the BEAR model. In particular, the following tables present aggregate results for the Preliminary Recommendation, including a Baseline or business-as-usual (BAU) that assumes historical trends of energy efficiency. We see here that macroeconomic impacts are relatively (percentage results in Table A12) limited.

Table A12: Aggregate Results for Preliminary Recommendation Scenario

Impact Indicator	BAU	Recommended
Real Output ($billion)	3,606	3,640
Gross State Product ($billion)	2,598	2,602
Personal Income ($billion)	2,096	2,092
Per Capita Income (1000s)	48.000	47.479
Employment (Millions)	18.410	18.431
Emissions (MMTCO2e)	596	427
Carbon Price (Dollars)	0	12
Job Growth (thousands)	0	21
Emissions Change (percent)	0	-28
Targeted Reduction (percent)	0	100

This policy package combines significant emissions reduction with in-state economic growth, as measured by real GSP and employment. This result has been a robust characteristic of BEAR and E-DRAM scenarios since the original assessments in support of AB 32 and it is driven by the pro-growth characteristics of energy efficiency and expenditure shifting.[37] Aggregate personal income for the BEAR estimates declines very slightly (less than 2/10 of one percent) in 2020, yet more than 186,000 new jobs are created as the state shifts to more service-intensive economy. The primary reason real GSP differs from real Personal Income is price effects. Real incomes are affected because the policies considered increase the cost of living for most households, but by only a few tenths of one percent, about one tenth of California's average inflation rate over the last two decade. In light of the scope of GHG mitigation achieved,

[37] For a more detailed recent assessment of this issue, see Roland-Holst: 2008

this price effect should be seen as extremely modest. Moreover, this result is consistent with earlier BEAR and E-DRAM work.

Table A13: Aggregate Variation for Preliminary Recommendation Scenario
(all figures in percent change from the BAU unless otherwise noted)

	Recommended
Real GSP	0.2
Personal Income	-0.2
Employment (Millions)	0.1
Jobs	21
Emissions Change (percent)	-28
Targeted Reduction (percent)	100
Permit Price (Dollars)	12

It is noteworthy that the permit cost for cap and trade component, or model-determined carbon fee arising from the trading system, is relatively low. Permit price estimates are important to the policy debate, since they represent a proxy for adjustment costs. This price is relatively low because, after the Recommended policies, emissions need to be lowered by only an additional (35 out of remaining 462) 7.6 percent to reach the state's 2020 goal. These results suggest that the private sector can complete the residual mitigation to meet the 2020 goals at relatively modest cost if market mechanisms distribute the adjustment burden across the state's diverse economy.

Sector-Specific Measures Scenario

Table A14 shows the results for the Sector-Specific Measures Scenario. The results of this scenario also show positive impacts on the California economy. Real output and GSP, both increase. Personal income decreases slightly but employment increases as jobs are shifted to service industry and more labor-intensive sectors.

Table A14: Aggregate Results for All Regulations Scenario

Impact Indicator	BAU	All Regs
Real Output	3,606	3,656
Gross State Product	2,598	2,608
Personal Income	2,096	2,093
Per Capita Income (1000s)	48.000	47.503
Employment (Millions)	18.410	18.476
Emissions (MMTCO2e)	596	427
Carbon Price (Dollars)	0	0
Job Growth (thousands)	0	66
Emissions Change (percent)	0	-26
Targeted Reduction (percent)	0	100

Table A15 shows the percent change from the business-as-usual case. The impacts can be characterized as generally positive. California economy is enormous and the proposed regulations, from an economics point of view, are not only doable, but add stimulus and maintain a sound economy. The BEAR analysis shows that the state can attain its climate action objectives without sacrificing aggregate economic growth.

Table A15: Aggregate Variation for Sector-Specific Measures Scenario
(all figures in percent change from BAU unless otherwise noted)

	All Regs
Real GSP	0.4
Personal Income	-0.1
Employment (Millions)	0.4
Jobs	66
Emissions Change (percent)	-26
Targeted Reduction (percent)	93
Permit Price (Dollars)	0

Model Limitations

While researchers who developed and implement the BEAR model do not advocate particular climate policies, their primary objective is to promote evidenced-based dialogue that can make public policies more effective and transparent. California's bold initiative in this area makes it an essential testing ground and precedent for climate policy in other states, nationally, and internationally. As part of its leadership on climate change the state must assess the direct and indirect economic effects of the many possible approaches to its stated goals for emissions reduction. High standards for economic analysis are needed to anticipate the opportunities and adjustment challenges that lie ahead and to design the right policies to meet them. Progress in this area can increase the likelihood of two essential results: that the California mechanism works effectively and that it achieves the right balance between public and private interest.

The BEAR model's sectoral detail, model-determined emissions, and dynamic innovation and forecasting characteristics enable it to capture a wide range of program characteristics and their role in economic adjustments to climate action. BEAR was designed to model cap and trade systems, and includes all the major design features such as variable auction allocation systems, model-determined permit prices, banking options, safety valves, and fee/rebate systems for CO2 and up to thirteen other criteria pollutants.

All models are necessarily simplifications of reality. While many details of California's economy are omitted from the BEAR assessment framework, however, it does provide reliable guidance regarding the economic impacts that would ensue from climate action measures of the kind considered in the Scoping Plan. The BEAR model has been peer reviewed and represents the most advanced research technologies for economic policy simulation. Still, it is important to understand the uncertainties and limitations that forecasting entails, particularly for complex and unprecedented policy initiatives like the ones considered here. There are three general contexts where the model's results should be interpreted with care.

External shocks: Although it is the world's eighth largest economy, California is and will remain subject to external events beyond its own control. Seismic activity, extreme weather events, and even global energy prices are largely exogenous to the state, yet these will all affect our future. In most cases, however, it can be argued that BEAR results comparing baseline and policy impact will remain applicable. If energy prices were to rise substantially, however, the current estimates of economic benefits from climate action would be lower than actual benefits (compared to the baseline).

Heterogeneity: The main way in which models like BEAR simplify economic reality is by aggregation, examining the behavior of whole sectors of the state economy rather than individual enterprises. Thus a single bank might fail, but the banking sector looks fine on average. Likewise, heterogeneity of technology, decision making, and other firm and plant level characteristics will make climate adaptation a complex and variegated process. BEAR does not predict these individual adjustments, and will thus not capture many adverse and beneficial experiences that make up the aggregate outcomes estimated here. Because this type of heterogeneity is at the core of the potential for market mechanisms, such as a cap and trade program, to reduce the costs of implementing regulations, BEAR can be expected to underestimate the benefits from market-based compliance mechanisms in implementing AB 32. Investing in this kind of detailed insight is more resource intensive, might be desirable for private actors in the economy, but it is not necessarily an efficient use of public resources.

Innovation: The overall process of technological change is notoriously difficult to forecast, and individual innovation events virtually impossible. Although we know innovation will be important to California's progress toward a lower carbon future, BEAR does not attempt to predict this component of adjustment determined withing the model. Having said this, more innovation research would certainly improve guidance for policy makers who want to structure appropriate incentives for technological progress.

The more modest goal of the modeling was to elucidate economic effects of Preliminary Recommendation scenario. In this context, further progress in the policy dialogue will require greater sophistication in both the positive research and its appraisal. In the former category, three areas of improvement should be high priorities for climate change economic modeling:

1. Raw engineering data. There is a tremendous need for increased coverage and greater precision in data on costs, technology profiles, point source emissions across detailed US industrial classifications. It would also be desirable to have more data of this kind in raw form, as opposed to secondary aggregates which may include discount rates and other adjustment factors.

2. More intensive sensitivity analysis and counterfactual experiments. All modeling work in this area needs to evolve from "just-in-time" individual policy analysis to more detached appraisal of structural characteristics. This takes time, but will provide essential insight about future research

priorities and policy robustness. This research can help adjudicate disputes about behavioral questions, while also improving the structural features of policy models.

3. Wider policy and research dialogue. Policy making and research processes in the US should continue to widen and improve their internal dialogues, including drawing on insights from European experience and developing country issues, and encouraging greater interaction between the science/technology and economic communities.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

THE ADMINISTRATOR

APR 24 2009

Mr. Paul R. Cort
Earthjustice
426 17th Street, 5th Floor
Oakland, California 94612

Dear Mr. Cort:

The U.S. Environmental Protection Agency (EPA) has considered the petition you submitted on February 10, 2009, on behalf of the Sierra Club and the National Resources Defense Council asking the Agency to reconsider:

- specific provisions in the final EPA rule entitled Implementation of New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$), 73 Fed. Reg. 28321 (May 16, 2008); and
- the January 14, 2009 letter from then Administrator Stephen L. Johnson denying your July 15, 2008 petition for reconsideration of this rule.

The specific provisions of the May 16, 2008 rule for which you have requested EPA reconsideration include (1) the transition schedule and interim requirements for the prevention of significant deterioration (PSD) programs in SIP-approved states; (2) the grandfathering provision concerning the continued use of the PM_{10} Surrogacy Policy in the federal PSD regulations at 40 CFR 52.21(i)(1)(xi); (3) the transition period for addressing condensable particulate matter emissions; and (4) the preferred interpollutant trading ratios under the nonattainment area NSR program.

Under the authority of section 307(d)(7)(B) of the Clean Air Act, EPA grants the February 10 petition for reconsideration in order to allow for public comment on each of the four issues raised in your petition. To respond to your February 10 petition, the Agency plans to publish a notice of proposed rulemaking in the Federal Register in the near future. As part of this notice, the Agency intends to propose to repeal the grandfathering provision on the grounds that it was adopted without prior public notice and is no longer substantially justified in light of the resolution of the technical issues with respect to $PM_{2.5}$ monitoring, emissions estimation, and air quality modeling that led to the PM_{10} Surrogacy Policy in 1997. At this time, the Agency has not determined any specific action to be proposed concerning the other three issues raised in your petition.

Further, under the authority granted by section 307(d)(7)(B) of the Clean Air Act, I hereby stay 40 CFR 52.21(i)(1)(xi) (the grandfathering provision under the federal PSD program) for three months pending reconsideration. A stay pending reconsideration is justified for the reasons discussed above, that this provision was adopted without prior public notice and is no longer substantially justified in light of the resolution of the technical issues with respect to $PM_{2.5}$ monitoring, emissions estimation, and air quality modeling that led to the PM_{10} Surrogacy Policy in 1997.

We appreciate your comments and interest in this important matter.

Sincerely,

Lisa P. Jackson

cc: David S. Baron, Earthjustice

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In the Matter of: Final Rule Published at 73 Fed. Reg. 28321 (May 16, 2008), entitled "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)," Docket No. EPA-HQ-OAR-2003-0062, RIN 2060-AN86

PETITION FOR RECONSIDERATION

Pursuant to Section 307(d)(7)(B) of the Clean Air Act ("Act"), Natural Resources Defense Council, and Sierra Club ("Petitioners") petition the Administrator of the Environmental Protection Agency ("the Administrator" or "EPA") to reconsider the final rule referenced above as well as the January 14, 2009 letter from Stephen L. Johnson ("Johnson Letter") denying Petitioners' July 15, 2008 petition for reconsideration.[1] The last-minute denial signed by Administrator Johnson relied on absurd arguments to defend the legally defective final rule and in some cases even worsens those defects. Because the grounds for the objections raised in this petition for reconsideration, as well as the original, arose after the close of the public comment period for the challenged rule, and these objections are of central relevance to the outcome of the rule, the Administrator must "convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed." Clean Air Act § 307(d)(7)(B). Reconsideration is further warranted because the Johnson Letter was issued without any public notice and comment opportunity. As further discussed below, some of the rationales offered in the Johnson Letter were not previously provided by EPA. Reconsideration is therefore warranted to provide Petitioners the opportunity to comment on rationales that arose after the close of comment on the original rule proposal.

OBJECTIONS

In their original petition for reconsideration, Petitioners identified four exemptions or so-called "flexibilities" introduced for the first time in the final rule. These provisions were never offered for public comment and were not logical outgrowths of the proposed rule. In each case, EPA violated the requirements of Clean Air Act section 307(d)(3)(C), which requires EPA to present for public comment "the major legal interpretations and policy considerations underlying the proposed rule." The Johnson Letter made no attempt to deny or excuse several of these failures, and for the others offered groundless arguments based on a revisionist interpretation of the original proposal. In the end, the Johnson Letter offered the excuse that EPA preferred not to expend resources on complying with the procedural requirements of the law. But compliance with the law's notice and comment requirements is plainly not optional, regardless of the resources required, as Administrator Johnson surely knew. For each of the elements described below, Petitioners ask that the Administrator reject this flouting of

[1] For your convenience, this original petition for reconsideration is enclosed at Attachment A.

the law and stay the challenged elements of the final rule pending completion of a proper public review process.

The hasty, last-minute denial by Administrator Johnson failed to address many of the substantive issues raised in Petitioners' original petition for reconsideration. Petitioners hereby resubmit the original petition and incorporate it herein by reference. Below, Petitioners focus on the absurd arguments made in the Johnson Letter defending the addition of the challenged provisions and attempting to dismiss the significance of EPA's illegal actions.

A. EPA's decision to extend the deadline to 2011 for States to revise the prevention of significant deterioration ("PSD") programs in their state implementation plans ("SIPs") is illegal.

1. EPA offered no opportunity for public comment on the new deadline or the underlying legal rationale.

In the notice of proposed rulemaking, EPA proposed that "States with SIP-approved PSD programs [must] submit revised PSD programs for $PM_{2.5}$ at the same time that they must submit nonattainment NSR programs for $PM_{2.5}$ (April 5, 2008)." 70 Fed. Reg. 65894, 66043 (Nov. 1, 2005). EPA decided to split out the portions of the proposed rule relating to new source review and finalized those portions on May 16, 2008. Notwithstanding the fact that the final rule was published after the April 5, 2008 SIP submittal deadline, EPA did not revise the deadline for submitting the nonattainment NSR programs for $PM_{2.5}$. Yet in the final rule, EPA announced for the first time that instead of requiring PSD SIP submittals at the same time as nonattainment NSR SIP submittals, PSD submittals could be delayed until May 16, 2011. 73 Fed. Reg. 28321, 28341 (May 16, 2008). EPA's rationale, offered for the first time in the final rule, was that no statutory deadline applies to the SIP revisions required under this rule, so the regulatory deadlines adopted as part of EPA's NSR Reform relaxation rulemaking should govern. *See* 73 Fed. Reg. at 28340-41. This legal analysis is nowhere to be found in the proposed rule and is fundamentally flawed.

As explained more fully in Petitioners' original petition for reconsideration, the statute *does* specify a deadline for revising SIPs following the adoption or revision of a national ambient air quality standard ("NAAQS"). Section 110(a)(1) provides that SIPs are due within 3 years after the promulgation of a new or revised primary NAAQS. Section 110(a)(2)(C) states that each SIP shall include a permit program as required in Part C of the Act (*i.e.*, the PSD permit program). There is no ambiguity in this language or in how these deadlines apply to the current rulemaking.

As EPA explained in the notice of proposed rulemaking, the regulations being challenged here govern how States must revise their SIPs to implement the revised particulate matter NAAQS. *See* 70 Fed. Reg. at 65894. EPA has already acknowledged that the deadline in 110(a)(1) applies to SIP submittals required to implement a new or revised NAAQS, even where EPA issues new regulations specifying what that implementation requires. *See* 52 Fed. Reg. 24672 (July 1, 1987). In that 1987 rulemaking, just as here, EPA revised the PSD and NSR rules to implement changes made to the particulate matter NAAQS. In that rulemaking EPA found that the deadline for revised PSD SIPs was governed by section 110(a)(1) and required SIP revisions within 9 months after the revision of the NAAQS. *Id.* at 24683. EPA cannot change its interpretation of the Act by announcing in a final rule with no opportunity for comment, its new legal conclusion that the statute does not provide a deadline applicable to this action.

Administrator Johnson's January 14, 2009 letter tries to claim that the public had notice of EPA's new legal interpretation and the possibility that EPA would significantly delay revision of SIP-approved PSD programs because this three-year extension is provided in the pre-existing PSD rules. The Johnson Letter further argues (for the first time) that the reason the deadline in section 110(a)(1) does not apply is because it only governs the "infrastructure" SIPs that EPA previously required. These groundless excuses are completely disingenuous.

The notice of proposed rulemaking *explicitly* stated that States would be required to submit SIP revisions to implement revised PSD programs for $PM_{2.5}$ "*at the same time that they must submit nonattainment NSR programs for* $PM_{2.5}$ (**April 5, 2008**)." 70 Fed. Reg. at 66043 (emphasis added). The proposal was absolutely unambiguous on this score, and offered no indication whatsoever that some other deadline was being considered, or that the "pre-existing" PSD rules even applied to this rulemaking. There was no mention at all of this pre-existing regulatory deadline provision, let alone any connection between this provision and the April 2008 deadline that EPA had proposed. To the contrary, it is clear that EPA, at the time, did not believe this regulatory deadline provision was relevant to a rulemaking governing the implementation of a revised NAAQS. EPA proposed to allow States less than two and a half years to revise their SIP-approved PSD programs (not the three allowed under the regulatory provision), and tied the deadline not to the date of promulgation of the final rule as the regulatory deadline provision does, but to the SIP submittal deadlines provided in the statute. Had EPA mentioned the possibility that the regulatory deadline provision, and not the statute, would apply, commenters would have been able to show why that regulatory deadline provision is inconsistent with the governing statutory deadlines.

The Johnson Letter attempted to add new arguments for ignoring the statutory deadline in section 110(a)(1) based on what EPA guidance calls the "infrastructure SIPs." This new line of argument only highlights the illegality of EPA's final decision. The Johnson Letter claims that the requirements of section 110(a)(1) with respect to the 1997 $PM_{2.5}$ NAAQS were met with the submittal of these infrastructure SIPs, and that a PSD program implementing the $PM_{2.5}$ NAAQS was not part of this required submittal. This argument is completely new – it appeared nowhere in the proposed or final rule. Moreover, it has absolutely no basis in the statute. Section 110(a)(1) says that, "[e]ach State shall . . . adopt and submit [a SIP] to the Administrator[] within 3 years . . . after the promulgation of a [NAAQS] . . . ." Section 110(a)(2)(C) further states that each such SIP shall include "regulation of the modification and construction of any stationary source . . .

to assure that national ambient air quality standards are achieved, including a permit program as required in part[] C . . . ." *See also* CAA § 110(a)(2)(J) (requiring each plan to meet the applicable requirements of part C). There is no ambiguity in the statute regarding the deadline for these revisions to the SIPs.

EPA's infrastructure SIP guidance says nothing that purports to change these deadlines. The guidance says "EPA believes that the currently-approved section 110 SIPs may be adequate because many of the required section 110(a) SIP elements are general information and authorities that constitute the 'infrastructure' of the air quality management plan . . . ." Memorandum from Sally L Shaver, Dir., Air Quality Strategies and Standards Div., OAQPS, to Regional Air Div. Dir., "Re-issue of the Early Planning Guidance for the Revised Ozone and Particulate Matter (PM) National Ambient Air Quality Standards (NAAQS)," at 5 (June 12, 1998). It goes on to note that:

> States, however, should review and revise, as appropriate, the ozone and PM SIPs to ensure they are adequate. In particular, given that EPA has issued new PM standards for fine particles ($PM_{2.5}$), it is conceivable that some States may need to adopt language specific to the $PM_{2.5}$ NAAQS formally to ensure it has adequate authority to implement the $PM_{2.5}$ NAAQS under section 110(a). . . . If a State's section 110 SIP is not adequate for purposes of the revised ozone or PM standards, as required in the Act, the States must revise the SIP and submit it to EPA within 3 years of the NAAQS promulgation (by July 2000).

Id. at 6. In Attachment A to the guidance, EPA lists the "Required Section 110 SIP Elements," which includes the PSD program requirement of section 110(a)(2)(J). EPA's guidance makes it clear that the SIP revisions due under section 110(a)(1) included revisions to the PSD programs necessary to ensure implementation of the new $PM_{2.5}$ NAAQS. Thus, even if it could override the statute (which it cannot), this guidance in fact reaffirms the plain statutory reading that precludes EPA's attempt to illegally delay the SIP submittal deadline until 2011. The Johnson Letter's creation of this new "infrastructure SIP" argument highlights the fact that the public has never had an opportunity to point out the inconsistencies between EPA's claims and its own guidance interpreting these provisions.

2. EPA's decision to waive compliance with $PM_{2.5}$ standards in States with SIP-approved PSD programs is illegal.

The most egregious part of EPA's decision to delay the deadline for revising SIP-approved PSD programs is that in the interim States may rely on EPA's 1997 PM_{10} surrogate policy, which allows permits to ignore the $PM_{2.5}$ NAAQS and instead look only at whether a source will cause or contribute to a violation of the 24-hour PM_{10} NAAQS. *See* 73 Fed. Reg. at 28341 (allowing States to continue to implement the PM_{10} program pursuant to the document entitled "Interim Implementation of the New Source Review Requirement for $PM_{2.5}$" (John S. Seitz, EPA, October 23, 1997)). The denial letter defends this decision with the incredible claim that "the surrogate policy does not 'waive' or 'exempt' sources from complying with the statutory requirements."

As the Bush Administration was well aware, the surrogate policy does unquestionably waive the Act's most central requirements for major sources and permitting authorities – namely, the requirement to assure compliance with national ambient air quality standards. The Act expressly requires a PSD permit applicant to "*demonstrate*[] . . . that emissions from construction or operation of such facility will not cause, or contribute to, air pollution in excess of *any . . . national ambient air quality standard* in any air quality control region . . . ." As EPA has long known, a demonstration of compliance with PM_{10} standards does not by any stretch of the imagination constitute a demonstration of compliance with $PM_{2.5}$ standards. As more fully documented in Petitioners' first reconsideration petition, and not disputed by the Bush Administration, there is no scientifically supported showing that compliance with the 24-hour PM_{10} standard means that compliance with both the 24-hour and annual $PM_{2.5}$ standards is even probable. Indeed, the evidence is to the contrary. The vast majority of areas that are nonattainment for the $PM_{2.5}$ *do not* violate the PM_{10} standard. In the face of this plain evidence, it is absolutely absurd to allow major sources to pretend that their compliance with the PM_{10} standard is "proof" that they will comply with $PM_{2.5}$ standards. The absurdity of this approach is dramatically highlighted by the fact that EPA itself does not allow use of such a surrogate approach for federally permitted new sources applying for permits today. Thus, there can be no question that the purpose of the surrogate policy is to excuse sources from making the NAAQS compliance demonstration *vis-à-vis* the $PM_{2.5}$ NAAQS. *See* 73 Fed. Reg. at 28341 (explaining that its new decision in the final rule to extend the use of the surrogate policy meant that EPA was "finalizing proposed option 1, *without the requirement of demonstrating compliance with the $PM_{2.5}$ NAAQS*") (emphasis added).

The results of this approach are outlandish in the extreme. The policy allows the permitting of major new factories and power plants right next to, or even in, areas that are already violating $PM_{2.5}$ standards without even looking at the new plant's impact on $PM_{2.5}$ levels. Instead, the permit applicant need only look at impacts on PM_{10} levels, which as noted above, are unlikely to be violated in most areas violating the $PM_{2.5}$ standard. Thus, the policy produces the absurd result of allowing a huge new source to be built that will worsen $PM_{2.5}$ violations, and yet pretend that all is well because it will not cause or contribute to a PM_{10} violation. This is not merely a hypothetical. As documented in Petitioners' motion for a stay in the Court of Appeals (incorporated herein by reference), and not disputed by the Bush Administration, there are numerous examples of pending power plant proposals that meet just the above description. *See* Petitioners' Mot. for a Stay Pending Review at 15-19, *NRDC v. EPA*, Case No. 08-1250 (D.C. Cir. filed Aug. 28, 2008).

EPA's position appears to be that sources cannot be constructed if they will cause or contribute to a violation of the $PM_{2.5}$ NAAQS, but that no demonstration of compliance is required unless someone first proves that such a violation will occur. This type of argument – that there is no violation unless someone from the public can prove one – flatly violates that statute, which places the burden *on the permit applicant* to demonstrate that no violations will occur. That requirement is waived under the surrogate policy.

The Bush Administration tried to defend the surrogate policy as by asserting (contrary to EPA's own conclusions in the proposed rule[2]) that because $PM_{2.5}$ is a subset of PM_{10} all sources that would be major for $PM_{2.5}$ will also be major for PM_{10}. This observation is utterly irrelevant, as the issue here is not identifying which sources are major for $PM_{2.5}$, but rather whether those sources will cause or contribute to violations of the $PM_{2.5}$ standards.

Even if emissions estimates and modeling of PM_{10} were accurate surrogates for estimating emissions and ambient concentrations of $PM_{2.5}$, which they are plainly not, showing that those results demonstrate compliance with the 24-hour PM_{10} NAAQS provides absolutely no basis to conclude that the 24-hour and annual $PM_{2.5}$ NAAQS will not be violated. The Bush Administration deliberately ignored this glaring defect in its defense of the surrogate policy.

The surrogate policy plainly waives otherwise applicable statutory requirements. Even though the previous administration seemed to forget this frequently, EPA is not free to waive statutory requirements it finds inconvenient or burdensome. *See New York v. EPA*, 413 F.3d 3, 41 (D.C. Cir. 2005) ("Absent clear congressional delegation… EPA lacks authority to create an exemption from New Source Review by administrative rule."); *see also Engine Mfrs. Ass'n v. EPA*, 88 F.3d 1075, 1089 (D.C. Cir. 1996) ("[A]n agency may not avoid the Congressional intent clearly expressed in the text simply by asserting that its preferred approach would be better policy.").

This failure to protect the $PM_{2.5}$ NAAQS is among the most troubling results of the final rule. The sources EPA will allow to be permitted without assuring compliance with $PM_{2.5}$ standards could cause long-term attainment problems for many areas – problems that could easily be avoided if the correct analysis were required immediately. It is particularly inexcusable for EPA to allow continued use of PM_{10} as a surrogate *more than a decade after adoption of the $PM_{2.5}$ standards*. There is no question that permit applicants, States and EPA have the technical ability to require demonstration of compliance with $PM_{2.5}$ standards, rather than relying on a surrogate approach that is not defensible on the law or the science. EPA must withdraw the decision to extend the exemptions for sources in States with SIP-approved PSD programs.

B. EPA's new exemption for certain sources to avoid compliance with federal PSD requirements based on their date of application is illegal.

[2] EPA explained that if condensables are not included, sources' total $PM_{2.5}$ emissions in excess of the major source threshold will be missed. *See* 70 Fed. Reg. at 66044 (explaining the that PM_{10} will not act as a reasonable surrogate for $PM_{2.5}$ "where a source emitted significant amounts of condensible emissions that would not otherwise be counted under a State's PM_{10} program"). This problem of "missing" otherwise major sources is more important for $PM_{2.5}$ sources because condensables tend to make up a much more significant portion of $PM_{2.5}$ than PM_{10}. *See id.* at 66039.

1. EPA offered no opportunity for public comment on the announcement in the final rule to grandfather certain PSD sources out of the obligation to comply with $PM_{2.5}$ requirements.

The final rule announced that sources submitting complete applications prior to July 15, 2008 that had relied on EPA's 1997 surrogate policy could continue to ignore the statutory obligations related to the $PM_{2.5}$ NAAQS. 73 Fed. Reg. at 28340 (codified at 40 CFR § 52.21(i)(1)(xi)); *see also id.* at 28341 (allowing States with SIP-approved PSD programs to include similar grandfathering provisions). This is particularly astounding because the final rule for the first time actually *codifies* the 1997 surrogate policy without ever having allowed the public to comment on the appropriateness or legality of the surrogate policy.

The Johnson Letter made no attempt to deny that this "grandfather" exemption was newly added to the final rule without notice or an opportunity for public comment, and there is no possible argument that this exemption is a logical outgrowth of the proposal. The proposed rulemaking explained that the scientific uncertainties that led EPA to issue the PM_{10} surrogate policy in 1997 "have been resolved in most respects." 70 Fed. Reg. at 66043. As a result, EPA announced that following promulgation of the final rule, reliance on the surrogate policy would no longer be allowed and the requirement to demonstrate compliance with the $PM_{2.5}$ NAAQS "will take effect immediately on the effective date in States that issue permits under a delegation from EPA." *Id.* There was no mention or any indication that certain sources would be carved out of these immediately effective requirements based on the date of their application. This is a plain violation of section 307(d)(3) of the Act and therefore demands withdrawal and reconsideration of this provision.

The fact that the Bush Administration did not even respond to Petitioner's reconsideration petition on this point, much less offer any defense to the flagrant procedural violation described in that petition, is by itself more than sufficient grounds for the new Administration to revisit the issue.

2. EPA has no authority to "grandfather" sources out of complying with the statute.

Notwithstanding the absence of any excuse for violating the procedural requirements of the Act, the Johnson Letter nonetheless tried to defend the merits of the exemption. The arguments offered, however, are simply stunning. Administrator Johnson admitted that this grandfathering provision does not grow out of any authority in the Act. Instead, Administrator Johnson suggested that, even though the only grandfathering expressly allowed under the Act in section 168(b) does not apply to the sources covered by EPA's rule, nothing in the Act precludes the agency from allowing "other" grandfathering by regulation. This position reflects a fundamental confusion over who gets to write the law.

As explained above, the purpose and effect of the grandfathering provision is to allow sources to continue to rely on the surrogate policy, which illegally waives, among other things, the requirement to demonstrate that emissions will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS. Grandfathered sources must demonstrate only that the 24-hour PM_{10} NAAQS will not be violated and can rest on that showing unless someone proves a $PM_{2.5}$ NAAQS violation will occur. The affirmative obligations of section 165(a)(3) have been illegally waived. Again, if no requirements of the statute were being waived, there would be no need for these grandfathering provisions.

EPA cannot waive statutory requirements without express authority to do so. *See New York v. EPA*, 413 F.3d at 41. Congress gave EPA limited express authority in section 168(b), but nowhere else. The Johnson Letter's admission that this grandfathering provision is not covered by section 168(b) ends the debate. That Congress provided limited authority to grandfather certain sources is proof that other such exemptions are not authorized.

The Johnson Letter's offered another new assertion in defense of the grandfathering exemption – namely, the appalling claim that this exemption "is of little consequence." The letter claims that "only" nine sources fall within the grandfathering provision, and comments were submitted on "only" six of these. As EPA never made this claim in the proposed rule, the Johnson Letter's reliance on the claim violates the notice and comment rights of Petitioners and the public, who never had the chance to comment on its relevance or validity. Thus again, this new defense is by itself grounds for granting this petition. On the merits, aside from being statutorily irrelevant (as the Act does not allow waiver of the relevant requirements for any reason), a claim that "only" nine sources are affected simply cannot be the position of an agency charged with protecting the public health of the Nation's population. It should go without saying that the construction of even *one* major source that is allowed to violate national health-based standards is of major consequence to the people impacted by pollution from that source who will be forced to breathe unhealthy air. Moreover, EPA's characterization of these sources is completely disingenuous. Several of the facilities on EPA's list are not just "major" sources emitting more than 250 tons per year, but are massive coal-fired power plants that will emit *thousands* of tons per year of $PM_{2.5}$. The list includes the Desert Rock power plant in New Mexico (a 1500 megawatt coal-fired power plant that will emit 1,125 tons of PM_{10} per year, most of that presumably in the form of condensable $PM_{2.5}$), the White Pine power plant in Nevada (a 1600 megawatt coal plant that will emit 2,687 tons of PM_{10} per year), and the Ely Energy Center plant in Nevada (a 1500 megawatt coal plant with project PM_{10} emissions of 1788 tons per year). Moreover, several of these sources – Big West, Colusa, and Victorville 2 – will be located in or near areas that are attainment for PM_{10} but nonattainment for $PM_{2.5}$. As a result, demonstrating compliance with the PM_{10} NAAQS for these sources will ignore the clear likelihood that these sources will contribute to existing violations of the $PM_{2.5}$ NAAQS.

Petitioners have further discovered that the Bush Administration's list of affected plants, which was also offered to the D.C. Circuit under penalty of perjury, is incomplete. For example, the Russell City Energy Center in Hayward, California, was not included in

EPA's list of nine sources even though the Bay Area Air Quality Management District is the delegated PSD permitting authority and has proposed a permit that invokes the grandfathering exemption of the final rule to justify its refusal to evaluate $PM_{2.5}$ impacts from the proposed source.[3] The Russell City Energy Center is a perfect example of why this grandfathering exemption is so clearly illegal. The San Francisco Bay Area has monitored exceedances of the 2006 $PM_{2.5}$ 24-hour NAAQS of 35 ug/m3 since 2004. *See* Letter from James Goldstene, Executive Officer, California Air Resources Board, to Wayne Nastri, Regional Administrator, Region 9, U.S. EPA (Dec. 17, 2007) (State recommendations for area designations under the $PM_{2.5}$ NAAQS based on 2004 through 2006 monitoring data).[4] Based on these monitoring results, on December 22, 2008, EPA signed a notice designating the Bay Area as nonattainment for $PM_{2.5}$.[5] There is no possible dispute that the new $PM_{2.5}$ and NOx emissions from this source will contribute to the existing violations of the $PM_{2.5}$ NAAQS, since air quality in the Bay Area already exceeds the 24-hour $PM_{2.5}$ standard. And yet, amazingly, the Bay Area Air Quality Management District has argued that as long as it can show that the 24-hour PM_{10} NAAQS will not be violated, no further analysis is required. When such egregiously illegal permitting decisions are allowed to proceed under this policy, it is all the more galling for EPA to claim that as long as no one objects, these permitting decision are inconsequential.

C. EPA's decision to allow States to ignore condensable particulate matter from their permitting analysis was not a logical outgrowth of the proposed rule.

The Johnson Letter claimed that the final provisions allowing States to ignore condensable particulate matter were not adopted without notice because "[t]he final rule merely deferred the effective date of the proposed action and preserved the status quo in the interim – requiring continued enforcement of those SIPs and permits that clearly address [condensable particulate matter]." Johnson Letter at 4. This attempt to rewrite history provides no excuse at all for the procedural violation.

The proposed rule explained that "[c]ondensible emissions commonly make up a significant component of $PM_{2.5}$ emissions, and the failure to include them may result in adverse consequences to the environment." 70 Fed. Reg. at 66039. EPA added that, "[w]hile EPA *has always* included condensible emissions in its definition of particulate matter emissions, insofar as these emissions are measured by applicable test methods or included in emissions factors, we believe that the greater significance of condensible emissions in addressing $PM_{2.5}$ warrants greater emphasis in including these emissions in implementing the major NSR program." *Id.* (emphasis added). The proposal noted that "EPA has issued guidance clarifying that PM_{10} includes condensible particles and that,

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[3] Statement of basis available at www.baaqmd.gov/pmt/public_notices/2008/15487/index.htm.

[4] The State reevaluated and confirmed its recommendation to designate the Bay Area as nonattainment for $PM_{2.5}$ based on 2005 through 2007 monitoring data. *See* Letter from James Goldstene, Executive Officer, California Air Resources Board, to Wayne Nastri, Regional Administrator, Region 9, U.S. EPA (Oct. 18, 2008). These letters from the California Air Resources Board are available at: www.epa.gov/pmdesignations/2006standards/rec/region9R.htm

[5] Available at: www.epa.gov/pmdesignations/2006standards/documents/2008-12-22/FR_Final_24hr_PM2.5_Designations_010609.pdf

where condensible particles are expected to be significant, States should use methods that measure condensible emissions," and that "States are already required under the consolidated emissions reporting rule to report condensible emissions . . . and Method 202 in Appendix M of 40 CFR part 51 quantifies condensible particulate matter." *Id.* How anyone could have read this discussion and concluded that EPA was also considering allowing States to exclude condensable emissions from permitting decisions is beyond the pale. "Whatever a 'logical outgrowth' of this proposal may include, it certainly does not include the Agency's decision to repudiate its proposed interpretation and adopt the inverse." *See Environmental Integrity Project v. EPA*, 425 F.3d 992, 998 (D.C. Cir. 2005)

The most shocking thing about the new defense offered in the Johnson Letter is that it actually moves the consideration of condensables backwards by inventing a new "*status quo*." The Johnson Letter suggest that the *status quo* allowed States that had not previously addressed condensable particulate matter to exclude condensables from permits. Johnson Letter at 4. This was never the legal position of EPA. As noted above, the proposal explained that EPA "has always" included condensables in the definition of particulate matter and its guidance instructed States to use methods that measure condensables where those emissions are expected to be significant. The proposal, after noting "misconceptions" as to whether condensable emissions must be included, sought only to "clarify" the *status quo* – not change it – that "condensible emissions must be included when determining whether a source is subject to the major NSR program." 70 Fed. Reg. at 66039. It is appalling for EPA to now argue that it has always been EPA's policy that condensables can be excluded if a State so chooses. Moreover, this new rationale was offered for the first time in the Johnson Letter. It did not appear in the notice of proposed rulemaking or even in the final rule. The final rule justified the exclusion of condensables on the ground that a commenter had raised concerns about monitoring – a ground that itself had never been subjected to public comment. Again, the Johnson Letter's reliance on newly minted rationales never before set forth for public review and comment warrants reconsideration of that letter, as well as the underlying rule.

On the merits, as explained in the original petition for reconsideration, the exclusion of condensable $PM_{2.5}$ emissions violates a host of statutory provisions, including the requirements to permit major sources of any pollutant (§§ 169(1), and 182), apply required controls for all regulated pollutants (§§ 165(a)(4), 171(3), and 173), and attain the $PM_{2.5}$ NAAQS as expeditiously as possible but no later than 2010 (§§ 172(a)(2)(A), (c)(1), (c)(6), 188(c), and 189). The Johnson Letter made no attempt to refute any of these legal defects associated with the exclusion of condensable $PM_{2.5}$ emissions.

The Johnson Letter must be withdrawn in order to avoid creation of new law to allow the exclusion of condensable emissions. EPA never indicated in the proposed rule that it would allow such an exclusion and offered no opportunity for the public to comment on the legality of such an exclusion.

D. EPA provided no opportunity for the public to comment on the new interpollutant trading ratios.

Petitioners raised a number of objections to EPA's arbitrary and illegal decision to adopt in the final rule, without notice and comment, "preferred" interpollutant trading ratios to facilitate the interpollutant trading of emissions offsets under the NSR program. *See* 73 Fed. Reg. at 28339. The Johnson Letter ignored these objections, instead offering only that these ratios will be open to public review in subsequent SIP and permit approvals. This is a transparently illegal attempt to shift the obligation to provide a technical basis from EPA to the public.

It is a fundamental principle of administrative law that agencies must provide a rational basis for their decisions. *See Motor Vehicles Mfrs. Ass'n v. State Farm Mut. Auto. Ins.*, 463 U.S. 29, 43 (1983). Yet EPA is refusing to allow the public to comment on the basis for EPA's preferred ratios. Instead, States may *presume* these ratios will be approved by EPA (*i.e.*, the State need not provide *any* technical basis), and it is up to the public to provide a "credible" basis for showing why the ratios are inappropriate. *See* 73 Fed. Reg. at 28339. That the public, and not the agency, has the technical burden of proof is astounding given that EPA admits that "[t]here is considerable uncertainty about the relationship of precursor and direct $PM_{2.5}$ emissions to localized ambient $PM_{2.5}$ concentration both spatially and temporally." *Id.* Given this uncertainty and variability, the only permissible presumption is that the ratios in different areas will be different, not that a uniform ratio is valid unless proven otherwise. Not only must the public make the technical case on the appropriate ratios, it must make this case in every single SIP approval action in order to prevent these indefensible ratios from being used. This is not a legally adequate substitute for the public review required under section 307(d)(3)(C) of the Act.

The Johnson Letter's assertion that permit review will also provide the necessary public review is even more outrageous. Pending SIP approval of revised nonattainment new source review programs, States will issue nonattainment new source review permits pursuant to Appendix S of 40 CFR part 51. These permits can rely on EPA's preferred ratios even though the ratios will not yet have been approved into the SIP. Thus, anyone that objects to the technical basis of these ratios must comment on the inappropriateness of these ratios in every single permit that proposes to allow interpollutant trading. The Johnson Letter's assertion that this provides adequate opportunity for public review is utterly disingenuous, especially since EPA itself concluded that "we do not believe that available models can determine the effects of interpollutant trades at a single source . . . [and w]e will not accept case-by-case demonstrations on an individual source permit basis." 73 Fed. Reg. at 28339. In other words, the Bush Administration put the burden on the public to make a credible case for rejecting the preferred ratios – ratios that have never been justified through an open review process – yet acknowledged that in the context of a specific permitting action, such a credible case may not be possible to prove.

Before EPA can establish presumptions on important technical conclusions that will have immediate impacts on permitting decisions, EPA must provide the public an opportunity to review and comment on those conclusions. As outlined in the original petition for reconsideration, and undenied by the Johnson Letter, the ratios announced in the final rule suffer from fundamental technical flaws. As such they must be immediately withdrawn until they have been adopted through the proper notice and comment procedures.

PETITION FOR STAY

Petitioners reiterate their request that EPA stay those portions of the final rule (including the preamble) challenged herein. A stay of these provisions is warranted to prevent irreparable harm to the members of the public (including Petitioners' members) from the construction and operation of major sources of $PM_{2.5}$ pollution without the safeguards mandated by Congress in the Act. That harm is presented not only from threatened exposure to increased levels of dangerous $PM_{2.5}$ pollution, but also from implementation of rules and policies on which Petitioners and their members had no opportunity to comment. Petitioners' motion for stay in the D.C. Circuit, incorporated herein by reference, provides extensive evidence of the imminent threats faced by Petitioners' members and the public if these illegal Bush Administration rules are allowed to govern new source permitting in the coming months.

As documented in EPA's most recent review of the PM NAAQS, $PM_{2.5}$ pollution is linked to tens of thousands of premature deaths annually, and is a major contributor to visibility impairment in many parts of the nation. EPA has repeatedly found that the PM_{10} NAAQS does not adequately protect against these effects, and that PM_{10} is not an accurate surrogate for fine particles or their adverse health and welfare impacts.

The threat to Petitioners' members and the public is compounded by the fact that sources permitted under these illegal policies will likely emit $PM_{2.5}$ pollution long after EPA's "transition" period ends. For example, new coal-fired power plants, like those EPA acknowledges will be grandfathered out of $PM_{2.5}$ compliance, typically remain in operation for at least 30 years. Petitioners' members and many others will be exposed to emissions from these plants for decades. There is accordingly an urgent need to ensure that emission limits adequate to protect the NAAQS are imposed *before* these plants are built, and that those limits address all components of $PM_{2.5}$ – not just a fraction.

For all the foregoing reasons, Petitioners ask EPA to stay the above-referenced provisions of the final rule. Petitioners further ask that EPA respond to this stay request within 30 days of the date of this petition.

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DATED: February 10, 2009

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ATTACHMENT A

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In the Matter of: Final Rule Published at 73 Fed. Reg. 28321 (May 16, 2008), entitled "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers (PM2.5)," Docket No. EPA-HQ-OAR-2003-0062, RIN 2060-AN86

PETITION FOR RECONSIDERATION

Pursuant to Section 307(d)(7)(B) of the Clean Air Act, Natural Resources Defense Council, and Sierra Club petition the Administrator of the Environmental Protection Agency ("the Administrator" or "EPA") to reconsider the final rule referenced above ("NFRM," "final rule" or "rule"). The grounds for the objections raised in this petition arose after the period for public comment and are of central relevance to the outcome of the rule. The Administrator must therefore "convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed." CAA § 307(d)(7)(B).

INTRODUCTION

This petition raises objections to the final rule captioned above. Each objection is "of central relevance to the outcome of the rule," CAA § 307(d)(7)(B), in that it demonstrates that the rule is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." *Id.* § 307(d)(9)(A). With respect to each objection, moreover, the regulatory language and EPA interpretations that render the rule arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law appeared for the first time in the NFRM published on May 16, 2008, 73 Fed. Reg. 28321. A Federal Register notice soliciting comment on the rule was published on November 1, 2005, 70 Fed. Reg. 65984. The public comment period on the November 1, 2005 notice closed on January 31, 2006. 70 Fed. Reg. 63902 (Nov. 15, 2005). The grounds for the objections raised in this petition thus "arose after the period for public comment." CAA § 307(d)(7)(B). Because judicial review of the rule is available by the filing of a petition for review by July 15, 2008, the grounds for the objections arose "within the time specified for judicial review." CAA § 307(d)(7)(B).

OBJECTIONS

I. EPA's New Transition Flexibility For PSD Programs In SIP-Approved States Is Illegal And Arbitrary

The final rule unlawfully and arbitrarily includes new requirements governing the way in which States with prevention of significant deterioration ("PSD") programs approved into their state implementation plans ("SIPs") will come into compliance with the new PSD rules governing PM2.5. 73 Fed. Reg. at 28340-42. In the final rule, EPA announced that such States are excused from the proposed April 5, 2008 SIP submittal deadline, and, instead, will have until May 16, 2011 to revise their PSD programs and submit those revisions for approval into the SIP. *Id.* at 28341. In addition, EPA eliminated the proposed requirements that during the interim period before the SIP-approved PSD program is revised, States must (1) require sources to demonstrate that emissions will not cause or contribute to a violation of the national ambient air quality standards ("NAAQS") for PM2.5, and (2) include condensable PM2.5 emissions in determining major NSR applicability. *Id.*

This new scheme governing the transition period for States with SIP-approved PSD programs is an about-face on the transition program proposed, and was added to the rule after the close of the public comment period. Thus, the grounds for our objections arose after the period for public comment, and the raising of those objections during the public comment period was impracticable. *See* CAA § 307(d)(7)(B). These objections are of central relevance to the rule, *see id.*, because they go to the core requirements of how and when PSD programs will be revised to comply with the PM2.5 NAAQS – including the public's opportunity to comment on those provisions, and the consistency of those provisions with the Act and with fundamental standards of reasoned agency decision-making.

A. EPA Unlawfully and Arbitrarily Failed to Seek Public Comment on the Final Rule's Transition Requirements For SIP-Approved PSD Programs

EPA unlawfully failed to present this new transition scheme for States with SIP-approved PSD programs and accompanying rationale to the public for comment. Under Clean Air Act section 307(d), which EPA has found applicable to this proceeding, EPA must present for public comment "the major legal interpretations and policy considerations underlying the proposed rule." § 307(d)(3)(C). The same requirement would apply under the Administrative Procedure Act ("APA"). 5 U.S.C. § 553. EPA's rejection of the deadlines and requirements to safeguard the PM2.5 NAAQS that EPA included in the proposal is not a logical outgrowth of that proposal. *See Environmental Integrity Project v. EPA*, 425 F.3d 992, 998 (D.C. Cir. 2005) ("Whatever a 'logical outgrowth' of this proposal may include, it certainly does not include the Agency's decision to repudiate its proposed interpretation and adopt the inverse."). EPA therefore committed a procedural violation by failing to solicit public comment on this new transition scheme. *See* CAA § 307(d)(9)(D). That procedural violation meets the criteria set forth in the Act for reversal based on procedural violations. *Id.*

First, EPA's procedural dereliction is arbitrary and capricious. *See* CAA § 307(d)(9)(D)(i). EPA, after providing the legal rationale for the proposed deadlines and safeguard requirements governing the transition for SIP-approved states, now completely ignores that rationale and finalizes a new scheme that is nearly the exact opposite of the proposal without any public notice and comment.

Second, via the present petition, petitioners have satisfied the requirements of Clean Air Act section 307(d). *See* CAA § 307(d)(9)(D)(ii).

Third, the challenged errors "were so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made." *See* CAA §§ 307(d)(8) and 307(d)(9)(D)(iii). EPA did not merely fail to seek public comment on some small aspect of the challenged provisions. Rather, it failed to seek comment on completely reversing itself on how and when SIP-approved PSD programs must be revised to comply with the PM2.5 NAAQS promulgated in 1997. The new transition scheme purports to allow source to be constructed or expanded even if they result in long-term contributions to violations of the PM2.5 NAAQS. Had EPA obeyed the law by soliciting public comment, it would have learned of the serious substantive objections detailed below – objections that address the lack of statutory basis for the challenged provisions, and those provisions' inconsistency with fundamental principles of reasoned agency decision-making.

B. EPA's Transition Scheme Is Unlawful and Arbitrary.

The law governing when SIPs with PSD programs are due following a revision to the NAAQS is clear. Section 110(a)(1) provides that SIPS are due within 3 years after the promulgation of a new or revised primary NAAQS. Section 110(a)(2)(C) states that each plan shall include a permit program as required in Part C of the Act. There is no ambiguity in this language or in how these deadlines apply to the current rulemaking. This rulemaking governs how States must revise their SIPs to implement the revised particulate matter NAAQS. Those NAAQS were promulgated on July 18, 1997. 62 Fed. Reg. 38652 (July 18, 1997). Revised PSD SIP to implement these revised NAAQS were therefore due by July 18, 2000.

EPA, however, proposed to set a PSD SIP submittal deadline of April 5, 2008. 70 Fed. Reg. at 66043. This deadline is the same deadline for submitting SIPs with nonattainment NSR programs and is based on the requirement in section 172(b), which requires nonattainment area SIPs, including nonattainment NSR permitting programs, no later than 3 years from the date of the nonattainment designation. Since EPA delayed designating areas until April 5, 2005, the nonattainment area SIP submittal deadline was delayed until April 5, 2008. 70 Fed. Reg. 944 (Jan. 5, 2005). EPA's rationale for applying the same SIP submittal deadline for both attainment and nonattainment area permit programs was based on administrative convenience and not on the law.

EPA in the final rule abandons even that "compromise" solution and instead suggests that States may have until July 15, 2011 – 3 years from the effective date of this final rule – to revise and submit PSD or NSR SIPs that address PM2.5. 73 Fed. Reg. at 28341. EPA claims that the Act does not specifically address the timeframe by which States must submit SIP revisions when EPA revises PSD and NSR rules, and argues that this new deadline is consistent with the approach taken in the NSR Reform rulemaking. *Id.*

The relevant dates here, however, are those tied to the revision of the NAAQS. EPA cannot avoid these statutory deadlines by "reframing" this action into something else. EPA has already acknowledged that the deadline in 110(a)(1) applies to SIP submittals required to implement a new or revised NAAQS even where EPA is issuing rulemaking specifying what that implementation requires. *See* 52 Fed. Reg. 24672 (July 1, 1987). In that rulemaking, just as here, EPA revised the PSD and NSR rules to implement changes made to the particulate matter NAAQS. In that rulemaking EPA found that the deadline for revised PSD SIPs was governed by section 110(a)(1) and required SIP revisions within 9 months after the revision of the NAAQS. *Id.* at 24683.

EPA's reliance on the NSR Reform rulemaking as precedent for determining the appropriate deadline for this rulemaking is absurd. That rulemaking had nothing to do with the implementation of a new or revised NAAQS. Moreover, that rulemaking was to promote "flexibility" for permitted sources and was not needed or intended to protect air quality under even the existing NAAQS. *See* 67 Fed. Reg. 80186 (Dec. 31, 2002). There is no legal or policy similarity between that Reform rulemaking and the current rulemaking required to ensure permitting programs are adequate to implement the revised NAAQS.

The new deadlines for both PSD and NSR SIP revisions violate the plain language of sections 110(a)(1) and 172(b). The decision with respect to the PSD programs is made even more illegal by EPA's new decision in the final rule to abandon all safeguards that might arguably have protected air quality in areas attaining the NAAQS. With the nonattainment NSR program, EPA at least has decided that it will implement the substitute Appendix S provisions during the interim period while states revise their NSR SIPs. 73 Fed. Reg. at 28342. EPA announced in the final rule that no such substitute requirements or other safeguards need be applied in attainment areas. *Id.* at 28341.

Section 165(a)(3) plainly prohibits the construction or modification of a facility unless the owner or operator of that facility demonstrates that:

> emissions from construction or operation of that facility will not cause, or contribute to, air pollution in excess of any (A) maximum allowable increase or maximum allowable concentration for any pollutant in any area to which this part applies more than one time per year, (B) national ambient air quality standard in any air quality control region, or (C) any other applicable emission standard or standard of performance under this Act[.]

Likewise, section 165(a)(4) requires best available controls for each pollutant subject to regulation under the Act. There is no "transition period" allowed under these provisions. The requirements apply to any "major emitting facility on which construction is commenced *after the date of enactment of this part.*" CAA § 165(a) (emphasis added).

EPA had proposed that during any interim period before States revise their SIP PSD programs, States would be allowed to implement their existing PSD programs using coarse particulates ("PM10") as a surrogate for PM2.5 *provided* the States met specific requirement "to assure that the use of PM10 is protective of the PM2.5 NAAQS." 70 Fed. Reg. at 66044. The proposal required that States: (1) meet the requirements of Clean Air Act section 165(a)(3) by demonstrating that emissions from the construction or operation of the source will not cause or contribute to a violation of the PM2.5 NAAQS; and (2) include condensable PM2.5 emissions in determining whether the source is "major." 70 Fed. Reg. at 66044. EPA explained that these requirements were necessary to ensure that the PM2.5 NAAQS would be protected and that all sources subject to PSD based on PM2.5 emissions would be covered. *Id.* In particular, EPA noted that while generally, if a source emits more than 100 or 250 tons per year of PM2.5, it will also be a major source for PM10 because PM2.5 is a subset of PM10, this is only assured if States include condensable PM2.5 emissions in determining major source applicability as a condition of using PM10 as a surrogate. *Id.* Otherwise, a source could be emitting more than 100/250 tons per year of PM2.5 and these emissions would be missed in PM10 emission measurements.

EPA abandoned these safeguards in the final rule with no explanation as to how protection of the NAAQS and regulation of all major PM2.5 sources would be assured. 73 Fed. Reg. at 28341. EPA gives no explanation of how the PM2.5 NAAQS will be protected if States are no longer required to demonstrate that emissions from the construction or operation of the source will not cause or contribute to a violation of the PM2.5 NAAQS. Nor does EPA address how it can assure that the requirements of section 165 will be met without requirements to ensure all major sources of PM2.5 are subject to permitting. EPA repeats its statement that all major sources of PM2.5 are major sources of PM10 but ignores the scenario EPA itself acknowledged regarding sources with significant condensable emissions that are not captured by PM10 measurements. This is the height of arbitrary decision making.

EPA's "transition period" is not allowed under the statute. As of July 18, 2000, all SIP-approved State programs were required to implement their PSD permitting programs to address PM2.5. To the extent those programs cannot assure compliance with the statutory requirements of section 165 of the Act, EPA was obligated to institute a SIP call and implement the PSD permitting federally. EPA has arbitrarily abandoned even the minimal safeguards in its proposal, and has no legal basis for arguing that a three-year transition period can be allowed during which time permitting agencies can continue to use PM10 as a surrogate while ignoring the PM2.5 NAAQS. As such, EPA must rescind its final decision to allow States until 2011 to revise their SIP-approved PSD programs and to use PM10 as a surrogate for permitting during the interim. Because the deadline for adopting SIP PSD permitting programs has long since passed, EPA must immediately issue a SIP call for all PSD programs that do not meet the Part C requirements for implementing PM2.5. EPA must implement the federal PSD regulations in 40 CFR § 52.21 while these States revise their SIPs.

II. EPA's New Pronouncement That Sources Relying On EPA Guidance May Be "Grandfathered" And Need Not Comply With PM2.5 PSD Requirements Is Illegal And Arbitrary

The final rule unlawfully and arbitrarily includes a new pronouncement that:

> EPA will allow sources or modifications who previously submitted applications in accordance with the PM10 surrogate policy for purposes of permitting if EPA or its delegate reviewing authority subsequently determines the application was complete as submitted.

73 Fed. Reg. at 28340 (codified at 40 CFR § 52.21(i)(1)(xi)); *see also id.* at 28341 (allowing States with SIP-approved PSD programs to include similar grandfathering provisions). EPA made no mention of "grandfathering" in the proposed rule and the proposed regulatory text included no such provision. Thus, the grounds for our objections arose after the period for public comment, and the raising of those objections during the public comment period was impracticable. *See* CAA § 307(d)(7)(B). Those objections are of central relevance to the rule, *see id.*, because they go to the core requirements of PSD permits implementing the PM2.5 NAAQS – including the public's opportunity to comment on these requirements, and the consistency of these requirements with the Act and with fundamental standards of reasoned agency decision-making.

A. EPA Unlawfully and Arbitrarily Failed to Seek Public Comment On The Final Rule's Grandfathering Provision For Sources Subject To PSD Permitting

EPA unlawfully failed to present this grandfathering provision and accompanying rationale to the public for comment. Moreover, EPA's approach attempts to codify the October 23, 1997 surrogate policy without ever subjecting that policy to notice and comment rulemaking. Under Clean Air Act section 307(d), which EPA has found applicable to this proceeding, EPA must present for public comment "the major legal interpretations and policy considerations underlying the proposed rule." § 307(d)(3)(C). The same requirement would apply under the APA. 5 U.S.C. § 553. EPA therefore committed procedural violations by failing to solicit public comment on: (1) whether it is lawful or appropriate to exempt certain permit applicants from the new PSD requirements; and (2) whether the requirements in EPA's October 23, 1997 surrogate policy are sufficient to comply with the Act and excuse compliance with these new PSD requirements. *See* CAA § 307(d)(9)(D). These procedural violations meet the criteria set forth in the Act for reversal based on procedural violations. *Id.*

First, EPA's procedural dereliction is arbitrary and capricious. *See* CAA § 307(d)(9)(D)(i). There is no rationale for adding this grandfathering provision in the final rule without any public notice and comment. It not a logical outgrowth of any proposed provision or any requirement in the statute.

Second, via the present petition, petitioners have satisfied the requirements of Clean Air Act section 307(d). *See* CAA § 307(d)(9)(D)(ii).

Third, the challenged errors "were so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made." *See* CAA §§ 307(d)(8) and 307(d)(9)(D)(iii). EPA failed to seek comment on a major new exemption to the PSD rules, as well as the codification of a policy that violates the plain language of the Clean Air At and has never been subject to any formal review. The new provision added in 40 CFR § 52.21(i)(1)(xi) purports to allow a significant number of major sources to be constructed without meeting the part C requirements of Clean Air Act title I for protecting the PM2.5 NAAQS, which are already more than 10 years old. These sources will be allowed to be constructed or expanded even if they result in long-term contributions to violations of the PM2.5 NAAQS. Had EPA obeyed the law by soliciting public comment, it would have learned of the serious substantive objections detailed below – objections that address the lack of statutory basis for the challenged provisions, and those provisions' inconsistency with fundamental principles of reasoned agency decision-making.

B. EPA's Grandfathering Provision Is Unlawful and Arbitrary.

There is no authority for EPA's PSD exemption for major sources based on the date of their permit application. Section 165(a) prohibits the construction of major emitting facilities that do not comply with the applicable permitting requirements where "construction is commenced after the date of the enactment of this part . . . ." CAA § 165(a). As EPA is well aware, the term "commenced" is specifically defined in section 169(2) and requires more than merely a complete application. § 169(2) (requiring not only approval of permits but also either actual physical construction or binding agreements for construction). Congress specifically addressed the issue of grandfathering in section 168(b) and again allowed for the grandfathering of only those sources on which "construction had commenced" before the enactment of the 1997 Clean Air Act Amendments. There is no suggestion that sources who merely have complete applications are entitled to similar treatment.

EPA's only argument for allowing the grandfathering of sources with complete applications is that a similar approach was adopted in the 1987 rulemaking implementing the revisions of the PM NAAQS from the total suspended particulates indicator to PM10. 73 Fed. Reg. at 28340. The 1987 rulemaking, however, also offered no statutory basis for the exemption. EPA rationale for the exemption in 1987 was only that such exemptions were necessary out of "fairness." 52 Fed. Reg. at 24683.

Even if such claims of "fairness" could be used to trump the plain language of the statute, EPA's invocation of such fairness claims in this rulemaking is hollow and arbitrary. Here the revised NAAQS have been in effect for over ten years. There is no "surprise" or quick change in the legal requirements for permit applicants. Unlike the situation in 1987, where EPA adopted its grandfathering provision at the same time as it revised the NAAQS, there is no similar claim now that time is needed to adjust to the new national standards, which have been in effect for over ten years.

EPA suggests that using PM10 as a surrogate for PM2.5 is needed to be fair to permit applicants but even the "fairness" rationale for the 1997 surrogate policy itself has become stale. In the 1997 memo announcing the surrogate policy, EPA claimed that allowing sources to rely on PM10 as a surrogate for PM2.5 permitting was appropriate "[i]n view of the significant technical difficulties that now exist with respect to PM2.5 monitoring, emissions estimation, and modeling." Memorandum from John S. Seitz, Dir., OAQPS, to Regional Air Directors, "Interim Implementation of New Source Review Requirements for PM2.5" (Oct. 23, 1997) ("Seitz Memo"). EPA cannot reasonably claim that these technical difficulties persist now ten years later. *Cf. id.* at 2 (noting that technical difficulties would be addressed by projects underway that would be completed by 2002). The ambient monitoring program for PM2.5 is now established and has been used by EPA to make attainment designations. States likewise have relied on these monitors as well as modeling to prepare their nonattainment SIPs, which were due last April. Stack monitoring and emissions estimation, likewise, cannot be claimed as legitimate excuses as States have had to adopt enforceable reasonably available control technology requirements for stationary sources. If EPA were to persist in such claims it would undercut the approvability of any SIP that purports to include meaningful controls on stationary sources and demonstrate attainment of the PM2.5 NAAQS. EPA cannot claim that States can demonstrate attainment of the PM2.5 NAAQS in nonattainment areas while still claiming that it is impossible for these same States to demonstrate that the PM2.5 NAAQS will be protected in attainment areas. Nor can EPA claim that these technical difficulties persist when EPA is at the same time requiring permitting for all sources that do not qualify for this exemption. The excuses for failing to implement PM2.5 permitting programs ran out long ago and there is no legitimate "fairness" justification for allowing sources to continue to rely on EPA's illegal surrogate policy in the face of the plain language of the Act.

Through this illegal grandfathering announcement EPA also seeks to codify the 1997 surrogate policy which EPA has, to this point, said "do[es] not bind State and local governments and the public as a matter of law." Seitz Memo at 2. Now, through this final rule, permitting agencies in delegated States will be pushed to honor this surrogate policy and those challenging permits that fail to address PM2.5 will have this newly added regulatory provision offered as the legal defense. EPA is making this policy into law without ever having subjected it to public notice and comment.

Had EPA allowed such comment it would have been told that the policy violates numerous provisions of Clean Air Act section 165. First, as EPA admits, the use of PM10 as a surrogate may miss major sources of PM2.5 where those sources emit significant amounts of condensable PM2.5. *See* 70 Fed. Reg. at 66044. The requirement of section 165(a) requiring PSD permitting for the construction of *any* major emitting facility therefore cannot be assured through the blind use of PM10 as a surrogate for PM2.5. *See* CAA § 165(a)(3); *see also id.* § 169 (defining major emitting facility based on emissions of "any pollutant"). Second, the use of PM10 as a surrogate fails to meet the requirements of section 165(a)(3) requiring the owner or operator of the facility to demonstrate that emissions will not cause or contribute to air pollution in excess of "any" NAAQS. *See* § 165(a)(3). Third, the use of PM10 as a surrogate means that sources will not demonstrate that PM2.5, which is undeniably a "regulated pollutant," will be subject to best available control technology. *See* § 165(a)(4). Fourth, modeling using PM10 as a surrogate will fail to satisfy the class I protection requirement and the air quality impact analysis vis-à-vis PM2.5 concentrations as required by sections 165(a)(5) and (6). *See* § 165(a)(5) and (6). Finally, there is no possible claim that using PM10 as a surrogate can satisfy the requirement in section 165(a)(7) for monitoring in areas affected by the source because the surrogate policy neither requires sources to evaluate the PM2.5 effect nor establish monitoring specific to PM2.5. *See* § 165(a)(7).

Nor can states implementing delegated programs meet the overarching requirement of Clean Air Act section 110(a)(2)(C) that they have a permitting program in place that is "necessary to assure that the national ambient air quality standards are achieved . . . ." *See* § 110(a)(2)(C). If States must, according to the new rules, allow sources to be permitted based only on an analysis of PM10 emissions and impacts, they cannot reasonably claim that the permitting program assures the PM2.5 NAAQS will be protected.

This failure to protect the PM2.5 NAAQS is among the most troubling results of this grandfathering decision. The sources EPA will allow to be permitted without consideration of PM2.5 impacts could cause long-term attainment problems for many areas – problems that could easily be avoided if the correct analysis were required immediately. Accordingly, EPA must rescind its final decision grandfathering sources with complete applications that fail to meet the permitting requirements for PM2.5. EPA must also instruct States with SIP-approved programs that such grandfathering is not allowed under the Clean Air Act. EPA must require that PM2.5 be addressed in all permits for sources that did not commence construction before the effective date of the PM2.5 NAAQS.

II. Condensable PM Emissions

The final rule illegally and arbitrarily allows the states and EPA to exclude condensable particulate matter emissions ("condensables") from NSR applicability determinations and emission control requirements until January 1, 2011. As further discussed below, the proposed rule allowed no such exclusions, but instead required inclusion of condensables in applicability determinations and emission limitations as of the effective date of the rule. Thus, the rule's provisions governing condensable emissions were significantly modified after the close of the public comment period in ways that did not reflect logical outgrowths of the proposal. The grounds for our objections therefore arose after the period for public comment, and the raising of those objections during the public comment period was impracticable. *See* CAA § 307(d)(7)(B). Those objections are of central relevance to the rule, *see id.*, because they go to the core procedural and substantive validity of the provisions of the rule governing the limitation of PM2.5 emissions (of which condensables are major components) --

including the public's opportunity to comment on those provisions, and the consistency of those provisions with the Act and with fundamental standards of reasoned agency decision-making.

A. EPA Unlawfully and Arbitrarily Failed to Seek Public Comment on the Final Rule's Provisions Allowing Exclusion of Condensables From Applicability Determinations and Emission Limitations

EPA unlawfully failed to present for public comment provisions of the final rule allowing exclusion of condensables from NSR applicability determinations and emission control requirements until January 1, 2011 (collectively, "condensable exclusions"). Nor did EPA present for public comment the rationale articulated in the final rule for the condensable exclusions. Under § 307(d) (which EPA has found applicable to this proceeding), EPA must present for public comment "the major legal interpretations and policy considerations underlying the proposed rule." § 307(d)(3)(C). The same requirement would apply under the APA. 5 U.S.C. § 553. EPA's condensable exclusions and accompanying rationales are not logical outgrowths of the proposal. They did not appear in the notice or proposed rulemaking, nor did EPA otherwise present them to the public for comment. To the contrary, the notice of proposed rulemaking proposed to regulate condensables immediately. It was only in the final rule that EPA for the first time indicated that it would adopt the condensable exclusions.

For all the foregoing reasons, EPA committed a procedural violation (*see* § 307(d)(9)(D)) by failing to solicit public comment on the above-described provisions of the final rule. That procedural violation meets the criteria set forth in § 307(d)(9)(D) for reversal based on procedural violations. First, EPA's procedural dereliction is arbitrary and capricious. *See* § 307(d)(9)(D)(i). EPA has exempted from regulation significant components of PM2.5 in a manner not proposed at the time of public notice and comment.

Second, via the present petition, petitioner have satisfied the requirements of § 307(d). *See* § 307(d)(9)(D)(ii).

Third, the challenged errors "were so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made." *See* § 307(d)(8), *cited in* § 307(d)(9)(D)(iii). EPA did not merely fail to seek public comment on some minor aspect of the rules, but rather on whether to allow years of delay in regulating condensable emissions that comprise a major part of PM2.5 pollution. EPA itself found that condensables "commonly make up a significant component of PM2.5 emissions, and the failure to include them may result in adverse consequences to the environment." 70 Fed. Reg. 65984, 66039 (Nov. 1, 2005). Had EPA obeyed the law by soliciting public comment, it would have learned of the serious substantive objections detailed below -- objections that address the lack of statutory basis for the challenged exclusions, and those exclusions' inconsistency with fundamental principles of reasoned agency decision-making.

B. The Final Rule's Provisions Allowing Exclusion of Condensables from Regulation are Unlawful and Arbitrary

1. Exclusion Violates Act's PSD and NSR Provisions

EPA violated the Act's express terms in allowing the exclusion of condensables from the determination of a whether a new or modified source is a "major" source subject the Act's PSD and/or nonattainment NSR requirements. Section 302(j) of the Act defines a "major stationary source" or "major emitting facility" as one that emits or has the potential to emit, 100 tons per year or more "of any air pollutant," except as otherwise expressly provided in the Act. Other specific provisions of the Act define different tonnage thresholds for "major" sources, but do not otherwise change the above-referenced portions of §302(j) definition. *See, e.g.*, § 182 (setting lower major source thresholds for serious and above ozone nonattainment areas); § 169(1). EPA itself has found, as it must, that condensables are "a component of direct PM emissions" and "a significant component of direct PM2.5 emissions." 73 Fed. Reg. 28334. EPA has similarly defined PM10 as including condensables. Memorandum from Stephen D. Page, April 5, 2005, re: "Implementation of New Source Review Requirements in PM2.5 Nonattainment Areas" at 3 n.3. Because PM10 and PM2.5 are indisputably "pollutants" (§302(g)), EPA has no authority to exclude condensables in determining whether a source is "major" for those pollutants for NSR purposes. A source is "major" for NSR/PSD purposes if it has actual or potential emissions of 100 tpy or more of any "air pollutant" -- not just a portion of the air pollutant. Likewise, the Act's provisions requiring permits for modification of major sources are triggered by changes that increase "the amount of any air pollutant emitted" by such source, a provision that again cannot be read as meaning only a "part of the amount" emitted. *See* §§ 111(a)(4), 169(2)(C), 171(4).

EPA also has no power to allow permitting authorities to exclude condensables in establishing enforceable emission limits for PM10 or PM2.5. A PSD permit may not be issued unless, among other things, the source shows that "emissions from construction or operation" of the source will not cause or contribute to air pollution in excess of any increment, any NAAQS, or any applicable emission standard or limitation. § 165(a)(3). If "emissions from…operation" of the source will include condensables, the source must show that those emissions will not cause or contribute to violations of increments, NAAQS, and emission limits: the source cannot pretend that the condensable emissions are not there, and EPA cannot lawfully or rationally allow the source or permitting authority to do so. Likewise, a PSD permit must subject the source to the "best available control technology for each pollutant subject to regulation under [the Act] emitted from, or which results from, such facility." § 165(a)(4). PM-10 and PM2.5 are indisputably pollutants subject to regulation under the Act, and condensables are indisputably components of those pollutants: Thus condensables must be subjected to BACT emission limits.

Further, the Act's nonattainment NSR provisions require new and modified major sources to achieve the "lowest achievable emission rate," defined as the more stringent of the most stringent emission limitation in a SIP (unless the source shows such limitations are not achievable) or achieved in practice for the class or category of source. §§ 171(3), 173. There is no language in these provisions allowing states or EPA to ignore condensables (or any other pollutant components) in determining the most stringent emission limitations, nor would such a reading be consistent with the statutory language and purpose. *See also* § 302(j) (defining "emission limitation" as a requirement which limits emissions "of air pollutants" – not fractions or components of air pollutants). Moreover, EPA concedes that some states do in fact limit condensable emissions, and LAER for PM sources would plainly have to ensure emission limits at least as stringent. The nonattainment NSR provisions also require offsets sufficient to ensure "that the total tonnage of increased emissions of the air pollutant from the new or modified source shall be offset by an equal or greater reduction . . . in the actual emissions of such air pollutant." § 173(c)(1). Again, the statute does not limit offsets to only a fraction of the relevant air pollutant, but rather requires an offset in the "actual emissions," which necessarily includes the condensable fraction of such emissions. Moreover, the offsets must be sufficient to ensure reasonable further progress (RFP), and RFP cannot be assured without accounting for all emissions, including the condensable portion.

2. Act Precludes 3-Year Phase in Period

The Act does not allow EPA to adopt a 3-year phase in period for including condensables in the applicability and compliance determinations. EPA has no authority delay or defer NSR and PSD requirements, or selectively waive portions thereof. The 3-year phase in period is far beyond the deadlines for states to have in place enforceable SIPs to implement the PM-10 and PM2.5 standards. CAA § 110(a)(1) (requiring states to submit SIPs within 3 years of NAAQS revision – *i.e.* by 2000 for the 1997 PM NAAQS revision – to implement the new NAAQS); § 172(b) (requiring submittal of nonattainment SIPs within 3 years of nonattainment designations); § 189 (setting deadlines for PM10 SIP submittals). As EPA itself has noted, the Act's NSR provisions apply "[a]s of the date areas are designated attainment or nonattainment" under a standard." *See* 68 Fed. Reg. 32802, 32843 (2003).

The phase in period also undermines and cannot be reconciled with the requirement for expeditious attainment. CAA §§ 172(a)(2)(A) and 188(c). EPA admits that most PM2.5 emissions may be in a condensable state. Based on an analysis of particle size distribution, EPA estimated that "about 78 percent of the total PM2.5 emissions would be condensable PM." 70 Fed. Reg. at 66051. EPA adds that because controls to date have reduced the filterable portion of PM2.5 emissions but not the condensable portion, "the significance of the condensable emissions as a proportion of direct PM2.5 emissions may be greater than indicated." *Id.* EPA further acknowledges that certain areas will need to address direct PM2.5 emissions from stationary sources in order to demonstrate attainment and that measurements and controls that only address the filterable portion of these direct emissions "would limit the control measures available for developing cost effective strategies to achieve attainment of the PM2.5 NAAQS." *Id.* at

66049. Even if EPA had not made any of these admissions on the importance of controlling condensable PM2.5 emissions for attainment, there can be no argument that allowing States to ignore controls on any portion of stationary source emissions violates the overriding Clean Air Act requirement for expeditious attainment.

The decision to allow States until 2011 to establish emission limits for condensable PM is particularly astounding since it pushes control beyond the outside attainment deadline of 2010, thereby illegally flouting the statutory mandate that implementation plans provide for attainment as expeditiously as practicable, and no later than the outside attainment date. CAA §§ 172(a)(2)(A), (c)(1), (c)(6), 188(c), and 189. *See also* § 173(a)(1)(A).

4. EPA Cannot Lawfully or Rationally Establish Presumptions That SIPs and Permits Exclude Condensables

EPA states that it will not revisit applicability determinations made prior to the end of the transition period insofar as the quantity of condensable PM emissions are concerned "unless the applicable implementation plan clearly required consideration of condensable PM." 73 Fed. Reg. at 28335. As noted above, condensable PM is by definition a part of the pollutants PM10 and PM2.5: EPA cannot lawfully or rationally establish an additional requirement that SIPs "clearly require consideration of condensable PM" emissions before such emissions must be included in applicability determinations.

EPA also has no authority to "interpret PM emissions limitations in existing permits or permits issued during the transition period as not requiring quantification of condensable PM2.5 for compliance purposes unless such a requirement was clearly specified in the permit conditions or the applicable implementation plan." 73 Fed. Reg. at 28335. Such a policy is unlawful for all the above-stated reasons. It also illegally and arbitrarily establishes an "interpretation" of PM emission limitations in already-issued permits that does not necessarily reflect either the applicable SIP provisions or the intent of the permitting authority. For example, prior to this rule, a permitting authority could have justifiably assumed, consistent with the Act and prior EPA guidance, that an emission limit for PM necessarily encompassed condensables. Or the permitting authority might have expressly indicated in a public notice, fact sheet or response to comments, that it intended a permit limit for PM to encompass condensables, even though the final permit did not expressly so state. EPA cannot retroactively change such permits and permitting proceedings without acting arbitrarily and without flouting the public notice and comment rights of affected persons – who could not have know at the time of permitting that EPA intended to misread the permits as excluding condensables.

5. EPA's Justification for the Condensable Exclusion is Arbitrary and Capricious

As noted above, EPA admits that condensable PM likely represents the bulk of direct PM2.5 emissions from stationary sources and that controls on these sources may be important for several areas to attain the PM2.5 NAAQS. EPA also admits that methods exist for measuring condensable PM and that States have established emission limits or emission testing requirements that include the measurement of condensable PM. 70 Fed. Reg. at 66050; 72 Fed. Reg. at 20652; 73 Fed. Reg. at 28334-35. Specifically, EPA describes the use of Conditional Method 40 with EPA method 202 as the most reliable measurement of total direct PM2.5 and added that "Conditional Method 40 has been used at several facilities in the U.S. and the hardware required to implement this method has been readily available since the mid-1980's." 70 Fed. Reg. at 66050. EPA is also aware through comments on the proposed rule that EPA Method 202 has been widely used to measure condensable PM including in recent permits issued to the Longview, Thoroughbred, Oak Creek and Weston coal-fired EGUs. Comments Prepared by Clean Air Task Force, Earthjustice and Environmental Defense on Proposed Rule to Implement the Fine Particle NAAQS, at 32 (Jan. 31, 2006) [Available in Docket at EPA-HQ-OAR-2003-0062-0108.1]. These comments also describe the various controls available and already in use to reduce condensable PM emissions, including scrubbers, wet electrostatic precipitators, and sorbent injection. *Id.* Finally, EPA admits that the information on condensable PM emissions is adequate for use in inventories and attainment demonstrations. 72 Fed. Reg. at 20652.

Given this record, there is no rational basis for claiming that condensable PM cannot be accounted for in applicability and compliance determinations today. Nor does EPA attempt to provide a basis. EPA only cites generalized "concerns" raised by commenters. 74 Fed. Reg. at 28335. EPA fails to explain why these concerns are of such credibility and magnitude as to justify ignoring condensable emissions entirely until 2011.

States face many uncertainties in quantifying and measuring emissions, and yet they still must act in accordance with the deadlines and requirements of the Clean Air Act. EPA can offer no explanation as to why the particular issues surrounding measurement of condensable PM rise to some new level of difficulty that precludes moving forward with the best available information and tools. Even if EPA could waive inclusion of condensables in applicability and compliance determinations, it has offered no rational basis for doing so. As such, the adoption of a transition period is arbitrary and capricious and must be removed from the final rule.

III. Interpollutant Trading

The final rule unlawfully and arbitrarily includes preferred interpollutant trading ratios to facilitate the interpollutant trading of emissions offsets under the NSR program. 73 Fed. Reg. at 28339. The proposed rule suggested that EPA would allow states to implement interpollutant offsets based on air quality modeling showing that such trades would produce an air quality benefit. 70 Fed. Reg. at 66043. However, in the final rule EPA dramatically changed course and announced that states could simply incorporate into their SIPs "preferred interpollutant trading ratios" developed by EPA with no public input. Thus, the rule's treatment of interpollutant offsets was significantly modified after the close of the public comment period in ways that did not reflect logical outgrowths of the proposal. The grounds for our objections therefore arose after the period for public comment, and the raising of those objections during the public comment period was impracticable. *See* CAA § 307(d)(7)(B). Those objections are of central relevance to the rule, *see id.*, because they go to the core requirements of how stationary sources will comply with the Act's offset provisions – including the public's opportunity to comment on those provisions, and the consistency of those provisions with the Act and with fundamental standards of reasoned agency decision-making.

A. EPA Unlawfully and Arbitrarily Failed to Seek Public Comment on the Final Rule's Provisions Establishing Preferred Interpollutant Trading Ratios.

EPA unlawfully failed to present for public comment the agency's adoption of preferred interpollutant trading ratios for emissions offsets. Nor did EPA present for public comment the rationale articulated in the final rule for establishing such ratios and for selecting the specific ratios that EPA chose. Under Clean Air Act section 307(d), which EPA has found applicable to this proceeding, EPA must present for public comment "the major legal interpretations and policy considerations underlying the proposed rule." CAA § 307(d)(3)(C). The same requirement would apply under the APA. 5 U.S.C. § 553. EPA's adoption of preferred interpollutant trading ratios and the specific ratios selected are not logical outgrowths of the proposal. These aspects of the final rule did not appear in the notice or proposed rulemaking, nor did EPA otherwise present them to the public for comment.[1] Not until the final rule did EPA provide any indication that it was even considering establishing preferred ratios for interpollutant offsets. EPA therefore committed a procedural violation by failing to solicit public comment on this new approach to interpollutant offsets. *See* § 307(d)(9)(D).

[1] In proposing to allow interpollutant trading, EPA suggested two alternative frameworks under which states could regulate such trades:

> Under one approach, a State would develop its own interprecursor trading rule for inclusion in its SIP, based on a modeling demonstration for a specific nonattainment area. The EPA would review a State interprecursor trading rule during the SIP approval process. Once approved, the State could follow this approach on all future NSR permits issued. Another approach would be to review individual trades as part of the major NSR permitting process. The EPA and the public would have an opportunity to comment on whether the modeling or other technical evidence presented by a particular State is sufficient to support interprecursor offsets for that specific permit application. Under either approach, a State could not allow interprecursor trading without EPA approval.

70 Fed. Reg. at 66043. Each of these alternatives presupposes that the implementation of interpollutant emissions offsets will rely on SIP- or source-specific technical analyses demonstrating the efficacy of such trades. EPA did not even seek comment on the possibility of preferred trading ratios, much less the specific ratios the agency ultimately selected: "The EPA is requesting comment on whether, States should be required to demonstrate the adequacy of offset ratio(s) using modeling as part of a State rule, in demonstrations for specific nonattainment areas, and/or on a permit-by-permit basis, and/or on some other basis. *Id.*

That procedural violation meets the criteria set forth in the Act for reversal based on procedural violations. *Id.* First, EPA's procedural dereliction is arbitrary and capricious. *See* § 307(d)(9)(D)(i). After proposing to allow interpollutant offsets based on SIP or source-specific technical analyses, in the final rule EPA has announced what is essentially a "one-size fits all" approach – developed without any public comment – that completely ignores the real world implications of interpollutant emissions offsets in order to facilitate such trades. Second, via the present petition, petitioners have satisfied the requirements of Clean Air Act section 307(d). *See* § 307(d)(9)(D)(ii). Third, the challenged errors "were so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made." *See* §§ 307(d)(8) and 307(d)(9)(D)(iii). EPA did not merely fail to seek public comment on some minor aspect of the rules, but rather on an approach that completely undermines the fundamental basis of the emissions offset requirement for new and modified sources in nonattainment areas – that such offsets will prevent additional degradation of air quality. Had EPA obeyed the law by soliciting public comment, it would have learned of the serious substantive objections detailed below – objections that address the lack of statutory basis for the challenged provisions, and those provisions' inconsistency with fundamental principles of reasoned agency decision-making.

B. EPA's Preferred Interpollutant Trading Ratios Are Unlawful and Arbitrary.

1. The Clean Air Act Does Not Permit Interpollutant Offset Trading.

The plain language of the Clean Air Act forbids interpollutant emissions offsets. Section 173(c)(1) of the Act provides:

> The owner or operator of a new or modified major stationary source may comply with any offset requirement in effect under this part for increased emissions of any air pollutant only by obtaining *emission reductions of such air pollutant* from the same source or other sources in the same nonattainment area, except that the State may allow the owner or operator of a source to obtain *such emission reductions* in another nonattainment area if (A) the other area has an equal or higher nonattainment classification than the area in which the source is located and (B) emissions from such other area contribute to a violation of the national ambient air quality standard in the nonattainment area in which the source is located.

CAA § 173(c)(1) (emphasis added). In requiring that increases in the emissions of one air pollutant be offset by reductions in the emissions "of such air pollutant," Congress has clearly foreclosed the option of offsetting additional emissions of one pollutant with reductions in emissions of any other pollutant. The Act simply does not permit the level of flexibility that EPA is attempting to inject into this process.

The Act's definition of "air pollutant," which incorporates precursors, § 302(g), does not disturb the plain language of section 173(c)(1), because the Act specifically provides for how precursors are to be treated for purposes of compliance with offset requirements. Thus, subpart 2 of Part D of the Act establishes specific ratios for offsets of VOCs, an ozone precursor, in ozone nonattainment areas. *See, e.g.*, § 182(e)(1) (requiring that, in extreme nonattainment areas "the ratio of total emission reductions of VOCs to total increased emissions of such air pollutant shall be at least 1.5 to 1," or less under certain conditions). Congress' approach to ozone precursors in the offset provisions of subpart 2 demonstrates that Congress intended for EPA to treat pollutants and their precursors alike, maintaining in each instance the basic requirement that increases in emissions of one pollutant (or precursor) must be offset with reductions in emissions of that same pollutant (or precursor).

Trading at ratios of less than 1-to-1 is further prohibited by section 173(c)(1), which requires that "the total tonnage of increased emissions of the air pollutant from the new or modified source shall be offset *by an equal or greater reduction*, as applicable, in the actual emissions of such air pollutant from the same or other sources in the area" (emphasis added). Thus, any offset must assure a total tonnage reduction equal to or greater than the total tonnage of increased emissions of the air pollutant. EPA's preferred ratios violate this mandate by allowing increased emissions of NOx and SO2 to be offset by lesser reductions in PM2.5 emissions. For example, EPA's rule would allow a 200 ton increase in NOx emissions to be offsets by a 1 ton decrease in PM2.5 emissions.

2. EPA's Justification for Its Preferred Interpollutant Trading Ratios is Arbitrary and Capricious.

EPA's preferred trading ratios also suffer from glaring deficiencies and logical gaps that reflect arbitrary and capricious decisionmaking.

In the final rule, EPA conceded that important uncertainties surrounded the extent to which the impacts of direct PM2.5 and PM2.5 precursor emissions vary with distance and time. Yet, rather than recognize that such uncertainty precluded the setting of non-arbitrary "preferred" ratios, EPA took the exact opposite tack. EPA chose to set uniform preferred ratio and allow states to adopt them into SIPs without any additional analysis. 73 Fed. Reg. at 28340. Moreover, EPA inexplicably and irrationally cited as support for its uniform trading ratios the fact that "[t]here is considerable uncertainty about the relationship of precursor and direct PM2.5 emissions to localized ambient PM2.5 concentration both spatially and temporally." *Id.* There is no logic whatsoever to EPA's assertion that by encouraging states to adopt the agency's "one size fits all" approach to interpollutant offsets the agency was "opt[ing] for program flexibility." *Id.*

EPA compounded the arbitrariness of its approach to interpollutant offsets by failing to complete any air quality modeling to ascertain the real world impacts of its preferred ratios. The only analysis of this complex issue contained in the docket is a memo from a member of EPA's Air Quality Modeling Group that summarizes the results of response surface modeling of interpollutant offsets. Adding an additional level of abstraction to the analysis, EPA's response surface modeling provides only an estimate of the results that EPA's Community Multi-scale Air Quality modeling program would provide – it is a model of a model. This approach is a complete about-face from EPA's position in the proposed rule that interpollutant offsets are only permissible when the air quality benefits have been assured through modeling or source-specific technical analysis.

Even the "meta-modeling" that EPA performed demonstrates the irrationality of a one size fits all approach to interpollutant trading. For example, EPA only established ratios for NOx to primary PM2.5 by eliminating from its analysis entirely "those counties predicted to have an issue with NOx disbenefits." Memorandum from Tyler J. Fox, Air Quality Modeling Group at 13 (July 23, 2007). Given that EPA's own analysis thus demonstrated the infeasibility of uniform trading ratios, it is wholly irrational for EPA to nevertheless allow states to incorporate, without any further analysis, EPA's preferred ratios into their SIPs to govern future emissions offsets, even in areas likely to experience the NOx disbenefits that EPA excluded from its study.

Moreover, the final rule contains an internal inconsistency with regard to the feasibility of implementing interpollutant offsets. EPA announced its preferred ratios for trades between primary PM2.5 and NOx with a caveat that they are based on an assumption that there will also be "a local demonstration that NOx reductions are beneficial in reducing PM2.5 concentrations (*i.e.*, no disbenefits from NOx reductions as noted previously)." 73 Fed. Reg. at 28339. Similarly, EPA's explanation of its preferred ratio for trades between primary PM2.5 and SO2 notes that the agency "recognize[s] there is spatial variability here between urban and regionally located sources of these pollutants that can be addressed through a local demonstration to determine an area-specific relationship, as appropriate." *Id.* However, EPA's approach allows interpollutant trading to occur in the absence of such locally focused analyses. It is impossible to reconcile the prerequisite for a local impact analysis with EPA's decision to allow states to adopt and implement its preferred ratios with no additional analysis.[2]

EPA's preferred ratios are further arbitrary because they are based on modeling of only nine urban areas, when there are nearly 40 PM2.5 nonattainment areas. EPA does not show that that these nine areas are representative, either of all PM2.5 nonattainment areas or of those within the East or West.

Aside from being unsupported by the agency's own analysis, EPA's preferred interpollutant ratios rely on a fundamentally mistaken assumption: reductions in

[2] In the Response to Comment document for the final rule, EPA asserts that "the existing NA NSR regulations require a demonstration that proposed offsets, in combination with a project's emissions increase, will result in a net air quality benefit, which may require modeling in the case of direct PM emissions. These existing requirements apply to direct PM2.5 emissions offsets as they have in the past to offsets for other indicators of PM." EPA, *Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers in Diameter (PM2.5): Response to Comments*, at 75 (2008). However, this statement leaves unclear whether EPA intends to apply the net air quality benefit demonstration requirement to interpollutant offsets allowed by a SIP.

precursors can offset the impact of additional emissions of primary PM2.5 in the vicinity of the new or modified direct PM2.5 source. On the contrary, because it takes time for precursor emissions to transform into PM2.5, while large sources of direct PM2.5 emissions have their greatest impact in the immediately adjacent area, reductions in PM2.5 precursors would have a much more diffuse impact than reductions in direct PM2.5.[3] For example, EPA's approach will allow direct PM2.5 emissions increases that cause a NAAQS violation at a monitor located near a new or modified source to be offset by reductions in precursors from a source too distant to avoid that NAAQS violation. Moreover, while the Act allows sources to obtain emissions reductions from other nonattainment areas that contribute to nonattainment in the vicinity of the source, § 173(c)(1), coupling this provision with EPA's interpollutant trading regime leads to the highly unrealistic assumption that all sources of PM2.5 precursors contribute equally to downwind PM2.5 concentrations.

In sum, EPA's decision to adopt preferred interpollutant trading ratios for PM2.5 offsets is arbitrary and capricious. The numerous flaws in EPA's treatment of this issue require that the agency's preferred ratios be eliminated from the final rule.

IV. Petition for Stay

Petitioners further request that EPA stay those portions of the final rule (including the preamble) that: a) allow applicants for PSD permits to avoid demonstrating that their emissions will not cause or contribute to a violation of the PM2.5 NAAQS, and allowing them instead to merely show compliance with the PM10 NAAQS; b) allow sources that applied for PSD permits prior to the effective date of the rule to be permitted under EPA's 1997 PM10 surrogate policy rather than demonstrating compliance with the PM2.5 NAAQS; and c) allow the exclusion of condensables from NSR/PSD applicability and compliance determinations. A stay in these provisions is warranted to prevent irreparable harm to the members of the public (including petitioners' members) from the construction and operation of major sources of PM2.5 pollution without the safeguards mandated by Congress in the Act. That harm is presented not only from threatened exposure to increased levels of dangerous PM2.5 pollution, but also from implementation of rules and policies on which petitioners and their members had no opportunity to comment.

The provisions that petitioners seek to stay would allow numerous major sources to be permitted without any showing that such sources will not cause or contribute to PM2.5 NAAQS violations in areas where petitioners' members live, work and recreate. *See* EPA's Advanced Notice of Proposed Rulemaking "Regulating Greenhouse Gas Emissions under the Clean Air Act" at 479 (noting that EPA, state and local permitting authorities issue approximately 200 to 300 PSD permits nationally every year) (available at http://www.epa.gov/climatechange/emissions/downloads/ANPRPreamble5.pdf). The condensable exclusions will also allow substantial PM2.5 emissions to go unregulated,

[3] *See also* Robert E. Yuhnke, et al., Comments on Proposed Interim Motor Vehicle Emissions Budgets for South Coast Air Basin, at § II.A (discussing elevated PM2.5 concentrations in near-source environment) (Attached).

threatening exposure of petitioners' members to much higher PM2.5 emissions than allowed by the Act. As documented in EPA's most recent review of the PM NAAQS, PM2.5 pollution is linked to tens of thousands of premature deaths annually, and is a major contributor to visibility impairment in many parts of the nation. EPA has repeatedly found that the PM10 NAAQS do not adequately protect against these effects, and (as documented above) that PM10 is not an accurate surrogate for fine particles or their adverse health and welfare impacts.

The threat to petitioners' members and the public is compounded by the fact that sources permitted under these illegal policies will likely emit PM2.5 pollution long after EPA's "transition" period ends. A new coal-fired power plant typically remains in operation for at least 30 years. *See, e.g.*, National Energy Technology Laboratory, U.S. Department of Energy, *Cost and Performance Baseline for Fossil Energy Plants* at 51 (2007) (available at http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf. Dozens of such plants are currently seeking permits, and some have submitted applications already found complete. *See* http://www.sierraclub.org/environmentallaw/coal/plantlist.asp. Petitioners' members and many others will be exposed to emissions from these plants for decades. There is accordingly an urgent need to ensure that emission limits adequate to protect the NAAQS are imposed *before* these plants are built, and that those limits address all components of PM2.5 – not just a fraction.

In contrast to the irreparable harm faced by petitioners' members and the public, there is no comparable harm to the regulated sources. Those sources have know for more than a decade that compliance with the PM2.5 NAAQS would be required, and EPA's notice of proposed rulemaking specifically required compliance with that NAAQS.

For all the foregoing reasons, petitioners ask EPA to stay the above-referenced provisions of the final rule. We further ask that EPA respond to this stay request within 30 days of the date of this petition.

DATED: July 15, 2008

/s/ *Paul R. Cort*

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Weyman Lee, P.E.
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Feb. 6, 2009

Dear Mr. Lee:

The East Bay Chapter of the California Native Plant Society (EBCNPS) appreciates the opportunity to offer comment on the Bay Area Air Quality Management District's proposed PSD Permit for the Russell City Energy Center. The California Native Plant Society is a non-profit organization of more than 10,000 laypersons, professional botanists, and academics in 32 chapters throughout California. The Society's mission is to increase the understanding and appreciation of California's native plants and to preserve them in their natural habitat through scientific activities, education, and conservation.

With respect to the PSD permit, EBCNPS is particularly interested in the air quality impacts to sensitive natural resources. The proposed Russell City Energy Center has been an extremely complicated project extending over 8 years, involving serious legal disputes and input from community organizations, multiple agencies at every level of government from the local to the federal, and many members of the public. The Statement of Basis has surprisingly little to say about impacts to the adjacent wetlands. Therefore, we find it necessary to address various contextual aspects of the project as well as offering specific comments and questions on the Statement of Basis for the PSD permit. We also comment on the process itself and whether the public's legal right to know, to comment, and to receive responses to comment has been duly served. After all, this project, should it be approved and built, will be the 5th largest point source for air emissions in the entire Bay Area.

The Scientific Context: Quality of Analysis

EBCNPS came late to the issue last year not having received public notice from any of the agencies. However, having reviewed the public documents, consultants' reports, and letters from agencies, we are stunned at the lack of consideration given to the impacts of RCEC to these important wetlands. The salt marsh community is listed in the California Natural Diversity Database as sensitive, containing special status native plant species and providing habitat for many different state and federally listed birds and mammals.

Attachment 1 lists the Special Status Plant Species Potentially Occurring in the RCEC project area (original site). This list was compiled by the consultant for the original

RCEC site on the basis of just one survey conducted in the spring. Because the survey did not follow accepted protocols which call for multiple site visits throughout the blooming season, the consultant missed a population of *Centromadia parryi ssp. congdonii* (formerly *Hemizonia parryi ssp. congdonii*) at the vernal pool at the project site. The consultant also incorrectly indicated that there would be no habitat for this CNPS List 1 B plant in the project area, as indicated in the attached Table. The consultant's report does not indicate whether the Hayward Regional Shoreline was surveyed. Presumably the consultant also did not survey the serpentine outcrops in the hills to the east where there would be maximum annual impacts from NOx and where there are known rare plant populations of *Streptanthus albidus var. peramoenus*. Nitrogen deposition on serpentine can have indirect negative impacts to special status plant species (see below, Lessons of Metcalf).

Thus far, there has been no analysis of air quality impacts to the special status wildlife in the salt marsh, mud flats, and other wetland communities at the Hayward Regional Shoreline. These wetlands play a critical role in the ecological health of the area. They are the "kidneys" that filter the Bay waters, removing toxic compounds, including heavy metals. These compounds can be stored in plant tissues and in sediment, and they can also bioaccumulate and move up food chains to affect wildlife. The wetlands are important feeding grounds and stopover points in the Pacific Flyway for migratory waterfowl, earning the Hayward Regional Shoreline designation as an Important Bird Area. Because BAAQMD is charged with showing that a major industrial project such as RCEC will have no significant impacts from air emissions to the sensitive wetlands communities adjacent to the shoreline, the Statement of Basis must include solid evidence of analysis and conclusive evidence that significant impacts will not occur before it can grant a PSD permit. This is a very tall order indeed given the size and nature of the project and the proximity of the wetlands. This task is even further magnified by the decision to allow emission offsets for NO2 and POC.

The Science Behind BAAQMD's Conclusions

In order for the public to be reassured (and for BAAQMD to prove) that the agency has done its job of protecting sensitive receptors (including human beings and sensitive natural resources) from the impacts of air emissions from RCEC, there has to be some connection made between conclusions drawn from computer modeling and the real world context where impacts would be made. The Statement of Basis fails to make this connection. While there are many pages of tables that describe various emissions, toxic compounds, and limits on emissions, the only graphic in the entire document that indicates a connection between the results of the model and the actual sites is an aerial photo in Appendix E on page 158 (Figure 1.Location of project maximum impacts). It appears again in Appendix C, Page 89. There is no scale to indicate distance nor is the photo labeled to indicate sensitive receptors in the adjacent wetlands or locations of groups of human receptors such as schools, colleges, residences, or businesses. The only reference geographic location mentioned is the Fremont- Chapel Way Monitoring Station, 18.3 km away from the site, and the source of background modeling data used to simulate the air at the proposed plant site. There is little opportunity for the reader to examine the assumptions made regarding the models nor any discussion of the interpretation made from these models. And, of critical importance there are no graphics that show the area covered by the model for the toxic emissions.

Since much of the data for these tables is derived from the applicant's operation of other power plants, there is no indication of potential bias or inaccuracy in this data. This data forms the input to the computer models that are then used to describe the levels of emissions and whether they meet established standards and whether they have significant impacts. There are also no statements regarding the statistical limits of confidence that would apply to the results of the models themselves. From a scientific point of view, conclusions drawn between the modeling and the real world of impacts are highly suspect in terms of their accuracy and predictability.

And when no analysis is even attempted, as is the case with nitrogen deposition and its indirect impacts upon sensitive plant communities through fertilization of invasive grass species such as *Spartina alterniflora* or *Lolium multiflorum*, one cannot draw the conclusion of no significant impact from nitrogen emissions. Instead BAAQMD states that "Maximum project NO2, CO, SO@, and PM10 concentrations would be less than all of the national primary and secondary ambient air quality standards which are designed to protect the public welfare from any known or anticipated effects, including plant damage. Therefore, the facility's impact on soils and vegetation would be insignificant."(Appendix E, Page 160). Given BAAQMD's prior experience with the Metcalf Energy Center, it is clear that the District chose not to address *any known or anticipated effects* of nitrogen deposition (see below, Lessons of Metcalf).

Similarly, in the case of the toxic emissions impacts, no attempt was made to look at sensitive receptors such as small mammals and birds in the adjacent marsh. Assumptions about levels of impact to human bodies from toxic emissions cannot be applied to small mammals and birds. There is a well known relationship between body mass and metabolic rate—the larger the body mass the slower the metabolic rate. Small mammals and birds respire and metabolize at a much higher rate than human beings, and their life spans are also much shorter (two traits that make them useful for lab testing of toxic and carcinogenic compounds). Thus, one cannot conclude that the federally endangered Salt marsh harvest mice or any of the birds utilizing the wetlands are safe from toxic impacts of air emissions even if models show no effects to humans. In addition, since the emissions from the power plant will deposit on plants that form the diet of some of these animals, there is a second route of exposure. There is also the possibility that some toxic compounds will bioaccumulate—a phenomenon never mentioned in the Statement of Basis.

With respect to the chronic exposure modeling, the assumption is made that chronic exposure to the toxic compounds will last only one year (Appendix D, Page 151). The time frame makes no sense. Presumably the power plant would be in operation for perhaps decades-- certainly more than a year. The toxic compounds associated with the operation of the plant therefore continue to be emitted over the lifetime of the facility. Therefore, the results of the chronic toxicity models are completely invalid based on underreporting. Finally, the toxic modeling does not include background levels of carcinogenic or toxic compounds from other sources. Therefore, the true body burden or critical load of these compounds in nearby sensitive receptors is never expressed.

Lessons from Metcalf

The Statement of Basis refers often to information and data taken from the operation of the Metcalf Energy Center, another Calpine power plant near San Jose. Therefore, it seems fair and appropriate to refer to the case of Metcalf in addressing how differently the impacts to sensitive natural resources have been handled with respect to RCEC. The CEC held a public workshop on 10/27/99 in the San Jose area attended by representatives of the Santa Clara Chapter of the California Native Plant Society, Calpine, the US Fish and Wildlife Service, and others in the San Jose area. The purpose of the meeting was to address the biological impacts of air emissions from MEC—among them, nitrogen deposition and its fertilizing effects on non-native grasses on nearby serpentine soils. The concerns were that the non-native grasses would out compete the native larval hostplant for the federally endangered Bay Checkerspot Butterfly. As a result of these and other meetings, the air emissions were mitigated through acquisition of 100 acres of land on Coyote Ridge managed by the Silicon Valley Land Conservancy.

By contrast, no public meeting was ever held to review the air quality impacts of RCEC to the sensitive wetlands at the Hayward Regional Shoreline despite the fact that there are numerous federally and state listed species at this site and that the proposed RCEC site is less than 1500 feet from the wetlands. Although initially, a request for a formal Biological Opinion was initiated by the East Bay Regional Park District which sought information on the various impacts of RCEC, including air quality impacts to listed plant and animal species (see attachment 2), Calpine eventually withdrew from the site and moved the proposed plant to a new paved site some 1300 feet to the northwest.

Since the CEC refused to re-open the environmental review of the project, despite the East Bay Regional Park District's repeated request for information on air quality impacts (see attachment 3), and because BAAQMD's Statement of Basis still does not address these, there has never been an analysis of the air quality impacts to the sensitive natural resources at the Hayward Shoreline. Accordingly, there are also no mitigations for the project's emissions.

Analysis of Secondary Growth

The Statement of Basis concludes on page 16 that the project will not cause any secondary growth. Yet it already has. The local water treatment plant was expanded to handle the anticipated amount of cooling water that the original plant design called for.

Often once a high impact project has been approved in an area, it paves the way for other similar projects. The Eastshore power plant was once such example, though it has since been denied.

BACT Cost-effectiveness Data

The inclusion of Appendix F, entitled BACT Cost-effectiveness Data, is a bewildering addition to the Statement of Basis. First, the appendix consists of portions of two reports addressing a cost analysis of NOx Control Alternatives and a BACT analysis. These reports are 10 and 9 years old respectively. This information is unacceptably out of date. Second, the appendix consists of barely readable excerpts pulled from the reports with no accompanying explanation. As such the information is meaningless.

The Procedural Context

The Lack of CEQA Equivalence

Although the process by which the California Energy Commission regulates power plant siting is supposed to be equivalent to the CEQA process, there are many ways in which it is a poor substitute. Usually and as a matter of course, the lead agency is located in the vicinity where a project is proposed. This facilitates the important role of public participation. While the CEC has the option of conducting local meetings to gain public response (see above, Lessons from Metcalf), CEC has conducted its meetings in Sacramento far from Hayward where RCEC would be built, placing a burden on members of the public who cannot get away from work to attend hearings and offer comment.

In addition, as lead agency, the CEC is supposed to coordinate the input from regulatory agencies and be sure that agencies are informed of meetings and deadlines. CEC failed to notice the California Department of Fish and Game regarding its meeting to hear the applicant's request for a second extension. When a CDFG biologist learned of the hearing and attempted to speak, she was cut off, although CDFG has regulatory standing by virtue of the state listed plants and animals at the Hayward Shoreline. Nor has the CEC responded to a letter from the East Bay Regional Park District (see attachment 1) requesting information on various impacts. The CEC has also failed to respond in writing to written comments from the public submitted during the allowed comment period, an important requirement of CEQA.

Access and transparency

Until the recent decision by the EPA appeals board to require BAAQMD to re-hear the PSD permit, the Air District has appeared to have been hostile to public comment. Once the noticing violation came to light, the District should have granted its mistake and re-opened the public record to comment. Instead, the District chose an adversarial route and attempted to prevent further input. This state of affairs does damage to the District's credibility as a regulatory agency.

Now that we have the opportunity to comment on the amassed materials underlying the proposed decision to grant the PSD permit, it's possible to analyze the quality of the information provided to the public and whether it assists or prevents understanding. BAAQMD's Statement of Basis for the proposed PSD permit is an example of a document that unnecessarily challenges public understanding. It is poorly organized so that the reader does not know whether information is current or part of a previous document that no longer fully pertains. There are passages of language that have been stricken from the record so that the reader encounters random sentences with lines through them without any explanation. The reader must hunt throughout the document to try to compare information in order to understand the basis for various decisions. In part, this problem arises from the fact that, once the RCEC changed sites and fundamental aspects of its design, it should have been considered a new project and been required to start at the beginning of the process rather than being granted several extensions.

Other confusing aspects of the Statement of Basis document include the way that technical information is displayed and expressed. Units of measure and their abbreviations on tables are not defined, or the units are switched from mass to volume or their time frames are changed without corresponding changes in units. Sometimes there is no agreement between what emissions are per hour and what they would be per day if one multiplies the one-hour rates by 24. Tables with similar information appearing throughout the document do not consistently bear the footnotes that explain critical aspects of the information and assumptions made. For instance in the beginning of the document Table 6 on page 15, Maximum Facility Toxic Air Contaminants, contains no footnotes to show which emissions are carcinogenic, while Table B-7, Worst-Case Annual TAC Emissions for Gas Turbines and HRSGs, is buried in Appendix B on page 145 and does indicate which compounds are carcinogenic. The District has not made clear whether the cooling tower will use 135,000 gpm of water (see Table B-4, page 143) or 141,352 gpm (Appendix B, Page145). Since these are not small differences and Total Dissolved Solids (hence particulate matter) are calculated from the water flow, they call into question what other inaccuracies may be in the document.
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BAAQMD's Role in Informing the Public

The public hearing in Hayward two weeks ago made clear that a certain segment of the population was under the misconception that building and operating the RCEC would mean that older dirtier power plants would be closed. In point of fact, the Air District has no decision-making ability as to whether a plant closes. That is the decision of the ISO, the plant operator. To let stand that misimpression is disingenuous, since it fails to make clear that there will not be a net gain in air quality should RCEC come online.

BAAQMD has a significant public information campaign underway for its Spare the Air program. There are notices on the daily weather page of the San Francisco Chronicle, TV commercials, news spots, and outdoor signs posted. There is now an enforcement program in place whereby residential offenders are to be fined. All of this campaign is directed toward informing the public about the importance of decreasing particulate matter in the Bay Area air basin from wood-burning and about the Air District's role in promoting air quality. While the Spare the Air program is important, it seems inconsistent to insist that the public do its fair share on the one hand, while the District is proposing to issue a permit to RCEC for the right to emit massive amounts of particulate matter into the air.

Even more significantly, BAAQMD posts a table on its website entitled, "Ambient Air Quality Standards & Bay Area Attainment Status." Under Particulate Matter Fine (PM2.5), footnote 10 states, "**U.S. EPA lowered the 24-hour PM 2.5 standard from 65 ub/m3 to 35 ug/m3 in 2006. EPA issued attainment status designations for the 35 ug/m3 standard on December 22, 2008. EPA has designated the Bay Area as non-attainment for the 35 ug/m3 PM2.5 standard. The EPA order will be effective in April, 2009, 90 days after publication of the EPA findings in the Federal Register**." We could find virtually no mention of this in the Statement of Basis. Surely, the Air District is aware of this non-attainment status and new standard. In what way will the District address RCEC's contribution to particulate matter given the new status? Again, failure to mention this critical regulatory change in the Statement of Basis does great damage to the Air District's credibility.

Just a few weeks ago, the New England Journal of Medicine reported on the first epidemiological study showing that reducing air pollution translates into longer lives. Focusing on particulate matter in 51 cities, the researchers found on average particulate matter levels fell from 21 ug/m3 to 14 ug/m3 and that in these areas, people lived an average of 2.72 years longer. Given that the Bay Area is at nonattainment for the new 35 ug/m3 level which is 2.5 times the 14 ug/m3 cited above, we have a very long way to go to improve the quality of air that we breathe. We cannot afford an RCEC.

Conclusions

During the 8 years since the project was first proposed, we have passed through an unprecedented period of history bearing directly upon factors that would influence the siting of a major fossil fuel burning plant. The world has wakened to the threat of global warming from greenhouse gas emissions, California appears at last to be winning its battle with the federal government over the state's right to insist upon cleaner air, the energy market is experiencing a state of unprecedented volatility wherein the heavy reliance on fossil fuels has been shown to have enormous environmental, economic, and social costs, the global economy has been rocked to its foundations, and a new American president has promised us change that will move us closer toward beginning to rectify these ills. Perhaps most importantly, many people have begun to recognize their own responsibility to decrease their ecological footprint and have become increasingly sophisticated in the role they must play and in how they want their government and regulatory agencies to respond to the challenges that face us. Nowhere is that more apparent than in the Bay Area.

Now more than ever, against this progressive backdrop, the Russell City Energy Center appears as a problem looking for a solution rather than the other way around. As fossil fuel burning plants go, by comparison with a coal-burning plant for instance, RCEC might produce fewer emissions. However, from the beginning, the central irreconcilable problem has been its chosen location 1500 feet from sensitive wetlands that, by any standard, are to be accorded legal protection from its impacts. Although 8 long years have passed during which this project has persisted and hundreds of pages of documents have been produced, no amount of paper can conceal the obvious conclusion that basic common sense dictates: **locating a major power plant immediately next to a major wetland ecosystem means significant and unacceptable levels of impacts**.

We strongly urge the Bay Area Air Quality Management District to deny the PSD permit for the Russell City Energy Center.

Sincerely,

Laura Baker, M.A. Ecology and Systematic Biology
Conservation Committee Chair
East Bay Chapter of the California Native Plant Society

Ohlone Audubon Society, Inc.

A chapter of the National Audubon Society
Serving Southern Alameda County, CA

December 27, 2008

Mr. Weyman Lee, P. E.
Senior Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

RE: Proposed Statement of Basis and Proposed Permit Conditions for amended PSD Permit. Application #15487, Russell City Energy Center

Dear Mr. Lee,

Ohlone Audubon Society has serious concerns about several ecological impacts of the proposed gas-powered energy plant that is to be built in close proximity to the Hayward area shoreline. This is a vicinity of high quality habitat for shorebirds, some of them endangered or threatened. When the power plant was first proposed in 2001-2002, some of the pollutants were not studied. The amounts of Nitrogen Oxides, Carbon Monoxide, and Particulate Matter that would be emitted would appear to pose a threat to the nearby bird population, the plant communities and to the residents in the immediate areas as well. In addition it seems quite possible, even with the tall smoke stacks, that some of these pollutants would find their way to the Central Valley which already has an impacted air quality.

When the Russell City power plant was first proposed, global warming did not seem to pose the very serious threat it does currently. Solar panels were less available and less affordable than they are today. Instead of building that monstrous power plant that will pollute and heat the air, would it not be better to consider a more environmentally friendly solution to our energy needs-namely solar power?

Ohlone Audubon Society urges the Bay Area Air Quality Management District to help Hayward be clean and green by promoting solar power and not a gas-fired power plant.

Yours truly,

Evelyn M. Cormier

Evelyn M/Cormier, President
Ohlone Audubon Society
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Hayward, CA 94544

BAY AREA AIR QUALITY
MANAGEMENT DISTRICT
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RECEIVED

OBJECTION TO FOSSIL FUEL FIRED POWER PLANT(S)

We the undersigned customers of Pacific Gas and Electric Company (PG&E) and citizens wish to file a complaint against PG&E's for causing the development of fossil fuel fired electricity generation without satisfying at least the 20% renewable energy portfolio requirements. We object to further generation that produces un sequestered carbon dioxide.

We ratepayers dispute the Application for Expedited Approval of the Amended Power Purchase Agreement for Calpine's Hayward planned plant. We request Public Participation Hearings be held in Hayward California on this Application. (U39E) under Application 08-09-007 filed September 10, 2008.

We object to the proposed site of the Plant next to the Federally protected Endangered Species of the San Francisco Bay without a Formal Biological Opinion from the United Sates Department of Fish and Wildlife.

We object to the proposed site and the propensity to site plants in neighborhoods of color and/or low income.

We object to the Bay Area Air Quality Management District (BAAQMD) or United States Environmental Protection Agency issuing Air pollution permits for this project. The U.S. Environmental Protection Agency (EPA) rescinded a pollution permit issued for Calpine Corp.'s Russell City Energy Center by BAAQMD and ordered the air district to re-notice and re-open a public comment period before it makes a new decision on the permit. In its 42-page remand order issued July 29, 2008 the three-judge environmental appeals board of the EPA delivered a stern rebuke to the air district over the way it complied with public notice and outreach regulations for the Hayward plant's pollution permit.

We object to the California Energy Commission approving an extension of the operation date without environmental review.

We object to the City of Hayward accepting $10,000,000 from Calpine and approving the project without environmental review or consistency with Hayward laws. The City of Hayward is requested to participate in all proceedings regarding this matter to protect the people of Hayward and the laws of the city.

We wish to have public notice of all actions and have the opportunity to participate.

We dispute the subjective projections of increased demand to justify ratepayers funding this development despite the fact that actual use in today's economy is not increasing per the projections.

Christine Dorigo [signature]

First Name Last Name Signature

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OBJECTION TO FOSSIL FUEL FIRED POWER PLANT(S)

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We object to the City of Hayward accepting $10,000,000 from Calpine and approving the project without environmental review or consistency with Hayward laws. The City of Hayward is requested to participate in all proceedings regarding this matter to protect the people of Hayward and the laws of the city. We request that the City of Hayward consider cancellation of this project as part of their Climate Action Plan.

We wish to have public notice of all actions and have the opportunity to participate.

We dispute the subjective projections of increased demand to justify ratepayers funding this development despite the fact that actual use in today's economy is not increasing per the projections.

Laura | Swan | Laura Swan
First Name | Last Name | Signature

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Comments of Robert Sarvey on the Draft PSD permit for the Russell City Energy Center Application Number 15487

Dear Mr. Lee,

Thank you for the opportunity to comment on the Draft PSD permit for the Russell City Energy Center Application Number 15487. The Statement of Basis is very confusing since the amended FDOC was issued on June 19, 2007 and contradicts many of the values that are presented in Amended PSD permit which was circulated on December 8, 2008 almost 18 months later. The District should reopen the FDOC to reflect the changes that are presented in the Amended PSD Permit. These permits are extremely technical and difficult for the public to understand and when different values are presented for the same impacts members of the public lose confidence in the District and the EPA process. Furthermore since the amended FDOC was issued several air pollution laws including the California NO2 standard have changed. Compliance with these new laws may be demonstrated in the Amended PSD permit but not reflected in the Amended FDOC.

California NO2 Standard

Page 159 of the air quality impact analysis demonstrates that the project violates the California 1 hour Ambient Air Quality Standard for NO_2. The California Ambient Air Quality standard for NO2 is 338 ug/m_3, while the projects impact combined with background is 370 ug/m3 (as shown in table 6 on page 159). The California Air Resource Board has promulgated new standards and established that deleterious health effects occur when NO2 concentrations exceed 338 ug/m3. (http://www.arb.ca.gov/research/aaqs/no2-rs/no2-doc.htm) Page 92 states that the project does not violate the state 1 hour NO2 standard because the projects maximum impacts are 130 ug/m_3 and background is 130 ug/m_3. The statement is unsupported by any analysis in the statement of basis. The statement of basis should provide an analysis demonstrating compliance with the NO2 standard since the air quality impact analysis contradicts the values presented on page 92. The new NO2 analysis and amended FDOC should be recirculated to the public for comment.

Ammonia Transportation

Page 26 of the permit states, "A second potential environmental impact that may result from the use of SCR involves ammonia transportation and storage. The proposed facility will utilize aqueous ammonia in a 29.4% (by weight) solution for SCR ammonia injection, which will be transported to the facility and stored onsite in tanks. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident. This risk will be addressed in a number of ways under safety regulations and sound industry safety codes and standards, including the implementation of a Risk Management Program to prevent and respond to accidental releases."

The project, if allowed to use SCR, can eliminate the impact from transportation accidents by utilizing a technology called NOxOUT ULTRA®. There are dozens of systems in service, one in Southern California at UC Irvine. Most of the UC campuses have decided not to risk bringing ammonia tankers through campus or having to offload or store ammonia. NOxOUT ULTRA is being specified for new units at UCSD, University of Texas and Harvard. The NOxOUT ULTRA system requires a tank for the urea. The urea is usually in a 50 to 32 % solution. Urea has no vapor pressure and no smell. If it spills, the evaporated water will leave behind a pile of crystal salts. There are no hazards to labeling or training required for the operator and absolutely no risk to adjacent facilities or neighbors. Like aqueous ammonia, NOxOUT ULTRA needs controls to manage the input from the power plant indicating how much reagent the SCR requires. Like aqueous ammonia, the system requires an air blower and heater to heat the air. The heated air goes to a decomposition chamber instead of a vaporizer. In the decomposition chamber, the urea solution is added. The water in the urea solution is vaporized and the additional heat required will then decompose the urea to ammonia. The gas/carrier air is then swept to the AIG and to the SCR. If the urea pump is stopped and air is left in service, the chamber is swept clear of ammonia in less than seven seconds. So in an emergency, there is very little, if any, ammonia exposure. Other than the seven seconds between the chamber and the AIG, the only exposure is the harmless urea. Since the ammonia will be transported through an environmental Justice community, all precautions should be taken since the community already has a high number of toxic and hazardous materials stored and transported through it. Attachment 1 contains a brochure on the NOxOUT ULTRA system.

<u>Secondary Particulate Formation</u>

Page 26 of the permits BACT analysis states, "The Air District also evaluated the potential for ammonia slip emissions to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. Moreover, the Air District has found that the formation of ammonium nitrate in the Bay Area air basin appears to be constrained by the amount of nitric acid in the atmosphere and not driven by the amount of ammonia in the atmosphere, a condition known as being "nitric limited". Where an area is nitric acid limited, emissions of additional ammonia will not contribute to secondary particulate matter formation because there is not enough nitric acid for it to react with. Therefore, ammonia emissions from the SCR system are not expected to contribute significantly to the formation of secondary particulate matter. Any potential for secondary particulate matter formation is at most speculative, and would not provide a reason to eliminate SCR as a control alternative."

The District has based its conclusion that the project area is nitric limited on a BAAQMD Office Memorandum from David Fairly to Tom Perardi and Rob DeMandel (footnote 21) , "A First Look at NOx/Ammonium Nitrate Tradeoffs, dated September 8, 1997." The District memorandum outlines two objectives. One, whether the Bay Area is ammonia limited, and two, to what extent reducing NOx emissions would reduce ammonium nitrate. Among the findings presented in this memorandum, the District staff believes that " San Jose and Livermore are not ammonia limited' during wintertime high particulate matter conditions; rather, these two areas are nitric acid limited. Other findings stated in the memorandum include recognition that the District analyses do not provide solid "footing to do planning or to provide guidelines to industry for such tradeoffs [between NOx and ammonium nitrate]." Thus, the District memorandum is very specific to say that San Jose and Livermore, not the entire Bay Area air basin or the project location, are nitric acid limited, and that no guidelines have been formed to address the ammonia induced PM10lPM2.5 problem. This project is located in the Hayward area of Alameda County, which is outside of the area where the District has made the determination; therefore, the Districts contention that the increase in ammonia emissions from this facility would not cause any increase in PMlOlPM2.5 emission impacts is not supported by the District memorandum. The District needs a site specific study to make such broad conclusions and an analysis needs to be conducted not only to evaluate the use of SCR, but also to assess environmental impacts of secondary particulate and its effect on the deterioration of air quality in the BAAQMD. The project's PM 2.5 impacts may be much larger than modeled and subject to additional analysis.

The District needs to conduct a BACT analysis on the ammonia emission slip limit. Several Projects including the ANP Blackstone Project have 2ppm ammonia slip limits, which are designed to prevent additional particulate matter formation and limit the transportation of ammonia though the surrounding communities.

CO BACT

The statement of basis concludes that a CO limit of 4ppm over 3 hours is BACT. (Page 32) This conclusion was determined by analyzing emissions data from the Metcalf Energy Center. The Metcalf Energy Center does not utilize an oxidation catalyst for CO emissions, so to base the permit decision on a project that contains no CO abatement device when the proposed Russell City Project will have an oxidation catalyst is an inappropriate comparison. The USEPA, in a June 18th 2001 letter to the San Luis Obispo County Air Pollution Control District has commented that the BACT limit for gas turbines should be set at 2 ppm for NOx on an hourly basis while the NH3 slip maintained at 5 ppm. In addition, the EPA stated that BACT for CO should be set at 2 ppm on a 3-hour rolling average.

Several Projects have achieved a lower CO emissions rates in conjunction with a 2ppm NOx limit. One is the Salt River Project in Arizona, which meets a 2ppm NOx limit and a 2ppm CO limit that has been verified by source testing. (http://cfpub1.epa.gov/rblc/cfm/ProcDetl.cfm?facnum=25662&procnum=102130) The Las Vegas Cogeneration facility has a 2ppm NOx limit and a 2ppm CO limit. (http://cfpub1.epa.gov/rblc/cfm/ProcDetl.cfm?facnum=26002&Procnum=103714) Based on available information, the district should choose a 2ppm CO limit for this project to comply with BACT.

Start up and Shutdown Emission Limits

The district reports on page 41 of the permit that the Palomar Project has reduced NOx start up emissions by introducing ammonia earlier in the start up cycle and using the OP-Flex system. "By taking these steps, the facility was able to optimize its operating procedures and bring down its startup emissions. The facility has reported encouraging results from the first few months of operating with these new techniques."

The district then eliminates the technology because only one quarterly report from the quarterly variance reports to the SDPCD is available on the success of the new technology. "It is not possible, however, to determine based on this limited data what reductions, if any, are attributable to OpFlex and what reductions are attributable to the operational changes the facility was able to make for its specific turbines. Moreover, the facility has operated only for a relatively limited period of time with these enhancements, and so it is difficult to determine from the limited data available so far what improvements can reliably be achieved throughout the life of the facility."

Included as attachment 2 to these comments are three more Hearing Board Variance 4073; Quarterly Reports that were acquired through a public records request. By utilizing earlier ammonia injection and utilizing the OP flex system, the Russell City Power Projects start up emissions can be reduced drastically. It must be required as BACT since it has been proved in operation for over a year, and it will reduce the project's potential to violate the new California NO2 standard and eliminate the deficient daily emission reduction credits needed for the facility, as explained below.

Emissions Reduction Credit shortfall

Table B-12 on page 147 of the statement of basis lists the maximum daily NO 2 emissions of 1,553 pounds per day. The permit proposes to only offset 134.6 tons of NO2 per year or 737.54 pounds per day. The ERC's will not provide adequate mitigation for the potential 1533 pounds per day of NO2 emitted by the project. The surrendered ERC's only mitigate 49% of the projects daily NO2 emissions due to the excessive start up and shut down emissions. This could leave as much as 49% of the projects daily NO2 emissions unmitigated. On days when violations of the ozone standards occur, the project's emissions would contribute to violations of the standard.

Previously Used ERC's

The ERC's listed for the Russell City Energy Center have already been pledged to another Calpine Project in the BAAQMD. Certificate Number 687 for 43.8 tons of POC has already been pledged to offset emission increases for the East Altamont Energy Center. Certificate Number 602 for 41 tons of POC was also allocated to the East Altamont Energy Center. Due to the fact that the EAEC was sited on the border of the BAAQMD and the SJVUAPCD these ERC's were subject to extensive scrutiny by the CEC, the SJVUAPCD, and the public, during the siting of the EAEC. The transfer of ERC's should be subject to public notice and comment.

Greenhouse Gas Emissions

The BAAQMD now requires a fee for greenhouse gas emissions. (http://www.baaqmd.gov/pln/climatechange.htm#GHGFee) The license should acknowledge the green house gas fees to be paid to the BAAQMD. Greenhouse gas emissions are evaluated based on the natural gas consumption of the project. The ammonia slip will also contribute to greenhouse gas emissions from the project and should be included in the evaluation. The District should do a true BACT analysis on greenhouse gases and not just adopt the California Public Utilities Commission (CPUC) adopted Emissions Performance Standard for the state's Investor Owned Utilities of 1,100 pounds (or 0.5 metric tons) CO2 per megawatt-hour (MW-hr).

Environmental Justice

The District states on page 65 of the statement of basis, "Another important consideration that the Air District evaluated is environmental justice. The Air District is committed to implementing its permit programs in a manner that is fair and equitable to all Bay Area residents regardless of age, culture, ethnicity, gender, race, socioeconomic status, or geographic location in order to protect against the health effects of air pollution. The Air District has worked to fulfill this commitment in the current permitting action."

Other than issue the public notice in Spanish on its website for comments on this permit, the district has done nothing different from any other permitting action to evaluate the specific environmental justice impacts of this project on the minority community. The District believes by conducting a health risk assessment, which it does for every project or modeling criteria pollutant impacts, it has met its environmental justice obligations in the permitting process. The District's reasoning is that since the modeling they performed meets their requirements for the general population, the minority community can't possibly be harmed by the projects emissions. The very purpose of the environmental justice evaluation is to identify the minority population's health vulnerabilities and existing pollution and hazardous materials sources and identify how the project affects the minority community, not the general population. The District evaluation falls short of even the basic environmental justice analysis.

Poor health and premature death are by no means randomly distributed in Alameda County. Low-income communities and communities of color suffer from substantially worse health outcomes and die earlier. Many studies note that these differences are not adequately explained by genetics, access to health care or risk behaviors, but instead are to a large extent, the result of adverse environmental conditions. The RCEC is sited in a geographic area already disproportionately burdened by illness and death. The presence of a disproportionate concentration of persons with asthma, chronic lung disease, congestive heart failure, and other chronic conditions that are exacerbated by air pollution must factor into the decision of where to site this power plant; especially because these populations affected by the power plant are predominately low-income communities of color. The minorities are not distributed throughout the population randomly, but instead are concentrated disproportionately in proximity to the proposed Hayward site.

In the two zip codes near the site 94544 and 94545 residents have a high mortality rate and on average they live five years less than the county- wide expectancy rate. Death rates from air pollution-associated diseases such as coronary heart disease, chronic lower respiratory disease, are substantially and statistically significantly higher than those for the County, representing an ongoing, excess burden of mortality. The rate of death from chronic lower respiratory diseases was 43 percent higher and the rate from coronary heart disease was 16 percent higher than the County average. Hospitalizations due to air pollution- associated diseases are substantially higher in the two zip codes close to the proposed site. From 2003 to 2005 the hospitalization rates for coronary heart disease, chronic obstructive pulmonary disease, congestive heart failure and asthma in the two zip codes nearest the proposed site, 94544 and 94545, was statistically significantly higher than Alameda County rates which means they do not occur by chance. Specifically, hospitalization rates due to coronary heart disease was 60 percent higher; chronic obstructive pulmonary disease, 20 percent higher; congestive heart failure, 35 percent higher; and asthma hospitalization rates 14 percent higher than the County rate. The fact that rates of these illnesses are significantly higher in the proposed plant area than in the rest of the county suggests a level of vulnerability in this population that is higher than the rest of the county.

A proper Environmental Justice process begins with the demographic screening analysis which the CEC staff has performed and concluded that the majority of the community surrounding the RCEC is indeed minority. At that point in the analysis the public participation process should have been used to define and evaluate environmental justice concerns. Community leaders and community stakeholders should have been consulted to identify their concerns. The District should have consulted with the county health agencies to identify existing health concerns. Then the District should have examined the synergistic effects of existing pollution that already exists in the community. In this community there are multiple environmental stresses. There is a railroad which passes though the area, there are truck terminals and other heavy industries and a sewage treatment plant in the affected community. The District has not identified and examined the existing local sources of criteria pollutants and toxic emissions and evaluated their impacts in conjunction with the emissions form the RCEC.

Environmental Justice Guideline's emphasize the importance of reaching out to the community and involving them in the development of the mitigation measures and alternatives. A good example of how this process is done is the community outreach that was performed by the CCSF in the SFERP proceeding. In that proceeding over 20 community meetings were held and the community was engaged in deciding appropriate mitigation measures and alternatives. Public advocacy groups were consulted and included in the decision making. Air Quality Monitoring stations were set up in the community to examine existing air quality in the affected community.
(http://www.energy.ca.qov/sitin~cases/sanfrancisco/documents/applicant/data response 1Al2004-07-08 DATA RESPONSE-PDF)

The environmental justice argument against the RCEC is made even stronger by the fact that the risk assessment model may underestimate the health risk of substances that interact synergistically, as pointed out in the risk assessment guidelines. The potential for multiple and varied air and non-airborne pollutants to act synergistically, rather than additively as assumed by the risk assessment model, requires an analysis of the overall toxic burden associated with this Hayward location. Low-income, minority populations have historically been exposed to a much higher burden of environmental toxicity. The Districts Environmental Justice Analysis does not accept the existing ordinate disease nor does it adequately measure the health risks associated with potential, synergistic interactions among the substances, profoundly important aspects of environmental justice. Siting the Russell City Power plant in Hayward will disproportionately impact the geographic area, home to a comparatively high, non-white population that is already burdened by existing morbidity and mortality from diseases associated with air pollution or other existing environmental factors. It is that burden that must be analyzed to truly determine if the minority population near the proposed power plant will be affected. The district is required to address environmental justice issues in the PSD process.

Pack, Heidi K.

From:	Hunt, Kelly [KHunt@Semprautilities.com]
Sent:	Thursday, April 12, 2007 3:06 PM
To:	Kellogg, Kellie; Pack, Heidi K.; Moore, Steve ; Miller, Taylor; Baerman, Daniel; Waller, Fred A.; Hardman, Charles; Blackburn, Suzanne; Annicchiarico, John; Haury, Evariste
Subject:	Updated: Palomar Energy Center Variance Report - 4073 1st Quarter 2007
Attachments:	Hearing Board Quarterly Report for 1st Quarter 2007.pdf

Ms. Kellogg,

Please find attached an updated copy of the 1st quarter report to the Hearing Board for 2007. This report **supersedes the submission made on 4/11/07 and** is intended for the Hearing Board meeting to be held on April 26, 2007. I apologize for any inconvenience this may have caused you. This report covers the items required by Condition F.3. of the Board's April 27, 2006 order for Variance 4073. In addition, this report covers Enforcement Condition 1 concerning compliance with required increment of progress.

If you have any questions, please feel free to call me at 760-432-2504.

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Comments of Robert Sarvey on the Draft PSD permit for the Russell City Energy Center Application Number 15487

Dear Mr. Lee,

Thank you for the opportunity to comment on the Draft PSD permit for the Russell City Energy Center Application Number 15487. The Statement of Basis is very confusing since the amended FDOC was issued on June 19, 2007 and contradicts many of the values that are presented in Amended PSD permit which was circulated on December 8, 2008 almost 18 months later. The District should reopen the FDOC to reflect the changes that are presented in the Amended PSD Permit. These permits are extremely technical and difficult for the public to understand and when different values are presented for the same impacts members of the public lose confidence in the District and the EPA process. Furthermore since the amended FDOC was issued several air pollution laws including the California NO2 standard have changed. Compliance with these new laws may be demonstrated in the Amended PSD permit but not reflected in the Amended FDOC.

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Page 159 of the air quality impact analysis demonstrates that the project violates the California 1 hour Ambient Air Quality Standard for NO_2. The California Ambient Air Quality standard for NO2 is 338 ug/m_3, while the projects impact combined with background is 370 ug/m3 (as shown in table 6 on page 159). The California Air Resource Board has promulgated new standards and established that deleterious health effects occur when NO2 concentrations exceed 338 ug/m3. (http://www.arb.ca.gov/research/aaqs/no2-rs/no2-doc.htm) Page 92 states that the project does not violate the state 1 hour NO2 standard because the projects maximum impacts are 130 ug/m_3 and background is 130 ug/m_3. The statement is unsupported by any analysis in the statement of basis. The statement of basis should provide an analysis demonstrating compliance with the NO2 standard since the air quality impact analysis contradicts the values presented on page 92. The new NO2 analysis and amended FDOC should be recirculated to the public for comment.

Ammonia Transportation

Page 26 of the permit states, “A second potential environmental impact that may result from the use of SCR involves ammonia transportation and storage. The proposed facility will utilize aqueous ammonia in a 29.4% (by weight) solution for SCR ammonia injection, which will be transported to the facility and stored onsite in tanks. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident. This risk will be addressed in a number of ways under safety regulations and sound industry safety codes and standards, including the implementation of a Risk Management Program to prevent and respond to accidental releases.”

The project, if allowed to use SCR, can eliminate the impact from transportation accidents by utilizing a technology called NOxOUT ULTRA®. There are dozens of systems in service, one in Southern California at UC Irvine. Most of the UC campuses have decided not to risk bringing ammonia tankers through campus or having to offload or store ammonia. NOxOUT ULTRA is being specified for new units at UCSD, University of Texas and Harvard. The NOxOUT ULTRA system requires a tank for the urea. The urea is usually in a 50 to 32 % solution. Urea has no vapor pressure and no smell. If it spills, the evaporated water will leave behind a pile of crystal salts. There are no hazards to labeling or training required for the operator and absolutely no risk to adjacent facilities or neighbors. Like aqueous ammonia, NOxOUT ULTRA needs controls to manage the input from the power plant indicating how much reagent the SCR requires. Like aqueous ammonia, the system requires an air blower and heater to heat the air. The heated air goes to a decomposition chamber instead of a vaporizer. In the decomposition chamber, the urea solution is added. The water in the urea solution is vaporized and the additional heat required will then decompose the urea to ammonia. The gas/carrier air is then swept to the AIG and to the SCR. If the urea pump is stopped and air is left in service, the chamber is swept clear of ammonia in less than seven seconds. So in an emergency, there is very little, if any, ammonia exposure. Other than the seven seconds between the chamber and the AIG, the only exposure is the harmless urea. Since the ammonia will be transported through an environmental Justice community, all precautions should be taken since the community already has a high number of toxic and hazardous materials stored and transported through it. Attachment 1 contains a brochure on the NOxOUT ULTRA system.

<u>Secondary Particulate Formation</u>

Page 26 of the permits BACT analysis states, “The Air District also evaluated the potential for ammonia slip emissions to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. Moreover, the Air District has found that the formation of ammonium nitrate in the Bay Area air basin appears to be constrained by the amount of nitric acid in the atmosphere and not driven by the amount of ammonia in the atmosphere, a condition known as being “nitric limited". Where an area is nitric acid limited, emissions of additional ammonia will not contribute to secondary particulate matter formation because there is not enough nitric acid for it to react with. Therefore, ammonia emissions from the SCR system are not expected to contribute significantly to the formation of secondary particulate matter. Any potential for secondary particulate matter formation is at most speculative, and would not provide a reason to eliminate SCR as a control alternative."

The District has based its conclusion that the project area is nitric limited on a BAAQMD Office Memorandum from David Fairly to Tom Perardi and Rob DeMandel (footnote 21) , "A First Look at NOx/Ammonium Nitrate Tradeoffs, dated September 8, 1997." The District memorandum outlines two objectives. One, whether the Bay Area is ammonia limited, and two, to what extent reducing NOx emissions would reduce ammonium nitrate. Among the findings presented in this memorandum, the District staff believes that " San Jose and Livermore are not ammonia limited' during wintertime high particulate matter conditions; rather, these two areas are nitric acid limited. Other findings stated in the memorandum include recognition that the District analyses do not provide solid "footing to do planning or to provide guidelines to industry for such tradeoffs [between NOx and ammonium nitrate]." Thus, the District memorandum is very specific to say that San Jose and Livermore, not the entire Bay Area air basin or the project location, are nitric acid limited, and that no guidelines have been formed to address the ammonia induced PM10lPM2.5 problem. This project is located in the Hayward area of Alameda County, which is outside of the area where the District has made the determination; therefore, the Districts contention that the increase in ammonia emissions from this facility would not cause any increase in PMlOlPM2.5 emission impacts is not supported by the District memorandum. The District needs a site specific study to make such broad conclusions and an analysis needs to be conducted not only to evaluate the use of SCR, but also to assess environmental impacts of secondary particulate and its effect on the deterioration of air quality in the BAAQMD. The project's PM 2.5 impacts may be much larger than modeled and subject to additional analysis.

The District needs to conduct a BACT analysis on the ammonia emission slip limit. Several Projects including the ANP Blackstone Project have 2ppm ammonia slip limits, which are designed to prevent additional particulate matter formation and limit the transportation of ammonia though the surrounding communities.

CO BACT

The statement of basis concludes that a CO limit of 4ppm over 3 hours is BACT. (Page 32) This conclusion was determined by analyzing emissions data from the Metcalf Energy Center. The Metcalf Energy Center does not utilize an oxidation catalyst for CO emissions, so to base the permit decision on a project that contains no CO abatement device when the proposed Russell City Project will have an oxidation catalyst is an inappropriate comparison. The USEPA, in a June 18th 2001 letter to the San Luis Obispo County Air Pollution Control District has commented that the BACT limit for gas turbines should be set at 2 ppm for NOx on an hourly basis while the NH3 slip maintained at 5 ppm. In addition, the EPA stated that BACT for CO should be set at 2 ppm on a 3-hour rolling average.

Several Projects have achieved a lower CO emissions rates in conjunction with a 2ppm NOx limit. One is the Salt River Project in Arizona, which meets a 2ppm NOx limit and a 2ppm CO limit that has been verified by source testing. (http://cfpub1.epa.gov/rblc/cfm/ProcDetl.cfm?facnum=25662&procnum=102130) The Las Vegas Cogeneration facility has a 2ppm NOx limit and a 2ppm CO limit. (http://cfpub1.epa.gov/rblc/cfm/ProcDetl.cfm?facnum=26002&Procnum=103714) Based on available information, the district should choose a 2ppm CO limit for this project to comply with BACT.

Start up and Shutdown Emission Limits

The district reports on page 41 of the permit that the Palomar Project has reduced NOx start up emissions by introducing ammonia earlier in the start up cycle and using the OP-Flex system. "By taking these steps, the facility was able to optimize its operating procedures and bring down its startup emissions. The facility has reported encouraging results from the first few months of operating with these new techniques."

The district then eliminates the technology because only one quarterly report from the quarterly variance reports to the SDPCD is available on the success of the new technology. "It is not possible, however, to determine based on this limited data what reductions, if any, are attributable to OpFlex and what reductions are attributable to the operational changes the facility was able to make for its specific turbines. Moreover, the facility has operated only for a relatively limited period of time with these enhancements, and so it is difficult to determine from the limited data available so far what improvements can reliably be achieved throughout the life of the facility."

Included as attachment 2 to these comments are three more Hearing Board Variance 4073; Quarterly Reports that were acquired through a public records request. By utilizing earlier ammonia injection and utilizing the OP flex system, the Russell City Power Projects start up emissions can be reduced drastically. It must be required as BACT since it has been proved in operation for over a year, and it will reduce the project's potential to violate the new California NO2 standard and eliminate the deficient daily emission reduction credits needed for the facility, as explained below.

Emissions Reduction Credit shortfall

Table B-12 on page 147 of the statement of basis lists the maximum daily NO 2 emissions of 1,553 pounds per day. The permit proposes to only offset 134.6 tons of NO2 per year or 737.54 pounds per day. The ERC's will not provide adequate mitigation for the potential 1533 pounds per day of NO2 emitted by the project. The surrendered ERC's only mitigate 49% of the projects daily NO2 emissions due to the excessive start up and shut down emissions. This could leave as much as 49% of the projects daily NO2 emissions unmitigated. On days when violations of the ozone standards occur, the project's emissions would contribute to violations of the standard.

Previously Used ERC's

The ERC's listed for the Russell City Energy Center have already been pledged to another Calpine Project in the BAAQMD. Certificate Number 687 for 43.8 tons of POC has already been pledged to offset emission increases for the East Altamont Energy Center. Certificate Number 602 for 41 tons of POC was also allocated to the East Altamont Energy Center. Due to the fact that the EAEC was sited on the border of the BAAQMD and the SJVUAPCD these ERC's were subject to extensive scrutiny by the CEC, the SJVUAPCD, and the public, during the siting of the EAEC. The transfer of ERC's should be subject to public notice and comment.

Greenhouse Gas Emissions

The BAAQMD now requires a fee for greenhouse gas emissions. (http://www.baaqmd.gov/pln/climatechange.htm#GHGFee) The license should acknowledge the green house gas fees to be paid to the BAAQMD. Greenhouse gas emissions are evaluated based on the natural gas consumption of the project. The ammonia slip will also contribute to greenhouse gas emissions from the project and should be included in the evaluation. The District should do a true BACT analysis on greenhouse gases and not just adopt the California Public Utilities Commission (CPUC) adopted Emissions Performance Standard for the state's Investor Owned Utilities of 1,100 pounds (or 0.5 metric tons) CO2 per megawatt-hour (MW-hr).

Environmental Justice

The District states on page 65 of the statement of basis, "Another important consideration that the Air District evaluated is environmental justice. The Air District is committed to implementing its permit programs in a manner that is fair and equitable to all Bay Area residents regardless of age, culture, ethnicity, gender, race, socioeconomic status, or geographic location in order to protect against the health effects of air pollution. The Air District has worked to fulfill this commitment in the current permitting action."

Other than issue the public notice in Spanish on its website for comments on this permit, the district has done nothing different from any other permitting action to evaluate the specific environmental justice impacts of this project on the minority community. The District believes by conducting a health risk assessment, which it does for every project or modeling criteria pollutant impacts, it has met its environmental justice obligations in the permitting process. The District's reasoning is that since the modeling they performed meets their requirements for the general population, the minority community can't possibly be harmed by the projects emissions. The very purpose of the environmental justice evaluation is to identify the minority population's health vulnerabilities and existing pollution and hazardous materials sources and identify how the project affects the minority community, not the general population. The District evaluation falls short of even the basic environmental justice analysis.

Poor health and premature death are by no means randomly distributed in Alameda County. Low-income communities and communities of color suffer from substantially worse health outcomes and die earlier. Many studies note that these differences are not adequately explained by genetics, access to health care or risk behaviors, but instead are to a large extent, the result of adverse environmental conditions. The RCEC is sited in a geographic area already disproportionately burdened by illness and death. The presence of a disproportionate concentration of persons with asthma, chronic lung disease, congestive heart failure, and other chronic conditions that are exacerbated by air pollution must factor into the decision of where to site this power plant; especially because these populations affected by the power plant are predominately low-income communities of color. The minorities are not distributed throughout the population randomly, but instead are concentrated disproportionately in proximity to the proposed Hayward site.

In the two zip codes near the site 94544 and 94545 residents have a high mortality rate and on average they live five years less than the county- wide expectancy rate. Death rates from air pollution-associated diseases such as coronary heart disease, chronic lower respiratory disease, are substantially and statistically significantly higher than those for the County, representing an ongoing, excess burden of mortality. The rate of death from chronic lower respiratory diseases was 43 percent higher and the rate from coronary heart disease was 16 percent higher than the County average. Hospitalizations due to air pollution- associated diseases are substantially higher in the two zip codes close to the proposed site. From 2003 to 2005 the hospitalization rates for coronary heart disease, chronic obstructive pulmonary disease, congestive heart failure and asthma in the two zip codes nearest the proposed site, 94544 and 94545, was statistically significantly higher than Alameda County rates which means they do not occur by chance. Specifically, hospitalization rates due to coronary heart disease was 60 percent higher; chronic obstructive pulmonary disease, 20 percent higher; congestive heart failure, 35 percent higher; and asthma hospitalization rates 14 percent higher than the County rate. The fact that rates of these illnesses are significantly higher in the proposed plant area than in the rest of the county suggests a level of vulnerability in this population that is higher than the rest of the county.

A proper Environmental Justice process begins with the demographic screening analysis which the CEC staff has performed and concluded that the majority of the community surrounding the RCEC is indeed minority. At that point in the analysis the public participation process should have been used to define and evaluate environmental justice concerns. Community leaders and community stakeholders should have been consulted to identify their concerns. The District should have consulted with the county health agencies to identify existing health concerns. Then the District should have examined the synergistic effects of existing pollution that already exists in the community. In this community there are multiple environmental stresses. There is a railroad which passes though the area, there are truck terminals and other heavy industries and a sewage treatment plant in the affected community. The District has not identified and examined the existing local sources of criteria pollutants and toxic emissions and evaluated their impacts in conjunction with the emissions form the RCEC.

Environmental Justice Guideline's emphasize the importance of reaching out to the community and involving them in the development of the mitigation measures and alternatives. A good example of how this process is done is the community outreach that was performed by the CCSF in the SFERP proceeding. In that proceeding over 20 community meetings were held and the community was engaged in deciding appropriate mitigation measures and alternatives. Public advocacy groups were consulted and included in the decision making. Air Quality Monitoring stations were set up in the community to examine existing air quality in the affected community.
(http://www.energy.ca.qov/sitin~cases/sanfrancisco/documents/applicant/data response 1Al2004-07-08 DATA RESPONSE-PDF)

The environmental justice argument against the RCEC is made even stronger by the fact that the risk assessment model may underestimate the health risk of substances that interact synergistically, as pointed out in the risk assessment guidelines. The potential for multiple and varied air and non-airborne pollutants to act synergistically, rather than additively as assumed by the risk assessment model, requires an analysis of the overall toxic burden associated with this Hayward location. Low-income, minority populations have historically been exposed to a much higher burden of environmental toxicity. The Districts Environmental Justice Analysis does not accept the existing ordinate disease nor does it adequately measure the health risks associated with potential, synergistic interactions among the substances, profoundly important aspects of environmental justice. Siting the Russell City Power plant in Hayward will disproportionately impact the geographic area, home to a comparatively high, non-white population that is already burdened by existing morbidity and mortality from diseases associated with air pollution or other existing environmental factors. It is that burden that must be analyzed to truly determine if the minority population near the proposed power plant will be affected. The district is required to address environmental justice issues in the PSD process.

http://www.epa.gov/compliance/resources/policies/ej/ej_permitting_authorities_memo_120100.pdf

The 1998 EPA guidelines require Agencies to consider a wide range of demographic, geographic, economic, human health and risk factors. One of the three most important factors identified in the 1998 EPA guidelines is "whether communities currently suffer or have historically suffered from environmental health risks and hazards." The 1998 EPA Guidelines require the agencies conducting an Environmental Justice Analysis to define the sensitive receptor analysis to the actual unique circumstances affecting the minority community not a generic definition of sensitive receptor that was utilized by the District and the CEC.

Soils and Vegetation Analysis Nitrogen Deposition

Nitrogen deposition consists of the input of reactive nitrogen species from the atmosphere to the biosphere. Pollutants that contribute to nitrogen deposition derive mainly from nitrogen oxides and ammonia emissions, which the RCEC would emit during normal operation. Emissions of NOx and ammonia contribute to nitric acid deposition that occurs via precipitation and fog and in dry deposition as well. Acute exposures to ammonia can adversely affect plant growth and productivity, resistance to drought and frost, responses to insect pests and pathogens, mycorrhizal and other beneficial root associations, and inter-specific competition and biodiversity in sensitive plant communities. Of particular concern for the RCEC project is the effect on serpentine soil plant communities, which are know to be particularly sensitive to nitrogen deposition. Serpentine soils in the San Francisco Bay Area support native grassland plant communities that can provide habitat for rare and endemic species. Nonnative annual grasses have invaded most grassland communities in California, but highly specialized plant species that are adapted to nutrient-poor serpentinitic soils can thrive in soils that are deficient in nitrogen, potassium, phosphorus, and other nutrients due to a competitive advantage over the faster growing non-native annual species. The competitive advantage of these specialized plant species can be lost when nitrogen deposition from air pollution fertilizes serpentine plant communities and nitrogen ceases to be a limiting nutrient for plant growth. Increased nitrogen levels often allow non-native annual grasses to out-compete the native species.

The nearest serpentine plant community to the project area is Fairmont Ridge in Lake Chabot Regional Park, approximately four miles northeast of the RCEC. Fairmont Ridge is located in the East Bay Hills adjacent to Lake Chabot. The California Native Grasslands Association identifies this area as a Purple Needlegrass Grassland community, and is noted as an area of serpentine soil in the USFWS's 1998 Recovery Plan for Serpentine Soil Species of the San Francisco Bay Area.

The BAAQMD and the CEC have failed to analyze the projects nitrogen deposition impacts on serpentine soil plant communities in the Bay Area.

SDG&E®

A Sempra Energy company

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April 11, 2007

Ms. Catherine Santos
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Santos and Members of the Board:

Set forth below is SDG&E's 2007 first quarter report to the Hearing Board. This report will cover the items required by Condition F. 3. of the Board's April 27, 2006 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

The increments of progress table attached to the Board's order is included with this letter as Attachment 1. The primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E timely filed the permit application on May 31, 2006. A rule amendment concerning Rule 69.3.1 is still under consideration by District staff and SDG&E and District staff met on February 16, 2007 to discuss the matter further.

Petitioner has timely satisfied all increments of progress within Petitioner's control. The increments of progress table also includes District staff and other third-party actions concerning rule development and permit processing. These actions were included in the increments of progress solely to describe the third-party actions necessary to resolve the regulatory issues prompting the variance. SDG&E will defer to District staff to provide an update to the Board on District's processing of SDG&E's permit application submittal, rule development and a possible revised schedule.

2. Engineering or operational alternatives [Order, Condition F.3 (1)]

Information concerning engineering or operational alternatives considered by Petitioner to ensure maximum control of emissions as recommended by District staff was included in the application for amended permit conditions submitted on May 31, 2006. SDG&E included information concerning reductions related to early ammonia injection and installation of a new software program being developed by General Electric for turbines such as those operating at Palomar ("OpFlex"). SDG&E also included information concerning seven other potential alternatives as requested by District staff.

On December 20, 2006, at District staff's request, Petitioner provided additional information regarding engineering and operational alternatives, including additional evaluation of early ammonia injection and economic impacts of several potential alternatives.

In addition, OpFlex, a General Electric turbine control system software was installed in mid-October, 2006. The turning process allows combustion turbines to minimize emissions between 20 and 60% load, by optimizing the fuel flow to the four gas stages in each combustion can. This precisely controls the flame for optimum combustion to minimize emissions. There were no equipment or hardware changes.

3. NOx Emissions Data [Order, Condition F.3 (2)]

Information concerning NOx emissions from the facility during the period of the 1 year variance to present is included in attachment 2. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.3 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data

A summary how the plant has reduced NOX emissions by various controls that it has established since the inception of the variance is included as attachment 3.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

SAN DIEGO AIR POLLUTION CONTROL DISTRICT HEARING BOARD

Palomar Energy Center

PROPOSED INCREMENTS OF PROGRESS
(As of 4/11/07)

MILESTONE **DATE**

	Description	Permit Modification	Rule Change	Variance(s)
1	Variance 4068 hearing for 90-day issued			2/9/06
2	Emergency Variance 4069 for condition 21 issued to enable early ammonia injection.			2/23/06
3	*Palomar submits request for Rule Change to APCD*		*3/6/06*	
4	*APCD requests more data for rule change*		*3/14/06*	
5	*Mtg. with APCD concerning Data Requests*		*3/30/06*	
6	*Additional mtg. with APCD (Steve Moore) concerning Data Requests*		*4/4/06*	
7	*SDG&E submits requested data to APCD (Moore)*		*4/7/06*	
8	SDG&E submits summary of requested Permit Modification topics to APCD (covering matters of concern to staff beyond start up)	4/7/06		
9	Mtg. with APCD – QA/QC Plan Addendum (relating to some permit amendment topics)	4/11/06		
10	Request for Permit Modification Fee Estimate submitted to APCD by SDG&E	4/11/06		
11	*APCD (Moore) submits new data request to SDG&E (replaces 3/30 & 4/4 requests)*		*4/14/06*	
12	*Data submitted to APCD (Moore)*		*4/25/06*	
13	Variance 4073 Hearing			4/27/06
14	*Mtg. scheduled with APCD and CEC (in response to 4/7 letter from SDG&E) to discuss permit and rule amendment issues*	5/3/06 (COMPLETED 5/3/06)	*5/3/06* (COMPLETED 5/3/06)	
15	Proposed Permit Pre-application Mtg. with APCD and CEC –	5/19/06 (COMPLETED		

			5/9 & 5/23/06)		
16	Proposed Permit Application Submittal		5/31/06 (COMPLETED 5/31/06)		
17	Quarterly Progress Update (April – June) to Hearing Board				July 27, 2006 (Completed)
18	APCD Permit Application Completeness Review	Respond to APCD data requests while in process	June – July 2006 (Completed)		
19	*APCD drafts rule change*			*April – June 2006*	
20	Quarterly Progress Update (July - September)to Hearing Board				October 27, 2006 (Completed)
21	*APCD holds public workshop on rule amendment*			*July 2006*	
22	*APCD publishes draft rule for public comment*	*30-day public notice required*		*August 2006*	
23	*APCD prepares final rule adoption documents*	*Final rule and "staff report" are prepared for County Board of Supervisors review and adoption*		*September 2006*	
24	*Air Quality Advisory Committee*	*Appointed committee reviews and advises the Board*		*October 2006*	
25	*Board adoption of rule*	*Upon adoption, SDAPCD considers rule to be the version for compliance*		*October 2006*	
26	Proposed Permit Modification (ATC/PDOC) published for public comment	30-day public comment period	October 2006		
27	Final ATC/FDOC revisions	Final language that incorporates public comments is developed	November 2006		
28	Final ATC/FDOC Issued		November 2006		

29	SDG&E petitions CEC for companion amendment of Conditions of Certification (CoC)		December 2006		
30	Quarterly Progress Update (October - December) to Hearing Board				Completed January 25, 2007
31	CEC issues amendment of CoC		March 2007		
32	Quarterly Progress Update (January - March) to Hearing Board				April 26, 2007

Attachment 2

CT1 YTD Summary

	Tons	#
2Q06	9.23	18,460
3Q06	8.61	17,220
4Q06	8.63	17,260
1Q07	8.88	17,760
Total	35.35	70,700

Note: Total NOx includes startup emissions.

CT2 YTD Summary

	Tons	#
2Q06	9.28	18,560
3Q06	8.95	17,900
4Q06	9.70	19,400
1Q07	8.73	17,460
Total	36.66	73,320

Note: Total NOx includes startup emissions.

CT1 Startup YTD Summary

	Tons	#
2Q06	3.19	6,380
3Q06	1.38	2,760
4Q06	0.52	1,040
1Q07	0.38	760
Total	5.47	10,180

CT2 Startup YTD Summary

	Tons	#
2Q06	3.64	7,280
3Q06	1.10	2,200
4Q06	0.52	1,040
1Q07	0.43	860
Total	5.69	10,520

[1] Data gathered from CEMS Startup/Shutdown Incident Reports

[2] Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

OPFLEX AND EARLY AMMONIA INJECTION EFFECTS ON STARTUP EMISSIONS PALOMAR ENERGY CENTER

Subject:

This Evaluation assesses the effects of two major Palomar Energy Center efforts to reduce startup emissions.

Discussion:

Early Ammonia Injection is a SDG&E project to minimize NOx emissions during the startup process by reducing and optimizing the temperature at which ammonia is injected to the SCR's, thereby reducing NOx emissions during the startup process. The original control system allowed ammonia injection when the temperature at the SCR increased to 550 deg F during the plant startup process. This temperature was chosen to provide a safety margin above the required SCR operating temperature. If ammonia is injected at too low of a temperature, the SCR is not effective, there can be elevated ammonia slip, and there is potential for poisoning of the SCR catalyst.

Palomar personnel have analyzed the temperature requirements for the SCR and evaluated the risks associated with low temperature ammonia injection, along with the benefits of emissions reductions obtained by lowering the injection temperature. The evaluation indicated that a significant lowering of the temperature was possible, as long as close attention was paid to the environmental conditions at all locations surrounding the catalyst. The temperature set point for ammonia injection was lowered in two steps as a prudent sequence to confirm the benefits and minimize risk. The first setpoint was lowered during the summer 2006. The setpoint was lowered again to 485 deg F in October 2006.

OpFlex is a General Electric proprietary software improvement that manages the fuel splits and fuel temperature control to minimize NOx and CO emissions at part load, and significantly reduces NOx during the startup process. The turbines can now be operated down to approximately 45% load and remain in compliance with all operating emissions limitations. The NOx produced during the startup process is also minimized approximately 25% to 45%, although not to the point of compliance with the 2.0 ppmvd@15% O2 permit limit.

OpFlex was installed in mid-October, 2006. Subsequent to the installation, Palomar Operations has studied the emissions enhancements OpFlex provides, and has made adjustments to the startup process to take advantage of these enhancements to reduce startup emissions. There have been no extended startups since the installation of OpFlex, so the extended startup procedure has not yet been optimized.

Results:

OpFlex and the final adjustment to the enhanced ammonia injection setpoint were implemented at approximately the same time in mid October, so the emissions improvements attributable to each are somewhat difficult to assign. However, this analysis endeavors to separate the projects and summarize the success of each.

With the SCR at normal operating temperature, ammonia injection can lower startup-related NOx concentrations by approximately 10.0 ppm. At base load, this equates to approximately 45 lbs/hr reduction of NOx mass emissions. This mass emissions reduction remains relatively constant even at reduced operating loads if sufficient NOx is present in the exhaust stream from the turbine.
During a typical hot start following a nightly shutdown, the enhanced, lowered temperature setpoint for ammonia injection allows the ammonia to be injected approximately 60 to 90 minutes earlier than the original setpoint (550 deg F) would have allowed. This provides for a reduction of at least 45 lbs NOx produced during the hot startup. The early ammonia injection NOx reduction for an extended startup will be even greater, conservatively estimated to be 60 lbs NOx per extended start.

OpFlex lowers the NOx produced by the turbine during the startup process at all loads above approximately 25%. The NOx is lowered enough above 45% load that in conjunction with the SCR, the stack emissions are reduced below the permit limit of 2.0 ppmvd@15% O2.

Plant Operations personnel have optimized the startup process to take advantage of this reduction of NOx above 25%. When plant conditions allow, the turbine is immediately ramped to approximately 43%, so that the turbine exhaust emissions are high only for the first 20 – 30 minutes of operation, and the magnitude of these high emissions are greatly reduced above 25%.

Recent normal startups following a typical nightly shutdown have resulted in NOx emissions of 28 lbs NOx, and 10 lbs. CO. For NOx, these results are the combination of OpFlex and early ammonia injection. Prior to the OpFlex and early ammonia projects, a typical regular startup would have produced approximately 120 lbs of NOx and 35 lbs of CO. (Note: Startups early in the project life produced highly variable emissions results). All of the CO reduction for recent startups is attributable to the shorter startup allowed by OpFlex, while 45 lbs. of NOx reduction are attributable to early ammonia injection, and 47 lbs. attributable to OpFlex. See the Summary Table below:

Summary:

Early ammonia injection and OpFlex have both been highly successful in reducing emissions during normal startups. The emissions during an extended startup will also be greatly reduced, although more testing and optimization is required before the results can be quantified. The table below is illustrative of starts after an overnight shutdown of one turbine, which has been a typical mode of operation during the past year. Somewhat higher emissions could occur for longer shutdowns.

Regular Startup Summary Table:

	Startup Emissions before Opflex/Early NH3	Reduction Attributable to Early NH3 Inj.	Reduction Attributable to OpFlex	Recent Regular Startup Results – Note 1 (Nov. 2006 – Feb. 2007)
NOx (lbs.)	120	45	47	28
CO (lbs.)	35	0	25	10

Note 1: Excludes startups after lengthy shutdown (>24 hours) or after HRSG forced cool down for maintenance.

Pack, Heidi K.

From: Hunt, Kelly [KHunt@Semprautilities.com]
Sent: Friday, April 13, 2007 8:54 AM
To: Waller, Fred A.; Pack, Heidi K.; Hartnett, Gary; LaBlond, Jason
Subject: FW: Palomar Energy Exceedances Covered Under Variance 4073, March 2007 YTD
Importance: High
Attachments: PEC Exceedance Covered Under Variance 4073 March 2007YTD.pdf

Please see email below.

Kelly Hunt
Generation Compliance Manager
San Diego Gas & Electric
2300 Harveson Place, SD1473
Escondido, CA 92029
760-432-2504 (Office)
760-432-2510 (Fax)
khunt@semprautilities.com

From: Waller, Fred A.
Sent: Friday, April 06, 2007 5:07 PM
To: Hunt, Kelly
Subject: Palomar Energy Exceedances Covered Under Variance 4073, March 2007 YTD
Importance: High

Kelly,
Please forward this Report of Violation to APCD Compliance (Mr. Jason LaBlond, Mr. Gary Hartnett and copy Ms. Heidi Gabriel-Pack).

Mr. LaBlond,
In a previous telephone conversation we discussed the reporting requirements of APCD Rule 19.2(d)(3)-Report of Violation. You indicated that an email notification to you will suffice to meet the reporting requirements. Additionally, Ms. Heidi Gabriel-Pack, approved monthly reporting of violations which are covered under Variance 4073.

In previous months in 2006, SDG&E had provided a monthly summary report of Violations/Exceedances covered under Variance 4073 to you and copied Mr. Gary Hartnett and Ms. Heidi Gabriel-Pack. SDG&E is submitting this summary report to notify the District of one exceedance in March 2007 covered by Variance 4073 which occurred at the Palomar Energy Center, 2300 Harveson Place, Escondido, CA 92009 .

If you have any questions, please feel free to call.

Fred Waller
Environmental Specialist-Generation
Office: 760 432 2507
Cell: 619 778 6029

SDGE
Palomar Energy Center
APCD Application Number 976846

Event	Date	Stack/ Unit	Clock Hour	Pollutant	Magnitude	Unit of Measure	Permit Condition/Limit	Cause/Reason	Comments	Date Reported to District
1	4/3/06	1	9:00	N/A	5 hrs 48 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
2	4/3/06	1	10:00	N/A	5 hrs 48 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
3	4/3/06	2	9:00	N/A	5 hrs 15 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
4	4/3/06	2	10:00	N/A	5 hrs 15 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
5	5/5/06	1	6:00	NOx	128.4	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
6	5/5/06	2	5:00	NOx	143.9	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
7	5/8/06	1	7:00	NOx	106.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
8	5/9/06	2	7:00	NOx	132.5	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
9	5/10/06	2	6:00	NOx	121.4	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
10	5/13/06	2	8:00	NOx	124.7	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
11	5/14/06	2	8:00	NOx	123.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
12	5/15/06	1	3:00	NOx	101.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
13	5/16/06	2	8:00	NOx	141.1	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
14	5/30/06	2	0:00	N/A	2 hrs 19 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	8/10/06
15	6/4/06	1	10:00	N/A	2 hr 26 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	7/9/06
16	6/13/06	1	19:00	NOx	117.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	7/9/06
17	6/13/06	1	19:00	N/A	2 hr 5 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	1/11/07

SDGE
Palomar Energy Center
APCD Application Number 976846

Event	Date	Stack/ Unit	Clock Hour	Pollutant	Magnitude	Unit of Measure	Permit Condition/Limit	Cause/Reason	Comments	Date Reported to District
18	6/15/06	1	10:00	N/A	2 hr 9 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	7/9/06
19	~~6/16/06~~	~~2~~	~~6:00~~	~~N/A~~	~~2 hr 9 min~~	~~Hrs/Mins~~	~~AQ 40: 2 hour startup duration~~	~~Typical regular startup.~~	Reported in error. Was not a violation.	~~7/9/06~~
20	6/16/06	2	6:00	NOx	109.9	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	8/10/06
21	7/2/06	1	9:00	N/A	5 hrs 32 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
22	7/2/06	1	10:00	N/A	5 hrs 32 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
	Aug 2006: No events to report.									
	Sept 2006: No events to report.									
23	10/11/06	1	11:00	N/A	4 hr 45 min	Hrs/Mins	AQ 39: 4 hour startup duration	Extended startup.	Covered under Variance #4073	11/13/06
24	10/12/06	2	6:00	N/A	2 hr 20 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	11/13/06
25	10/12/06	2	6:00	NOx	223.5	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	11/13/06
26	10/12/06	1	3:00	NOx	127.5	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	11/13/06
27	November 2006: No events to report.									
28	December 2006: No events to report.									
29	January 2006: No events to report.									
30	February 2006: No events to report.									
31	03/21/07	1	15	N/A	2 hrs 2 min	Hrs/Mins	AQ 40: 2 hour startup duration	Regular startup with generator testing required by WECC.	Covered under Variance #4073	4/9/07

Events 1, 2, 3 and 4 (exceedance of Extended Startup duration limit) were not reported in April 2006 due to confusion over the Reporting requirment of Rule 19.2(d) and the existing Variance 4068.
Event 14 was not reported in the July 2006 monthly report due to oversight made during the CEMS report review process.

SDGE
Palomar Energy Center
APCD Application Number 976846

Event	Date	Stack/ Unit	Clock Hour	Pollutant	Magnitude	Unit of Measure	Permit Condition/Limit	Cause/Reason	Comments	Date Reported to District
	Event 18 was not a violation of AQ 40: 2 hour Regular Startup duration limit. On 6/16/06 CTG 2 was actually started up within the 2 hour limit.									
	Event 17 was not reported in the July 2006 monthly report due to oversight made during the CEMS report review process.									
	Event 19 was not reported in the July 2006 monthly report due to oversight made during the CEMS report review process.									

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:

B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric per Condition No. F.3 and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073.

ACTION:

There being no motion made, the Air Pollution Control District Hearing Board, unable to discuss the report due to a lack of a quorum, acknowledged the submission of the report and at the discretion of the Board, continued this item to a future date. Member Rodriguez would be provided a copy of the report to review and if she determined that there needs to be further discussion on this report, the Clerk of the Board will schedule a special meeting of the Hearing Board to address concerns.

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

____
Kellie C. Kellogg, Deputy Clerk

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COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

2007 JUL 13 AM 8:44

THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

Daniel Baerman
Director of Electric Generation
2300 Harveson Place
Escondido, CA 92029
Tel: 760-432-2501
dbaerman@semprautilities.com

July 11, 2007

Ms. Kellie Kellogg
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Kellogg and Members of the Board:

Set forth below is SDG&E's second quarter 2007 report to the Hearing Board. This report will cover the items required by Condition F. 2. of the Board's April 26, 2007 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

The increments of progress table attached to the Board's order is included with this letter as Attachment 1. The primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E responded to the District on May 4, 2007, agreeing to the language of the draft S/A issued on April 20, 2007. SDG&E was informed on July 9, 2007 that the District intends to issue the final S/A no later than July 26, 2007. A rule amendment workshop concerning Rule 69.3.1 has been scheduled for August 3, 2007 by District staff.

2. Engineering or operational alternatives [Order, Condition F.2 (1)]

No additional information to report at this time.

3. NOx Emissions Data [Order, Condition F.2 (2)]

Information concerning NOx emissions from the facility during the previous quarter is included in Attachment 2. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.2 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data [Order, Condition F.2 (4)]

No further data has been requested by the Board at this time.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

Attachment 2

CT1 Quarterly Summary

	Tons	#
Apr-07	2.17	4,340
May-07	2.48	4,960
Jun-07	2.74	5,480
Total	7.39	14,780

Note: Total NOx includes startup emissions.

CT1 Startup Summary

	Tons	#
Apr-07	0.00	0.00
May-07	0.07	143.85
Jun-07	0.03	54.35
Total	0.10	198.20

CT2 Quarterly Summary

	Tons	#
Apr-07	2.65	5,300
May-07	2.69	5,380
Jun-07	2.52	5,040
Total	7.86	15,720

Note: Total NOx includes startup emissions.

CT2 Startup Summary

	Tons	#
Apr-07	0.03	63.13
May-07	0.15	307.98
Jun-07	0.14	271.20
Total	0.32	642.31

CT1 YTD Summary

	Tons	#
3Q06	8.61	17,220
4Q06	8.63	17,260
1Q07	8.88	17,760
2Q07	7.39	14,780
Total	33.51	67,020

Note: Total NOx includes startup emissions.

CT1 Startup YTD Summary

	Tons	#
3Q06	1.38	2,760
4Q06	0.52	1,040
1Q07	0.38	760
2Q07	0.10	200
Total	2.38	4,760

CT2 YTD Summary

	Tons	#
3Q06	8.95	17,900
4Q06	9.70	19,400
1Q07	8.73	17,460
2Q07	7.86	15,720
Total	35.24	70,480

Note: Total NOx includes startup emissions.

CT2 Startup YTD Summary

	Tons	#
3Q06	1.10	2,200
4Q06	0.52	1,040
1Q07	0.43	860
2Q07	0.32	640
Total	2.37	4,740

Data gathered from CEMS Startup/Shutdown Incident Reports
Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

There have been no excess emissions as defined in Board Order 4073 on April 26, 2007

Exhibit 3

SAN DIEGO AIR POLLUTION CONTROL DISTRICT HEARING BOARD

COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

Palomar Energy Center

2007 MAY 14 AM 8:35

PROPOSED INCREMENTS OF PROGRESS

(As of4/26/07)

THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

MILESTONE **DATE**

	Description	Permit Modification	Rule Change	Variance(s)
1	Variance 4068 hearing for 90-day issued			2/9/06
2	Emergency Variance 4069 for condition 21 issued to enable early ammonia injection.			2/23/06
3	*Palomar submits request for Rule Change to APCD*		*3/6/06*	
4	*APCD requests more data for rule change*		*3/14/06*	
5	*Mtg. with APCD concerning Data Requests*		*3/30/06*	
6	*Additional mtg. with APCD (Steve Moore) concerning Data Requests*		*4/4/06*	
7	*SDG&E submits requested data to APCD (Moore)*		*4/7/06*	
8	SDG&E submits summary of requested Permit Modification topics to APCD (covering matters of concern to staff beyond start up)	4/7/06		
9	Mtg. with APCD – QA/QC Plan Addendum (relating to some permit amendment topics)	4/11/06		
10	Request for Permit Modification Fee Estimate submitted to APCD by SDG&E	4/11/06		
11	*APCD (Moore) submits new data request to SDG&E (replaces 3/30 & 4/4 requests)*		*4/14/06*	
12	*Data submitted to APCD (Moore)*		*4/25/06*	
13	Variance 4073 Hearing			4/27/06
14	*Mtg. scheduled with APCD and CEC (in response to 4/7 letter from SDG&E) to discuss permit and rule amendment issues*	5/3/06 (COMPLETED 5/3/06)	*5/3/06* (COMPLETED 5/3/06)	
15	Proposed Permit Pre-application Mtg. with APCD and CEC –	5/19/06 (COMPLETED		

	Description		Permit Modification	Rule Change	Variance(s)
			5/9 & 5/23/06)		
16	Proposed Permit Application Submittal		5/31/06 (COMPLETED 5/31/06)		
17	Quarterly Progress Update (April – June) to Hearing Board				July 27, 2006 (Completed)
18	APCD Permit Application Completeness Review	Respond to APCD data requests while in process	June – July 2006 (Completed)		
19	*APCD drafts rule change*			*April – June 2006*	
20	Quarterly Progress Update (July - September)to Hearing Board				October 27, 2006 (Completed)
21	*APCD holds public workshop on rule amendment*			*July 2006*	
22	*APCD publishes draft rule for public comment*	*30-day public notice required*		*August 2006*	
23	*APCD prepares final rule adoption documents*	*Final rule and "staff report" are prepared for County Board of Supervisors review and adoption*		*September 2006*	
24	*Air Quality Advisory Committee*	*Appointed committee reviews and advises the Board*		*October 2006*	
25	*Board adoption of rule*	*Upon adoption, SDAPCD considers rule to be the version for compliance*		*October 2006*	
26	Proposed Permit Modification (ATC/PDOC) published for public comment	30-day public comment period	October 2006		
27	Final ATC/FDOC revisions	Final language that incorporates public comments is developed	November 2006		
28	Final ATC/FDOC		November		

	Description		Permit Modification	Rule Change	Variance(s)
	Issued		2006		
29	SDG&E petitions CEC for companion amendment of Conditions of Certification (CoC)		December 2006		
30	Quarterly Progress Update (October - December) to Hearing Board				Completed January 25, 2007
31	CEC issues amendment of CoC		March 2007		
32	Quarterly Progress Update (January - March) to Hearing Board				April 26, 2007;completed
33	**Extension of Regular Variance Granted**				**April 26, 2007**
34	See Tentative Rule Schedule for Rule 69.3.1, Exhibit 2 to Board Order Granted April 26, 2007.		May-December, 2007		
35	Quarterly Progress Update (April – June) to Hearing Board				July 26, 2007;
36	Quarterly Progress Update (October-December) to Hearing Board				January 17, 2008

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric per Condition No. F.3 and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073

ACTION:
ON MOTION of Member Rodríguez, seconded by Member Reider, the Air Pollution Control District Hearing Board accepted the quarterly report and directed San Diego Gas & Electric to provide the Board with revised Increments of Progress, reflecting the testimony of County Counsel representing the APCD. The revision to the Increments of Progress Schedule (IOPS) pertained to the accurate reflection of issuance of authority to construct or permit to operate. The revised IOPS is to be submitted to the Air Pollution Control District Hearing Board for the meeting of October 25, 2007.

AYES: Rodríguez, Tonner, Reider
ABSTAIN: Rappolt
RECUSED: Gabrielson

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

By Kellie C. Kellogg
Kellie C. Kellogg
Deputy Clerk

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric/Palomar Energy Center per Condition No. F.3, and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073.

ACTION:
ON MOTION of Member Gabrielson, seconded by Member Tonner, the Air Pollution Control District Hearing Board accepted the report from San Diego Gas & Electric.

AYES: Rappolt, Gabrielson, Tonner
ABSENT: Rodriguez

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

Kellie C. Kellogg

Kellie C. Kellogg, Deputy Clerk

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COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

2007 OCT 11 PM 3: 17

THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

Daniel Baerman
Director of Electric Generation
2300 Harveson Place
Escondido, CA 92029
Tel: 760-432-2501
dbaerman@semprautilities.com

October 11, 2007

Ms. Kellie Kellogg
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Kellogg and Members of the Board:

Set forth below is SDG&E's third quarter 2007 report to the Hearing Board. This report will cover the items required by Condition F. 2. of the Board's April 26, 2007 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

Referenced below are the increments of progress table attached to the Board's order; the primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E responded to the District on May 4, 2007, agreeing to the language of the draft S/A issued on April 20, 2007. SDG&E was updated by the District on October 8, 2007 on the progress of the issuance of the final S/A. The District intends to issue to final S/A no later than November 30, 2007. A rule amendment workshop concerning Rule 69.3.1 was held on August 3, 2007 by District staff.

2. Engineering or operational alternatives [Order, Condition F.2 (1)]

No additional information to report at this time.

3. NOx Emissions Data [Order, Condition F.2 (2)]

Information concerning NOx emissions from the facility during the previous quarter is included in Attachment 2. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.2 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data [Order, Condition F.2 (4)]

SDG&E received a letter dated September 14, 2007 from the District requesting a cold start and source test. The cold start and source test is scheduled to occur during the period of October 21, 2007 and October 26, 2007. District staff will be onsite to witness the test.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

CT1 3q07 NOx Summary

	Tons	#
Jul-07	3.01	6,011
Aug-07	3.21	6,419
Sep-07	2.97	5,932
Total	9.18	18,362

Note: Total NOx includes startup emissions.

CT1 Startup Only Summary

	Tons	#
Jul-07	0.33	658
Aug-07	0.17	341
Sep-07	0.19	386
Total	0.69	1,386

CT2 3q07 NOx Summary

	Tons	#
Jul-07	3.38	6,766
Aug-07	3.26	6,513
Sep-07	3.20	6,410
Total	9.84	19,689

Note: Total NOx includes startup emissions.

CT2 Startup Only Summary

	Tons	#
Jul-07	0.09	180
Aug-07	0.10	208
Sep-07	0.09	173
Total	0.28	561

CT1 YTD NOx Summary

	Tons	#
4Q06	8.63	17,260
1Q07	8.88	17,760
2Q07	7.39	14,780
3Q07	9.18	18,362
Total	34.08	68,162

Note: Total NOx includes startup emissions.

CT1 YTD Startup Only

	Tons	#
4Q06	0.52	1,040
1Q07	0.38	760
2Q07	0.10	200
3Q07	0.69	1,386
Total	1.69	3,386

CT2 YTD NOx Summary

	Tons	#
4Q06	9.70	19,400
1Q07	8.73	17,460
2Q07	7.86	15,720
3Q07	9.84	19,689
Total	36.13	72,269

Note: Total NOx includes startup emissions.

CT2 YTD Startup Only

	Tons	#
4Q06	0.52	1,040
1Q07	0.43	860
2Q07	0.32	640
3Q07	0.28	561
Total	1.55	3,101

Data gathered from CEMS Startup/Shutdown Incident Reports
Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

There have been no excess emissions as defined in Board Order 4073 on April 26, 2007

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric per Condition No. F.3 and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073.

ACTION:
ON MOTION of Member Gabrielson, seconded by Member Rodriguez, the Air Pollution Control District Hearing Board accepted the report.

AYES: Rappolt, Rodriguez, Gabrielson, Tonner
ABSTAIN: None

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

By Kellie C. Kellogg
Kellie C. Kellogg
Deputy Clerk

SDG&E®

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COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

2008 JAN 14 AM 8: 40

THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

Daniel Baerman
Director of Electric Generation
2300 Harveson Place
Escondido, CA 92029
Tel: 760-432-2501
dbaerman@semprautilities.com

January 13, 2008

Ms. Kellie Kellogg
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Kellogg and Members of the Board:

Set forth below is SDG&E's fourth quarter 2007 report to the Hearing Board. This report will cover the items required by Condition F. 2. of the Board's April 26, 2007 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

Referenced below are the increments of progress table attached to the Board's order; the primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E responded to the District on May 4, 2007, agreeing to the language of the draft S/A issued on April 20, 2007. The District issued the final S/A on November 6, 2007. A rule amendment workshop concerning Rule 69.3.1 was held on August 3, 2007 by District staff.

2. Engineering or operational alternatives [Order, Condition F.2 (1)]

No additional information to report at this time.

3. NOx Emissions Data [Order, Condition F.2 (2)]

Information concerning NOx emissions from the facility during the previous quarter is included in Attachment 1. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.2 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data [Order, Condition F.2 (4)]

SDG&E received a letter dated September 14, 2007 from the District requesting a cold start and source test. The cold start and source test occurred on October 22, 2007. District staff was onsite to witness the test. The District has the source test report and raw data as requested.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

CT1 4q07 NOx Summary

	Tons	#
Oct 07	2.59	5,179
Nov 07	2.92	5,831
Dec 07	3.52	7,038
Total	9.02	18,048

Note: Total NOx includes startup emissions.

CT1 Startup Only Summary

	Tons	#
Oct 07	0.18	356
Nov 07	0.13	262
Dec 07	0.03	52
Total	0.34	670

CT2 4q07 NOx Summary

	Tons	#
Oct 07	2.63	5,255
Nov 07	3.47	6,949
Dec 07	3.37	6,732
Total	9.47	18,936

Note: Total NOx includes startup emissions.

CT2 Startup Only Summary

	Tons	#
Oct 07	0.00	0
Nov 07	0.29	573
Dec 07	0.09	173
Total	0.37	747

CT1 12-Mo NOx Summary

	Tons	#
1Q07	8.88	17,760
2Q07	7.39	14,780
3Q07	9.18	18,362
4Q07	9.02	18,048
Total	34.48	68,950

Note: Total NOx includes startup emissions.

CT1 12-Mo Startup Only

	Tons	#
1Q07	0.38	760
2Q07	0.10	200
3Q07	0.69	1,386
4Q07	0.34	670
Total	1.51	3,016

CT2 12-Mo NOx Summary

	Tons	#
1Q07	8.73	17,460
2Q07	7.86	15,720
3Q07	9.84	19,689
4Q07	9.47	18,936
Total	35.90	71,805

Note: Total NOx includes startup emissions.

CT2 12-Mo Startup Only

	Tons	#
1Q07	0.43	860
2Q07	0.32	640
3Q07	0.28	561
4Q07	0.37	747
Total	1.40	2,808

Data gathered from CEMS Startup/Shutdown Incident Reports
Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

There have been no excess emissions as defined in Board Order 4073 on April 26, 2007

http://www.epa.gov/compliance/resources/policies/ej/ej_permitting_authorities_memo_120100.pdf

The 1998 EPA guidelines require Agencies to consider a wide range of demographic, geographic, economic, human health and risk factors. One of the three most important factors identified in the 1998 EPA guidelines is "whether communities currently suffer or have historically suffered from environmental health risks and hazards." The 1998 EPA Guidelines require the agencies conducting an Environmental Justice Analysis to define the sensitive receptor analysis to the actual unique circumstances affecting the minority community not a generic definition of sensitive receptor that was utilized by the District and the CEC.

Soils and Vegetation Analysis Nitrogen Deposition

Nitrogen deposition consists of the input of reactive nitrogen species from the atmosphere to the biosphere. Pollutants that contribute to nitrogen deposition derive mainly from nitrogen oxides and ammonia emissions, which the RCEC would emit during normal operation. Emissions of NOx and ammonia contribute to nitric acid deposition that occurs via precipitation and fog and in dry deposition as well. Acute exposures to ammonia can adversely affect plant growth and productivity, resistance to drought and frost, responses to insect pests and pathogens, mycorrhizal and other beneficial root associations, and inter-specific competition and biodiversity in sensitive plant communities. Of particular concern for the RCEC project is the effect on serpentine soil plant communities, which are know to be particularly sensitive to nitrogen deposition. Serpentine soils in the San Francisco Bay Area support native grassland plant communities that can provide habitat for rare and endemic species. Nonnative annual grasses have invaded most grassland communities in California, but highly specialized plant species that are adapted to nutrient-poor serpentinitic soils can thrive in soils that are deficient in nitrogen, potassium, phosphorus, and other nutrients due to a competitive advantage over the faster growing non-native annual species. The competitive advantage of these specialized plant species can be lost when nitrogen deposition from air pollution fertilizes serpentine plant communities and nitrogen ceases to be a limiting nutrient for plant growth. Increased nitrogen levels often allow non-native annual grasses to out-compete the native species.

The nearest serpentine plant community to the project area is Fairmont Ridge in Lake Chabot Regional Park, approximately four miles northeast of the RCEC. Fairmont Ridge is located in the East Bay Hills adjacent to Lake Chabot. The California Native Grasslands Association identifies this area as a Purple Needlegrass Grassland community, and is noted as an area of serpentine soil in the USFWS's 1998 Recovery Plan for Serpentine Soil Species of the San Francisco Bay Area.

The BAAQMD and the CEC have failed to analyze the projects nitrogen deposition impacts on serpentine soil plant communities in the Bay Area.

1

RECEIVED
09 FEB -5 AM 10:26
BAY AREA AIR QUALITY
MANAGEMENT DISTRICT

Weyman Lee, P.E., Senior Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Dear Mr. Lee:

We are writing to oppose the building of The Russell City Energy Center. We do not want to see The Bay Area Air Quality Management District issue a Prevention of Significant Deterioration (PSD) Permit. In fact, we wish all business relating to this project be halted immediately and all money spent on studying any proposal relating to this project also stopped.

The original idea for this power plant was made at a time of high stress during the mismanaged power struggles of the early 2000's (which were proven to be manipulated by Enron and other greedy corporate executives). The technology for this type of power plant is already outdated and we should be looking for cleaner, alternative energy sources. Not to mention the fact that this power plant is generating power for the affluent people of The Peninsula and that we, the people of Hayward and the surrounding communities, businesses, and schools will be victims of the pollution created by this facility. Another negative impact of The Russell Energy Center is its adverse effect on the ecology of the Bay and its tidal marshes. Many citizens have expressed a desire to RESTORE the Bay and its wetlands . . . trying to connect people with our own wonderful, natural resources. Besides polluting the air, water, and ground, this facility would be an eyesore and an ugly mark on the face of Hayward and The East Bay.

As a senior engineer and high ranking official with The Bay Area Air Quality Management District, we respectfully ask you to revoke the pending PSD permit and halt all action regarding The Russell Energy Center. Think carefully about such an important decision that most people of the region are against. Imagine if your family lived, worked, and went to school within one mile of such an ugly, dirty, inefficient, 1960's-vintage source of electricity.

Let's move ahead and think ahead to find a different way to operate and live the lives we live. Let's believe it and make happen! Let's start with stopping The Russell Energy Center.

Thank you for your time on this very important issue.

Sincerely, Timothy K. Devine - Timothy K. Devine
Leping Daphne Devine - [signature]
Arthur Jen - Arthur Jen
Rita Jen - Rita Jen (and "wa wa" our 12 yr. old chihuahua)

24702 Broadmore Ave.
Hayward, CA 94544-1126

February 6, 2009

VIA ELECTRONIC AND U.S. MAIL

Mr. Weyman Lee
Senior Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis St.
San Francisco, CA 94109
weyman@baaqmd.gov

Re: Proposed Statement of Basis and Proposed Permit Conditions for amended PSD Permit. Russell City Energy Center, Application # 15487

Dear Mr. Lee:

I am writing in opposition to the proposed Amended Federal Prevention of Significant Deterioration ("PSD") Permit for the Russell City Energy Center. The Russell City Energy Center would be located in my Congressional District in an area that is bordered by an important biological area on one side and a 69% minority and low-income residential community on the other side. My constituents are overwhelmingly opposed to a new power plant in an area that already suffers from poor air quality. The proposed PSD permit fails to meet federal requirements regarding the use of best available control technology ("BACT"). Although including limits on greenhouse gas emissions in the proposed permit is commendable, it must be done right. Unfortunately, the proposed permit is based on a defective BACT analysis. It fails to prevent air quality impacts that will contribute to violations of the national ambient air quality standards ("NAAQS") in the Hayward area should the Russell City plant be built. Finally, the draft permit does not adequately take into account the potential negative impact on critical habitats and wildlife along the adjacent Hayward Shoreline. For these reasons I urge you to not approve the proposed permit.

The San Francisco Bay Area is classified as non-attainment for Ozone, PM-10, and PM-2.5. In fact, the air quality in the Bay Area is so poor that the BAAQMD last year instituted "Spare the Air" days and has made it illegal to burn fireplaces on these days. How can the BAAQMD reconcile prohibiting my constituents from lighting a woodstove in order to protect air quality while approving a 600 megawatt fossil fuel powered plant that will produce 86.8 tons/year of PM-10?

I commend BAAQMD for recognizing the necessity of setting a CO_2 limit. Under the Clean Air Act, CO_2 is a pollutant subject to regulation and control using the BACT analysis. In this case, the District's analysis is faulty. The District completely ignores possible alternatives, such as new technologies or use of non-fossil fuel energy in combination with natural gas combustion. Instead the focus is primarily on the efficiency of the turbines that Calpine has already purchased. Relying on the California Energy Commission's (CEC) 2002 analysis, the District ignores efficiency improvements that have occurred during the last 6+ years and bases the CO2 limits on what the old technology can achieve. Such a foregone conclusion is in violation of the strict analysis required under the Clean Air Act. While the turbines purchased for Russell City may have represented the best available control technology in 2002, the BAAQMD cannot conclude that they meet BACT standards now.

The proposed permit does not address the impacts that the Russell City plant will have on nearby critical habitats and wildlife populations. The facility is slated for construction adjacent to 1,713 acres of salt, fresh, and brackish water marshes, seasonal wetlands, and public trails. This land is habitat for 208 bird species and many small mammals. Twenty of these species are rare, threatened, or endangered, including the Salt Marsh Harvest Mouse, Western Snowy Plover, and the California Clapper Rail. The endangered harvest mouse is endemic only to the Bay Area and is specially protected by a preserve in the Hayward marsh just down stream of a proposed flood control channel for the power plant. There is no analysis in the proposed permit regarding the direct and indirect impacts that emissions from the Russell City plant will have on these critical wildlife populations. The permitting process should not move forward until the impacts on these populations are fully known.

The proposed permit is faulty on numerous levels and should not be approved. The Bay Area is already a non-attainment area for ozone and particulate matter pollution. The sitting of a large new power plant in the Hayward community will exacerbate the health risks associated with air pollution, particularly for children and seniors in the nearby area and will lead to additional air quality non-attainment days. The District conducts an erroneous BACT analysis regarding CO2 emissions and relies on outdated information. Finally, the District fails to examine the effects that increased air pollution will have on adjacent wildlife. For these reasons, the BAAQMD should withdraw the proposed permit.

Sincerely,

Pete Stark
Member of Congress

Cc: Debbie Jordan, EPA

COMMUNITIES FOR A
BETTER
ENVIRONMENT

February 6, 2009

Weyman Lee, P.E., Senior Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Re: Draft PSD Permit for Russell City Energy Center

Dear Mr. Lee:

Communities for a Better Environment ("CBE") submits this letter in opposition to the proposed Prevention of Significant Deterioration ("PSD") Permit for a potential power plant in Hayward, CA, known as Russell City Energy Center.

CBE is a unique organization, employing community organizers, researchers, and lawyers to serve the cause of environmental justice by empowering underrepresented communities. Established in 1978 in California, CBE works with community members in low income communities of color to fight pollution. CBE's members in the Bay Area suffer disproportionately from the impacts of local and regional air pollution. Specifically, CBE works with communities in Alameda and Contra Costa counties, where industrial pollution sources exacerbate the impacts from goods movement and mobile sources from ports and the freeways that bisect these traditionally disempowered communities. Residents of the communities where CBE works, such as East Oakland and Richmond, are predominantly people of color whose voice is not heard by those who decide how much pollution they will breathe.

CBE has long worked statewide to ensure that new sources of energy are as clean they can be, and to prevent new power plants from exacerbating existing environmental injustice. CBE has specific concerns around construction of new fossil-fueled power plants in this era of increased awareness of impacts from particulate matter, carbon monoxide, VOCs and hazardous air pollutants. In addition to these concerns, the Russell City project is a step in the wrong direction in addressing green house gas emissions. We particularly object to the prospect of locating this new, dirty power plant in this part of the Bay Area, using old equipment not designed for the job it will perform.

CBE incorporates by reference the comments submitted by Citizens Against Pollution, Sierra Club, and other members of the Hayward and Bay Area communities, and joins them in asking you to perform a new analysis and circulate for public comment a new draft permit that meets the requirements of state and federal law.

Sincerely,
/s/
Shana Lazerow
Staff Attorney, Communities for a Better Environment

1440 Broadway #701 · Oakland, CA 94612 · Ph: (510) 302-0430 // Legal fax (510) 302-0438
In Southern California: 5610 Pacific Blvd., Suite 203 · Huntington Park, CA 90255 · Ph: (323) 826-9771

February 5, 2009

Weyman Lee,
P.E., Senior Air Quality Engineer
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San Francisco, CA, 94109
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weyman@baaqmd.gov.

Jack Broadbent
Air Pollution Control Officer
jbroadbent@baaqmd.gov
Brian Bunger, Esq. and Alexander Crockett, Esq.
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Lisa P. Jackson
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Environmental Protection Agency
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Table of Contents

I. INTRODUCTION

Thank you for the opportunity to comment[1] on the "amended" PSD permit for the Russell City Energy Center Application Number 15487. CAlifornians for Renewable Energy, Inc. ("CARE") objects to this permit. This also serves as a Complaint to Office of the Administrator of the U.S. Environmental Protection Agency (USEPA) and the California Air Resources Board (ARB) under 42 USC § 7604.[2] In the July 29, 2008 "Remand" of the United States Environmental Protection Agency (USEPA) Environmental Appeals Board ("EAB" or "Board") admonished the Bay Area Air Quality Management District ("BAAQMD" or "District") to "scrupulously adhere to all relevant requirements in section [40 C.F.R. § 124.10(d)] concerning the initial notice of draft PSD permits (including development of mailing lists), as well as the proper content of such notice" but the District failed to properly carry out this order.[3]

The District, like Pacific Gas and Electric (PG&E)[4] claim that when the EAB reviewed the original PSD permit appeal by Mr. Simpson "[t]he EAB, found no substantive defects in the PSD permit and its decision denied review of each of the substantive claims raised in the appeal." The remand order from the EAB decision does not deny review of the substantive PSD issues raised by Mr. Simpson but states that permit must be re-noticed and that the appeal board refrains from opining on the substantive PSD issues raised by Mr. Simpson "at this time."

> "The District's notice deficiencies require remand of the Permit to the District to ensure that the District fully complies with the public notice and comment provisions at section 124.10. Because the **District's renoticing of the draft permit will allow Mr. Simpson and other members of the public the opportunity to submit comments on PSD-related issues during the comment**

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[1] These comments were prepared by Michael E. Boyd, Bob Sarvey, and Rob Simpson. The comments on environmental justice are sponsored by Lynne Brown.

[2] This Complaint also includes an attached ratepayers citizens *Complaint Petition* filed before the California Public Utilities Commission (CPUC) in the *Application of Pacific Gas and Electric Company for Expedited Approval of the Amended Power Purchase Agreement for the Russell City Energy Company Project (U39E)* under Docket A.08-09-007 at: http://docs.cpuc.ca.gov/efile/CM/96544.pdf

[3] In re: Russell City Energy Center Permit No. 15487 USEPA EAB PSD Appeal No. 08-01

[4] See September 10, 2008 testimony at page 1-5 http://docs.cpuc.ca.gov/published/proceedings/A0809007.htm

period, the Board refrains at this time from opining on such issues raised by Mr. Simpson in his appeal."
Remand Order at page 3[5]

There are in fact several PSD related issues that the EAB appeals Board will have to review when the EAB is petitioned after the BAAQMD issues the draft permit. We have reviewed comments on the draft PSD permit from several major environmental organizations including the Sierra Club, Earth Justice, and Golden Gate University which we incorporate by this reference as if fully set forth by CARE and Rob Simpson. Despite claims otherwise the remand order from the EAB on the original Russell City PSD permit dismisses all substantive comments other than public notice requirement, this is simply not true. Major issues remain with this permit.

II. DISTRICT IS CIRCUMVENTING PUBLIC PARTICIPATION

The District continues to fail to implement 40 CFR 52.21, 40 CFR 124 and the Clean Air Act in its consideration of PSD permit for the Russell City Energy Center (RCEC). The District is circumventing public participation by failing to provide access to the administrative record. Petitioner(s)[6] have requested access to the record Since September 11 2008 without satisfaction. After no less than 10 requests in writing in person and by telephone the District has provided limited response providing no basis for the permitting. It has been impossible for the public to participate with no discernible docket for the facility as would be provided if the EPA issued the permit. When the EPA issues PSD permits there is an accessible docket and supporting documentation available on the EPA website. The Notice that was included for the PSD Permit at the District's website[7] failed to include a copy of the Application No. 15487.[8] With no discernable docket at the District there is no way that the public can identify the basis for permitting actions to effectively participate.

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[5] For a electronic copy of the *Remand Order*;
See:http://yosemite.epa.gov/OA/EAB_WEB_Docket.nsf/Filings%20By%20Appeal%20Number/EA6F1B6AC88CC6F085257495006586FB/$File/Remand...50.pdf

[6] Petitioner(s) are CARE, Rob Simpson, and Robert Sarvey.

[7] See http://www.baaqmd.gov/pmt/public_notices/2008/15487/index.htm

[8] A copy of the initial authority to construct (ATC) is also not provided on the District's website. On February 4, 2009 Rob Simpson request to see a copy of the Application No. 15487 at the District's Offices in San Francisco but none was provided.

The documents issued by the District are fatally flawed. The District has recently issued no less than 4 “fact sheets” for RCEC each in conflict with the others and none satisfying the requirements of 40 CFR 124.8.[9] The public can not rely on any of the “Fact Sheets” issued by the District. The District has also issued 2 different “Public Notices” and 2 different Statements of Basis, 3 of the 4 “Fact Sheets” the 2 different Public Notices and the 2 different Statements of Basis all make false claims of propriety by claiming that this is an amendment of a PSD permit when no such permit has ever been issued. “The Air District is proposing to incorporate the changes that have been made to the proposed project into the Federal PSD Permit that was initially issued in 2002, including the new project site.” Fact sheet 1 and 2. "The initial project, proposed by an affiliate of Calpine Corporation, received all necessary air quality permits and was licensed by the California Energy Commission (CEC) in 2002." Fact sheet #3

The "amended" Permit fails to comply with 40 CFR 51.166 (2) "Within one year after receipt of a complete application, the reviewing authority shall ... (vii) Make a final determination whether construction should be approved, approved with conditions, or disapproved".

In the December 10, 2008 *Corrected Notice of Public Hearing and Notice Inviting Written Public Comment on Proposed Amended PSD Permit* the District states " [t]he project will utilize the Best Available Control Technology to minimize emissions of these air pollutants as required by 40 C.F.R. Section 52.21. The proposed project will not consume a significant degree of any PSD increment." The Notice goes on to state:

> The proposed amended PSD Permit is a federal permit issued by the District on behalf of the United States Environmental Protection Agency (“EPA”). The District issues PSD permits under a Delegation Agreement with EPA. The District also participates in the California Energy Commission’s licensing process under state law and issues a District Authority to Construct incorporating the Energy Commission’s requirements. The District issued an Authority to Construct for the Russell City Energy Center jointly in the same document with the federal PSD Permit on November 1, 2007. District claims only the federal PSD Permit has been remanded, and only the federal PSD permit is being re-noticed. The Authority to Construct is not being reopened and this notice applies only to the proposed amended PSD permit.

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[9] 40 CFR 124.8 (3) For a PSD permit, the degree of increment consumption expected to result from operation of the facility or activity. (4) A brief summary of the basis for the draft permit conditions including references to applicable statutory or regulatory provisions.

CARE objects to this because the USEPA EAB revoked the PSD Permit on remand as was demonstrated in the second EAB Appeal[10] where the EAB found there was no federal PSD Permit to Appeal. So there is no PSD permit to amend and therefore the so-called "amended Permit" is a faux substitute for the "draft permit, providing public notice fully consistent with the requirements of 40 C.F.R. § 124.10.32" as directed by the EAB.

III. BACT IS PART OF THE CAA AND THE PDOC INCLUDES THE DISTRICT'S BACT ANALYSIS THEREFORE CLEARLY THE PDOC AND DRAFT PSD PERMIT ARE INTERDEPENDENT

Congress enacted the PSD provisions of the Clean Air Act (CAA) in 1977 for the purpose of, among other things, "insu[ring] that economic growth will occur in a manner consistent with the preservation of existing clean air resources."[11] The statute requires preconstruction approval in the form of a PSD permit before anyone may build a new major stationary source or make a major modification to an existing source[12] if the source is located in either an "attainment" or "unclassifiable" area with respect to federal air quality standards called "national ambient air quality standards" (NAAQS).[13] EPA designates an area as "attainment" with respect to a given NAAQS if the concentration of the relevant pollutant in the ambient air within the area meets the limits prescribed in the applicable NAAQS. CAA § 107(d)(1)(A), 42 U.S.C. § 7407(d)(1)(A). A "nonattainment" area is one with ambient concentrations of a criteria

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[10] See In re: Russell City Energy Center Permit USEPA EAB Appeal No. 08-07

[11] CAA § 160(3), 42 U.S.C. § 7470(3).

[12] The PSD provisions 2 that are the subject of the instant appeal are part of the CAA's New Source Review (NSR) program, which requires that persons planning a new major emitting facility or a new major modification to a major emitting facility obtain an air pollution permit before commencing construction. In addition to the PSD provisions, explained infra, the NSR program includes separate "nonattainment" provisions for facilities located in areas that are classified as being in nonattainment with the EPA's national Ambient Air Quality Standards. See infra; CAA §§ 171-193, 42 U.S.C. §§ 7501-7515. These nonattainment provisions are not relevant to the instant case.

[13] See CAA §§ 107, 160-169B, 42 U.S.C. §§ 7407, 7470-7492. NAAQS are "maximum concentration ceilings" for pollutants, "measured in terms of the total concentration of a pollutant in the atmosphere." See U.S. EPA Office of Air Quality Standards, New Source Review Workshop Manual at C.3 (Draft Oct. 1990). The EPA has established NAAQS on a pollutant-by-pollutant basis at levels the EPA has determined are requisite to protect public health and welfare. See CAA § 109, 42 U.S.C. § 7409. NAAQS are in effect for the following six air contaminants (known as "criteria pollutants"): sulfur oxides (measured as sulfur dioxide ("SO_2")), particulate matter ("PM"), carbon monoxide ("CO"), ozone

Continued on the next page

pollutant that do not meet the requirements of the applicable NAAQS. *Id.* Areas "that cannot be classified on the basis of available information as meeting or not meeting the [NAAQS]" are designated as "unclassifiable" areas. *Id.* The PSD Regulations provide, among other things, that the proposed facility be required to meet a "best available control technology" ("BACT")[14] emissions limit for each pollutant subject to regulation under the Clean Air Act that the source would have the potential to emit in significant amounts.[15]

The District processes PSD permit applications and issues permits under the federal PSD program, pursuant to a delegation agreement with the USEPA. The District's regulations, among other things, prescribe the federal and State of California standards that new and modified sources of air pollution in the District must meet in order to obtain an "authority to construct" from the District.[16]

In addition to the substantive provisions for EPA-issued PSD permits, found primarily at 40 C.F.R. § 52.21, PSD permits are subject to the procedural requirements of Part 124 of Title 40 of the Code of Federal Regulations (Procedures for Decisionmaking), which apply to most EPA-issued permits.[17] These requirements also apply to permits issued by state or local governments pursuant to a delegation of federal authority, as is the case here. Among other things, Part 124 prescribes procedures for permit applications, preparing draft permits, and issuing final permits, as well as filing petitions for review of final permit decisions. *Id.* Also, of particular relevance to this proceeding, part 124 contains provisions for public notice of and public participation in EPA

Continued from the previous page
(measured as volatile organic compounds ("VOCs")), nitrogen dioxide ("NO2") (measured as NOx), and lead. 40 C.F.R. § 50.4-.12. See CAA §§ 107, 161, 165, 42 U.S.C. §§ 7407, 7471, 7475.

[14] BACT is defined by the CAA, in relevant part, as follows:

> The term "best available control technology" means an emissions limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of such pollutant.

CAA § 169(3), 42 U.S.C. § 7479(3); see also 40 C.F.R. § 52.21(b)(12).

[15] CAA § 165(a)(4), 42 U.S.C. § 7475(a)(4); see also 40 C.F.R. § 52.21(b)(5).

[16] See Bay Area Air Quality Management District Regulation ("DR") New Source Review Regulation 2 Rule 2, 2-2-100 to 2-2-608 (Amended June 15, 2005), available at http://www.baaqmd.gov/dst/regulations/rg0202.pdf.

[17] See 40 C.F.R. pt. 124.5

permitting actions. See 40 C.F.R. § 124.10 (Public notice of permit actions and public comment period); *id.* § 124.11 (Public comments and requests for public hearings); *id.* § 124.12 (Public hearings).[18]

The District's Regulation 2 Rule 3 - 403 state "[w]ithin 180 days of accepting an [CEC Application for Certification] AFC as complete, the APCO shall conduct a Determination of Compliance [DOC] review and make a preliminary decision [PDOC] as to whether the proposed power plant meets the requirements of District regulations. If so, the APCO shall make a preliminary determination of conditions to be included in the Certificate, including specific BACT requirements and a description of mitigation measures to be required." Regarding the public notice requirement District's Regulation 2 Rule 3 - 404 goes on to state " [t]he preliminary decision [PDOC] made pursuant to Section 2-3-403 shall be subject to the public notice, public comment and public inspection requirements contained in Section 2-2-406 and 407 of Rule 2." Regulation 2 Rule 2 - 406 states " [t]he APCO shall make available for public inspection, at District headquarters, the information submitted by the applicant, and if applicable the APCO's analysis, and the preliminary decision to grant or deny the authority to construct including any proposed conditions... Furthermore, all such information shall be transmitted, upon the date of publication, to the ARB and the regional office of the EPA if the application is subject to the requirements of Section 2-2-405. Regulation 2 Rule 2 - 407 states " [i]f the application is for a new major facility or a major modification of an existing major facility, or requires a PSD analysis, or is subject to the MACT requirement, the APCO shall within 180 days following the acceptance of the application as complete, or a longer time period agreed upon, take final action on the application after considering all public comments. Written notice of the final decision shall be provided to the applicant, the ARB and the EPA..."

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[18] The requirement for EPA to provide a public comment period when issuing a draft permit is the primary vehicle for public participation under Part 124. Section 124.10 states that "[p]ublic notice of the preparation of a draft permit ... shall allow at least 30 days for public comment." 40 C.F.R. § 124.10(b). Part 124 further provides that "any interested person may submit written comments on the draft permit ... and may request a public hearing, if no public hearing has already been scheduled." Id. § 124.11.

In addition, EPA is required to hold a public hearing "whenever [it] ... finds, on the basis of requests, a significant degree of public interest in a draft permit(s)." Id. § 124.12(a)(1). EPA also has the discretion to hold a hearing whenever "a hearing might clarify one or more issues involved in the permit decision." Id. § 124.12(a)(2).

Since BACT is part of the CAA and the PDOC includes the District's BACT analysis therefore clearly the PDOC[19] and draft PSD Permit are interdependent on the findings from the federal BACT analysis conducted by the District purportedly in 2002 and again in 2007. The PSD permitting procedures at the heart of this dispute were triggered by RCEC's application to the CEC, on November 17, 2006, to amend the CEC's original 2002 certification of RCEC's proposal to build a 600-MW natural gas-fired, combined cycle power plant in Hayward, California.[20] According to the District Air Quality Engineer who oversaw the RCEC's PSD permitting, the District, after conducting an air quality analysis, issued its PDOC/draft PSD permit, notice of which it published in the Oakland Tribune on April 12, 2007. Declaration of Wyman Lee, P.E. ("Lee Decl.") ¶ 2. RCEC originally filed for certification by the CEC in early or mid-2001, and was initially certified by the CEC on Sept. 11, 2002, pursuant to the *Warren-Alquist Act*, see supra. During the initial CEC certification process, which also incorporated the District permitting, the District issued a PDOC/Draft PSD Permit to RCEC in November 2001. However, the District did not proceed to issue a final PSD permit because RCEC withdrew plans to construct the project in the spring of 2003. See Letter from Gerardo C. Rios, Chief, Permits Office, U.S. EPA Region 9, to Ryan Olah, Chief Endangered Species Division, U.S. Fish and Wildlife Service (Jun. 11, 2007). The amended CEC certification and PSD permitting were required purportedly because RCEC afterwards proposed relocating the project 1,500 feet to the north of its original location[21].

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[19] The District's process for permitting power plants is integrated with the CEC's certification process to support the latter's conformity findings, as reflected in the District's regulations specific to power plant permitting. See DR, Power Plants Regulation 2 Rule 3 §§ 2-3-100 to 2- 3-405, available at http://www.baaqmd.gov/dst/regulations/rg0202.pdf. These regulations state that "[w]ithin 180 days of [the District's] accepting an [application for certification] as complete [for purposes of compliance review], the [District Air Pollution Control Officer] shall conduct a ... review [of the application] and make a "preliminary decision" as to "whether the proposed power plant meets the requirements of District regulations." Id. § 2-3-403. If the preliminary decision is affirmative, the District's regulations provide that the District issue a preliminary determination of compliance (PDOC) with District regulations, including "specific BACT requirements and a description of mitigation measures to be required." Id. The District's regulations further require that "[w]ithin 240 days of the [District's] acceptance of an [application for certification] as complete," the District must issue a final Determination of Compliance ("FDOC") or otherwise inform the CEC that the FDOC cannot be issued. Id. § 2-3-405.9

[20] See Declaration of J. Mike Monasmith ("Monasmith Decl.") 2, Att. A.

[21] See Final PSD Permit, Application No. 15487 ("Final Permit") at 3.

IV. DISTRICT FAILS TO CONSIDER GREENHOUSE GAS EMISSIONS AS REGULATED POLLUTANTS

CARE also disagrees with the subject permit because it does not consider greenhouse gas emissions as regulated pollutants. Carbon Dioxide, CO_2, and Nitrous Oxide, N_2O, are components of the emissions expected from the Russell City Energy Center and yet they are not included as regulated emissions. The United States Environmental Protection Agency (USEPA) website[22] recognizes the climate change impacts of these emissions and yet these impacts were not included as pollutants.

This project has been located so as to disparately place environmental burdens upon low-income, minority residents, and this project significantly increases emissions of greenhouse gases responsible for global warming. The United States Supreme Court has affirmed that "[t]he harms associated with climate change are serious and well recognized," *Massachusetts v. EPA*, 549 U.S. 497, 127 S. Ct. 1438, 1455 (April 2, 2007).

In that case, the Supreme Court ruled that the Clean Air Act (CAA or Act) authorizes regulation of greenhouse gases (GHGs) because they meet the definition of air pollutant under the Act.[23] This is the provision entitling CARE to commence a civil action against the

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[22] http://epa.gov/climatechange/index.html

[23] 42 USC § 7604. Citizen suits

(a) Authority to bring civil action; jurisdiction

Except as provided in subsection (b) of this section, any person may commence a civil action on his own behalf—

(1) against any person (including (i) the United States, and (ii) any other governmental instrumentality or agency to the extent permitted by the Eleventh Amendment to the Constitution) who is alleged to have violated (if there is evidence that the alleged violation has been repeated) or to be in violation of (A) an emission standard or limitation under this chapter or (B) an order issued by the Administrator or a State with respect to such a standard or limitation,

(2) against the Administrator where there is alleged a failure of the Administrator to perform any act or duty under this chapter which is not discretionary with the Administrator, or

(3) against any person who proposes to construct or constructs any new or modified major emitting facility without a permit required under part C of subchapter I of this chapter (relating to significant deterioration of air quality) or part D of subchapter I of this chapter (relating to nonattainment) or who is alleged to have violated (if there is evidence that the alleged violation has been repeated) or to be in violation of any condition of such permit.

The district courts shall have jurisdiction, without regard to the amount in controversy or the citizenship of the parties, to enforce such an emission standard or limitation, or such an order, or to order the

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Administrator to perform such act or duty, as the case may be, and to apply any appropriate civil penalties (except for actions under paragraph (2)). The district courts of the United States shall have jurisdiction to compel (consistent with paragraph (2) of this subsection) agency action unreasonably delayed, except that an action to compel agency action referred to in section 7607 (b) of this title which is unreasonably delayed may only be filed in a United States District Court within the circuit in which such action would be reviewable under section 7607 (b) of this title. In any such action for unreasonable delay, notice to the entities referred to in subsection (b)(1)(A) of this section shall be provided 180 days before commencing such action.

(b) Notice

No action may be commenced—

(1) under subsection (a)(1) of this section—

(A) prior to 60 days after the plaintiff has given notice of the violation

(i) to the Administrator,

(ii) to the State in which the violation occurs, and

(iii) to any alleged violator of the standard, limitation, or order, or

(B) if the Administrator or State has commenced and is diligently prosecuting a civil action in a court of the United States or a State to require compliance with the standard, limitation, or order, but in any such action in a court of the United States any person may intervene as a matter of right.

(2) under subsection (a)(2) of this section prior to 60 days after the plaintiff has given notice of such action to the Administrator,

except that such action may be brought immediately after such notification in the case of an action under this section respecting a violation of section 7412 (i)(3)(A)or (f)(4) of this title or an order issued by the Administrator pursuant to section7413 (a) of this title. Notice under this subsection shall be given in such manner as the Administrator shall prescribe by regulation.

(c) Venue; intervention by Administrator; service of complaint; consent judgment

(1) Any action respecting a violation by a stationary source of an emission standard or limitation or an order respecting such standard or limitation may be brought only in the judicial district in which such source is located.

(2) In any action under this section, the Administrator, if not a party, may intervene as a matter of right at any time in the proceeding. A judgment in an action under this section to which the United States is not a party shall not, however, have any binding effect upon the United States.

(3) Whenever any action is brought under this section the plaintiff shall serve a copy of the complaint on the Attorney General of the United States and on the Administrator. No consent judgment shall be entered in an action brought under this section in which the United States is not a party prior to 45 days following the receipt of a copy of the proposed consent judgment by the Attorney General and the Administrator during which time the Government may submit its comments on the proposed consent judgment to the court and parties or may intervene as a matter of right.
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(d) Award of costs; security

The court, in issuing any final order in any action brought pursuant to subsection (a) of this section, may award costs of litigation (including reasonable attorney and expert witness fees) to any party, whenever the court determines such award is appropriate. The court may, if a temporary restraining order or preliminary injunction is sought, require the filing of a bond or equivalent security in accordance with the Federal Rules of Civil Procedure.

(e) Nonrestriction of other rights

Nothing in this section shall restrict any right which any person (or class of persons) may have under any statute or common law to seek enforcement of any emission standard or limitation or to seek any other relief (including relief against the Administrator or a State agency). Nothing in this section or in any other law of the United States shall be construed to prohibit, exclude, or restrict any State, local, or interstate authority from—

(1) bringing any enforcement action or obtaining any judicial remedy or sanction in any State or local court, or

(2) bringing any administrative enforcement action or obtaining any administrative remedy or sanction in any State or local administrative agency, department or instrumentality, against the United States, any department, agency, or instrumentality thereof, or any officer, agent, or employee thereof under State or local law respecting control and abatement of air pollution. For provisions requiring compliance by the United States, departments, agencies, instrumentalities, officers, agents, and employees in the same manner as nongovernmental entities, see section 7418 of this title.

(f) "Emission standard or limitation under this chapter" defined

For purposes of this section, the term "emission standard or limitation under this chapter" means—

(1) a schedule or timetable of compliance, emission limitation, standard of performance or emission standard,

(2) a control or prohibition respecting a motor vehicle fuel or fuel additive, or [1]

(3) any condition or requirement of a permit under part C of subchapter I of this chapter (relating to significant deterioration of air quality) or part D of subchapter I of this chapter (relating to nonattainment),,[2] section 7419 of this title (relating to primary nonferrous smelter orders), any condition or requirement under an applicable implementation plan relating to transportation control measures, air quality maintenance plans, vehicle inspection and maintenance programs or vapor recovery requirements, section 7545 (e) and (f) of this title (relating to fuels and fuel additives), section 7491 of this title (relating to visibility protection), any condition or requirement under subchapter VI of this chapter (relating to ozone protection), or any requirement under section 7411 or 7412 of this title (without regard to whether such requirement is expressed as an emission standard or otherwise); [3] or

(4) any other standard, limitation, or schedule established under any permit issued pursuant to subchapter V of this chapter or under any applicable State implementation plan approved by the Administrator, any permit term or condition, and any requirement to obtain a permit as a condition of operations[4] which is in effect under this chapter (including a requirement applicable by reason of section 7418 of this title) or under an applicable implementation plan.

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BAAQMD and CEC as its delegate. CARE intends to do so after the expiration of the 60 day waiting period.

V. SPECIFIC "AMENDED" PSD PERMIT COMMENTS

1. Pursuant to Regulation 2-2-306, a non-criteria pollutant PSD analysis is required for sulfuric acid mist emissions if the proposed facility will emit H_2SO_4 at rates in excess of 38 lb/day and 7 tons per year. According to the statement of basis RCEC has agreed to permit conditions limiting total facility H_2SO_4 emissions to 7 tons per year and requiring annual source testing to determine SO_2, SO_3, and H_2SO_4 emissions. If the total facility emissions ever exceed 7 tons per year, then the applicant must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist emissions." The permit is silent on whether the project could emit 38 pounds per day therefore a PSD analysis of sulfuric acid mist must be considered.

2. Page 159 of the Statement of basis states that the California 1 hour Ambient air quality Standard for NO_2 is not violated by the project. This statement is false as the California ambient air quality standard for NO_2 is 338 $\mu g/m^3$ while the projects impact combined with background is 370 $\mu g/m^3$ as shown in table 6 on page 159. The California Air Resource Board has promulgated new standards and established that deleterious health effects occur when NO_2 concentrations exceed 338 $\mu g/m^3$.[24] The statement of basis on page 92 states the correct one

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(g) Penalty fund

(1) Penalties received under subsection (a) of this section shall be deposited in a special fund in the United States Treasury for licensing and other services. Amounts in such fund are authorized to be appropriated and shall remain available until expended, for use by the Administrator to finance air compliance and enforcement activities. The Administrator shall annually report to the Congress about the sums deposited into the fund, the sources thereof, and the actual and proposed uses thereof.

(2) Notwithstanding paragraph (1) the court in any action under this subsection to apply civil penalties shall have discretion to order that such civil penalties, in lieu of being deposited in the fund referred to in paragraph (1), be used in beneficial mitigation projects which are consistent with this chapter and enhance the public health or the environment. The court shall obtain the view of the Administrator in exercising such discretion and selecting any such projects. The amount of any such payment in any such action shall not exceed $100,000.

[24] See http://www.arb.ca.gov/research/aaqs/no2-rs/no2-doc.htm

hour NO_2 California standard. Page 92 also states that the project does not violate the state 1 hour standard because the projects maximum impacts are 130 $\mu g/m^3$ and background is 130 $\mu g/m^3$. It is not clear in the permit which is the actual impact from NO_2 emissions.

3. Page 26 of the permit states, "A second potential environmental impact that may result from the use of SCR involves ammonia transportation and storage. The proposed facility will utilize aqueous ammonia in a 29.4% (by weight) solution for SCR ammonia injection, which will be transported to the facility and stored onsite in tanks. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident. This risk will be addressed in a number of ways under safety regulations and sound industry safety codes and standards, including the implementation of a Risk Management Program to prevent and respond to accidental releases." The project if allowed to use SCR can eliminate the impact from transportation accidents by utilizing a technology called NO_xOUT ULTRA®. There are dozens of systems in service, one in Southern California at UC Irvine. The plant manager welcomes calls about the system (Jerry Nearhoof, 949 824 2781). Most of the UC campuses have decided not to risk bringing ammonia tankers thru campus or having to offload or storing ammonia. NO_xOUT ULTRA is being specified for new units at UCSD, University of Texas and Harvard. For Aqueous systems you need a tank, a control module, pumps, carrier air, and a vaporizer. The vaporizer requires some heat input to allow the system to drive off or vaporize the water. The resultant ammonia gas and carrier air is sent to an ammonia injection grid (AIG) which uniformly injects the ammonia in the flue gas just ahead of the SCR catalyst. In comparison, the NO_xOUT ULTRA system requires a tank for the urea. The urea is usually in a 50 to 32 % solution. Urea, has no vapor pressure. Has no smell. If it spills the evaporated water will leave behind a pile of crystal salts. There are no hazards labeling or training required for the operator and absolutely no risk to adjacent facilities or neighbors. Like aqueous ammonia NO_xOUT ULTRA needs controls to manage the input from the power plant indicating how much reagent the SCR requires. Like aqueous ammonia the system requires an air blower and heater to heat the air. The heated air goes to a decomposition chamber instead of a vaporizer. In the decomposition chamber, the urea solution is added. The water in the urea solution is vaporized and the additional heat required will then decompose the urea to ammonia. The gas/carrier air is then swept to the AIG and to the SCR. If the urea is pump is stopped and air is left in service the

chamber is sweep clear of ammonia in less than 7 seconds. So in an emergency, there is very little if any ammonia exposure. Other than the 7 seconds between the chamber and the AIG, the only exposure is the harmless urea. There is a premium for urea solutions vs. aqueous ammonia and the capital cost for the process vs. an aqueous ammonia system is competitive. The cost for a decomposition chamber is higher than an ammonia vaporizer, but the cost of urea storage is less than an ammonia tank due to all the hazard considerations. Since the ammonia will be transported thru an Environmental Justice community all precautions should be taken since the community already has a high number of toxic and hazardous materials stored and transported through it. Attachment 1 contains a brochure on the NO_xOUT ULTRA system.

4. Page 26 of the permits BACT analysis states,

> The Air District also evaluated the potential for ammonia slip emissions to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. Moreover, the Air District has found that the formation of ammonium nitrate in the Bay Area air basin appears to be constrained by the amount of nitric acid in the atmosphere and not driven by the amount of ammonia in the atmosphere, a condition known as being "nitric limited". Where an area is nitric acid limited, emissions of additional ammonia will not contribute to secondary particulate matter formation because there is not enough nitric acid for it to react with. Therefore, ammonia emissions from the SCR system are not expected to contribute significantly to the formation of secondary particulate matter. Any potential for secondary particulate matter formation is at most speculative, and would not provide a reason to eliminate SCR as a control alternative.

The District has based its conclusion that the project area is nitric limited on a BAAQMD Office Memorandum from David Fairly to Tom Perardi and Rob DeMandel, "A First Look at NO_x/Ammonium Nitrate Tradeoffs, dated September 8, 1997. The District memorandum outlines two objectives. One, whether the Bay Area is ammonia limited, and two, to what extent reducing NOx emissions would reduce ammonium nitrate. Among the findings presented in this memorandum, the District staff believes that ". . . San Jose and Livermore are not ammonia limited' during wintertime high particulate matter conditions; rather, these two areas are nitric acid limited. Other findings stated in the memorandum include recognition that the District analyses do not provide solid "...footing to do planning or to provide guidelines to industry for such tradeoffs [between NO_x and ammonium nitrate]." Thus, the District memorandum is very specific to say that San Jose and Livermore, not the entire Bay Area air basin or the project location, are nitric acid limited, and that no guidelines have been formed to address the ammonia induced PM10/PM2.5 problem.

This project is located in the Hayward area of Alameda County, which is outside of the area where the District has made the determination; therefore, the Districts contention that the increase in ammonia emissions from this facility would not cause any increase in PM10/PM2.5 emission impacts is not supported by the District memorandum. The District needs a site specific study to make such broad conclusions and an analysis needs to be conducted not only to evaluate the use of SCR but also to asses environmental impacts of secondary particulate and its effect on the deterioration of air quality in the BAAQMD. The projects PM 2.5 impacts may be much larger than modeled and should be subject to additional analysis.

The District needs to conduct a BACT analysis on the ammonia emission slip limit. Several Projects including the ANP Blackstone Project have 2 ppm ammonia slip limits which are designed to prevent additional particulate matter formation and limit the transportation of ammonia though the surrounding communities.

5. The statement of basis concludes that a CO limit of 4 ppm over 3 hours is BACT. (Page 32) That conclusion was determined from analyzing emissions data from the Metcalf Energy Center. The Metcalf energy center does not utilize an oxidation catalyst for CO emissions so to base the permit decision on a project that contains no CO abatement device when the proposed Russell City Project will have an oxidation catalyst is an inappropriate comparison. Several Projects have achieved a lower CO emissions rate in conjunction with a 2ppm NO_x limit. One is the Salt River Project in Arizona which meets a 2ppm NO_x limit and a 2ppm CO limit that has been verified by source testing. The Las Vegas Cogeneration facility has a 2ppm NOx limit and a 2ppm CO limit.[25] Based on available information the district should choose a 2ppm CO limit for this project to comply with BACT. [26]

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[25] See http://cfpub1.epa.gov/rblc/cfm/ProcDetl.cfm?facnum=25662&procnum=102130
[26] See http://cfpub1.epa.gov/rblc/cfm/ProcDetl.cfm?facnum=26002&Procnum=103714

6. The district reports on page 41 of the permit that the Palomar Project has reduced NO_x start up emissions by introducing ammonia earlier in the start up cycle and using the OP-Flex system. "By taking these steps, the facility was able to optimize its operating procedures and bring down its startup emissions. The facility has reported encouraging results from the first few months of operating with these new techniques." The district then eliminates the technology because only one quarterly report from the quarterly variance reports to the SDPCD is available on the success of the new technology. "It is not possible, however, to determine based on this limited data what reductions, if any, are attributable to OpFlex and what reductions are attributable to the operational changes the facility was able to make for its specific turbines. Moreover, the facility has operated only for a relatively limited period of time with these enhancements, and so it is difficult to determine from the limited data available so far what improvements can reliably be achieved throughout the life of the facility. Included as attachment 2 to these comments are three more Hearing Board Variance 4073; Quarterly Reports" that were acquired through a public records request. By utilizing earlier ammonia injection and utilizing the OP flex system the Russell City Power Projects start up emissions can be reduced drastically. Its must be required as BACT since it has been proved in operation for over a year and it will reduce the projects potential to violate the new California NO_2 standard and eliminate the deficient daily emission reduction credits needed for the facility as explained below.

7. Table B-12 on page 147 of the statement of basis lists the maximum daily NO_2 emissions of 1,553 pounds per day. The permit proposes to only offset 134.6 tons of NO_2 per year or 737.54 pounds per day. The ERC's will not provide adequate mitigation for the potential 1533 pounds per day of NO_2 emitted by the project. The surrendered ERC's only mitigate 49% of the projects daily NO_2 emission due to the excessive start up and shut down emissions. This could leave as much as 49% of the projects daily NO_2 emissions unmitigated. On days when violations of ozone standards occur the projects emissions would contribute to violations of the standard.

8. The ERC's listed for the Russell City Energy Center have already been pledged to another Calpine Project in the BAAQMD. Certificate Number 687 for 43.8 tons of POC has

already been pledged to offset emission increases for the East Altamont Energy Center. Certificate Number 602 for 41 tons of POC was also allocated to the East Altamont Energy Center. Since these ERC's were subject to extensive scrutiny by the CEC, the SJVUAPCD and the public this transfer of ERC's should be subject to public notice and comment.

9. The BAAQMD now requires a fee for greenhouse gas emissions.[27] The license should acknowledge the green house gas fees to be paid to the BAAQMD. Greenhouse gas emissions are evaluated based on the natural gas consumption of the project. The ammonia slip will also contribute to greenhouse gas emissions from the project and should be included in the evaluation. The District should do a true BACT analysis on greenhouse gases and not just adopt the maximum allowable greenhouse gas emission per megawatt as specified by the State.

10. **Environmental Justice**[LB] ---The District state on page 65 of the statement of basis "Another important consideration that the Air District evaluated is environmental justice. The Air District is committed to implementing its permit programs in a manner that is fair and equitable to all Bay Area residents regardless of age, culture, ethnicity, gender, race, socioeconomic status, or geographic location in order to protect against the health effects of air pollution. The Air District has worked to fulfill this commitment in the current permitting action." Other than issue the public notice in Spanish on its website for comments on this permit the district has done nothing different from any other permitting actions to evaluate the specific environmental justice impacts of this project on the minority community. The District believes by conducting a health risk assessment which it does for every project or modeling criteria pollutant impacts the district believes that its met its environmental justice obligation in the permitting process. The District reasoning is that since the modeling they performed meets their requirements for the general population the minority community can't possibly be harmed by the projects emissions. The very purpose of the environmental justice evaluation is to identify the minority population's health vulnerabilities and existing pollution and hazardous materials sources and identify how the project affects the minority community not the general population. The District evaluation falls short of even the basic environmental justice analysis.

Poor health and premature death are by no means randomly distributed in Alameda County. Low-income communities and communities of color suffer from substantially worse health outcomes and die earlier. Many studies note that these differences are not adequately explained by genetics, access to health care or risk behaviors but instead are to a large extent the result of adverse environmental conditions. The Russell City Power Project is sited in a geographic area already disproportionately burdened by illness and death. The presence of a disproportionate concentration of persons with asthma, chronic lung disease, congestive heart failure and other chronic conditions that are exacerbated by air pollution must factor into the decision of where to site this power plant. Especially because these populations affected by the power plant are predominately low-income communities of color. The minorities are not distributed throughout the population randomly but instead are concentrated disproportionately in proximity to the proposed Hayward site.

As noted in the CEC staff report, Hayward is more ethnically diverse, with a significantly larger, non-white population than Alameda County. In the two zip codes near the site 94544 and 94545 residents have a high mortality rate and on average they live five years less than the county- wide expectancy rate. Death rates from air pollution-associated diseases such as coronary heart disease, chronic lower respiratory disease, are substantially and statistically significantly higher than those for the County, representing an ongoing, excess burden of mortality. The rate of death from chronic lower respiratory diseases was 43 percent higher and the rate from coronary heart disease was 16 percent higher than the County rate. Hospitalizations due to air pollution- associated diseases are substantially higher in the zip codes close to the proposed site. From 2003 to 2005 the hospitalization rates for coronary heart disease, chronic obstructive pulmonary disease, congestive heart failure and asthma in the two zip codes nearest the proposed site, 94544 and 94545, was statistically significantly higher than Alameda County rates. Which means hospitalizations due to air pollution will not occur by chance. Specifically, hospitalization rates due to coronary heart disease was 60 percent higher; chronic obstructive pulmonary disease, 20 percent higher; congestive heart failure, 35 percent higher; and asthma

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[27] See http://www.baaqmd.gov/pln/climatechange.htm#GHGFee

hospitalization rates 14 percent higher than the County rate. A disproportionate burden of the cost of these preventable hospitalizations, particularly among the uninsured, is borne by Alameda County taxpayers. The fact that rates of these illnesses are significantly higher in the proposed plant area than in the rest of the County suggests a level of vulnerability in this population that is higher than the rest of the County. A proper Environmental Justice process begins with the demographic screening analysis which the CEC staff has performed and concluded that the majority of the community surrounding the RCEC is indeed minority. There is no dispute on that fact. At that point in the analysis the public participation process should have been used to define and evaluate environmental justice concerns. Community leaders and community stakeholders should have been consulted to identify their concerns. The District should have consulted with the county health agencies to identify existing health concerns. Then the District should have examined the synergistic effects of existing pollution that already exists in the community. In this community there are multiple environmental stresses. There is a railroad which passes though the area, there are truck terminals and other heavy industries and a sewage treatment plant in the affected community. The District has not identified and examined the existing local sources of criteria pollutants and toxic emissions and evaluated their impacts in conjunction with the emissions from the RCEC.

Environmental Justice Guideline's emphasize the importance of reaching out to the community and involving them in the development of the mitigation measures and alternatives. A good example of how this process is done is the community outreach that was performed by the CCSF in the SFERP proceeding. In that proceeding over 20 community meetings were held and the community was engaged in deciding appropriate mitigation measures and alternatives. Public advocacy groups were consulted and included in the decision making. Air Quality Monitoring stations were set up in the community to examine existing air quality in the affected community.[28]

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[28] See http://www.energy.ca.qov/sitin~cases/sanfrancisco/documents/applicant/data response 1Al2004-07-08 DATA RESPONSE-PDF

The environmental justice argument against the RCEC is made even stronger by the fact that the risk assessment model may underestimate the health risk of substances that interact synergistically, as pointed out in the risk assessment guidelines. The potential for multiple and varied air and non-airborne pollutants to act synergistically, rather than additively as assumed by the risk assessment model, requires an analysis of the overall toxic burden associated with this Hayward location. Low-income, minority populations have historically been exposed to a much higher burden of environmental toxicity. The District's Environmental Justice Analysis does not accept the existing ordinate disease nor does it adequately measure the health risks associated with potential, synergistic interactions among the substances, profoundly important aspects of environmental justice.

Siting the Russell City Power plant in Hayward will disproportionately impact the geographic area, home to a comparatively high, non-white population that is already burdened by existing morbidity and mortality from disease associated with air pollution or other existing environmental factors. It is that burden that must be analyzed to truly determine if the minority population near the proposed power plant will be affected. The district is required to address environmental justice issues in the PSD process.[29] The 1998 EPA guidelines require Agencies to consider a wide range of demographic, geographic, economic, human health and risk factors. One of the three most important factors identified in the 1998 EPA guidelines is “whether communities currently suffer or have historically suffered from environmental health risks and hazards.” The 1998 EPA Guidelines require the agencies conducting an Environmental Justice Analysis to define the sensitive receptor analysis to the actual unique circumstances affecting the minority community not a generic definition of sensitive receptor that was utilized by the District and the CEC.

VI. COMMENTS AND REQUESTS FOR CLARIFICATION ON THE "AMENDED" PSD PERMIT STATEMENT OF BASIS

The Russell City Energy Center, described in detail in subsequent sections of this document, is a proposed 600 megawatt natural gas fired combined-cycle power plant, proposed to be built near the corner of Depot Road and Cabot Boulevard, in Hayward, CA. *SOB at page 3*

1 Is this the correct location or would the end of Depot road or the “southeastern shore of the San Francisco bay in the City of Hayward” be more accurate?

2. Could the site descriptions in question 1 affect public interest or informed participation?

The Energy Commission’s licensing decision is appeal able directly to the California Supreme Court. *SOB at 6*

3. Does the Energy Commission have other administrative appeal venues?

4. Could disclosure of other Energy Commission appeal venues affect public interest or informed participation?

The Air District Authority to Construct is appealable to the District’s Hearing Board and subsequently to the Superior Court of California. Federal PSD Permits are initially appealable the EPA’s Environmental Appeals Board in Washington, D.C., and subsequently to federal court. *SOB at 6*

5. Could someone appeal directly to Federal court or must they appeal to the EAB first?

6 Could disclosure of other appeal venues affect public interest or informed participation?

The proposed Russell City facility was initially licensed in 2002, but it was relocated and so its permits had to be updated. *SOB at 6*

7. Why was it relocated?

8. Could the reason for relocation affect public interest or informed participation?

The amended authority to construct (ATC) and the amended Federal PSD Permit were issued jointly in the same document, in accordance with the Air District’s administrative practice. *SOB at 6*

9. Is the PSD permit a component of the ATC or is the authority to construct valid without a PSD permit?

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[29] See http://www.epa.gov/compliance/resources/policies/ej/ej_permitting_authorities_memo_120100.pdf

The Air District's ministerial Authority to Construct permit is appealable only on the narrow issue of whether the Air District correctly incorporated the Energy Commission's conditions of certification in the Authority To Construct. That is, an error in transcribing a permit condition from the Energy Commission's license into the Authority to Construct is appealable, but an appeal cannot seek to revisit substantive issues of what permit conditions are appropriate and required, which are addressed during the CEC licensing process and on any appeals there from. *SOB footnote 2 at 6*

10. Did the District comply with CEC AQ-SC10?
11. Could the district be compelled to comply with this condition of the CEC decision?
12. Could this information affect public interest or informed participation?

AQ-SC10 In lieu of complying with AQ-SC7, AQ-SC8, and AQ-SC9, the project's combustion turbine/HRSG units shall be designed and built with equipment and control systems to minimize start-up times and emissions. These could include the Fast-Start technology with an integrated control system and a once-through Benson boiler design, appropriate system configuration and equipment to facilitate operating chemistry during starting sequences, and an auxiliary boiler. *CEC final Decision.*

All appeal avenues have therefore been exhausted, and the state-law Energy Commission license and District Authority to Construct are not subject to further review. *SOB at 7*

13. Is this statement correct?
14. Does the Authority to Construct comply with all current laws?
15. Is the Authority to Construct a document that has been published by the District?
16. Where can the public locate the Authority to Construct?
17. Please provide a copy of the Authority to Construct.
18. Could availability of the Authority to Construct affect public interest or informed participation?

The Environmental Appeals Board ruled that the Air District had not mailed notice of the proposed amended Federal PSD Permit to several parties that were entitled to it, and so it remanded the permit to the District to re-notice the proposed permit and provide the public with a further opportunity to comment. *SOB at 7*

19. Is this what the EAB remand stated?
20. Could further disclosure of details of the Remand affect public interest or informed participation?

The analysis of elements that are not being amended shows that the conditions from the initial permit that are not being changed meet current applicable legal standards for Federal PSD Permits, and that they would comply with current PSD requirements even if they were being proposed anew at this time. *SOB at 7*

21. What aspects of the PSD permit are in conflict with state law; which state law?

The Air District is not reopening the state-law permitting process that was completed under the Warren-Alquist Act (culminating with the Energy Commission's license for the project and the District's incorporation of the Energy Commission's licensing conditions into the Authority to Construct permit). Those permitting actions under state law are final and all avenues for appeal have been exhausted. The Environmental Appeals Board's remand of the Federal PSD Permit to be re-noticed does not implicate these state-law permits. They are separate legal entities and the Environmental Appeals Board has not questioned their continued validity. *SOB at 7*

22. Is this a correct statement?

23. What if prior permitting actions do not comply with present laws?

The District invites all interested parties to comment on the Draft Amended PSD Permit. The legal requirements for PSD Permits are contained in Section 52.21 of Title 40 of the Code of Federal Regulations (40 C.F.R. Section 52.21). Comments should address only the Federal PSD issues in this proceeding. The District is not considering any issues related to the state-law Authority to Construct permit or the California Energy Commission's license for the project, or any other non-PSD issues. *SOB at 7*

24. If this is the Statement of Basis for the Federal action and the District has raised issues in the statement, are all issues raised by the district part of the basis for this permit and thereby subject to comment by the public or is this merely a venue for the district to create a record without allowing public participation; i.e., is this an ad-hoc rationalization for an action the District has already taken?

25. Could this restriction of public participation affect public interest or informed participation?

The Russell City Energy Center is a proposed 600 megawatt ("MW") natural gas fired combined cycle power plant proposed to be built by Russell City Energy Company, LLC, which is owned 65% by a subsidiary of Calpine Corporation and 35% by General Electric Corporation. *SOB at 9*

26. Why was General Electric ownership not disclosed on the Public notice?

27. Could this information affect public interest or informed participation?

The proposed facility would be located at 3862 Depot Road, near the corner of Depot Road and Cabot Boulevard, in Hayward, CA. *SOB at 9*

28. Why was the address changed?

29. What is the Address identified in the Authority to Construct?

The facility was originally permitted in 2002, but was subsequently relocated approximately 1,500 feet north of the original site and required the facility's permits to be amended. *SOB at 9*

30. Exactly How far is the new site from the old site?

31. Could this information affect public interest or informed participation?

The Russell City Energy Center will consist of the following permitted equipment: S-1 Combustion Turbine Generator (CTG) #1, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-1 Selective Catalytic Reduction System (SCR) and A-2 Oxidation Catalyst. *SOB at 10*

S-2 Heat Recovery Steam Generator (HRSG) #1, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-1 Selective Catalytic Reduction (SCR) System and A-2 Oxidation Catalyst. *SOB at 10*

S-3 Combustion Turbine Generator (CTG) #2, Westinghouse 501F, 2,038.6 MMBtu/hr maximum rated capacity, natural gas fired only; abated by A-3 Selective Catalytic Reduction System (SCR) and A-4 Oxidation Catalyst. *SOB at 10*

S-4 Heat Recovery Steam Generator (HRSG) #2, with Duct Burner Supplemental Firing System, 200 MMBtu/hr maximum rated capacity; Abated by A-3 Selective Catalytic Reduction (SCR) System and A-4 Oxidation Catalyst. *SOB at 10*

S-5 Cooling Tower, 9-Cell, 141,352 gallons per minute. *SOB at 10*

S-6 Fire Pump Diesel Engine, Clarke JW6H-UF40, 300 hp, 2.02 MMBtu/hr rated heat input. *SOB at 10*

32. Please answer the following equipment questions.

Turbine Questions

a. What are the identifying or serial numbers of the proposed turbines?

b. What year were they manufactured?

c. What year did Calpine acquire them?

d. How much did Calpine pay for the turbines?

e. Has Calpine sold any similar turbines in the last 3 years? If so for how much?

f. Are the turbines used?

g. If so, Have they been refurbished?

h. Where were they originally in service?

I. Provide emission records from their use.

J. Were emission reduction credits earned when the turbines were retired?

K. Please identify more efficient turbines or alternative configurations that would result in higher efficiency or reduced emissions.

33. Calpine's attorney represented the steam turbine may be removed from a partially built plant in another state. Please answer the above "turbine questions" for this equipment.

34. Is other equipment planned to be used that has been in use in other locations? If so please answer "turbine questions" for this equipment.

35. Does Calpine have any facilities planned or in operation that are more efficient or emit comparably fewer emissions than this facility?

36. Does Calpine's partner GE manufacture any more efficient or cleaner operating equipment than that which is proposed?

37. What is the estimated CO_2 output for this facility?

38 What would the CO_2 output be from the most efficient equipment available?

39. Could the answers to questions 30-36 affect public interest or informed participation?

Load Following: Facility would be operated to meet contractual load and spot sale demand, with a total output less than the base load scenario. *SOB at 11*

40. Does this mean that the facility can operate as a "peaker" ?

41. Could this affect the emission calculations?

EPA recently promulgated new amendments to the PSD regulations addressing PM2.5, and these amendments expressly incorporated the earlier guidance and made clear that for permit applications such as this one that were submitted and complete before July 15, 2008, permitting agencies should use the PM10 surrogate approach from the 1997 guidance. *SOB at 17 to 18*

38. When was this one submitted for public comment?

39. Is the permit subject to 40 CFR 51.166 (2) Within one year after receipt of a complete application, the reviewing authority shall (vii) Make a final determination whether construction should be approved, approved with conditions, or Disapproved?

40. What would be the effect of District compliance with 40 CFR 51.166?

See 73 Fed. Reg. 28231, 28349-50 (May 16, 2008) (to be codified at 40 C.F.R. § 52.21(i)(1)(xi)). The Air District expects shortly to be classified as "attainment" or "non-attainment" of the new PM2.5 standard by EPA. If the District is classified as "non-attainment", PM2.5 will be regulated under the District's NSR permitting program and will no longer be subject to PSD permit requirements. Permit applications such as this one that were received under the existing designation will continue to be processed under the PSD program using the surrogate approach as directed by EPA, however; *SOB footnote 7 at 18*

41. Has the District already been classified?

42. Would classification information, if already known, potentially affect public interest or informed participation?

U.S EPA lowered the 24-hour PM2.5 standard from 65 $\mu g/m^3$ to 35 m^3in 2006. EPA issued attainment status designations for the 35 m^3standard on December 22, 2008. EPA has designated the Bay Area as nonattainment for the 35 m^3 PM2.5 standard. The EPA order will be effective in April 2009, 90 days after publication of the EPA findings in the Federal Register [30]

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[30] See http://www.baaqmd.gov/pln/air_quality/ambient_air_quality.htm

43. Has the District already been classified?

44. Would classification information, if already known, potentially affect public interest or informed participation?

45. How would this process be different if the District processed this permit consistent with the new attainment status and without the surrogate approach?

Emissions rates in Table 8 are based on the emissions rates set forth in Section IV.A. above with one exception, sulfuric acid mist (H_2SO_4). Emissions of sulfuric acid mist are expected to be less than the PSD significance threshold of 7 tons per year, and the Air District is proposing an enforceable permit condition (Number 25) limiting sulfuric acid mist from the new combustion units to a level below the PSD trigger level. Compliance will be determined by use of emission factors (using fuel gas rate and sulfur content as input parameters) derived from annual compliance source tests. The annual source test will be conducted, as indicated in Condition number 34, to measure SO_2, SO_3, H_2SO_4 and ammonium sulfates. This approach is necessary because the conversion in turbines of fuel sulfur to SO_3, and then to H_2SO_4 is not well established. With this permit condition, sulfuric acid mist emissions will be less than the PSD significance threshold of 7 tons per year and the facility will not be subject to Federal PSD Permit requirements for sulfuric acid mist. *SOB footnote 9 at 18*

46. What is the Basis for "conversion" to be "not well established"?

47. What would it take to establish?

48. What Guarantee, that the emissions will not exceed the threshold limits for the other 364 day per year, exists?

49. What guarantee is there that the operator will not retest in the absence of oversight until compliance is demonstrated?

50. Can the district pre-establish an annual test dates to prevent test manipulation by retesting?

EPA has provided further guidance on how to implement this definition of "Best Available Control Technology" in its 1990 Draft New Source Review Workshop Manual ("NSR Workshop Manual"). EPA requires that the District implement the Best Available Control Technology requirement by conducting what EPA calls a "Top-Down BACT Analysis". As described in EPA's NSR Workshop Manual, a "Top-Down BACT Analysis" consists of five key steps... *SOB at 20*

51. It would appear that the District relied on the 1990 document for compliance how would reliance on present standards affect the permitting decision?

The majority of EPA's clarifications were proposed through a new definition of actual emissions at 40 CFR Subpart 51.166(f) and 40 CFR Subpart 52.21(f). Rather than revising the existing definition of actual emission (40 CFR 51.166(b)(21) and 52.21(b)(21)), which may continue to be used for other purposes under the PSD program, EPA's proposed new definition will only apply for determining increment consumption and providing exclusions to methods for determining increment analysis. Specifically, the proposed rule provides clarifications in the following eight areas.

> 1) Draft 1990 New Source Review Workshop Manual
> EPA clarifies that, while some of the views expressed in the draft NSR Manual may have been promulgated in other EPA regulations, the draft NSR Manual is not a binding regulation and does not by itself establish final EPA policy or authoritative interpretations of EPA regulations under the NSR program. In addition, EPA proposes to establish regulations that supersede many of the recommended approaches for conducting the increments analysis set forth in the draft NSR Manual and other EPA guidance documents.[31]
>
> The EPA's Environmental Appeals Board (``Board'') has sometimes referenced the draft NSR Manual as a reflection of our thinking on certain PSD issues, but the Board has been clear that the draft NSR Manual is not a binding Agency regulation. See, *In re: Indeck-Elwood, LLC, PSD Permit Appeal No. 03-04*, slip. op. at 10 n. 13 (EAB Sept. 27, 2006); *In re: Prairie State Generating Company, PSD Permit Appeal No. 05-05*, slip. op. at 7 n. 7 (EAB Aug 24, 2006). In these and other cases, the Board also considered briefs filed on behalf of the Office of Air and Radiation that provided more current information on the thinking of the EPA headquarters program office on specific PSD issues.[32]

NOx emissions as an ozone precursor are regulated under California law through the Energy Commission Licensing process and subsequent Air District Authority to Construct permit (discussed in more detail in Section II.A above). NO_2 is regulated under the Federal PSD program for sources in the Bay Area. *SOB footnote 11 at 21*

52. Does the intended permit comply with California's present NO_2 standard or does the District have authority to issue a permit that does not comply with California Law?

Kawasaki Heavy Industries purchased the XONON™ catalytic combustion technology from Catalytica Energy Systems in 2006. Kawasaki plans to use the XONON™ on its own turbines, but it is not known if Kawasaki will make the combustors available to other turbine manufacturers. *SOB at 24*

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[31] See http://trinityconsultants.com/air.asp?cp=133
[32] See http://www.epa.gov/EPA-AIR/2007/June/Day-06/a10459.htm

53. What is the basis for this information being "not known" and what would it take for the district to know?

The annualized SCR cost figures are based on a cost analysis conducted by ONSITE SYCOM Energy Corporation, updated and adjusted for inflation by the District. These total 1999 annualized cost for SCR was adjusted for inflation by the District using the Consumer Price Index (2008 value = 1999 value x 1.32). Emerachem provided the updated cost information for the EMx. *SOB footnote 19 at 26*

54. Does the District have some basis that the consumer price index is a valid method of guesstimating today's costs for SCR?

55 What would be a better method?

The CEC has modeled the health impacts arising from a catastrophic ammonia release and has found that the impacts would not be significant.[33] *SOB at 20*

56. Is it appropriate to use vintage data for present permitting or should the district consider potential impacts with contemporary data?

BAAQMD Office Memorandum from David Fairly to Tom Perardi and Rob DeMandel, "A First Look at NOx/Ammonium Nitrate Tradeoffs, dated September 8, 1997.
SOB footnote 21at 27

57. Has the District or any others taken a second look since this 1997 Memorandum?

See Metcalf Energy Monthly BAAQMD CEM Reports, from 5/1/2005 to 1/31/2008. The Air District focused on data from days without startup or shutdown activity. When the turbines/heat recovery boilers are starting up or shutting down, Carbon Monoxide emissions are much higher than during steady-state operations as discussed in more detail in subsequent sections. By

[33] California Energy Commission (CEC), 2002a. Final Staff Assessment (FSA) and Addendum, published on June 2002. BAAQMD Office Memorandum from David Fairly to Tom Perardi and Rob DeMandel, "A First Look at NOx/Ammonium Nitrate Tradeoffs, dated September 8, 1997.

See "Towantic Energy Project Revised BACT Analysis", RW Beck, February 18, 2000.

looking only at data from days without startups or shutdowns, the Air District has ensured that the limit it adopts will be appropriate for steady-state operating conditions.
SOB footnote 25 at 32

58. Will the Limit be appropriate for days with start up?

59. How often can the facility start up under this permit?

60. Has the impact of startup during shoreline fumigation time periods been disclosed?

61. Is it appropriate to use vintage data for present permitting or should the district consider potential impacts with contemporary data?

GE has declined to give emissions performance guarantees for start-up operations using the OpFlex™ software, explaining that startup emissions, by nature, are highly variable and dependent on specific plant equipment and configuration. (Telephone conversations with Bob Bellis and Derrick Owen, GE Energy on November 21, 2008.)
SOB footnote 37 at 41

62. Would a higher level of diligence or verification be appropriate than "telephone conversations" be appropriate for the district to make its determinations?

For all of these reasons, the Air District has eliminated the once-through boiler alternative as an appropriate BACT technology for startup emissions for a facility such as Russell City. The Air District has concluded that the adverse impacts of requiring a single-pressure steam turbine design outweigh the additional startup benefits that can be achieved. The Air District will continue to monitor the development of once-through boiler technologies, in particular the Siemens Flex Plant 30 design using a triple-pressure steam boiler. Such future developments could change the analysis regarding the tradeoffs between overall energy efficiency and startup performance. *SOB at 44*

63. Is this monitoring for potential modification of this permit or future permits?

The relocation and apparent redesign of the 29 percent aqueous ammonia tank and the ammonia facility as a whole will result in changes in impacts to off-site receptors in the event of an accidental spill of ammonia. The project owner prepared a new Off-Site Consequence Analysis (OCA) to evaluate the potential impacts of an ammonia spill with the new configuration. Staff reviewed the results of the OCA and found that the modeling was not consistent with previous modeling using the model SLAB. Staff cannot explain the discrepancies in the OCA modeling and thus conducted its own independent modeling using the U.S. EPA's SCREEN3 model. The results of this model show significant impacts off-site if an accidental release were to occur and fill the secondary containment area of 1,463 square feet with aqueous ammonia.[34]

64. It appears that the referenced CEC staff report states more then the SOB contemplates. Is the Screen 3 model the appropriate model for this analysis?

65. Did the District review the CEC modeling or rely purely on the staff report?

HAZ-2: The project owner shall provide a Risk Management Plan (RMP) and a Hazardous Materials Business Plan (HMBP), (that shall include the proposed building chemical inventory as per the UFC) to the City of Hayward Fire Department and the CPM for review at the time the RMP plan is first submitted to the U.S. Environmental Protection Agency (EPA). The project owner shall include all recommendations of the City of Hayward Fire Department and the CPM in the final documents. A copy of the final plans, including all comments, shall be provided to the City of Hayward and the CPM once EPA approves the RMP. [35]

66. Did the applicant complete the prerequisite of HAZ-2?

67. Shouldn't the determination of the significance of catastrophic ammonia release be completed by the district after review of the Risk Management plan?

The project was originally permitted in 2002, before Fast Start technology was developed, and the applicant purchased its equipment at that time based on the initial permits. Retrofitting that equipment now to incorporate Fast Start technology would require a complete redesign of the project and the purchase of new equipment. Furthermore, Siemens stated that emissions performance cannot be guaranteed unless the company supplies a fully integrated power plant with Fast Start technology (i.e. Flex Plant 10). (Telephone conference on November 6, 2008 with Candido Veiga, Siemens Pacific Northwest Region Vice President and Benjamin Beaver, Siemens Pacific Northwest Sales Manager.) It therefore appears that the facility would have to dispose of the equipment it has already purchased for the project and buy an entirely new integrated system. *SOB at 26*

68. How would the BACT determinations be different if Calpine did not claim to have the Equipment in stock?

69. Does Calpine or GE have Equipment available that would be cleaner?

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[34] See July 2007 CEC Final Staff Assessment (FSA) at 4.4- 2. See http://www.energy.ca.gov/2007publications/CEC-700-2007-005/CEC-700-2007-005-FSA.PDF
[35] See July 2007 CEC Final Staff Assessment (FSA) at 4.4- 6.

The facility has reported encouraging results from the first few months of operating with these new techniques.[] It is not possible, however, to determine based on this limited data what reductions, if any, are attributable to OpFlex and what reductions are attributable to the operational changes the facility was able to make for its specific turbines. Moreover, the facility has operated only for a relatively limited period of time with these enhancements, and so it is difficult to determine from the limited data available so far what improvements can reliably be achieved throughout the life of the facility. For all of these reasons, the Palomar data does not sufficiently demonstrate that there are specific, achievable emissions reductions to be gained simply from using the OpFlex technology itself. Further data will be needed to understand whether some or all of Palomar's proprietary approach for reducing emissions from its equipment can be adapted to other facilities.[36] *SOB at 41*

70. It would appear that the District has had an additional year and a half to obtain "encouraging results" from the Palomar facility. Why didn't the District update this info?

71. Could further "encouraging results affect the districts determination or public interest and informed public participation?

See Ambient Air Quality Impact Report, Colusa Generating Station, Clean Air Act PSD Permit No. SAC 06-01, EPA Region 9, May 2008. The record from that permitting action shows that EPA Region 9 considered OpFlex and the Palomar facility in response to a comment on the startup BACT issue. That comment was subsequently withdrawn and so EPA never responded to it formally on the record. But the fact that the agency determined that BACT does not require OpFlex is evident from the fact that the permit does not require it. *SOB footnote 41 at 42*

72. Please consider the referenced comments on Colusa as if incorporated here as comments for this permit and respond appropriately?

Data for the Flex Plant 10 comparison come from a permit application the Air District has received for a facility proposing to use a Flex Plant 10 design, District Application #18542. The proposed Flex Plant 10 facility will have a heat input capacity of 1857 MMBtu/hr. The District adjusted the proposed Russell City project's emissions numbers proportionally to the capacity difference between the two facilities to achieve an "apples-to-apples" comparison. Calculations assume ISO standard conditions and 59°F. Data for Russell City assume no supplemental duct burner firing, because the proposed Flex Plant 10 does not use duct burners.
SOB footnote 42 at 43

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[36] Letter written by Daniel S. Baerman, Director of Electric Generation, San Diego Gas and Electric, regarding "Hearing Board Variance 4073; Quarterly Report". Submitted to Catherine Santos, Clerk of the Hearing Board for the San Diego County Air Pollution Control District, dated April 11, 2007 SOB at 41

73. Does this mean that the permit application #18542 is not using BACT; why?

California Energy Commission Decision for the Russell City Energy Center AFC, Alameda County (Sept. 11, 2002), at p. 67. *SOB footnote 65 at 62*

This determination was made based on a comparison of three individual models of combined-cycle combustion turbines using data from Gas Turbine World, an independent technical magazine that covers the gas turbine industry. See Final Staff Assessment, California Energy Commission Final Staff Assessment for the Russell City Energy Center AFC, Hayward California, June 10 2002 (P800-02-007), at 5.3-4. The turbines evaluated had nominal energy efficiencies of between 55.8% and 56.5%. During review of the September 2007 amendment to that decision, CEC staff "testified that the proposed changes would not change any of the findings or conclusions in the 2002 Decision." Presiding Member's Proposed Decision, Russell City Energy Center, Amendment No. 1 (01-AFC-7C), Alameda County, August 23, 2007 (CEC-800-2007-003-PMPD), at 57. *SOB footnote 66 at 62*

See Final Staff Assessment, California Energy Commission Final Staff Assessment for the Russell City Energy Center AFC, Hayward California, June 10 2002 (P800-02-007), at 5.3-4. *SOB footnote 67 at 62*

74. Again is it appropriate to use this vintage data for present permitting or should the district consider potential impacts with contemporary data?

[T]he state-law permitting process is not being reopened at this time. *SOB at 65*

75. Why is the District not opening the State-law process?

76. What would the effect on permitting be if the District did open the state law process?

77. In what ways would the existing state-law process not conform to present regulatory requirements, today's emission standards, etc?

78. If this permit is found to contribute to a violation of state law, does the District have authority to issue this permit? Please cite specific statutory authority.

[T]he increased carcinogenic risk attributed to this project is less than 1.0 in one million, and the chronic hazard index and acute hazard index attributed to the emission of non-carcinogenic air contaminants are each less than 1.0. These risk levels are less than significant for project permitting purposes. The Air District reiterates these results here because they have informed the Air District's conclusions that the control technologies chosen to comply with the Federal PSD Permit requirements will not have any significant adverse ancillary environmental impacts. Please see Appendix B for further information on the Health Risk Assessment *SOB at 65*

79. Is the modeling used for the Health risk assessment the same as it should be for the PSD permit?

The Air District has concluded that there are no significant impacts due to air emissions related to the Russell City Energy Center after all of the mitigations required by Federal and District Regulations and the California Energy Commission are implemented. There is no adverse impact on any community due to air emissions from the Russell City Energy Center and therefore there is no disparate adverse impact on an Environmental Justice community located near the facility. *SOB at 66*

80. Is there an Environmental Justice Community near the facility?

81. If so what languages are spoken in the community?

82. What languages did the district issue documents in?

83. What specific outreach did the District make in this community?

84.. Has anyone from the District visited this community?

85. What mitigations directly benefit this community or are not merely regional in nature?

86. Has anyone from the District visited the site?

To help the reader understand which requirements are part of the proposed amended Federal PSD Permit and which are based solely on state law requirements, the state-law requirements are presented in “strike-through” format below. *SOB at 67*

87. Please help the public understand which requirements are based State and Federal law and which requirements represent change of the existing state law requirements?

Within 180 days of the issuance of the Authority to Construct for the RCEC, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous emission monitors, sampling ports, platforms, and source tests required by conditions 29, 30, 32, 34, and 43. The owner/operator shall conduct all source testing and monitoring in accordance with the District approved procedures. (Regulation 1-501)
SOB at 77

88. Has the applicant performed on the above condition or any condition of the Authority to Construct?

The proposed Russell City Energy Center Power Plant will emit the toxic air contaminants summarized in Table 6, "Maximum Facility Toxic Air Contaminant (TAC) Emissions". In accordance with the requirements of CEQA, BAAQMD Regulation 2-5, and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing the air pollutant dispersion model ISCST3 and the multi-pathway cancer risk and hazard index model ACE. *SOB at 82*

89. Are District actions for other facility's PSD permits subject to CEQA?

Based upon the results given in Table B-1, the Russell City Energy Center project is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy. *SOB at 83*

90. When was the health Risk assessment completed and by whom and should it be updated? If not, why not?

SUMMARY OF AIR QUALITY IMPACT ANALYSIS FOR THE RUSSELL CITY ENERGY CENTER December 8, 2008
SOB at 85

91. There appear to be differences between the Air Quality Impact analysis completed for the State permit and the one completed for the Federal permit. Please identify the differences?

92. Which (if any) document is correct and valid for state and federal permitting? When was the new modeling completed and by whom?

The EPA guideline models AERMOD (version 07026) and SCREEN3 (version 96043) were used in the air quality impacts analysis. Because an Auer land use analysis showed that the area within 3 km is classified as rural, the AERMOD option of increased surface heating due to the urban heat island was not selected. *SOB at 87*

93. The area to the East of the site is clearly highly developed, how would consideration of this fact affect the modeling results?

94. Table 2 of the newer air quality impact analysis is mostly blank. Please complete table 2.

95. Would complete information from table 2 be of interest to the public or promote informed participation?

Meteorological data was available from the Automated Surface Observing System (ASOS) at the Oakland International Airport for the years 2003-2007. The site is located 20.8 kilometers to the northwest of the RCEC. AERSURFACE (version 08009) was used to determine surface characteristics in accordance with USEPA's January 2008 "AERMOD Implementation Guide" at both the Oakland Airport and the RCEC project site. Based upon this comparison the Oakland ASOS data was considered representative of the RCEC project location and met all EPA data completeness requirements. *SOB at 87*

The meteorological data from Oakland would not seem indicative of Hayward Data as confirmed by the transcript of district employee Glen Long emails including.

96. Please provide data from 1 year of site specific monitoring.

Air Quality Modeling Results
The maximum predicted ambient impacts of the various modeling procedures described above are summarized in Table III for the averaging periods for which AAQS and PSD increments have been set. Shown in Figure 1 are the locations of the maximum modeled impacts. *SOB at 87*

97. Please provide complete impact tables for each modeling method.

98. Figure 1 on page 89 conflicts with figure 1 on page 158 which if any is to be relied on?

Soils and Vegetation Analysis
A detailed vegetation inventory in the project and impact area is also presented in the Russell City Energy Center AFC, Vol. I, May, 2001 and Russell City Energy Center AFC Amendment No. 1 (01- AFC-7), November 2006. *SOB at 90*

99. The impact area analysis (survey) was not updated for the 2006 amendment. Is there a possibility that vegetation may have changed in this last decade?

Some project area soils (Clear Lake, Danville, and Willows) are considered prime farmland soils when found in open field or agricultural areas, but none of the project facilities cross these soils in any other context than land that is zoned and used as urban, industrial land. *SOB at 90*

100. Does this statement confirm above concerns about "rural" classification?

There are 1.68 acres of seasonal wetlands on the 14.7-acre project site. *SOB at 91*

This statement appears to describe the original site as would all documents from that era.

101. Does this statement describe the present site?

102. What other data is reused from the original site?

103. Is it appropriate to use data from the wrong site?

Much of the historic salt marsh community within 1 mile of the site has been altered or eliminated by urban development, sewage treatment facilities, salt evaporation ponds, and the construction of dikes and levees to prevent flooding and intrusion of saltwater. *SOB at 91*

104. When was this determination made?

105. Does it describe the old site, as we are aware of no present salt evaporation ponds in the area?

106. How much of the Historic salt marsh community has been altered or eliminated?

107. Have there been restoration activities in the area since this statement was made?

Special environmental areas within a 1-mile radius of the project site include Cogswell Marsh, managed by the East Bay Regional Park District, the HARD marsh restoration project and Shoreline Interpretive Center, and a small section of Mt. Eden Creek. *SOB at 91*

108. Is the Don Edwards San Francisco Bay National Wildlife Refuge within 1 mile of the project site?

The California Department of Fish and Game, the U.S. Fish and Wildlife Service, and the California Coastal Conservancy launched a four- year public process to design a restoration plan for the South Bay Salt pond restoration Project. The final plan was adopted in 2008 and the first phase of restoration started later that year.

109. Is this within 1 mile of the site?

110. Have the above agencies been notified of the proximity to the site?

111. What is the actual distance to the waters of the San Francisco Bay?

112. Is the on site waterway affected by the tides?

113. What steps has the district taken to demonstrate consistency with the Coastal Zone Management act?

114. The Clean Water Act?

115. The Endangered Species Act?

116. The Migratory Bird Treaty Act?

117. What other Federal Act(s) should this permit be consistent with?

The project maximum one-hour average NO_2, including background, is 260 μg/m^3. This concentration is below the California one-hour average NO_2 standard of 338 μg/m^3. *SOB at 92*

118. Table 9 on page 116 states that the NO_2 emissions are 370 μg/m^3. Which (if any) is correct and why is there such a large discrepancy?

The maximum annual RCEC NO_2 impact is 0.16 μg/m^3. The maximum annual NO_2 background at the Fremont monitoring station between 2005 and 2007 was in 2005 at 28.2 μg/m^3. *SOB at 92*

119. Would the Hunters Point San Francisco or Oakland monitoring stations be more indicative of Hayward air quality?

120. What would the result be using upwind monitoring like Hunters Point or Oakland?

121. Is there a provision for local monitoring?

122. If so why was Hayward not monitored?

Hayward has multiple freeways, industrial and bridge impacts that Fremont does not have and is impacted by the port of Oakland and denser uses in Oakland and San Francisco.[37]

123 Is there a possibility that newer reference material is available that may lead to a different conclusion?

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[37] (USEPA 1991, "Air Quality criteria for oxides of nitrogen").
(USEPA 1979, "Air Quality criteria for carbon monoxide").
(Zimmerman et al.1989, "Polymorphic regions in plant genomes detected by an M13 probe"
(USEPA 1979, "Air Quality criteria for carbon monoxide")
(Lerman, S.L. and E.F. Darley. 1975. Particulates, pp. 141-158. In: Responses of plants to air pollution, edited by J.B. Mudd and T.T. Kozlowski. Academic Press. New York.)
"A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals," December 1980

The Department will no longer recommend comparison of modeled impacts to the 1980 sensitivity thresholds. This document is out of print (has been for at least 10 years) and appears to be no longer used by EPA. Alan Schuler, P.E., Environmental Engineer Alaska Department of Environmental Conservation

Is the District familiar with this USEPA determination[38]?

Please seek review of these materials and reference any newer data that has been used in other PSD permits or may be appropriate to validate or invalidate these reports.

124. Why does table 6 on page 93 reference a 4 hour averaging period for NO_2?

125. What would the 1 hour concentration be for start up and normal operation?

Growth Analysis

The proposed project will supply electricity to Northern California. The electricity from the new plant is expected to displace older, less efficient sources of electricity elsewhere in the region. *SOB at 93*

126. Please identify the basis for this statement and exactly which older less efficient sources this refers to and when they will be decommissioned?

There will be little or no associated industrial, commercial, or residential growth as a result of this project. *SOB at 93*

127. Is this project based upon future need based upon growth projections?

The electrical generating capacity from the project will be introduced into a regional electrical supply grid and therefore not stimulate local growth. *SOB at 93*

128. Does this logic mean that no electric generation that feeds into the "grid" contributes to growth and therefore growth analysis is unwarranted in grid connected permitting?

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[38] See http://www.dec.state.ak.us/air/ap/docs/modeling%20DEC%20Guidance%20re%20PSD%20Soil%20and%20Vegetation%20Assessments%2012-11-07.pdf

The entire permanent workforce is expected to commute from within Alameda County. *SOB at 93*

129. What are the emissions associated with temporary and permanent workers, like commuting?

The project was originally certified by the California Energy Commission in September, 2002. However, the site has been relocated approximately 1,500 feet to the north from the original location (1.24 miles east of Johnson Landing on the southeastern shore of the San Francisco Bay in the City of Hayward). *SOB at 99*

130. What is the actual distance from the original site to the new site?

131. What is the Actual distance from the site to Roberts Landing?

"Analysis of the potential adverse impacts on soils, flora and fauna should include existing vegetation types, the percent cover and biomass, spatial distribution and land use. Rare and endangered species and acidic wetlands should also be identified. Ozone concentrations and estimates of fluoride and heavy metal emissions must be supplied with pollutant baseline concentrations and pollutant contribution from all sources." [*April, 1981 PSD Guidance Document at 9.4*]

132. How has the District complied with the above quoted PSD guidance document?

The Energy Commission certified the construction and operation of the RCEC in September 2002, on 14.7 acres in the City of Hayward (the City) Industrial Corridor at the southwest corner of the intersection of Enterprise Avenue and Whitesell Street, directly south of the City's Water Pollution Control Facility (WPCF). The location is approximately two miles from the east entrance to the San Mateo-Hayward Bridge (State Route 92). Through the Petition to Amend, the project owner is now proposing to locate the facility west of the City's WPCF between Depot Road and Enterprise Avenue, approximately 1,300 feet northwest of the original location (300 feet boundary to boundary). The new location will total approximately 18.8 acres with all parcels located within the City of Hayward.
CEC FSA 1- 2 July 2007

133. Does this statement describe the present site?

134. What other data is reused from the original site?

135. Is it appropriate to use data from the wrong site?

Under the leadership of Senator, the South Bay Salt Ponds were purchased in 2003 from Cargill Inc. Funds for the purchase were provided by federal and state resource agencies and several private foundations. The 15,100 acre purchase represents the largest single acquisition in a larger campaign to restore 40,000 acres of lost tidal wetlands to San Francisco Bay.

Shortly after the property was purchased, the California Department of Fish and Game, the U.S. Fish and Wildlife Service, and the California Coastal Conservancy launched a four- year public process to design a restoration plan for the property. The final plan was adopted in 2008 and the first phase of restoration started later that year.

136. What is the distance to the South Bay Salt Pond Restoration Project?

137. Has the District informed the public, Dianne Feinstein, stakeholders and agencies associated with the National Wildlife Sanctuary and Salt Pond restoration project of the exact proximity?

138. Could this information affect their interest and informed participation?

The ammonia emissions resulting from the use of SCR may have another environmental impact through its potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia.
SOB at 109

139. How “difficult to estimate” is it to estimate would it be appropriate to make the effort?

However, it is the opinion of the Research and Modeling section of the BAAQMD Planning Division that the formation of ammonium nitrate in the Bay Area air basin is limited by the formation of nitric acid and not driven by the amount of ammonia in the atmosphere.
SOB at 109

140. When this opinion made and what was its basis?

Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter within the BAAQMD. The potential impact on the formation of secondary particulate matter in the SJVAPCD is not known.
SOB at 109

141. What would it require for the above potential impact to be “known”

This potential environmental impact is not considered adverse enough to justify the elimination of SCR as a control alternative.
SOB at 109

142. What is the threshold?

Table 7 (*SOB at 116*) summarizes the offset obligation of the RCEC.

The emission reduction credits presented in Table 7 exist as federally-enforceable, banked emission reduction credits that have been reviewed for compliance with District Regulation 2, Rule 4, “Emissions Banking”, and were subsequently issued as banking certificates by the BAAQMD under the applications cited in the table footnotes.

If the issued under any certificate exceeded 35 tons per year for any pollutant, the application was required to fulfill the public notice and public comment requirements of District Regulation 2-4-405. Accordingly, such applications were reviewed by the California Air Resources Board, U.S. EPA, and adjacent air pollution control districts to insure that all applicable federal, state, and local regulations were satisfied.

143. Please demonstrate the complete compliance history for the emission reduction credits creation and banking including any public notices.

(Information for certificate #30 is not available) SOB at 115

144. The above caption refers to an emission reduction credit for the facility. What rules apply to identification of Certificate sources?

145. Why are the emission reduction credits different in the CEC Decision?

AQ-SC11 The project owner shall surrender 12.2 tons per year of SOx or SOxequivalent emission reduction credits (ERCs) from certificate 989, 28.5 tons per year of POC ERCs, and 154.8 tons per year of NOx, or an equivalent combination of NOx and POC ERCs from certificates 602, 687, 688, and 855, prior to start of construction of the project.
CEC Final Decision at 86

146. Air Quality table 9 on page 116 appears to indicate that the facility would exceed current California NO_2 standards is this correct?

147. What Authority would allow the District to license the facility to exceed the California standard?

Pursuant to Regulation 2-2-306, a non-criteria pollutant PSD analysis is required for sulfuric acid mist emissions if the proposed facility will emit H2SO4 at rates in excess of 38 lb/day and 7 tons per year. However, RCEC has agreed to permit conditions limiting total facility H2SO4 emissions to 7 tons per year and requiring annual source testing to determine SO_2, SO_3, and H_2SO_4 emissions. If the total facility emissions ever exceed 7 tons per year, then the applicant must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist emissions. *SOB at 115*

148. Is there some basis in the emission profile that would inform the public of the expected Sulfuric Acid emission or reason to believe from the operation profile that the facility (as planned) would emit less than 7 tons per year or 38 pounds per day?

2. Emission Offsets
General Requirements
Pursuant to Regulation 2-2-302, federally enforceable emission offsets are required for POC and NOx (as NO_2) emission increases from permitted sources at facilities which will emit 15 tons per year or more on a pollutant-specific basis. For facilities that will emit more than 35 tons per year of NOx (as NO_2), offsets must be provided by the applicant at a ratio of 1.15 to 1.0. Pursuant to Regulation 2-2-302.2, POC offsets may be used to offset emission increases of NOx.
SOB at 115

149. Please demonstrate how emission trading and offsets comply with the Federal requirements of the PSD permit and how they protect air quality.

It should be noted that in the case of POC and NOx offsets, District regulations do not require consideration of the location of the source of the emission reduction credits relative to the location of the proposed emission increases that will be offset. Timing for Provision of Offsets
SOB at 113

150. Do Clean Air Act regulations require consideration of the location of the source of the emission reduction credits relative to the location of the proposed emission increases?

Pursuant to District Regulation 2-2-311, the applicant surrendered the required valid emission reduction credits to mitigate the emission increases for the facility prior to the issuance of the Authority to Construct on May 14, 2003. Pursuant to District Regulation 2, Rule 3, “Power Plants,” the Authority to Construct was issued after the California Energy Commission issued the Certificate for the proposed power plant
SOB at 116

151. Are the emission credits contemporaneous for Federal purposes?

The District-operated Fremont-Chapel Way Monitoring Station, located 18.3 km southeast of the project, was chosen as representative of background NO_2 concentrations. Table V contains the concentrations measured at the site for the past 5 years (1996 through 2000).
SOB at 161

152. Oakland or hunters point would be more representative of Hayward air quality but the District should require 1 year of current local monitoring and consider the its reports of the effects of the port of Oakland on Hayward.

Regulation 2, Rule 1, Sections 426: CEQA-Related Information Requirements
As the lead agency under CEQA for the proposed RCEC Project, the California Energy Commission (CEC) will satisfy the CEQA requirements of Regulation 2-1-426.2.1 by producing their Final Certification which serves as an EIR-equivalent pursuant to the CEC’s CEQA-certified regulatory program in accordance with CEQA Guidelines Section 15253(b) and Public Resource Code Sections 21080.5 and 25523
SOB at 117

153. How can the CEC be considered the lead agency when they have closed their administrative record so long before this permit?

(a) Any public agency which is a responsible agency for a development project that has been approved by the lead agency shall approve or disapprove the development project within whichever of the following periods of time is longer:
(1) Within 180 days from the date on which the lead agency has approved the project.
(2) Within 180 days of the date on which the completed application for the development project has been received and accepted as complete by that responsible agency.
(b) At the time a decision by a lead agency to disapprove a development project becomes final, applications for that project which are filed with responsible agencies shall be deemed withdrawn. [Government Code Section 65952]

CEQA Section 15052. Shift in Lead Agency Designation (a) Where a Responsible Agency is called on to grant an approval for a project subject to CEQA for which another public agency was the appropriate Lead Agency, the Responsible Agency shall assume the role of the Lead

Agency when any of the following conditions occur:
(1) The Lead Agency did not prepare any environmental documents for the project, and the statute of limitations has expired for a challenge to the action of the appropriate Lead Agency.
(2) The Lead Agency prepared environmental documents for the project, but the following conditions occur:
(A) A subsequent EIR is required pursuant to Section 15162,
(B) The Lead Agency has granted a final approval for the project, and
(C) The statute of limitations for challenging the Lead Agency's action under CEQA has expired.
(3) The Lead Agency prepared inadequate environmental documents without consulting with the Responsible Agency as required by Sections 15072 or 15082, and the statute of limitations has expired for a challenge to the action of the appropriate Lead Agency.
(b) When a Responsible Agency assumes the duties of a Lead Agency under this section, the time limits applicable to a Lead Agency shall apply to the actions of the agency assuming the Lead Agency duties. [Note: Authority cited: Section 21083, Public Resources Code;
Reference: Section 21165, Public Resources Code.]

Public Resources Code 25519 (h) Local and state agencies having jurisdiction or special interest in matters pertinent to the proposed site and related facilities shall provide their comments and recommendations on the project within 180 days of the date of filing of an application.

BAAQMD rules
2-3-403 Preliminary Decision: Within 180 days of accepting an AFC as complete, the APCO shall conduct a Determination of Compliance review and make a preliminary decision as to whether the proposed power plant meets the requirements of District regulations. If so, the APCO shall make a preliminary determination of conditions to Bay Area Air Quality Management District 2-3-3 be included in the Certificate, including specific BACT requirements and a description of mitigation measures to be required.

2-3-405 Determination of Compliance, Issuance: Within 240 days of the acceptance of the AFC as complete, the APCO shall issue and submit to the commission a Determination of Compliance. If the Determination of Compliance cannot be issued, the APCO shall so advise the Commission. When the AFC is approved by the Commission, the APCO shall ascertain whether the Certificate contains all applicable conditions. If so, the APCO shall grant an authority to construct.

1744.5. Air Quality Requirements; Determination of Compliance. (a) The applicant shall submit in its application all of the information required for an authority to construct under the applicable district rules, subject to the provisions of Appendix B(g)(8) of these regulations.
(b) The local air pollution control officer shall conduct, for the commission's certification process, a determination of compliance review of the application in order to determine whether the proposed facility meets the requirements of the applicable new source review rule and all other applicable district regulations. If the proposed facility complies, the determination shall specify the conditions, including BACT and other mitigation measures, that are necessary for compliance. If the proposed facility does not comply, the determination shall identify the specific regulations which would be violated and the basis for such determination. The determination

shall further identify those regulations with which the proposed facility would comply, including required BACT and mitigation measures. The determination shall be submitted to the commission within 240 days (or within 180 days for any application filed pursuant to Sections 25540 through 25540.6 of the Public Resources Code) from the date of the acceptance.
(c) The local district or the Air Resources Board shall provide a witness at the hearings held pursuant to Section 1748 to present and explain the determination of compliance.
(d) Any amendment to the applicant's proposal related to compliance with air quality laws shall be transmitted to the APCD and ARB for consideration in the determination of compliance.
[Note: Authority cited: Sections 25218(e) and 25541.5, Public Resources Code. Reference: Sections 25216.3 and 25523, Public Resources Code.]
15162. Subsequent EIRs and Negative Declarations
a(3)(C) Mitigation measures or alternatives previously found not to be feasible would in fact be feasible, and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative

154. The CEC approved the project on October 3, 2007 Is the District now the lead agency?

Please process this application consistent with CEQA utilizing feasible alternatives.

§ 51.166 40 CFR Ch. I (7–1–08 Edition)
(q) *Public participation.* The plan shall provide that—
(1) The reviewing authority shall notify all applicants within a specified time period as to the completeness of the application or any deficiency in the application or information submitted. In the event of such a deficiency, the date of receipt of the application shall be the date on which the reviewing authority received all required information.
(2) Within one year after receipt of a complete application, the reviewing authority shall:
(i) Make a preliminary determination whether construction should be approved, approved with conditions, or disapproved.
(ii) Make available in at least one location in each region in which the proposed source would be constructed a copy of all materials the applicant submitted, a copy of the preliminary determination, and a copy or summary of other materials, if any, considered in making the preliminary determination.
(iii) Notify the public, by advertisement in a newspaper of general circulation in each region in which the proposed source would be constructed, of the application, the preliminary determination, the degree of increment consumption that is expected from the source or modification, and of the opportunity for comment at a public hearing as well as written public comment.
(iv) Send a copy of the notice of public comment to the applicant, the Administrator and to officials and agencies having cognizance over the location where the proposed construction would occur as follows: Any other State or local air pollution control agencies, the chief executives of the city and county where the source would be located; any comprehensive regional land use planning agency, and any State, Federal Land Manager, or
Indian Governing body whose lands may be affected by emissions from the source or modification.

(v) Provide opportunity for a public hearing for interested persons to appear and submit written or oral comments on the air quality impact of the source, alternatives to it, the control technology required, and other appropriate considerations.
(vi) Consider all written comments submitted within a time specified in the notice of public comment and all comments received at any public hearing(s) in making a final decision on the approvability of the application. The reviewing authority shall make all comments available for public inspection in the same locations where the reviewing authority made available preconstruction information relating to the proposed source or modification.
(vii) Make a final determination whether construction should be approved, approved with conditions, or disapproved.
(viii) Notify the applicant in writing of the final determination and make such notification available for public inspection at the same location where the reviewing authority made available preconstruction information and public comments relating to the source

155 How does this project conform with the above Federal requirement?

156. What other rules have changed or mistakes have been discovered by the District since the issuance of the FDOC or Authority to Construct?

The PSD proceedings that are the subject of this case are embedded in a larger California "certification" or licensing process for power plants conducted by the California Energy Commission ("CEC"),
Remand at 1

The PSD provisions 2 that are the subject of the instant appeal are part of the CAA's New Source Review ("NSR") program, which requires that persons planning a new major emitting facility or a new major modification to a major emitting facility obtain an air pollution permit before commencing construction. In addition to the PSD provisions, explained *infra*, the NSR program includes separate "nonattainment" provisions.
Remand at 5

As applied to the notice violation, the allegation of error is considered to be the Permit in its entirety. *See In re Chem. Waste Mgmt. of Ind.,* 6 E.A.D. 66, 76 (EAB 1995) (holding that the Board, in accordance with its review powers under 40 C.F.R. § 124.19, is "authorize[d] * * * to review any condition of a permit decision (or as here, the permit decision in its entirety.)."
Remand footnote 22 at 26

157. Is this permit being processed consistent with the EAB remand including the previous 3 statements?

AQ-SC10 In lieu of complying with **AQ-SC7**, **AQ-SC8,** and **AQ-SC9**, the project's combustion turbine/HRSG units shall be designed and built with equipment and control systems to minimize start-up times and emissions. These could include the Fast-Start technology with an integrated control system and a once-through Benson boiler design, appropriate system configuration and equipment to facilitate operating chemistry during starting sequences, and an auxiliary boiler. *CEC Final Decision at 86*

158. Had this requirement been supported by the Air District (as the concurrent El Segundo AFC) and Palomar the project would emit 48 tons or less instead of 86 tons of PM annually. Please process this application consistent with CEC AQ-SC10.

On February 19, 2008 the office of administrative law approved the new NO_2 standard of 338 $\mu g/m^3$ which went into effect on March 20, 2008.

159. Please process this permit consistent with the present NO_2 standards.

2-2-414.3 For determining whether the emission increases from the new or modified facility would cause or contribute to an air quality standard violation or an exceedance of a PSD increment, an analysis of the existing air quality in the impact area of the new or modified facility that includes one year of continuous ambient air quality monitoring data. The continuous air quality monitoring data shall have been gathered over a period of at least one year preceding the receipt of a complete application. The APCO may approve a shorter period (but not less than four months) provided that the period of monitoring includes the time frame when maximum concentrations are expected. The APCO may approve modeling in lieu of ambient air quality monitoring for pollutants for which no air quality standard exists.

160. Please complete 1 year of continuous ambient air quality monitoring data in the impact area (Hayward)

Ecosystems occurring in these areas include those commonly encountered in the foothills of the Coast Ranges, such as oak woodland and valley/foothill grassland. Biological habitats within the project area consist primarily of coastal salt marsh, brackish/freshwater marsh, salt production facilities (evaporation ponds). *SOB at 90*

161. There have not been salt production facilities in the area for many years. Please disclose when the identified salt production facilities ceased operations and utilize current information for permitting

15154. Projects Near Airports
(a) When a lead agency prepares an EIR for a project within the boundaries of a comprehensive airport land use plan or, if a comprehensive airport land use plan has not been adopted for a project within two nautical miles of a public airport or public use airport, the agency shall utilize the Airport Land Use Planning Handbook published by Caltrans' Division of Aeronautics to assist in the preparation of the EIR relative to potential airport-related safety hazards and noise problems.
(b) A lead agency shall not adopt a negative declaration or mitigated negative declaration for a project described in subdivision (a) unless the lead agency considers whether the project will result in a safety hazard or noise problem for persons using the airport or for persons residing or working in the project area.

161. Please assess the potential impact to the Hayward and Oakland Airport and air quality impact to in-flight receptors.

The following document is incorporated into these comments:

From: Schuler, Alan E (DEC)
Sent: Tuesday, December 11, 2007 1:46 PM
Subject: PSD Vegetation and Soil Assessments[39]

Also Incorporated for review by the District :

Advanced Power Plant Development and Analyses Methodologies Final Report
Reporting Period: August 1, 2000 – June 30, 2006[40]

Associated Growth
"Associated Growth" is additional commercial, residential, industrial and other growth that the project may cause or induce. This type of growth is growth in the local workforce and support infrastructure necessary to serve the proposed facility. Examples include additional residential housing, retail suppliers, and additional schools and municipal services that would be necessary to accommodate any new workers that would come to the area to work in the facility. Examples also include any additional commerce or industry necessary to provide goods and services used by the facility, maintenance facilities to serve the facility, and other similar support operations. Emissions from "associate growth" are the emissions associated with this additional human and

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[39] See http://www.dec.state.ak.us/air/ap/docs/modeling%20DEC%20Guidance%20re%20PSD%20Soil%20and%20Vegetation%20Assessments%2012-11-07.pdf
[40] See http://www.netl.doe.gov/technologies/coalpower/fuelcells/seca/pubs/reports/UCI%20Finall%20Report%20DE-FC26-00NT40845.pdf

economic activity generated as a result of the facility under review. The Air District undertook an associated growth analysis and found that there would be no significant associated growth.4
SOB at 16

Growth Analysis
The proposed project will supply electricity to Northern California. The electricity from the new plant is expected to displace older, less efficient sources of electricity elsewhere in the region. There will be little or no associated industrial, commercial, or residential growth as a result of this project. The electrical generating capacity from the project will be introduced into a regional electrical supply grid and therefore not stimulate local growth.
SOB at 93

162. These definitions of growth ignore the growth associated with increased electrical capabilities. Please assess the associated growth possibilities from an additional 600 megawatts of capacity. Please also assess the associated negative growth in sustainable generation.

Hereby incorporated into these comments:
September 8, 1988 MEMORANDUM [41]
SUBJECT: EPA Region IX Policy on PSD Permit Extensions
FROM: Wayne Blackard, Chief New Source Section
SUBJECT: EPA Region IX Policy on PSD Permit Extensions

The project maximum one-hour average NO_2, including background, is 260 μg/m^3. This concentration is below the California one-hour average NO_2 standard of 338 μg/m^3. Nitrogen dioxide is potentially phytotoxic, but generally at exposures considerably higher than those resulting from most industrial emissions. Exposures for several weeks at concentrations of 280 to 490 μg/m^3can cause decreases in dry weight and leaf area, but 1-hour exposures of at least 18,000 μg/m^3 are required to cause leaf damage. The maximum annual RCEC NO_2 impact is 0.16 μg/m^3. The maximum annual NO_2 background at the Fremont monitoring station between 2005 and 2007 was in 2005 at 28.2 μg/m^3. The total annual NO_2 concentration (project plus background) of 28.4 μg/m^3 is far below these threshold limits (219.0 μg/m^3). In addition, the total predicted maximum 1-hour NO_2 concentrations of 260 μg/m3 would be significantly less than the 1-hour threshold (7,500 μg/m^3 or 3,989 ppm) for 5 percent foliar injury to sensitive vegetation (USEPA 1991, "Air Quality criteria for oxides of nitrogen"). *SOB at 92*

163. Please use current reference material like the CEC Pier nitrogen deposition report included in the EAB appeal 08-01

164. Please use correct emission data including the results of 1 year of impact area monitoring.

[41] See http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/extnsion.pdf

Continued on the next page

165. Please also analyze the effects on the adjacent Vernal pools and protected habitats.

Permit Expiration
As provided in 40 CFR 52.21(r), this PSD Permit shall become invalid if construction:
A. is not commenced (as defined in 40 CFR 52.21(b)(9)) within 18 months after the approval takes effect;.. The stack gas volumetric flow rates.

The system shall meet EPA Performance Specifications 40 CFR 52, Appendix E.

Each CEMS shall meet the applicable requirements of 40 CFR 60 Appendix B, Performance Specifications 2, 3, and 4, and 40 CFR Part 60 Appendix F, Procedure 1, and shall be certified and tested.

Deposited ammonia also can contribute to problems of eutrophication in water bodies, and deposition of ammonium particles may effectively result in acidification of soil as ammonia is taken up by plants.

Except as provided in the grandfathering provisions that follow, these final rules go into effect and must be implemented beginning on the effective date of this rule, July 15, 2008 in all areas subject to 40 CFR 52.21, including the delegated States.

Consistent with 40 CFR 52.21(i)(1)(x), wherein EPA grandfathered sources or modifications with pending permit applications based on PM from the PM10 requirements established in 1987, EPA will allow sources or modifications who previously submitted applications in accordance with the PM10 surrogate policy to remain subject to that policy for purposes of permitting if EPA or its delegate reviewing authority subsequently determines the application was complete as submitted. This is contingent upon the completed permit application being consistent with the requirements pursuant to the EPA memorandum entitled ''Interim Implementation of New Source Review Requirements for PM2.5'' (Oct. 23, 1997) recommending the use of PM10 as a surrogate for PM2.5. Accordingly, we have added 40 CFR 52.21(i)(1)(xi) to reflect this grandfathering provision.

2. Transition With this finalization of the new PM2.5 NSR implementation requirements under 40 CFR 51.165, States now have the necessary tools to implement a NA NSR program for PM2.5. After the effective date of the amended rule (that is, July 15, 2008, States will no longer be permitted to implement a NA NSR program for PM10 as a surrogate for the PM2.5 NA NSR requirements.

Most States will then need to implement a transitional PM2.5 NA NSR program under appendix S (as amended in this rulemaking action) until EPA approves changes to a State's SIP-approved NA NSR program to reflect the new requirements under 40 CFR 51.165. At this time, we do not believe it is appropriate to allow grandfathering of pending permits being reviewed under the

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Continued from the previous page

PM10 surrogate program in nonattainment areas, mainly because of a State's obligations to expedite attainment and the fact that we had not established a similar precedent for transitioning from PM to PM10. [Fed. Reg. 28231, 28349-50 (May 16, 2008)][42]

166. The ammonia and other toxins effects on vegetation is ignored in the analysis. Please analyze.

During recent years, in response to an increased awareness of the adverse consequences of air pollution and environmental degradation, the government has enacted legislation that is of interest to lichenologists. This paper discusses the role of lichen research in the development of this legislation or in decisions made as a result of the legislation. The major acts of interest are the National Environmental Policy Act (NEPA) of 1969 and the Clean Air Act of 1970 and its 1977 amendments. Under NEPA, the federal government announced its commitment to maintain and enhance the environmental quality of the United States. Under the Clean Air Act, the Environmental Protection Agency was authorized to establish the National Ambient Air Quality Standards; the Prevention of Significant Deterioration Class I, II and III areas; and the "adverse impact" determination for Class I areas. After review of the air pollution literature, comparison of the effects of gaseous sulfur dioxide on photosynthesis in lichens and vascular plants showed that some lichens (1) may not be as sensitive as some crops, (2) may be more sensitive than some conifers, and (3) may be about as sensitive as some native herbs and shrubs. However, it appears that visible injury symptoms occur at lower doses in crops and conifers than in lichens. Evaluation of the lichen/air pollution research (e.g. mapping, laboratory and field fumigations, and ecological baseline studies) and a computer search of environmental impact statements showed that if the efforts of lichenologists are to be of use to government decision makers, the researchers must (1) use representative concentrations of pollutants, (2) use fluctuating exposures, in addition to constant concentrations, (3) use mixtures as well as single pollutants, (4) determine the importance of peak concentrations to long-term averages on effects, (5) develop dose-response curves for single and mixed pollutants, (6) relate laboratory results to field observations, (7) document changes in lichen communities related to measured concentrations of ambient pollutants, and (8) determine the significance of lichens in the structure and function of ecosystems.[43]

167. Please analyze the effects on aquatic vegetation and lichens.

168. Please demonstrate how the project complies with NEPA

Startup and Testing of Siemens V84.3A Combustion Turbine in Peaking Service at Hawthorn Station of Kansas City Power & Light Company[44]

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42 See http://edocket.access.gpo.gov/2008/pdf/E8-10768.pdf

43 See http://www.jstor.org/pss/3242790

44 See http://mydocs.epri.com/docs/public/TR-108609.pdf

ASTM fuel sulfur analysis methods were updated to correspond with NSPS Subpart GG as revised July 2004.[45]

The above linked documents are hereby incorporated into these comments

[40 CFR 124.13] (A comment period longer than 30 days may be necessary to give commenters a reasonable opportunity to comply with the requirements of this section. Additional time shall be granted under § 124.10 to the extent that a commenter who requests additional time demonstrates the need for such time.)

[40 CFR 124.8] Fact sheet (3) For a PSD permit, the degree of increment consumption expected to result from operation of the facility or activity.
(4) A brief summary of the basis for the draft permit conditions including references to applicable statutory or regulatory provisions and appropriate supporting references to the administrative record required by § 124.9 (for EPA-issued permits);
(5) Reasons why any requested variances or alternatives to required standards do or do not appear justified;
(6) A description of the procedures for reaching a final decision on the draft permit including:
(i) The beginning and ending dates of the comment period under § 124.10 and the address where comments will be received;
(ii) Procedures for requesting a hearing and the nature of that hearing; and
(iii) Any other procedures by which the public may participate in the final decision.
(7) Name and telephone number of a person to contact for additional information. and all variances that are to be included under § 124.63.

169. The District has not demonstrated compliance with the preceding laws. Please demonstrate compliance.

Under the federal Magnuson-Stevens Act and the Endangered Species Act, San Francisco Bay is considered critical habitat for certain fish species, such as Chinook salmon and Delta smelt, by the United States Fish and Wildlife Service and the National Marine Fisheries Service because

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[45] See http://www.adeq.state.ar.us/ftproot/pub/commission/p/08-007-P%20AEP%20Service%20Corp%20&%20Swepco-Hempstead%20Co%20Hunting%20Club/2008-12-03_Ex._116_Southern_Company_Calc_Method_3-03.pdf and http://www.baaqmd.gov/pmt/air_toxics/permit_modeling/psd_increment_consumption_status_report_4_16_08.pdf

the Bay plays an essential role in their life cycles. The Magnuson-Stevens Act requires that the National Marine Fisheries Service provide conservation recommendations to state agencies, such as the Commission, when a proposed project would have adverse impacts on essential fish habitat.

170. What efforts has the District taken to demonstrate consistency with the Magnuson-Stevens Act?

Dissolved oxygen is needed to support marine life and to help break down pollutants in the water. The amount of oxygen in the Bay is largely determined by the surface area of the Bay because primary sources of oxygen are: (1) churning waves that trap oxygen from the air; (2) the water surface, which absorbs oxygen from the air; and (3) the exposed mudflats, which both produce and absorb oxygen while the tide is out and transfer it to the water when the tide comes in.

171. What effect will the project have on these resources?

The Hayward Shoreline consists of marshland, bay and sloughs, and comprises of remaining natural wetlands in California. It plays an important role in providing wintering habitat for waterfowl of the Pacific Flyway. During years of drought the area becomes particularly important to waterfowl by virtue of its large expanse of aquatic habitat and the scarcity of such habitat elsewhere. The area provides critical habitat for other wildlife forms, including such endangered, rare, or unique species as the peregrine falcon, white-tailed kite, golden eagle, California clapper rail, black rail, salt-marsh harvest mouse, and Suisun shrew. The existence of this wide variety of wildlife is due to the relatively large expanse of unbroken native habitat and the diversity of vegetation and acquatic conditions that prevail in the marsh. Man is an integral part of the present marsh ecosystem and, to a significant extent, exercises control over the widespread presence of water and the abundant source of waterfowl foods. The Hayward Shoreline represents a unique and irreplaceable resource to the people of the state and nation. Future residential, commercial, and industrial developments could adversely affect the wildlife value of the area. It is the policy of the state and Nation to preserve and protect resources of this nature for the enjoyment of the current and succeeding generations.

172. How does this project protect these resources?

173. Oliver Salt Ponds is designated a “Rural Historic Landscape” How far is the project from the Oliver Salt Ponds and what has the District done to demonstrate consistency within the National Register of Historic Places.

The District must consult with the appropriate Federal, State and local land use agencies prior to issuance of a PSD permit preliminary determination. For the purposes of the Endangered Species Act (ESA), the District shall:

- Notify the appropriate Federal Land Manager (FLM) within 30 days of receipt of a PSD permit application. If the proposed project will impact a Class I area, notify the appropriate Federal Land Manager (FLM) no later than 60 days prior to issuing a public notice for the project.
- Notify the Fish and Wildlife Service (FWS) and EPA when a submitted PSD permit application has been deemed complete, in order to assist EPA in caring out its nondelegable responsibilities under Section 7 of the ESA (PL 97-304).
- Notify applicants of the potential need for consultation between EPA and FWS if an endangered species may be affected by the project.
- Refrain from issuing a final PSD permit unless FWS has determined that the proposed project will not adversely affect any endangered species
- EPA/BAAQMD PSD DELEGATION AGREEMENT

174. Please demonstrate the Districts efforts to comply with the above provision of the PSD delegation agreement. Specifically also include records of consultation with the CEC, USFWS, Alameda County, City of Hayward, Alameda county public health Department, Army Corp of Engineers California Department of Fish and Game and the Federal land manager(s) with jurisdiction over the United States waters of the San Francisco Bay and shoreline.

All Email communications from Rob Simpson and District responses are hereby incorporated into these comments by reference.

The CEC record for the Eastshore Energy Center and Russell City Energy Center are hereby incorporated by reference into these comments.

All questions posed in these comments that lead to a response that could lead to a better way to permit this facility are in effect requesting that the better way be utilized.

The District is requested to forward all applicable comments and permit information including those in the EAB appeal 08-01 to USFWS and other applicable agencies for their determinations.

(NOTE REVISED ADDRESS)
"Notice of Public Hearing and Notice Inviting Written Public Comment on" Proposed Air Quality Permit for the Russell City Energy Center, Hayward, CA

The Bay Area Air Quality Management District ("District") is proposing to issue an amended Prevention of Significant Deterioration ("PSD") Permit for the Russell City Energy Center. Before doing so, the District is providing the public with notice of its proposal and an opportunity to review and comment on the proposed permit. The District is also holding a public hearing to provide the public with an opportunity to comment in person. The proposed Russell City Energy Center is a 600-megawatt natural gas fired combined-cycle power plant to be built by Russell City Energy Company, LLC, (50 W. San Fernando Street, San Jose, CA 95113) an affiliate of Calpine Corporation.

The proposed facility would be located at 3862 Depot Road, near the corner of Depot Road and Cabot Boulevard, in Hayward, CA." *Notice*

Because the applicant address is placed first and in parenthesis and the (revised) site address is placed second and disjointed with an inaccurate reference to the sites proximity to Cabot Boulevard. The permit should be re-noticed.

A transcript of an August 18, 2008 email from Barbara Mcbride at Calpine to Weyman Lee at the District states: "Can you please change the name on the Russell City Energy Center Permit owner to Russell City Energy Company LLC and the address should be 3875 Hopyard Rd. #345 Pleasanton CA 94588. Thank you so much"

Because of the change in name and location of the applicant the permit should be re-noticed. Because the District identified Calpine but did not identify the other owner GE therefore the permit should be re-noticed. Because the notice and statement of basis do not reflect the new address identified by the applicant the permit should be re-noticed.

"The proposed power plant will consist of two combustion turbine generators, two heat recovery steam boilers, a steam turbine generator and associated equipment, a wet cooling system, and a diesel fire pump. The District initially issued a permit for the project in 2002, but it was subsequently relocated approximately 1,500 feet to the north. The permit therefore needs to be amended." *Notice*

Wet cooling systems are often associated with large outbreaks of Legionnaires' disease. Adequate consideration of the health risks of a wet cooling system has not been disclosed.

175. Please complete a Health Risk Analysis of the wet cooling system.

Because the District did not issue a PSD permit in 2002 and the relocation of the site has not been accurately disclosed the permit should be re-noticed.

"Under the proposed amended permit, the facility would be allowed to emit significant amounts of certain PSD-regulated air pollutants, including the following:

Nitrogen Oxides (as NO2): 134.6 tons per year
Carbon Monoxide (CO): 389.3 tons per year
Particulate Matter (PM): 86.8 tons per year" *Notice*

Because the pollutants disclosed do not reflect other pollutants subject to PSD limits and the disclosed pollutants are not expressed in context of their effects on air quality the permit should be re-noticed.

176. Please disclose the amount of particulate matter "spare the air days" eliminates and the cost of "spare the air days" in comparison to the cost of emission reduction credits and licensing using current BACT instead of this permit scheme.

"The project will utilize the Best Available Control Technology to minimize emissions of these air pollutants as required by 40 C.F.R. Section 52.21. The proposed project will not consume a significant degree of any PSD increment." *Notice*

Because the project does not propose to use the Best Available Control Technology the permit should be re-noticed.

Because the notice does not provide an accurate increment analysis or analysis on the effect on air quality the permit should be re-noticed.[46]

The revised public notice is not consistent with the notification that the District sent to USFWS and other agencies. They were sent only the first address and the site was incorrectly described as the corner of Depot Road and Cabot Boulevard and "industrial" with no reference to the actual shoreline location. The actual location should be disclosed to the public and involved agencies.

VII. CONCLUSIONS

The remand order from the EAB decision does not deny review of the substantive PSD issues raised by Mr. Simpson but states that permit must be re-noticed and that the appeal board refrains from opining on the substantive PSD issues raised by Mr. Simpson. The District is circumventing public participation by failing to provide access to the administrative record.

Since BACT is part of the CAA and the PDOC includes the District's BACT analysis therefore clearly the PDOC and draft PSD Permit are interdependent on the findings from the federal BACT analysis conducted by the District purportedly in 2002 and again in 2007. Therefore the District should re-notice the PDOC along with a "new" draft PSD permit consistent with the requirements of the CAA and the District's Regulations.

Because of the District's failure to carry out the USEPA EAB Remand Order to "scrupulously adhere to all relevant requirements in section [40 C.F.R. § 124.10(d)] concerning the initial notice of draft PSD permits (including development of mailing lists), as well as the proper content of such notice" therefore this also serves as a Complaint to Office of the

[46] As in the CEC emission impacts air quality table 3 (utilizing the old PM standards)
Continued on the next page

Administrator of the U.S. Environmental Protection Agency (USEPA) and the California Air Resources Board (ARB) under 42 USC § 7604.

Respectfully submitted,

Michael E. Boyd

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Michael E. Boyd President (CARE)
CAlifornians for Renewable Energy, Inc.
Phone: (408) 891-9677
E-mail: michaelboyd@sbcglobal.net
5439 Soquel Drive
Soquel, CA 95073

Lynne Brown

____

Lynne Brown Vice-President
CAlifornians for Renewable Energy, Inc. (CARE)
24 Harbor Road
San Francisco, CA 94124
Phone: (415) 285-4628
E-mail: l_brown369@yahoo.com

cc.
A.08-09-007 CPUC electronic service list

Verification

I am an officer of the Complaining Corporation herein, and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except matters, which are therein stated on information and belief, and as to those matters I believe them to be true.

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

Executed on this 5th day of February, 2009, at San Francisco, California.

Lynne Brown

____

Lynne Brown Vice-President
CAlifornians for Renewable Energy, Inc. (CARE)

Continued from the previous page
http://www.baaqmd.gov/pmt/air_toxics/permit_modeling/psd_increment_consumption_status_report_4_16_08.pdf

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a true copy of the *CARE and Rob Simpson comments on the "amended" PSD permit for the Russell City Energy Center Application Number 15487 and Complaint to Office of the Adminstrator USEPA and ARB under 42 USC § 7604*

Executed this 5th day of February, 2009 at Soquel, California.

Carol Paramoure

____

Carol Paramoure
5439 Soquel Drive
Soquel, California 95073
(831) 465-9809

Mary D. Nichols
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Lisa P. Jackson
Office of the Administrator
Environmental Protection Agency
Ariel Rios Building
Mail Code: 1101A
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Attachment 1

NO$_x$OUT® ULTRA™

NO$_x$ Reduction Process

TECHNICAL BENEFITS

- Simplified process, highly efficient urea conversion
- Non-hazardous materials throughout
- Low pressure operation
- Process controls designed to follow load and provide easy shutdown
- Liquid reagent system easily modified for dry urea feedstock
- Backed by Fuel Tech's proven start-up, optimization, and service experience

FUEL TECH™

Technology for a renewed environment™

Smart, safe, and simple... NOxOUT® ULTRA™ provides SCR ammonia supply without the headaches of hazardous chemical handling.

Selective catalytic reduction (SCR) has become a standard for meeting the most stringent NOx reduction requirements from power generation systems. Requiring ammonia (NH_3) as the reducing agent, operators of these systems have had little choice but to accept the handling issues, potential liability, and associated costs in using a hazardous chemical supply.

Fuel Tech's NOxOUT® ULTRA™ system is a new alternative that offers an ammonia feed from a safe urea supply. Available for new SCR systems and as a retrofit to existing applications, NOxOUT® ULTRA™ is a cost-effective solution that simplifies SCR operation.

Urea vs. NH_3

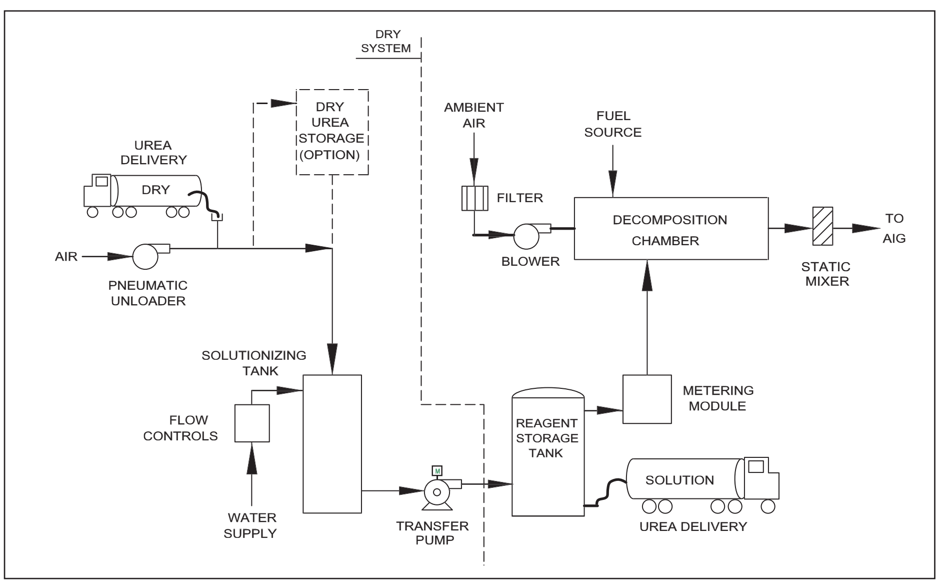
The advantages of a urea-based system over traditional anhydrous ammonia or aqueous supplies are clear. Anhydrous ammonia is classified as a hazardous chemical per CAA Section 112(r). As such, ammonia requires safety procedures to protect personnel, neighboring communities, and the environment from unforeseen chemical release. Reporting, record keeping, permitting, and emergency preparedness planning are generally all needed with on-site ammonia storage. Aqueous ammonia-based systems also require specialized equipment, including pressure vessels, a heated vaporizer, and other features, and have significantly higher operating costs than urea-based systems.

In contrast, urea products are non-hazardous sources of ammonia, so their transport, storage, and use are greatly simplified. Fuel Tech has extensive, proven experience with urea-based systems, and the NOxOUT® ULTRA™ system is built on that solid foundation.

Other urea-to-ammonia conversion systems on the market work by hydrolyzing urea on-site. These processes are complex, expensive, and include a high pressure vessel containing ammonia. NOxOUT® ULTRA™ is a more economical and easier way to generate ammonia.

Design Simplicity

The NOxOUT® ULTRA™ process provides ammonia for SCR systems by decomposing urea to feed the traditional ammonia injection grid (AIG). The process relies on post-combustion reactions in a chamber designed to

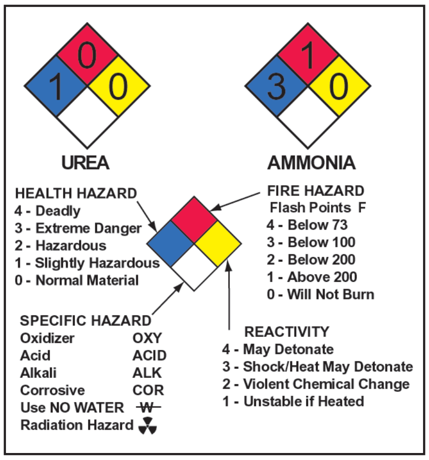


control urea decomposition in a specified temperature window (600-1000 °F). The NOxOUT® ULTRA™ system is simple, consisting of a blower, decomposition chamber, chemical pumping system, urea storage, and process controls.

Filtered ambient air is fed into the chamber through the use of a blower with automatic dampers to control discharge flow and pressure. A burner is fired downstream of the dampers, and an aqueous urea solution supplied by the storage and pumping system is sprayed into the post-combustion gases through the injectors. The urea is efficiently converted to ammonia in the decomposition chamber, and that ammonia feeds the AIG for a traditional SCR system.

System Options

The NOxOUT® ULTRA™ system can be customized for each application.



For larger systems, an in-duct gas-to-gas heat exchanger can be supplied to preheat the process air and minimize operating costs.

The liquid portion of the system can be supplied with dilution water capability to accommodate delivery of concentrated reagent solutions.

The dry urea system components can be supplied to provide flexibility for reagent selection.

New Process, Proven Technologies

The NOxOUT® ULTRA™ process incorporates commercially proven features of Fuel Tech's other NOx reduction products. Urea storage, pumping, metering, and injection are all standard to the NOxOUT® product line, first introduced in 1990. The NOxOUT CASCADE® process relies on careful duct and gas flow dynamics design. The NOxOUT SCR® system relies on the conversion of urea to ammonia for SCR reactions. So while NOxOUT® ULTRA™ is a new product to our mix of process solutions, the established technologies and know-how of Fuel Tech make it a uniquely reliable urea conversion system.

The NOxOUT® ULTRA™ system has all the benefits of direct ammonia supply for SCR without the cost, safety and environmental concerns associated with ammonia handling. More cost-effective than urea-hydrolyzing processes, NOxOUT® ULTRA™ from Fuel Tech is a smart choice for simplifying SCR operation with a urea-to-ammonia conversion process.

For more information on NOxOUT ULTRA™ programs available from Fuel Tech, call, fax, or write Fuel Tech at:

Fuel Tech, Inc. • 512 Kingsland Drive • Batavia, IL 60510
Phone 800.666.9688 • 630.845.4500 • Fax 630.845.4501
www.fueltechnv.com • webmaster@fueltechnv.com

Technology for a renewed environment™

Attachment 2

Pack, Heidi K.

From: Hunt, Kelly [KHunt@Semprautilities.com]
Sent: Thursday, April 12, 2007 3:06 PM
To: Kellogg, Kellie; Pack, Heidi K.; Moore, Steve ; Miller, Taylor; Baerman, Daniel; Waller, Fred A.; Hardman, Charles; Blackburn, Suzanne; Annicchiarico, John; Haury, Evariste
Subject: Updated: Palomar Energy Center Variance Report - 4073 1st Quarter 2007
Attachments: Hearing Board Quarterly Report for 1st Quarter 2007.pdf

Ms. Kellogg,

Please find attached an updated copy of the 1st quarter report to the Hearing Board for 2007. This report **supersedes the submission made on 4/11/07 and** is intended for the Hearing Board meeting to be held on April 26, 2007. I apologize for any inconvenience this may have caused you. This report covers the items required by Condition F.3. of the Board's April 27, 2006 order for Variance 4073. In addition, this report covers Enforcement Condition 1 concerning compliance with required increment of progress.

If you have any questions, please feel free to call me at 760-432-2504.

Kelly Hunt
Generation Compliance Manager
San Diego Gas & Electric
2300 Harveson Place, SD1473
Escondido, CA 92029
760-432-2504 (Office)
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SDGE®
A Sempra Energy company

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dbaerman@semprautilities.com

April 11, 2007

Ms. Catherine Santos
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Santos and Members of the Board:

Set forth below is SDG&E's 2007 first quarter report to the Hearing Board. This report will cover the items required by Condition F. 3. of the Board's April 27, 2006 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

The increments of progress table attached to the Board's order is included with this letter as Attachment 1. The primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E timely filed the permit application on May 31, 2006. A rule amendment concerning Rule 69.3.1 is still under consideration by District staff and SDG&E and District staff met on February 16, 2007 to discuss the matter further.

Petitioner has timely satisfied all increments of progress within Petitioner's control. The increments of progress table also includes District staff and other third-party actions concerning rule development and permit processing. These actions were included in the increments of progress solely to describe the third-party actions necessary to resolve the regulatory issues prompting the variance. SDG&E will defer to District staff to provide an update to the Board on District's processing of SDG&E's permit application submittal, rule development and a possible revised schedule.

2. Engineering or operational alternatives [Order, Condition F.3 (1)]

Information concerning engineering or operational alternatives considered by Petitioner to ensure maximum control of emissions as recommended by District staff was included in the application for amended permit conditions submitted on May 31, 2006. SDG&E included information concerning reductions related to early ammonia injection and installation of a new software program being developed by General Electric for turbines such as those operating at Palomar ("OpFlex"). SDG&E also included information concerning seven other potential alternatives as requested by District staff.

On December 20, 2006, at District staff's request, Petitioner provided additional information regarding engineering and operational alternatives, including additional evaluation of early ammonia injection and economic impacts of several potential alternatives.

In addition, OpFlex, a General Electric turbine control system software was installed in mid-October, 2006. The turning process allows combustion turbines to minimize emissions between 20 and 60% load, by optimizing the fuel flow to the four gas stages in each combustion can. This precisely controls the flame for optimum combustion to minimize emissions. There were no equipment or hardware changes.

3. NOx Emissions Data [Order, Condition F.3 (2)]

Information concerning NOx emissions from the facility during the period of the 1 year variance to present is included in attachment 2. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.3 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data

A summary how the plant has reduced NOX emissions by various controls that it has established since the inception of the variance is included as attachment 3.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

SAN DIEGO AIR POLLUTION CONTROL DISTRICT HEARING BOARD

Palomar Energy Center

PROPOSED INCREMENTS OF PROGRESS
(As of 4/11/07)

MILESTONE **DATE**

	Description	Permit Modification	Rule Change	Variance(s)
1	Variance 4068 hearing for 90-day issued			2/9/06
2	Emergency Variance 4069 for condition 21 issued to enable early ammonia injection.			2/23/06
3	*Palomar submits request for Rule Change to APCD*		*3/6/06*	
4	*APCD requests more data for rule change*		*3/14/06*	
5	*Mtg. with APCD concerning Data Requests*		*3/30/06*	
6	*Additional mtg. with APCD (Steve Moore) concerning Data Requests*		*4/4/06*	
7	*SDG&E submits requested data to APCD (Moore)*		*4/7/06*	
8	SDG&E submits summary of requested Permit Modification topics to APCD (covering matters of concern to staff beyond start up)	4/7/06		
9	Mtg. with APCD – QA/QC Plan Addendum (relating to some permit amendment topics)	4/11/06		
10	Request for Permit Modification Fee Estimate submitted to APCD by SDG&E	4/11/06		
11	*APCD (Moore) submits new data request to SDG&E (replaces 3/30 & 4/4 requests)*		*4/14/06*	
12	*Data submitted to APCD (Moore)*		*4/25/06*	
13	Variance 4073 Hearing			4/27/06
14	*Mtg. scheduled with APCD and CEC (in response to 4/7 letter from SDG&E) to discuss permit and rule amendment issues*	5/3/06 (COMPLETED 5/3/06)	*5/3/06* (COMPLETED 5/3/06)	
15	Proposed Permit Pre-application Mtg. with APCD and CEC –	5/19/06 (COMPLETED		

			5/9 & 5/23/06)		
16	Proposed Permit Application Submittal		5/31/06 (COMPLETED 5/31/06)		
17	Quarterly Progress Update (April – June) to Hearing Board				July 27, 2006 (Completed)
18	APCD Permit Application Completeness Review	Respond to APCD data requests while in process	June – July 2006 (Completed)		
19	*APCD drafts rule change*			*April – June 2006*	
20	Quarterly Progress Update (July - September)to Hearing Board				October 27, 2006 (Completed)
21	*APCD holds public workshop on rule amendment*			*July 2006*	
22	*APCD publishes draft rule for public comment*	*30-day public notice required*		*August 2006*	
23	*APCD prepares final rule adoption documents*	*Final rule and "staff report" are prepared for County Board of Supervisors review and adoption*		*September 2006*	
24	*Air Quality Advisory Committee*	*Appointed committee reviews and advises the Board*		*October 2006*	
25	*Board adoption of rule*	*Upon adoption, SDAPCD considers rule to be the version for compliance*		*October 2006*	
26	Proposed Permit Modification (ATC/PDOC) published for public comment	30-day public comment period	October 2006		
27	Final ATC/FDOC revisions	Final language that incorporates public comments is developed	November 2006		
28	Final ATC/FDOC Issued		November 2006		

29	SDG&E petitions CEC for companion amendment of Conditions of Certification (CoC)		December 2006		
30	Quarterly Progress Update (October - December) to Hearing Board				Completed January 25, 2007
31	CEC issues amendment of CoC		March 2007		
32	Quarterly Progress Update (January - March) to Hearing Board				April 26, 2007

Attachment 2

CT1 YTD Summary

	Tons	#
2Q06	9.23	18,460
3Q06	8.61	17,220
4Q06	8.63	17,260
1Q07	8.88	17,760
Total	35.35	70,700

Note: Total NOx includes startup emissions.

CT2 YTD Summary

	Tons	#
2Q06	9.28	18,560
3Q06	8.95	17,900
4Q06	9.70	19,400
1Q07	8.73	17,460
Total	36.66	73,320

Note: Total NOx includes startup emissions.

CT1 Startup YTD Summary

	Tons	#
2Q06	3.19	6,380
3Q06	1.38	2,760
4Q06	0.52	1,040
1Q07	0.38	760
Total	5.47	10,180

CT2 Startup YTD Summary

	Tons	#
2Q06	3.64	7,280
3Q06	1.10	2,200
4Q06	0.52	1,040
1Q07	0.43	860
Total	5.69	10,520

[1] Data gathered from CEMS Startup/Shutdown Incident Reports

[2] Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

OPFLEX AND EARLY AMMONIA INJECTION EFFECTS ON STARTUP EMISSIONS PALOMAR ENERGY CENTER

Subject:

This Evaluation assesses the effects of two major Palomar Energy Center efforts to reduce startup emissions.

Discussion:

Early Ammonia Injection is a SDG&E project to minimize NOx emissions during the startup process by reducing and optimizing the temperature at which ammonia is injected to the SCR's, thereby reducing NOx emissions during the startup process. The original control system allowed ammonia injection when the temperature at the SCR increased to 550 deg F during the plant startup process. This temperature was chosen to provide a safety margin above the required SCR operating temperature. If ammonia is injected at too low of a temperature, the SCR is not effective, there can be elevated ammonia slip, and there is potential for poisoning of the SCR catalyst.

Palomar personnel have analyzed the temperature requirements for the SCR and evaluated the risks associated with low temperature ammonia injection, along with the benefits of emissions reductions obtained by lowering the injection temperature. The evaluation indicated that a significant lowering of the temperature was possible, as long as close attention was paid to the environmental conditions at all locations surrounding the catalyst. The temperature set point for ammonia injection was lowered in two steps as a prudent sequence to confirm the benefits and minimize risk. The first setpoint was lowered during the summer 2006. The setpoint was lowered again to 485 deg F in October 2006.

OpFlex is a General Electric proprietary software improvement that manages the fuel splits and fuel temperature control to minimize NOx and CO emissions at part load, and significantly reduces NOx during the startup process. The turbines can now be operated down to approximately 45% load and remain in compliance with all operating emissions limitations. The NOx produced during the startup process is also minimized approximately 25% to 45%, although not to the point of compliance with the 2.0 ppmvd@15% O2 permit limit.

OpFlex was installed in mid-October, 2006. Subsequent to the installation, Palomar Operations has studied the emissions enhancements OpFlex provides, and has made adjustments to the startup process to take advantage of these enhancements to reduce startup emissions. There have been no extended startups since the installation of OpFlex, so the extended startup procedure has not yet been optimized.

Results:

OpFlex and the final adjustment to the enhanced ammonia injection setpoint were implemented at approximately the same time in mid October, so the emissions improvements attributable to each are somewhat difficult to assign. However, this analysis endeavors to separate the projects and summarize the success of each.

With the SCR at normal operating temperature, ammonia injection can lower startup-related NOx concentrations by approximately 10.0 ppm. At base load, this equates to approximately 45 lbs/hr reduction of NOx mass emissions. This mass emissions reduction remains relatively constant even at reduced operating loads if sufficient NOx is present in the exhaust stream from the turbine.

During a typical hot start following a nightly shutdown, the enhanced, lowered temperature setpoint for ammonia injection allows the ammonia to be injected approximately 60 to 90 minutes earlier than the original setpoint (550 deg F) would have allowed. This provides for a reduction of at least 45 lbs NOx produced during the hot startup. The early ammonia injection NOx reduction for an extended startup will be even greater, conservatively estimated to be 60 lbs NOx per extended start.

OpFlex lowers the NOx produced by the turbine during the startup process at all loads above approximately 25%. The NOx is lowered enough above 45% load that in conjunction with the SCR, the stack emissions are reduced below the permit limit of 2.0 ppmvd@15% O2.

Plant Operations personnel have optimized the startup process to take advantage of this reduction of NOx above 25%. When plant conditions allow, the turbine is immediately ramped to approximately 43%, so that the turbine exhaust emissions are high only for the first 20 – 30 minutes of operation, and the magnitude of these high emissions are greatly reduced above 25%.

Recent normal startups following a typical nightly shutdown have resulted in NOx emissions of 28 lbs NOx, and 10 lbs. CO. For NOx, these results are the combination of OpFlex and early ammonia injection. Prior to the OpFlex and early ammonia projects, a typical regular startup would have produced approximately 120 lbs of NOx and 35 lbs of CO. (Note: Startups early in the project life produced highly variable emissions results). All of the CO reduction for recent startups is attributable to the shorter startup allowed by OpFlex, while 45 lbs. of NOx reduction are attributable to early ammonia injection, and 47 lbs. attributable to OpFlex. See the Summary Table below:

Summary:

Early ammonia injection and OpFlex have both been highly successful in reducing emissions during normal startups. The emissions during an extended startup will also be greatly reduced, although more testing and optimization is required before the results can be quantified. The table below is illustrative of starts after an overnight shutdown of one turbine, which has been a typical mode of operation during the past year. Somewhat higher emissions could occur for longer shutdowns.

Regular Startup Summary Table:

	Startup Emissions before Opflex/Early NH3	Reduction Attributable to Early NH3 Inj.	Reduction Attributable to OpFlex	Recent Regular Startup Results – Note 1 (Nov. 2006 – Feb. 2007)
NOx (lbs.)	120	45	47	28
CO (lbs.)	35	0	25	10

Note 1: Excludes startups after lengthy shutdown (>24 hours) or after HRSG forced cool down for maintenance.

Pack, Heidi K.

From: Hunt, Kelly [KHunt@Semprautilities.com]
Sent: Friday, April 13, 2007 8:54 AM
To: Waller, Fred A.; Pack, Heidi K.; Hartnett, Gary; LaBlond, Jason
Subject: FW: Palomar Energy Exceedances Covered Under Variance 4073, March 2007 YTD
Importance: High
Attachments: PEC Exceedance Covered Under Variance 4073 March 2007YTD.pdf

Please see email below.

Kelly Hunt
Generation Compliance Manager
San Diego Gas & Electric
2300 Harveson Place, SD1473
Escondido, CA 92029
760-432-2504 (Office)
760-432-2510 (Fax)
khunt@semprautilities.com

From: Waller, Fred A.
Sent: Friday, April 06, 2007 5:07 PM
To: Hunt, Kelly
Subject: Palomar Energy Exceedances Covered Under Variance 4073, March 2007 YTD
Importance: High

Kelly,
Please forward this Report of Violation to APCD Compliance (Mr. Jason LaBlond, Mr. Gary Hartnett and copy Ms. Heidi Gabriel-Pack).

Mr. LaBlond,
In a previous telephone conversation we discussed the reporting requirements of APCD Rule 19.2(d)(3)-Report of Violation. You indicated that an email notification to you will suffice to meet the reporting requirements. Additionally, Ms. Heidi Gabriel-Pack, approved monthly reporting of violations which are covered under Variance 4073.

In previous months in 2006, SDG&E had provided a monthly summary report of Violations/Exceedances covered under Variance 4073 to you and copied Mr. Gary Hartnett and Ms. Heidi Gabriel-Pack. SDG&E is submitting this summary report to notify the District of one exceedance in March 2007 covered by Variance 4073 which occurred at the Palomar Energy Center, 2300 Härveson Place, Escondido, CA 92009 .

If you have any questions, please feel free to call.

Fred Waller
Environmental Specialist-Generation
Office: 760 432 2507
Cell: 619 778 6029

SDGE
Palomar Energy Center
APCD Application Number 976846

Event	Date	Stack/ Unit	Clock Hour	Pollutant	Magnitude	Unit of Measure	Permit Condition/Limit	Cause/Reason	Comments	Date Reported to District
1	4/3/06	1	9:00	N/A	5 hrs 48 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
2	4/3/06	1	10:00	N/A	5 hrs 48 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
3	4/3/06	2	9:00	N/A	5 hrs 15 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
4	4/3/06	2	10:00	N/A	5 hrs 15 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
5	5/5/06	1	6:00	NOx	128.4	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
6	5/5/06	2	5:00	NOx	143.9	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
7	5/8/06	1	7:00	NOx	106.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
8	5/9/06	2	7:00	NOx	132.5	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
9	5/10/06	2	6:00	NOx	121.4	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/12/06
10	5/13/06	2	8:00	NOx	124.7	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
11	5/14/06	2	8:00	NOx	123.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
12	5/15/06	1	3:00	NOx	101.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
13	5/16/06	2	8:00	NOx	141.1	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	5/16/06
14	5/30/06	2	0:00	N/A	2 hrs 19 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	8/10/06
15	6/4/06	1	10:00	N/A	2 hr 26 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	7/9/06
16	6/13/06	1	19:00	NOx	117.3	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	7/9/06
17	6/13/06	1	19:00	N/A	2 hr 5 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	1/11/07

SDGE
Palomar Energy Center
APCD Application Number 976846

Event	Date	Stack/ Unit	Clock Hour	Pollutant	Magnitude	Unit of Measure	Permit Condition/Limit	Cause/Reason	Comments	Date Reported to District
18	6/15/06	1	10:00	N/A	2 hr 9 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	7/9/06
19	~~6/16/06~~	~~2~~	~~6:00~~	~~N/A~~	~~2 hr 9 min~~	~~Hrs/Mins~~	~~AQ 40: 2 hour startup duration~~	~~Typical regular startup.~~	Reported in error. Was not a violation.	~~7/9/06~~
20	6/16/06	2	6:00	NOx	109.9	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	8/10/06
21	7/2/06	1	9:00	N/A	5 hrs 32 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
22	7/2/06	1	10:00	N/A	5 hrs 32 Min	Hrs/Mins	AQ-39: 4 hour startup duration	Typical extended startup.	Covered under Variance #4068	8/10/06
	Aug 2006: No events to report.									
	Sept 2006: No events to report.									
23	10/11/06	1	11:00	N/A	4 hr 45 min	Hrs/Mins	AQ 39: 4 hour startup duration	Extended startup.	Covered under Variance #4073	11/13/06
24	10/12/06	2	6:00	N/A	2 hr 20 min	Hrs/Mins	AQ 40: 2 hour startup duration	Typical regular startup.	Covered under Variance #4073	11/13/06
25	10/12/06	2	6:00	NOx	223.5	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	11/13/06
26	10/12/06	1	3:00	NOx	127.5	Lbs/hr	AQ 21: 100 lbs/hr	Early NH3 Injection during Startup	Covered under Variance #4073	11/13/06
27	November 2006: No events to report.									
28	December 2006: No events to report.									
29	January 2006: No events to report.									
30	February 2006: No events to report.									
31	03/21/07	1	15	N/A	2 hrs 2 min	Hrs/Mins	AQ 40: 2 hour startup duration	Regular startup with generator testing required by WECC.	Covered under Variance #4073	4/9/07

Events 1, 2, 3 and 4 (exceedance of Extended Startup duration limit) were not reported in April 2006 due to confusion over the Reporting requirment of Rule 19.2(d) and the existing Variance 4068.
Event 14 was not reported in the July 2006 monthly report due to oversight made during the CEMS report review process.

SDGE
Palomar Energy Center
APCD Application Number 976846

Event	Date	Stack/ Unit	Clock Hour	Pollutant	Magnitude	Unit of Measure	Permit Condition/Limit	Cause/Reason	Comments	Date Reported to District
	Event 18 was not a violation of AQ 40: 2 hour Regular Startup duration limit. On 6/16/06 CTG 2 was actually started up within the 2 hour limit.									
	Event 17 was not reported in the July 2006 monthly report due to oversight made during the CEMS report review process.									
	Event 19 was not reported in the July 2006 monthly report due to oversight made during the CEMS report review process.									

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric per Condition No. F.3 and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073.

ACTION:
There being no motion made, the Air Pollution Control District Hearing Board, unable to discuss the report due to a lack of a quorum, acknowledged the submission of the report and at the discretion of the Board, continued this item to a future date. Member Rodriguez would be provided a copy of the report to review and if she determined that there needs to be further discussion on this report, the Clerk of the Board will schedule a special meeting of the Hearing Board to address concerns.

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

____
Kellie C. Kellogg, Deputy Clerk

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COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

2007 JUL 13 AM 8:44

THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

Daniel Baerman
Director of Electric Generation
2300 Harveson Place
Escondido, CA 92029
Tel: 760-432-2501
dbaerman@semprautilities.com

July 11, 2007

Ms. Kellie Kellogg
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Kellogg and Members of the Board:

Set forth below is SDG&E's second quarter 2007 report to the Hearing Board. This report will cover the items required by Condition F. 2. of the Board's April 26, 2007 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

The increments of progress table attached to the Board's order is included with this letter as Attachment 1. The primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E responded to the District on May 4, 2007, agreeing to the language of the draft S/A issued on April 20, 2007. SDG&E was informed on July 9, 2007 that the District intends to issue the final S/A no later than July 26, 2007. A rule amendment workshop concerning Rule 69.3.1 has been scheduled for August 3, 2007 by District staff.

2. Engineering or operational alternatives [Order, Condition F.2 (1)]

No additional information to report at this time.

3. NOx Emissions Data [Order, Condition F.2 (2)]

Information concerning NOx emissions from the facility during the previous quarter is included in Attachment 2. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.2 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data [Order, Condition F.2 (4)]

No further data has been requested by the Board at this time.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

Attachment 2

CT1 Quarterly Summary

	Tons	#
Apr-07	2.17	4,340
May-07	2.48	4,960
Jun-07	2.74	5,480
Total	7.39	14,780

Note: Total NOx includes startup emissions.

CT1 Startup Summary

	Tons	#
Apr-07	0.00	0.00
May-07	0.07	143.85
Jun-07	0.03	54.35
Total	0.10	198.20

CT2 Quarterly Summary

	Tons	#
Apr-07	2.65	5,300
May-07	2.69	5,380
Jun-07	2.52	5,040
Total	7.86	15,720

Note: Total NOx includes startup emissions.

CT2 Startup Summary

	Tons	#
Apr-07	0.03	63.13
May-07	0.15	307.98
Jun-07	0.14	271.20
Total	0.32	642.31

CT1 YTD Summary

	Tons	#
3Q06	8.61	17,220
4Q06	8.63	17,260
1Q07	8.88	17,760
2Q07	7.39	14,780
Total	33.51	67,020

Note: Total NOx includes startup emissions.

CT1 Startup YTD Summary

	Tons	#
3Q06	1.38	2,760
4Q06	0.52	1,040
1Q07	0.38	760
2Q07	0.10	200
Total	2.38	4,760

CT2 YTD Summary

	Tons	#
3Q06	8.95	17,900
4Q06	9.70	19,400
1Q07	8.73	17,460
2Q07	7.86	15,720
Total	35.24	70,480

Note: Total NOx includes startup emissions.

CT2 Startup YTD Summary

	Tons	#
3Q06	1.10	2,200
4Q06	0.52	1,040
1Q07	0.43	860
2Q07	0.32	640
Total	2.37	4,740

Data gathered from CEMS Startup/Shutdown Incident Reports
Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

There have been no excess emissions as defined in Board Order 4073 on April 26, 2007

Exhibit 3

SAN DIEGO AIR POLLUTION CONTROL DISTRICT HEARING BOARD

COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

Palomar Energy Center

2007 MAY 14 AM 8: 35

PROPOSED INCREMENTS OF PROGRESS
(As of4/26/07)

THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

MILESTONE **DATE**

	Description	Permit Modification	Rule Change	Variance(s)
1	Variance 4068 hearing for 90-day issued			2/9/06
2	Emergency Variance 4069 for condition 21 issued to enable early ammonia injection.			2/23/06
3	*Palomar submits request for Rule Change to APCD*		*3/6/06*	
4	*APCD requests more data for rule change*		*3/14/06*	
5	*Mtg. with APCD concerning Data Requests*		*3/30/06*	
6	*Additional mtg. with APCD (Steve Moore) concerning Data Requests*		*4/4/06*	
7	*SDG&E submits requested data to APCD (Moore)*		*4/7/06*	
8	SDG&E submits summary of requested Permit Modification topics to APCD (covering matters of concern to staff beyond start up)	4/7/06		
9	Mtg. with APCD – QA/QC Plan Addendum (relating to some permit amendment topics)	4/11/06		
10	Request for Permit Modification Fee Estimate submitted to APCD by SDG&E	4/11/06		
11	*APCD (Moore) submits new data request to SDG&E (replaces 3/30 & 4/4 requests)*		*4/14/06*	
12	*Data submitted to APCD (Moore)*		*4/25/06*	
13	Variance 4073 Hearing			4/27/06
14	*Mtg. scheduled with APCD and CEC (in response to 4/7 letter from SDG&E) to discuss permit and rule amendment issues*	5/3/06 (COMPLETED 5/3/06)	*5/3/06* (COMPLETED 5/3/06)	
15	Proposed Permit Pre-application Mtg. with APCD and CEC –	5/19/06 (COMPLETED		

	Description		Permit Modification	Rule Change	Variance(s)
			5/9 & 5/23/06)		
16	Proposed Permit Application Submittal		5/31/06 (COMPLETED 5/31/06)		
17	Quarterly Progress Update (April – June) to Hearing Board				July 27, 2006 (Completed)
18	APCD Permit Application Completeness Review	Respond to APCD data requests while in process	June – July 2006 (Completed)		
19	*APCD drafts rule change*			*April – June 2006*	
20	Quarterly Progress Update (July - September)to Hearing Board				October 27, 2006 (Completed)
21	*APCD holds public workshop on rule amendment*			*July 2006*	
22	*APCD publishes draft rule for public comment*	*30-day public notice required*		*August 2006*	
23	*APCD prepares final rule adoption documents*	*Final rule and "staff report" are prepared for County Board of Supervisors review and adoption*		*September 2006*	
24	*Air Quality Advisory Committee*	*Appointed committee reviews and advises the Board*		*October 2006*	
25	*Board adoption of rule*	*Upon adoption, SDAPCD considers rule to be the version for compliance*		*October 2006*	
26	Proposed Permit Modification (ATC/PDOC) published for public comment	30-day public comment period	October 2006		
27	Final ATC/FDOC revisions	Final language that incorporates public comments is developed	November 2006		
28	Final ATC/FDOC		November		

	Description		Permit Modification	Rule Change	Variance(s)
	Issued		2006		
29	SDG&E petitions CEC for companion amendment of Conditions of Certification (CoC)		December 2006		
30	Quarterly Progress Update (October - December) to Hearing Board				Completed January 25, 2007
31	CEC issues amendment of CoC		March 2007		
32	Quarterly Progress Update (January - March) to Hearing Board				April 26, 2007;completed
33	**Extension of Regular Variance Granted**				**April 26, 2007**
34	See Tentative Rule Schedule for Rule 69.3.1, Exhibit 2 to Board Order Granted April 26, 2007.		May-December, 2007		
35	Quarterly Progress Update (April – June) to Hearing Board				July 26, 2007;
36	Quarterly Progress Update (October-December) to Hearing Board				January 17, 2008

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric per Condition No. F.3 and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073

ACTION:
ON MOTION of Member Rodríguez, seconded by Member Reider, the Air Pollution Control District Hearing Board accepted the quarterly report and directed San Diego Gas & Electric to provide the Board with revised Increments of Progress, reflecting the testimony of County Counsel representing the APCD. The revision to the Increments of Progress Schedule (IOPS) pertained to the accurate reflection of issuance of authority to construct or permit to operate. The revised IOPS is to be submitted to the Air Pollution Control District Hearing Board for the meeting of October 25, 2007.

AYES: Rodríguez, Tonner, Reider
ABSTAIN: Rappolt
RECUSED: Gabrielson

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

By Kellie C. Kellogg
Kellie C. Kellogg
Deputy Clerk

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric/Palomar Energy Center per Condition No. F.3, and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073.

ACTION:
ON MOTION of Member Gabrielson, seconded by Member Tonner, the Air Pollution Control District Hearing Board accepted the report from San Diego Gas & Electric.

AYES: Rappolt, Gabrielson, Tonner
ABSENT: Rodriguez

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

Kellie C. Kellogg

Kellie C. Kellogg, Deputy Clerk

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COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

2007 OCT 11 PM 3:17

THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

Daniel Baerman
Director of Electric Generation
2300 Harveson Place
Escondido, CA 92029
Tel: 760-432-2501
dbaerman@semprautilities.com

October 11, 2007

Ms. Kellie Kellogg
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Kellogg and Members of the Board:

Set forth below is SDG&E's third quarter 2007 report to the Hearing Board. This report will cover the items required by Condition F. 2. of the Board's April 26, 2007 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

Referenced below are the increments of progress table attached to the Board's order; the primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E responded to the District on May 4, 2007, agreeing to the language of the draft S/A issued on April 20, 2007. SDG&E was updated by the District on October 8, 2007 on the progress of the issuance of the final S/A. The District intends to issue to final S/A no later than November 30, 2007. A rule amendment workshop concerning Rule 69.3.1 was held on August 3, 2007 by District staff.

2. Engineering or operational alternatives [Order, Condition F.2 (1)]

No additional information to report at this time.

3. NOx Emissions Data [Order, Condition F.2 (2)]

Information concerning NOx emissions from the facility during the previous quarter is included in Attachment 2. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.2 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data [Order, Condition F.2 (4)]

SDG&E received a letter dated September 14, 2007 from the District requesting a cold start and source test. The cold start and source test is scheduled to occur during the period of October 21, 2007 and October 26, 2007. District staff will be onsite to witness the test.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

CT1 3q07 NOx Summary

	Tons	#
Jul-07	3.01	6,011
Aug-07	3.21	6,419
Sep-07	2.97	5,932
Total	9.18	18,362

Note: Total NOx includes startup emissions.

CT1 Startup Only Summary

	Tons	#
Jul-07	0.33	658
Aug-07	0.17	341
Sep-07	0.19	386
Total	0.69	1,386

CT2 3q07 NOx Summary

	Tons	#
Jul-07	3.38	6,766
Aug-07	3.26	6,513
Sep-07	3.20	6,410
Total	9.84	19,689

Note: Total NOx includes startup emissions.

CT2 Startup Only Summary

	Tons	#
Jul-07	0.09	180
Aug-07	0.10	208
Sep-07	0.09	173
Total	0.28	561

CT1 YTD NOx Summary

	Tons	#
4Q06	8.63	17,260
1Q07	8.88	17,760
2Q07	7.39	14,780
3Q07	9.18	18,362
Total	34.08	68,162

Note: Total NOx includes startup emissions.

CT1 YTD Startup Only

	Tons	#
4Q06	0.52	1,040
1Q07	0.38	760
2Q07	0.10	200
3Q07	0.69	1,386
Total	1.69	3,386

CT2 YTD NOx Summary

	Tons	#
4Q06	9.70	19,400
1Q07	8.73	17,460
2Q07	7.86	15,720
3Q07	9.84	19,689
Total	36.13	72,269

Note: Total NOx includes startup emissions.

CT2 YTD Startup Only

	Tons	#
4Q06	0.52	1,040
1Q07	0.43	860
2Q07	0.32	640
3Q07	0.28	561
Total	1.55	3,101

Data gathered from CEMS Startup/Shutdown Incident Reports
Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

There have been no excess emissions as defined in Board Order 4073 on April 26, 2007

COUNTY OF SAN DIEGO
AIR POLLUTION CONTROL DISTRICT HEARING BOARD
BOARD ORDER

ADMINISTRATIVE ITEM:
B. Submission of the quarterly report to the APCD Hearing Board from San Diego Gas & Electric per Condition No. F.3 and Enforcement Condition 1 concerning compliance with required increment of progress of Petition 4073.

ACTION:
ON MOTION of Member Gabrielson, seconded by Member Rodriguez, the Air Pollution Control District Hearing Board accepted the report.

AYES: Rappolt, Rodriguez, Gabrielson, Tonner
ABSTAIN: None

THOMAS J. PASTUSZKA
Clerk of the Hearing Board

By Kellie C. Kellogg
Kellie C. Kellogg
Deputy Clerk

COUNTY OF SAN DIEGO
BOARD OF SUPERVISORS

2008 JAN 14 AM 8: 40

THOMAS J PASTUSZKA
CLERK OF THE BOARD
OF SUPERVISORS

SDG&E®

A Sempra Energy company

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January 13, 2008

Ms. Kellie Kellogg
Clerk of Hearing Board for the
San Diego County Air Pollution Control District
San Diego County Administration Center, Room 402
1600 Pacific Highway
San Diego, CA 92123

Re: Hearing Board Variance 4073; Quarterly Report

Dear Ms. Kellogg and Members of the Board:

Set forth below is SDG&E's fourth quarter 2007 report to the Hearing Board. This report will cover the items required by Condition F. 2. of the Board's April 26, 2007 order for Variance 4073. In addition, this report will cover Enforcement Condition 1 concerning compliance with required increments of progress. Information is provided first concerning the increments of progress to place the balance of the information into context.

1. Increments of Progress [Order, Enforcement Condition 1]

Referenced below are the increments of progress table attached to the Board's order; the primary events are as follows:

SDG&E personnel and District staff have met several times, shared data, and continued an ongoing dialogue concerning the permit amendment application and preparation of an amendment to rule 69.3.1. SDG&E responded to the District on May 4, 2007, agreeing to the language of the draft S/A issued on April 20, 2007. The District issued the final S/A on November 6, 2007. A rule amendment workshop concerning Rule 69.3.1 was held on August 3, 2007 by District staff.

2. Engineering or operational alternatives [Order, Condition F.2 (1)]

No additional information to report at this time.

3. NOx Emissions Data [Order, Condition F.2 (2)]

Information concerning NOx emissions from the facility during the previous quarter is included in Attachment 1. Emissions were within applicable permit limits.

4. Turbine Start Up Activity and NOx Emissions [Order, Condition F.2 (3)]

Turbine start up activity and NOx emissions data associated with turbine start up is included in Attachment 2. Emissions were within limits established in Variance 4073. Emissions were reduced to the maximum extent feasible primarily by starting only one turbine at a time, by early injection of ammonia, by the installation and utilization of OpFlex and by completing start up as quickly as feasible. SDG&E continues to collect information on each start and adjust its system and start up procedures to minimize the duration of start up and associated emissions.

5. Other Data [Order, Condition F.2 (4)]

SDG&E received a letter dated September 14, 2007 from the District requesting a cold start and source test. The cold start and source test occurred on October 22, 2007. District staff was onsite to witness the test. The District has the source test report and raw data as requested.

SDG&E appreciates the ongoing cooperation of both the District staff and the Hearing Board concerning development of variance conditions, permit conditions and rule requirements. SDG&E is committed to managing the Palomar Energy Center in a manner that complies with all applicable air quality regulatory requirements.

If you have any questions on the above subject matter, please don't hesitate to reach me at (760) 732-2501.

Sincerely yours,

Dan Baerman

Cc: Heidi Gabriel-Pack
Steven Moore
John Annicchiarico
Evariste Haury
Jason LaBlond
Suzanne Blackburn
File# 3.1.1.4.2.2

CT1 4q07 NOx Summary

	Tons	#
Oct 07	2.59	5,179
Nov 07	2.92	5,831
Dec 07	3.52	7,038
Total	9.02	18,048

Note: Total NOx includes startup emissions.

CT1 Startup Only Summary

	Tons	#
Oct 07	0.18	356
Nov 07	0.13	262
Dec 07	0.03	52
Total	0.34	670

CT2 4q07 NOx Summary

	Tons	#
Oct 07	2.63	5,255
Nov 07	3.47	6,949
Dec 07	3.37	6,732
Total	9.47	18,936

Note: Total NOx includes startup emissions.

CT2 Startup Only Summary

	Tons	#
Oct 07	0.00	0
Nov 07	0.29	573
Dec 07	0.09	173
Total	0.37	747

CT1 12-Mo NOx Summary

	Tons	#
1Q07	8.88	17,760
2Q07	7.39	14,780
3Q07	9.18	18,362
4Q07	9.02	18,048
Total	34.48	68,950

Note: Total NOx includes startup emissions.

CT1 12-Mo Startup Only

	Tons	#
1Q07	0.38	760
2Q07	0.10	200
3Q07	0.69	1,386
4Q07	0.34	670
Total	1.51	3,016

CT2 12-Mo NOx Summary

	Tons	#
1Q07	8.73	17,460
2Q07	7.86	15,720
3Q07	9.84	19,689
4Q07	9.47	18,936
Total	35.90	71,805

Note: Total NOx includes startup emissions.

CT2 12-Mo Startup Only

	Tons	#
1Q07	0.43	860
2Q07	0.32	640
3Q07	0.28	561
4Q07	0.37	747
Total	1.40	2,808

Data gathered from CEMS Startup/Shutdown Incident Reports
Data gathered from CEMS Monthly Aggregate Reports
Opsflex installed on CTG1 on Oct 13, 2006.
Opsflex installed on CTG2 on Oct 12, 2006

There have been no excess emissions as defined in Board Order 4073 on April 26, 2007

GOLDEN GATE UNIVERSITY | School of Law

Environmental Law and Justice Clinic

February 5, 2009

By E-Mail and U.S. Mail
weyman@baaqmd.gov
Weyman Lee, P.E.
Senior Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis Street
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Re: Draft PSD Permit for Russell City Energy Center

Dear Mr. Lee:

We are writing on behalf of Citizens Against Pollution (CAP) to provide comments on the draft prevention of significant deterioration (PSD) permit for the proposed Russell City Energy Center. CAP is a grassroots group of Hayward residents, and its members have participated actively in proceedings relating to the Russell City Energy Center to ensure that the proposed power plant complies with the law. The group is pleased to have this opportunity to participate in this permit proceeding and thanks the Bay Area Air Quality Management District for holding the public hearing in Hayward at a time when community members could attend. CAP also appreciates the Spanish interpretation provided at the public hearing and the document repository and information that the District provided through its staff.

Earthjustice is also submitting a letter on behalf of CAP, and we are incorporating the comments in that letter by reference. Sierra Club has already submitted comments, and we adopt them as well. As stated in those comments and here, the District should not issue the permit as proposed because it fails to meet federal PSD and nonattainment new source review (NSR) requirements.

I. THE DISTRICT'S BACT ANALYSIS FOR STARTUP AND SHUTDOWN DOES NOT COMPLY WITH PSD AND NSR REQUIREMENTS.

A. The District Should Provide More Information on the Number of Startup and Shutdown Events to Quantify the Emissions as Accurately as Possible.

Russell City Energy Center (RCEC) is a 600-megawatt natural gas fired combined-cycle power plant proposed to be built in Hayward, California. The operation of the proposed facility "will be dictated by market circumstances and demand." Statement of Basis for Draft Amended Federal "Prevention of Significant Deterioration" Permit (Dec. 8, 2008) at 11 (SOB), *available at* http://www.baaqmd.gov/pmt/public_notices/2008/15487/index.htm. The District expects the facility to operate in base load and load following modes, as well as in partial and full shutdown modes. *Id.* The District explains that "load following" means

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that the facility "would be operated to meet contractual load and spot sale demand, with a total output less than the base load scenario." *Id.*

There is some information in the California Energy Commission (CEC) docket and in the SOB about what the proposed operation would entail for startup and shutdown events. But the information is incomplete and conflicting. We are unable to determine, for example, the maximum number of such events the proposed permit allows. According to CEC staff, "[t]he project owner has asserted that the more typical, normal operating day of the facility could include a hot startup, about 16 hours of normal operation followed by a shutdown." CEC Comments, Air Quality, Testimony of Tuan Ngo, P.E., June 2007 at 4.1-8 (CEC 2007 Staff Comments), *available at* http://yosemite.epa.gov/OA/EAB_WEB_Docket.nsf/Filings%20By%20Appeal%20Number/0CB7FC708E4DB9DC852573EF005A0063/$File/Exhibit%2014...16.60000.pdf.

In this regard, the District states that, "[b]ased upon contractual load and spot sale demand, it may be economically favorable to shut down one or more turbine/HRSG [heat recovery steam generator] power trains; this would occur during periods of low overall demand such as late evening and early morning hours." SOB at 11 (emphasis added). It is therefore entirely possible that the facility would start up and shut down to accommodate two daily periods of low demand, although the maximum mass emissions limit for startup and shutdown (Condition 20, SOB at 73) and daily maximum limit (Condition 22, SOB at 73) may affect that scenario. How the maximum limits affect the scenario, however, is unclear because there does not appear to be any information in the SOB about how many startup and shutdown events are expected to occur on a daily basis.

From the daily limits, it appears that the facility may be allowed to engage in a warm or hot start up and shut down once. This conclusion follows if one assumes that the emissions of 1,093 lbs per day of NOx result from one hot startup followed by 14 hours of normal operation, and that 1,093 lbs are attributable to both trains of turbines and HRSGs. CEC 2007 Staff Comments, at 4.1-8. But it is unclear, at least from reviewing the CEC comments alone, whether those emissions are from a startup of one train or both. Therefore, it is difficult to calculate the maximum startup and shutdown events from the maximum permitted daily emissions.[1]

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[1] According to yet another scenario, the CEC staff analyzed the project assuming 52 cold starts and 260 hot starts per year. CEC Final Staff Assessment, Russell City Energy Project, June 10, 2002 at 4.1-12, *available at* http://www.energy.ca.gov/sitingcases/russellcity/documents/2002-06-10_FSA.PDF. Based on this estimation, the CEC staff compared emissions from baseload (steady state) operation with emissions from maximum startups and shutdowns:

(con't on next page)

It appears that the facility would be engaged, at the very least, in frequent startup and shutdown events. Because the operating scenario contemplates frequent – even if unquantified to the public – startup and shutdown events, and because emissions are uncontrolled or incompletely controlled during these events, SOB at 38, the BACT analysis for these events is critical to CAP and other members of the public who will be exposed to RCEC's emissions.

The District should provide more information on the number of maximum predicted startup and shutdown events per day and per year because of the expected health impacts from uncontrolled or partially controlled emissions. Without accurate information on startup and shutdown events, the public is unable to know how much pollutants will be emitted. Without knowing the amount of emissions, neither the District nor the public can assess the true impact of the emissions. The expected operating scenario is also necessary for the BACT analysis and the comparisons that the District made in that analysis.

B. The District's BACT Analysis for Gas Turbine Startup and Shutdown Is Faulty Because the District's BACT Analysis Incorrectly Assumes that the Applicant Should Use the Equipment It Purchased in 2002, Before Receiving a PSD Permit.

1. The proposed permit is the first draft PSD permit, not a "Draft Amended PSD Permit," as there has not been a valid PSD permit before.

The District originally issued its Final Determination of Compliance for the facility in March 2002, based on a Preliminary Determination of Compliance issued in October 2001. *See* U.S. EPA – Bay Area Air Quality Management District Agreement for Limited Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21, dated Jan. 2006 at 4, ¶ 7 (Exhibit 1). The District, however, did not issue a final PSD permit at that time "because of a delay in the issuance of the Biological Assessment associated with the Endangered Species Act Section 7 process." *Id.* Thus, there was no 2002 permit.

AIR QUALITY Table 9
Project Maximum Annual Emissions
(tons per year [ton/year])

Operational Profile	**NOx**	**SO2**	**PM10**	**POC**	**CO**
52 cold starts and 260 hot starts for each CTG, Remainder of year at steady state.	199.0	12.42	83.39	28.67	610.08
Steady state operation, two CTGs, 1 full year	173.79	12.42	83.39	23.09	256.81
Cooling Tower	-	-	3.02	-	-
Emergency Generator (52 hours per year)	0.046	0.0001	<0.0001	0.037	0.0785
Diesel Fire Pump Engine (26 hours per year)	0.101	0.0028	0.0033	0.012	0.0611
Total Maximum Annual Emissions	199.1	12.43	86.42	28.72	610.22
Proposed Emissions Limits	134.6	12.2	86.4	27.8	584.2

Id. at 4.1-15. Note that the emission of NOx and especially CO are considerably higher assuming maximum number of startups and shutdowns.

Nor can the District call the permit it issued in November 2007 a PSD permit. On July 29, 2008, the EPA Environmental Appeals Board (EAB) issued a remand order in response to a petition from a Hayward resident, Rob Simpson, alleging violations of the PSD notice requirements. *See In re Russell City Energy Center* (EPA Environmental Appeals Board), PSD Appeal No. 08-01, *available* at http://yosemite.epa.gov/OA/EAB_WEB_Docket.nsf/ Filings%20By%20Appeal%20Number/EA6F1B6AC88CC6F085257495006586FB/$File/Remand...50.pdf. The EAB remanded Russell City's PSD permit, requiring the District to re-notice the draft permit in accordance with the federal PSD notice provisions. *Id.* at 39, 42. The EAB noted that the District's outreach efforts "fell significantly short of [federal PSD] section 124.10's requirements in numerous important respects." *Id.* at 38. To correct the deficiency, which the EAB characterized as a "complacent compliance approach," the EAB stated that, "the District must scrupulously adhere to all relevant requirements in section 124.10 concerning the initial notice of draft PSD permits (including development of mailing lists), as well as the proper content of such notice." *Id.* at 38, 39. The EAB emphasized that the notice deficiencies were not "harmless error" as the District contended, noting "the pivotal importance to Congress of providing adequate initial notice within EPA's public participation regime." *Id.* at 38.

Thus, the proposed permit is the first draft PSD permit for RCEC, there having been no valid permit issued in 2002 or 2007. This clarification is important because of the legal consequences that may flow from the wrong assumption that there exists a valid PSD permit. At least one consequence may be how we judge the integrity of the District's BACT analysis of the proposed energy production processes, given the District's emphasis on the applicant's purchase of the equipment based on a purported permit in 2002.

The District states that the applicant "purchased its equipment" in or about 2002, "based on the initial permits." SOB at 40 n.31. By "initial permits," the District cannot possibly be referring to a PSD permit since the District did not issue a PSD permit at that time. Because of this existing equipment – which the applicant purchased without a PSD permit – the District appears to have performed its PSD analysis to allow the applicant to retain the equipment. Because the District is required to select production processes and other controls that would achieve "an emissions limitation based on the maximum degree of reduction" in PSD review, *see* 42 U.S.C. § 7479(3) (BACT means "an emission limitation based on the maximum degree of reduction"), performing a BACT analysis with assumptions about specific production processes and equipment violates the law.

By calling the proposed permit a "draft amended PSD permit," and not explaining the full permitting history, the District is incorrectly informing the public that this process amends a valid, existing PSD permit. *See* SOB at 6-7; SOB at 9. That is not the case, and this mistake should be corrected so that the public can engage in a meaningful review of the District's draft permit.

As discussed below, the District's BACT analysis appears to start with a conclusion that the equipment the applicant purchased in 2002 should be retained. The District thus rejects both once-through steam boiler and turn-down technology, which are technically feasible. Not only are the two technologies feasible, but once-through steam boiler technology is being proposed for two other facilities within the District, and turn-down technology is achieved in practice at another facility. The District's analysis is thus insufficient and violates PSD and NSR requirements for selecting the most stringent emissions limit.

2. The District incorrectly rejected once-through steam boiler technology based on assumptions about existing equipment, and the District therefore violated the PSD and NSR requirements.

Once-through steam boiler technology uses external steam separators and surge bottles to reduce start-up durations. SOB at 39. The District rejects this technology, even though the District concludes that the technology is "ranked No. 1 in control effectiveness." SOB at 42, 44. A motivation for the decision appears to be the cost of disposing of the existing equipment:

> Note that the project was originally permitted in 2002 [note that the project did not receive a PSD permit at that time as explained in Section I above], before Fast Start technology was developed, and the applicant purchased its equipment at that time . . . . Retrofitting that equipment now to incorporate Fast Start technology would require a complete redesign of the project and the purchase of new equipment. Furthermore, Siemens stated that emissions performance cannot be guaranteed unless the company supplies a fully integrated power plant with Fast Start technology (*i.e.*, Flex Plant 10). . . . It therefore appears that the facility would have to dispose of the equipment it has already purchased for the project and buy an entirely new integrated system.

SOB at 40 n.31 (emphasis added); *see also* notes of the conversation referred to in n.31 (Exhibit 2) ("existing turbine cannot be retrofitted[;] will kill project because of cost") (emphasis added). The CEC record similarly shows that the primary reason for rejecting available technology was the cost of disposing of the already acquired equipment. Even though the CEC staff was recommending the technology – *see* letter from Paul C. Richins, Jr., Environmental Protection Office Manager, CEC, to Jack P. Broadbent, APCO, dated May 29, 2007, at 2 (Exhibit 3), *available at* http://www.energy.ca.gov/sitingcases/russellcity_amendment/documents/2007-05-31_LTR_BROADBENT.PDF – the applicant cited cost as a reason for not implementing it:

> Staff proposed technological solutions (Siemens-Westinghouse Fast-Start [once-through steam boiler technology] and General Electric OpFlex) which it believes would significantly reduce emissions from start-up events, but they were rejected by the Applicant for economic reasons.

Final Commission Decision, Russell City Energy Center, Amendment No. 1 (01-AFC-7C) (Oct. 2007) at 77, *available at* http://www.energy.ca.gov/2007publications/CEC-800-2007-003/CEC-800-2007-003-CMF.PDF.

This approach gets the PSD analysis backward. Analyzing BACT with specific equipment already in mind violates the mandate for setting the most stringent emissions limit at the time of permit issuance.[2] A centerpiece of PSD is the BACT requirement, which mandates new facilities

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[2] The 1990 Draft New Source Review Workshop Manual makes it plain that the review of BACT is as of the time of final permit issuance:

to use state of the art technology to prevent significant deterioration of the National Ambient Air Quality Standards.

This approach also gets the Nonattainment NSR analysis backward. (Such analysis is required for NOx, CO and PM2.5 here.) Under NSR, the applicant must meet the lowest achievable emissions rate or LAER. *See* 42 U.S.C. Section 7501(3); BAAQMD Regulation 2-2-314 (incorporating requirements of 40 C.F.R. § 51.165); 40 C.F.R. § 51.165(A)(1)(xlvi)(2)(explaining that State requirements need to be as stringent as the requirements in this section). LAER is defined as the "most stringent emissions limitation." *See* 40 C.F.R. § 51.165(A)(1)(xiii).

In performing the analysis, the District must apply the PSD requirements of Regulation 2-2 and 40 C.F.R. § 52.21 (as well as NSR requirements). *See* U.S. EPA – Bay Area Air Quality Management District Agreement for Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21, dated Feb. 4, 2008, at 3, *available at* http://www.epa.gov/region09/air/permit/pdf/baaqmd-delegation-agreement.pdf, (the District to apply Regulation 2-2 and 40 C.F.R. § 52.21, with exceptions not applicable here).

Regulation 2-2-206 plainly indicates that BACT is "the most effective emission control" or "the most stringent emission limitation," by defining BACT as "the more stringent of":

> 206.1 The most effective emission control device or technique which has been successfully utilized for the type of equipment comprising such a source; or
>
> 206.2 The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or
>
> 206.3 Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO; or
>
> 206.4 The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public

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> The BACT emission limit in a new source permit is not set until the final permit is issued. The final permit is not issued until a draft permit has gone through public comment and the permitting agency has had an opportunity to consider any new information that may have come to light during the comment period. Consequently, in setting a proposed or final BACT limit, the permit agency can consider new information it learns, including recent permit decisions, subsequent to the submittal of a complete application. This emphasizes the importance of ensuring that prior to the selection of a proposed BACT, all potential sources of information have been reviewed by the source to ensure that the list of potentially applicable control alternatives is complete (most importantly as it relates to any more effective control options than the one chosen) and that all considerations relating to economic, energy and environmental impacts have been addressed.

1990 New Source Review Workshop Manual, at B54-55, *available at* http://www.epa.gov/region07/programs/artd/air/nsr/nsrmemos/1990wman.pdf.

> comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations.

BAAQMD Regulation 2-2 (SIP-approved), *available at* http://yosemite.epa.gov/R9/r9sips.nsf/AgencyProvision/411642DA93F3D7A4882569900057D386/$file/BA+rg2-2sip.PDF?OpenElement.

In the District's own words, "[c]learly the recurring theme in the above definitions of BACT . . . is 'the most effective emission control' or 'the most stringent emission limitation.'" Bay Area Air Quality Management District Best Available Control Technology (BACT) Guideline ("BACT Guideline"), *available at* http://www.baaqmd.gov/pmt/bactworkbook/default.htm (definition of BACT and TBACT). Consistent with that theme, the definition reflects the policy choice in the Clean Air Act that BACT be technology forcing. The District indeed recognizes this choice in its BACT Guideline:

> For ease in permit application review, the above definition of BACT can be broken down to two general categories: 1) "technologically feasible and cost-effective" and 2) "achieved in practice." The first category is a more stringent level of BACT control and is technology forcing; it generally refers to advanced control devices or techniques.

Id. (Policy and Implementation Procedure, Interpretation of BACT). The choices reflected in the BACT Guideline are consistent with the Top-Down BACT Analysis because it, too, requires the District to select an emissions limitation based on the maximum degree of reduction. SOB at 20.

The District, however, does not use the required approach of selecting an emissions limit for the RCEC based on the maximum degree of reduction. The District identifies Flex Plant 10, a type of once-through steam boiler technology, as "technically feasible" for reducing startup emissions. SOB at 40. But the District rejects this technology apparently because the District improperly – and without adequate information – considers the costs that may result from disposing of existing equipment. *See* SOB at 40 n.31.

The District cannot take into account any loss the applicant may realize from the sale of old equipment in the BACT analysis because the applicant is proposing a new facility, not updating an existing facility. That is, the question is what the most stringent emission limit is, not whether a retrofit of existing equipment is cost effective. In addition, even if the cost information is relevant (which it is not), the District discloses no basis for the conclusion that the sale of existing equipment may result in a loss. There is no analysis of any such claimed loss. Additionally, the applicant purchased equipment when there was no valid PSD permit, and therefore there is no equitable reason to consider the cost of disposing of the equipment, whatever it may be (and, of course, as we stated earlier, BACT does not allow any such consideration).

Indeed, the PSD regulations prevent owners and operators from making irretrievable commitments such as contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, before receiving a PSD permit. *See* 40 C.F.R. § 52.21(b)(9) (definition of commencement of construction). Similarly, the Act bars "commencement of construction" before issuance of PSD and NSR permits. 42 U.S.C. § 7604(a)(3) (providing for citizen suits against those who violate the requirement of a PSD or NSR permit); *Id.* § 7413(b)(3) (federal enforcement for same); and, as earlier noted, commencement of construction is broadly defined to include activities that commit the source to obligations that may result in substantial loss. The purpose of such provisions is to ensure that the relevant agencies do not favor issuance of a permit or permit condition due to the owner or operator's irretrievable commitment of funds, to the detriment of public health and air quality.

Thus, the District erred in considering the costs, which are not even quantified, of the disposal of existing equipment in permitting a new facility. The District should not issue the permit without considering technology the CEC staff recommended for this project.

3. The District's energy efficiency and emissions comparison between Flex Plant 10 (once-through steam boiler technology) and the existing equipment is based on operating at maximum capacity and is therefore faulty for a facility that will frequently start up and shut down.

The District concludes that "once-through boiler technology would not be the most appropriate BACT technology because of the loss of efficiency that it would entail." SOB at 44. To reach this conclusion, the District compares Siemens Fast Start Flex Plant 10 unfavorably with the Siemens-Westinghouse triple-pressure gas turbine equipment that the applicant purchased. SOB at 43-44. The District's analysis is faulty because the calculations in Table 13, which compare estimated emissions from Flex Plant 10 with those from the triple-pressure system, assume that the plant is operating at maximum capacity. *See* SOB at 43. In fact, the facility will be operating with frequent startup and shutdown events. Such startups and shutdowns will undoubtedly have an effect on energy efficiency and emissions that the District's analysis fails to consider in its critique of the Flex Plant 10 design. *Id.*

For the District's rejection of Flex Plant 10 based on "energy efficiency" grounds to be meaningful, the District would have to base its comparison on the efficiency of the triple-pressure system under its true operating scenario, which involves frequent startup and shutdown events. At least one source states that the efficiency of the Westinghouse 501F turbine is between 36.5% and 56%, depending on whether it operates in combined cycle or simple cycle. *See* Alexander's Gas & Oil Connections Contracts Awarded, Vol. 3, Issue #28 (Dec. 24, 1998), *available at* http://www.gasandoil.com/goc/contract/cox85277.htm. Thus, depending on how the turbines are operating, the efficiency number the District uses, 55.8%, can be different. If the Westinghouse 501F's efficiency can be lower, Flex Plant 10, with its 48% efficiency, would compare favorably.

Thus, Flex Plant 10 has not been given a fair hearing. For all we know, energy efficiency and emission reductions from Flex Plant 10 during the frequent startups and shutdowns contemplated by this project more than offset the District's asserted inefficiency of the Flex Plant 10 design during base load operation. The District therefore should not eliminate Flex Plant 10 from its BACT analysis. *See* SOB at 44.

In fact, the District will soon be evaluating applications proposing Flex Plant 10 for two sites – Willow Pass and Marsh Landing. *See* Willow Pass Generating Station Application for Certification, Executive Summary 1-4 (June 2008), *available at* http://www.energy.ca.gov/sitingcases/willowpass/documents/applicant/afc/Volume_01/2.0%20Project%20Description.pdf (Willow Pass) and http://www.energy.ca.gov/sitingcases/marshlanding/documents/applicant/afc/Volume%20I/2_0%20Project%20Description.pdf (Marsh Landing). It is therefore incumbent on the District to do an adequate review of the technology for its appropriateness at Hayward.

4. The District's elimination of turn-down technology as BACT lacks basis because there is ample information on feasibility.

In addition to Flex Plant 10, the District identifies turn-down technology, such as OpFlex, to control startup and shutdown emissions. SOB at 39-40. According to the manufacturer, "OpFlex™ Turndown technology provides customers with GE's 7FA+e gas turbines greater flexibility in their operations. It's a software solution that optimizes the combustion process, extending low-emissions operation to lower load levels. Customers are able to reduce CO_2 and NOx emissions, while decreasing fuel expenses and avoiding maintenance costs." *See* product description *available at* http://ge.ecomagination.com/site/products/opflex.html.

The District concludes that it has "not found sufficiently strong evidence to conclude that turn-down technologies such as OpFlex are technically feasible at this time for control of start-up emissions." *Id.* at 42. This conclusion appears to be without basis. The technology itself has been in existence since at least December 2005. *See* industry news article, "GE Energy Announces New Startup Improvements For Gas Turbine And Combined Cycle Applications" (Dec. 6, 2005), *available at* http://news.thomasnet.com/companystory/471615. In addition, the technology has been achieved in practice at the Palomar Energy Center in San Diego County. SOB at 41. The Palomar facility appears to have employed this technology since at least some time in 2006. *See* "2007 Pacesetter Plant Award Palomar Energy Center, Central stations return to the city," Combined Cycle Journal (Fourth Quarter 2006) at 51 (Exhibit 4), *available at* http://www.psimedia.info/4Q%202006/406CCJ,%20p%2044-52.pdf; *see also* CEC Environmental Protection Office Manager's letter at 3 (Exhibit 3), (CEC staff's recommendation that the District consider for RCEC OpFlex and early injection of ammonia used at Palomar). Since the technology has been achieved in practice, it deserves serious consideration in the District's BACT analysis. *See* Regulation 2-2-206.1 (BACT includes "the most effective emission control device or technique which has been successfully utilized for the type of equipment comprising such a source").

But the District summarily rejects the technology. The District states that, because Palomar implemented operating procedures (*i.e.,* early ammonia injection in its Selective Catalytic Reduction system), it is unclear how much of the reductions in startup emissions at Palomar is due to OpFlex. *Id.* at 41-42.

The District's conclusion is based on a faulty assumption about BACT. As the District recognizes elsewhere, BACT is not just technology but can include techniques and methods for controlling emissions. *See, e.g.,* 42 U.S.C. § 7479(3). Thus, there is no reason why the use of OpFlex, together with other operational procedures, could not be considered BACT.

The District's conclusion is also based on a faulty assumption about LAER. The District also needs to comply with the nonattainment requirements since startup and shutdown affect emissions of NOx, POCs and PM. The District's focus on the applicant's equipment is inconsistent with LAER's focus on the end emissions rate. *See* 42 U.S.C. § 7501(3).

The District's conclusion is also based on insufficient information. It appears that the Palomar facility has been reporting emissions since at least April 2007. *Id.* at 41 n.40. Given the passage of time, there should be more than sufficient data to make the determination of OpFlex's effectiveness. But it appears that the District did not seek recent data to make a meaningful determination and hastily rejected OpFlex. (The District's engineer confirmed in response to a request from us that the District reviewed only 2006-2007 data from Palomar and does not have any 2008 data.)

Moreover, because the CEC reports that the applicant rejected OpFlex based on costs (*see* Final Commission Decision, Russell City Energy Center, Amendment No. 1 (01-AFC-7C) (Oct. 2007) at 77, *available at* http://www.energy.ca.gov/2007publications/CEC-800-2007-003/CEC-800-2007-003-CMF.PDF), the District must ensure that its analysis is untainted by factors that should not come into play in the BACT analysis, such as the cost of disposing of the existing equipment. Without such analysis, it appears that the District is performing its BACT analysis based on the applicant's equipment rather than on technology now available.

In short, the District has not performed a sufficient analysis to reject OpFlex and other operating procedures as BACT/LAER.

C. The District Should Provide a Factual Basis for the Long Startup Durations.

1. The District should analyze available technology for reducing startup durations.

The District indicates that cold startup time will be up to six hours, and warm and hot startups, up to three hours each. SOB at 13. These periods appear to be excessively lengthy. During these startup times, the emissions from the facility will be higher than during base load operation. SOB at 38-39. Thus, BACT should include methods and/or technology sufficient to minimize these times to protect the public from the harmful air emissions.

A shorter time appears feasible with the use of technology for reducing startup emissions. *See, e.g.,* Combined Cycle Journal, Fourth Quarter article at 51 (Exhibit 4) (with GE's OpFlex, the turbines "are in 6Q mode(full DLN) much sooner than they were initially"); Final PSD Permit issued to Colusa Generating Station on Sept. 29, 2008 at 7, *available at* http://www.regulations.gov/fdmspublic/component/main?main=DocketDetail&d=EPA-R09-OAR-2008-0436 (a 660-MW power plant with a cold startup duration of 270 minutes; warm, 180 minutes, and hot 90 minutes); Kelly e-mail, (Rapid Response technology "generally reduces SU [startup] time from 110 minutes to 65 minutes for CCGT [combined cycle generating turbine] plants . . .; it also allows SCR injection [ammonia injection into SCR] to start at 50 to 60% load) (Exhibit 5); Transcript of Informational Hearing Before the California Energy Resources Conservation and Development Commission; In the Matter of Application for Certification for the Willow Pass Generating Station Project (Dec. 18, 2008) at 28-29, *available at* http://www.energy.ca.gov/sitingcases/willowpass/documents/2008-12-18_TRANSCRIPT_INFORMATIONAL_HEARING.PDF (testimony that Flex Plant 10s can achieve base load generation in about an hour and that these start up times are "extremely fast compared to existing units which can take a minimum of three and possibly six hours of time to reach . . . baseload"). While we have not evaluated these technologies ourselves, the District should at the very least evaluate these and other technologies that are available now to do a proper BACT/LAER analysis to reduce startup times.

2. "Best work practices," reflecting practices used in power plants certified before 2001, may not be the "best."

Startup Duration: The District's reliance on records of startup durations from Delta, Los Medanos, Metcalf and Sutter Energy Centers (see SOB at 44-46) is inadequate. Those plants were licensed long ago, and thus the real startup times may not reflect best work practices for power plants that should use the newest equipment. *See* Commission Decision, Application for Certification for the Delta Energy Center, Calpine Corporation and Bechtel Enterprises, Inc. (Feb. 2000) at 11, *available at* http://www.energy.ca.gov/sitingcases/delta/documents/2000-02-09_DELTA_DECISION.PDF; Los Medanos (originally known as Pittsburg District Energy Facility), Commission Decision, Application for Certification, Pittsburg District Energy Facility (Aug. 1999) at 1, *available at* http://www.energy.ca.gov/sitingcases/pittsburg/documents/1999-08-17_DECISION.PDF California Energy Commission, The Metcalf Energy Center, Commission Decision (Sept. 2001) at 2, *available at* http://www.energy.ca.gov/sitingcases/metcalf/documents/2001-10-05.COMMISSION_DECIS.PDF; Sutter, licensed Apr. 14, 1999, *see* Fact Sheet, *available at* http://www.energy.ca.gov/sitingcases/sutterpower/index.html (licensed Apr. 14, 1999).

In addition, the District chose the longest startup duration from even those pre-2001 plants as the best work practice by explaining that "the BACT limit must be achievable at all times throughout the facility's operational life." SOB at 45-46. The District somehow believes that "[a] reasonable safety margin must be included so that the facility will be able to comply with its limits during every startup, even if emission for specific startups or as an average for startups as a whole may be less." SOB at 46. The District has provided no basis to justify this safety margin.

The permitting authority is allowed to adopt a compliance margin based on safety factors "where there is some degree of uncertainty regarding the maximum degree of emission reductions that is achievable." *See In re Prairie State Generating Co.*, PSD Appeal No. 05-05, 13 E.A.D. __, *slip. op.* at 72 (EAB Aug. 24, 2006), *aff'd, Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007), *reh'g denied and reh'g en banc denied,* 2007 U.S. App. LEXIS 24419 (7th Cir. 2007). But such a margin must be "fact-specific and unique to the particular circumstances of the selected technology, the context in which it will be applied, and available data regarding achievable emissions." *Prairie,* 13 E.A.D. __, *slip op.* at 73. Safety factors are allowed, for example, to account for "test method variability, location specific technology variability, and other practical difficulties in operating a particular technology." *See id.* (citations omitted). There is no factual analysis applicable to the proposed facility that justifies a margin.

The District did not examine the proposed facility's startup duration in the context of any of the factors mentioned in *Prairie*. Nor did the District review whether the other facilities' failure to achieve a shorter startup duration was due to those factors. The District, for example, provides no discussion of whether the emissions from the four facilities are from the periods when they were in compliance with their permit limits. Because the District failed to examine the specific factors, it appears that the District merely established the duration solely to provide a cushion. That is not the kind of analysis that *Prairie* contemplates because BACT could then easily turn into Reasonably Available Control Technology. The District should therefore eliminate the margin or do a better analysis of why a margin is justified in setting the best work practices.

<u>Startup Emissions Rate</u>: For the same reasons as a safety margin was inappropriate for startup durations, it is inappropriate for startup emissions rates. The District should therefore eliminate the margin or do a better analysis of why a margin is justified in setting the best work practices.

D. The District Must Include the Startup and Shutdown Durations as Permit Conditions.

The startup and shutdown durations do not appear to be included in the permit conditions. (They are included in the definitions, *see* SOB at 122, but they are not characterized as limits.) Without the durations being included as a condition, they may be practicably unenforceable. If indeed we are correct that such durations are not included in the permit conditions, the District should include the durations not merely as a definition but as permit conditions.[3] The District should also review each limit discussed in the SOB to ensure that the permit actually contains the limit. This error may not be an isolated problem.

E. The District Must Perform Its Own Analysis of CO and POC Emissions to Comply with NSR Requirements.

The District has not conducted an analysis of the expected emissions from startup for all of the pollutants. *See* SOB at 12-13. Rather, for CO and POC, the District relied on the emissions numbers "specified by applicant based on operational data," and, for NOx, the District relied solely on the "CEC's conditions of certification." SOB at 13. This fragmented approach is confusing, incomplete and inadequate. The District is tasked with protecting air quality and assuring that the applicant achieves the lowest achievable emissions rate for NOx and CO, for which the District is currently in nonattainment. *See* 42 U.S.C. Section 7501(3) (defining lowest

[3] We also note that the good air pollution practices requirement of 40 C.F.R. § 60.11(d) is also not made a permit condition. This omission may be because the proposed permit is a PSD permit and not a Title V permit, but CAP wants to be assured that all requirements that apply to the facility will be in a permit so that they can be enforced. *Compare* PSD permit from the Colusa Generating Station, which contains section 60.11(d) requirement.

achievable emissions rate). By blindly relying on the applicant's data and the CEC's analysis, the District has failed to determine whether the startup emission rates for these pollutants are the lowest achievable emissions rate.

II. THE DISTRICT DOES NOT APPEAR TO HAVE SET THE MOST STRINGENT EMISSIONS LIMITS FOR NOx, CO AND PM FOR THE TURBINES AND HEAT RECOVERY UNITS DURING PERIODS OF BASE LOAD AND LOAD-FOLLOWING OPERATION.

The District's proposed BACT for NOx, CO, and PM may not reflect the most stringent limitation under the PSD and NSR requirements of Regulation 2-2 and 40 C.F.R. § 52.21 because the District failed to review technology other than that reflected in the applicant's purchased equipment.

As we discussed in Part I above, rather than performing the evaluation of technology-forcing BACT, the District's BACT analysis focuses solely on controls on already purchased equipment. *See, e.g.,* SOB at 22 (NO_2), 29 (CO), 35 (PM). Because the District did not analyze the choice of the turbine itself – and presumably other equipment listed in the SOB at 10 – the District's analysis fails to identify the most stringent emissions limit. Thus, the District should not issue the proposed permit without performing an adequate analysis to set the most stringent emissions limits that comply with PSD and NSR requirements.[4]

III. THE DISTRICT HAS AUTHORITY AND IS REQUIRED TO SET THE "MOST STRINGENT EMISSIONS LIMIT" FOR CO_2.

A. CAP Supports the District's Authority to Perform a GHG Analysis Under the Clean Air Act and the California Health & Safety Code.

Hayward and other Alameda County residents, including CAP members, have long advocated for a greenhouse gases (GHGs) impact analysis and mitigation for the proposed project. Shortly before the issuance of the draft permit, CAP urged the District's Air Pollution Control Officer to consider whether to impose a CO_2 BACT limit and develop an adequate record for its decision. The applicant also requested a BACT analysis for GHGs, according to the District. SOB at 58.

CAP believes that performing a BACT analysis for GHGs is not only legally required but prudent. It is only a matter of time before EPA is compelled to recognize that GHGs are pollutants subject to regulation under the Clean Air Act, despite the memorandum that EPA issued shortly after the issuance of the draft permit (EPA's Interpretation of Regulations that

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[4] In addition, it is unclear whether the District fully reevaluated its BACT determination in the June 19, 2007 FDOC or relied on its previous determination in 2002. Although the hourly rate for NOx and CO changed in the 2007 FDOC, the annual rate did not change. *Compare* PDOC at 6 (proposed annual rate for NOx is 134.6 TPY) and PDOC at 11 (proposed hourly rate for NOx is 2.5 ppmvd NOx at 15% O2), *with* FDOC at 5 (annual rate for NOx listed as 134.6 TPY) and FDOC at 14 (hourly rate listed as 2.0 ppmvd NOx at 15% O2). These figures did not change in the current proposal. *See* SOB at 73 (annual rate for NOx listed as 134.6 TPY); SOB at 72 (hourly rate for NOx listed as 2.0 ppmvd NOx at 15% O2). If the hourly rate changed, the maximum annual rate should also have changed. This error gives the impression that some of the determinations date back to 2002.

Determine Pollutants Covered by Federal Prevention of Significant Deterioration (PSD) Program of December 18, 2008). As Sierra Club and others have persuasively argued, BACT requirements should apply to CO_2. *See, e.g.,* Petition for Reconsideration, which Sierra Club filed before the Administrator of the EPA in January 2009 (attached as an exhibit to Sierra Club's comments).

As the first air pollution control district to assess fees on GHG emissions to fund climate protection activities, the District is more than aware of the importance of its role in GHGs regulation and the critical need to reduce GHGs now. Without immediate reductions in GHG emissions, we are "very likely" to see larger changes in the climate system. *See* Summary for Policymakers in Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change (S. Solomon et al. eds. 2007), at 10; *see also* brief of amici curiae James Hansen, Mark Z. Jacobson, Michael Kleeman, Benjamin Santer and Stephen H. Schneider, *California v. US EPA*, No. 08-1178 (D.C. Cir.), filed Nov. 24, 2008, *available at* http://www.ggu.edu/school_of_law/academic_law_programs/jd_program/environmental_law/environmental_law_justice_clinic/attachment/Amici+Brief.pdf.

In addition to the critical need to reduce GHG emissions to prevent further – and potentially cataclysmic – disruptions of the climate system, it is important for the District to consider the local impacts of locally-emitted GHGs. According to Dr. Mark Z. Jacobson of Stanford University, emissions of CO_2 accumulate over cities because they do not immediately dissipate, and they intensify local air pollution problems such as ozone pollution. Mark Z. Jacobson, *Testimony for Hearing on Air Pollution Health Impacts of Carbon Dioxide*, U.S. House of Representatives Select Committee on Energy Independence and Global Warming, at 2–3, *available at* http://www.stanford.edu/group/efmh/jacobson/Testimony0408%202.pdf. Because the Bay Area is a nonattainment area for 8-hour ozone, *see* 40 C.F.R. § 81.305, it is particularly important to reduce local GHG emissions. CAP therefore supports the District's undertaking the CO_2 BACT analysis.

The District has authority to perform a CO_2 BACT analysis under the Clean Air Act as earlier discussed. (See Sierra Club petition for reconsideration.) The District also has authority under California law to perform the analysis and require measures to reduce CO_2. *See, e.g.,* Cal. Health & Safety Code § 40000 (air districts have primary authority under state law for "control of air pollution from all sources, other than emissions from motor vehicles"). As the California Air Pollution Control Officers Association stated in its white paper, "[t]he term air contaminant or 'air pollutant' is defined extremely broadly . . . . Greenhouse gases and other global warming pollutants such as black carbon would certainly be included in this definition." CEQA & Climate Change – Evaluating and Addressing Greenhouse Gas Emissions from Projects Subject to the California Environmental Quality Act at 22, *available at* http://www.capcoa.org/CEQA/CAPCOA%20White%20Paper.pdf. While the District asserts that it is performing only a federal PSD review, this California authority is relevant should EPA bar the District from regulating GHGs in the permit for the Russell City project based on the December 18, 2008 EPA Johnson memorandum.

B. The District Is Required to Set the "Most Stringent Emission Limitation" for CO_2.

The District is embarking on a critical task that may set precedents for other PSD permitting actions. The District's BACT limit for CO_2, however, violates the BACT requirement by failing to set the "most stringent emissions limit" and will set an unfavorable precedent on this important issue. The District, therefore, should not issue the permit as proposed.

1. The District does not provide a proper basis for a compliance margin.

Again, as with other conditions, the District attempts to justify a higher CO_2 limit by adopting a compliance margin based solely on looking at facilities with "similar turbines." *See* SOB at 63 ("Based on the available data the Air District has reviewed for similar turbines, and incorporating a reasonable compliance margin, the Air District concludes that if BACT is required for CO_2 emissions, an enforceable limit of 1100 lb/MW-hr would best represent the BACT requirement in the PSD regulation."). The District reviewed two facilities, Delta Energy Center and Metcalf Energy Center, which are 2000 and 2001-certified facilities (see discussion above in Section I.C.2). The District should not limit its review to similar turbines. The District does not explain why it cannot review CO_2 emissions from power plants using more up-to-date technology. (While the District reviewed data compiled by the CEC for the years 2004 and 2005 from an unidentified number of similar facilities, *see* SOB at 62, the District's failure to identify them deprives the public of evaluating the appropriateness of such a review. The public has no information as to the vintage of these facilities.)

Instead of establishing the most stringent controls, the District merely documents "the general level of CO_2 emissions performance" that is currently achieved by turbines. *See* SOB at 62. This "general level" of performance does not constitute BACT. As the District states, "there have historically been no enforceable emissions limitations on CO_2 emissions." BACT, however, is defined as "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation." Since there have never been emissions limitations imposed for CO_2, the District cannot determine the maximum degree of reductions for the pollutant based on reviewing the performance of other facilities, with no information about whether they are employing the maximum degree of reductions.

The District next attempts to justify the compliance margin by explaining that the District has only a "snapshot of turbine performance and not a continued demonstration of compliance with an enforceable CO_2 emission limitation throughout the turbines' total operational lifetime." *See* SOB at 62-63. But the District has only itself to blame for the "snapshot." The District reviewed only 2006 data from Delta and Metcalf. *See* SOB at 62. The District does not explain why it has not reviewed any 2007 and 2008 data for these facilities, while it obtained emissions data for Metcalf from 2008 and for Delta from 2007 and 2008 for startups and shutdowns, *see* SOB at 45-46. While it is quite possible that 2006 data are representative of those from other years, the District fails to make that determination or seek more data. Using such purported lack of data to justify an undefined compliance margin is inappropriate.

In addition, even if the District concludes that the applicant's existing equipment can achieve BACT limits after a proper PSD review, the District should explore whether the emissions from the other facilities reflect those from periods of compliance or noncompliance with permit limits. If, after all the appropriate review, the District genuinely cannot determine the proper emissions limit for the total lifetime of the facility, the District can set a limit for a select period.

The District's use of an unspecified compliance margin in establishing BACT emission limitations for CO_2 should therefore be revised because the use of a safety factor is inappropriate.

2. The selected emissions limit is not BACT because the most efficient modern combustion turbine combined cycle plant can achieve 800 lbs CO_2/MWhr.

Even assuming that this general level of CO_2 emissions performance constitutes BACT, the District selected a high limit. Even run-of-the-mill combined cycle plants are expected to achieve a much lower emissions limit, and the best combined cycle plant can achieve 800 lbs CO_2 per megawatt hour:

> The CPUC staff proposed 1,100 pounds carbon dioxide per megawatt-hour as an Interim Emissions Performance Standard in its October 2, 2006 Final Workshop Report. The standard was selected from proposals ranging from 800 to 1,400 lbs CO2/MWhr, and the earlier Revised Staff Report's recommendation of 1,000 lbs CO2/MWhr (0.46 metric tons CO2/MWhr). The CPUC staff's proposed EPS's of 1,000 or 1,100 lbs CO2/MWhr (0.50 metric tons CO2/MWhr) appear to be a compromise between the 800 lbs CO2/MWhr that the most efficient modern combustion turbine combined cycle plant could achieve, and the 1,400 lbs CO2/MWhr that might envelope the majority of natural gas burning technologies (e.g., steam cycle boiler, simple cycle combustion turbine, reciprocating engine, and a range of combustion turbine combined cycle units).

"Implementation of SB 1368 Emission Performance Standard," Staff Issue Identification Paper (Nov. 2006) at 13, *available at* http://www.energy.ca.gov/2006publications/CEC-700-2006-011/CEC-700-2006-011.PDF. Thus, the District should set a lower BACT limit for CO_2.

3. The District should analyze GHG emissions from startup and shutdown conditions and select BACT to control such emissions.

Startup and shutdown operations produce more greenhouse gases. As EPA explained in its AP-42 document on Natural Gas Combustion, "[m]ethane emissions are highest during low-temperature combustion or incomplete combustion, such as the start-up or shut-down cycle for boilers." *See* EPA, AP-42 Factors for Natural Gas Combustion, *available at* http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf. Methane is a GHG that is 21 times more powerful than CO_2, by weight, in trapping heat. EPA, Methane, *available at* http://www.epa.gov/methane/scientific.html. The District should therefore analyze GHG emissions from startup and shutdown conditions and select BACT to control such emissions.

IV. THE DISTRICT SHOULD REDO ANY NONATTAINMENT NSR REVIEW THAT IS MORE THAN 18 MONTHS OLD.

The Air District states that it is not considering any issues unrelated to PSD requirements and that PM 2.5 will be reviewed under PSD. SOB at 8, 17. By engaging in analysis of only PSD issues, the Air District is violating the Clean Air Act's requirement that nonattainment NSR be performed anew when construction fails to commence within 18 months of a previous NSR approval. The policy reason behind this requirement for new analysis is based on the requirement that the emissions limitation reflect the most stringent controls available at the time the permit is issued. Here, it appears that the NSR review was performed on June 19, 2007 and has not been updated. It has now been more than 18 months since that review. The District thus should have redone its LAER (called BACT in the District) analysis for NOx and POCs.

Specifically, the federal NSR regulations require a demonstration of adequacy of previous BACT determinations where 18 months have elapsed without commencement of construction, as is the case here:

> For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the least reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source.

40 C.F.R. § 51.166j(4). Other NSR/PSD regulatory requirements also demonstrate that BACT determinations over 18 months old are invalid without commencement of construction. *See* 40 C.F.R. § 52.21(b)(9) & (r)(2); *see also Sierra Club v. Franklin County Power of Illinois*, 546 F.3d 918, 931 (7th Cir. 2008) (affirming invalidation of a PSD permit that was over 18 months old); EPA Region IX Policy on PSD Permit Extensions at 1, *available at* http://epa.gov/region07/programs/artd/air/nsr/nsrmemos/extnsion.pdf ("A BACT analysis is required in all permit extension requests, as in an application for a new PSD permit"; "the import of this policy is to ensure that the proposed permit meets the current EPA requirements and that the public is kept apprised of the proposed action (*i.e.,* through the 30-day public comment period").

Therefore, the District should redo the NSR determination for NOx, POCs and PM.

V. THE DISTRICT SHOULD CALCULATE THE FACILITY'S POTENTIAL TO EMIT HAZARDOUS AIR POLLUTANTS.

The Statement of Basis indicates that the District conducted a review of non-PSD air quality-related requirements applicable to the RCEC project. SOB at 65-66. Yet the District's analysis fails to take into consideration the maximum achievable control technology (MACT) standards for hazardous air pollutants (HAPs). MACT standards would apply to the RCEC if the facility is a "major" source of HAP emissions. *See* 42 U.S.C. § 7412(c)(1). A "major source" is "any stationary source or group of stationary sources that emits or has the potential to emit 10 tons per year or more of any hazardous pollutant or 25 tons per year or more of any combination of hazardous air pollutants." *Id.* § 7412(a)(1) (emphasis added).

The proposed facility will emit acetaldehyde, acrolein, benzene, 1,3-butadiene, ethylbenzene, and formaldehyde. Table 6, SOB at 14. All of these are listed as HAPs. *See* 42 U.S.C. §7412(b)(1). There is nothing, however, in the Statement of Basis indicating that the District calculated RCEC's "potential to emit" HAPs for purposes of determining the applicability of section 112 of the Clean Air Act, 42 U.S.C. § 7412. Without such a calculation, it is impossible to know whether RCEC should be a major source subject to MACT.

The time to do the calculation is now because the BACT analysis must take into account environmental impacts, and the applicant must demonstrate in the PSD process that the proposed emissions will not be in excess of any other applicable emissions standard. *See* 42 U.S.C. § 7475(a)(3) and 7479(3).

VI. THE DISTRICT MUST DISCLOSE WHETHER THE EMISSION REDUCTION CREDITS ARE REQUIRED PURSUANT TO FEDERAL NONATTAINMENT NSR AND, IF SO, OFFSETS MUST COMPLY WITH FEDERAL LAW.

Because the District insists that it need not subject its decision to public review on issues other than PSD, the District has not provided adequate information about the emission reduction credits proposed for the facility. It is unclear whether emissions reductions credits proposed to be used are to satisfy federal or state requirements. Indeed, since nonattainment NSR is required here, any offsets must meet federal requirements for contemporaneousness and on-site generation. *See* Regulation 2-2-605.

VII. THE DISTRICT SHOULD DO A COMPLETE REVIEW OF STATE AND FEDERAL ISSUES BECAUSE OF THE FLAWS IN THE PERMITTING PROCESS, AND WITHDRAW THE DETERMINATION OF COMPLIANCE FROM THE CALIFORNIA ENERGY COMMISSION DOCKET.

CAP renews its request that the Air Pollution Control Officer (APCO) withdraw the Preliminary Determination of Compliance (PDOC) and the Final Determination of Compliance (FDOC) issued for the Russell City project and formally notify the CEC of the withdrawal. CAP made this request originally in a letter to the APCO in December 2008. While the District did not respond to CAP's letter, the District explains that it is addressing in this proceeding only the issues that the District is obligated to under the EAB remand. SOB at 7. The District further explains that, because "[a]ll appeal avenues have…been exhausted" as to other issues, it will not reopen the state law permitting process. *Id.* The District should reconsider this approach.

The approach does not comport with the duties the District has as a public health agency. Regardless of whether a citizen can enforce the law, the District should comply with the laws applicable to it. The District should note the stark contrast between the last permitting proceeding and this one in deciding whether to redo the permitting proceeding. In the last permitting proceeding, the District received no comments other than from the applicant and a late comment from the CEC. In this proceeding, a large number of people and representatives from various groups attended the public hearing. The District has also already received many written comments. Interest in this proceeding has been high. It is time for the District to consider why it received so few comments in the last proceeding and why this proceeding is receiving so much attention. It cannot be that the public is participating because this is a PSD proceeding. The public is participating because this is an issue of importance to them of which it has now received notice. In light of this difference in the level of participation, the District should reconsider its duty as a public health agency and redo the state analysis, in addition to the PSD analysis.

The first step in an analysis that comports with the District's duty as a public health agency is to withdraw the PDOC and the FDOC. By failing to withdraw them, the District is allowing the CEC to rely on the District's invalid determination of compliance. This result violates not only the District's duty but also the requirements of the Warren-Alquist State Energy Resources Conservation and Development Act (Warren-Alquist Act), which applies to the District.

The Warren-Alquist Act requires the District to perform a compliance review to ensure that a proposed facility will satisfy all applicable federal, regional, and local laws.[5] Because the PDOC and the FDOC do not satisfy the PSD requirements of the Clean Air Act for all of the reasons identified here and in other public comments, as well as the notice deficiencies that resulted in the EAB remand, the District can no longer represent to the CEC that the Russell City project "meets the requirements of the applicable new source review rule and all other applicable district regulations." Nor can the CEC complete the certification process without an FDOC that accurately determines compliance. *See* Cal. Code Regs., tit. 20, § 1744.5(b); *see also* "Public Participation in the Siting Process: Practice and Procedure Guide," CEC 700-2006-002 at 49, *available at* http://www.energy.ca.gov/sitingcases/index.html ("Delays in obtaining the Determination of Compliance can negatively impact the siting process schedule because the air quality compliance information is needed at the [siting] committee's formal hearings") (emphasis added). The District must therefore withdraw the PDOC and FDOC and notify the CEC of that decision.

Public participation is not merely procedural. Public notice is essential for citizens to participate meaningfully in decisions that affect them. Their comments improve government decision making through tough questions that citizens may ask. Their comments may also point to deficiencies that even the experts may have missed.

Thus, until after this process is complete, the District cannot represent to the CEC that the proposed facility complies with federal air quality requirements. For these reasons, CAP

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[5] The Warren-Alquist Act requires the local air pollution control officer to conduct, for the CEC's certification process, "a determination of compliance review of the application in order to determine whether the proposed facility meets the requirements of the applicable new source review rule and other applicable district regulations." Cal. Code Regs., tit. 20, § 1744.5(b). "If the proposed facility complies, the determination shall specify the conditions, including BACT and other mitigation measures, that are necessary for compliance." *Id.*

requests that the District withdraw the 2006 PDOC and 2007 FDOC, notify the CEC accordingly, and perform a complete review of the permitting issues, both federal and state.

VIII. THE PROPOSED POWER PLANT WOULD POSE INCREASED HEALTH RISKS TO COMMUNITIES THAT ARE ALREADY DISPROPORTIONATELY IMPACTED BY POLLUTION.

The District's analysis of environmental justice impacts fails to meet its obligation under Title VI to ensure that "No person in the United States shall, on the ground of race, color, or national origin, be excluded from participation in, be denied the benefits of, or be subjected to discrimination under any program or activity receiving Federal financial assistance." 42 U.S.C. § 2000d.

The District in fact fails to engage in any analysis of the environmental justice impacts of the proposed facility. The District merely states that "there is no adverse impact on any community due to air emissions [and] that therefore there is no disparate adverse impact on an Environmental Justice community located near the facility." *See* SOB at 66. Such an approach directly contradicts the environmental justice principles because it ignores that environmental justice communities have distinct characteristics that distinguish them from, and make them more vulnerable than, the general population.

Environmental justice communities are characterized primarily as low-income, minority, with English as a second language, and suffering from greater health vulnerabilities. To engage in an environmental justice analysis, the District must therefore examine the specific impacts of the proposed facility on such communities because numerous studies have shown that these communities bear more of the cumulative burden of pollution in California and around the nation. *See, e.g.*, Clifford Rechtschaffen, *The Evidence of Environmental Injustice,* Environmental Law News, Vol. 12, No. 3 (Fall 2003); "Still Toxic After All These Years," *available at* http://www.baehc.org/resources; Toxic Wastes and Race at Twenty, *available at* http://www.ucc.org/justice/environmental-justice/pdfs/toxic-wastes-and-race-at-twenty-1987-2007.pdf.

Specifically, as Sandra Witt, DrPH, Director of Planning, Policy and Health Equity for the Alameda County Public Health Department testified during the Eastshore Energy Center proceedings, the community of Hayward is home to a significantly larger non-white population than Alameda County as a whole. Testimony of Sandra Witt at 2 (Exhibit 6). Furthermore, the residents around the proposed site suffer from significantly higher rates of illness due to respiratory and circulatory system diseases. *Id.* at 3-4. The District's one-sentence discussion of the impacts of RCEC ignores the reality that environmental justice communities suffer from cumulative impacts of pollution. *Id. at 1-2*. Even an insignificant contribution of air emissions for the general population can thus be significant to an already suffering community.

Furthermore, the District's treatment of environmental justice disregards the authority it has under the Clean Air Act and its own policy. *See* Memorandum, from Gary S. Guzy, General Counsel, Office of General Counsel, re EPA Statutory and Regulatory Authorities Under Which Environmental Justice Issues May Be Addressed in Permitting (Dec. 1, 2000) at 10-12, *available* *at* http://www.epa.gov/compliance/resources/policies/ej/ej_permitting_authorities_memo_120100.pdf ("Guzy Memorandum") (Exhibit 7); Board of Directors of BAAQMD's Cumulative Impact Resolution (July 2008) (Exhibit 8) (requiring the District to "continue its commitment to address the cumulative impact of new and existing mobile and stationary sources of air pollution – particularly in disproportionately impacted communities – for sources that on a relative basis contribute most to health risk at a local and regional level"). The District should therefore do an analysis and address the impact of the proposed facility on the affected population.

Since the District has entirely failed to consider the cumulative impacts of increased emissions on what is a particularly vulnerable environmental justice community, it has ignored Title VI and its authority under the Clean Air Act and its Board of Directors' policy. The District should not issue the permit until it completes a more thorough environmental justice analysis.

IX. THE PERMIT SHOULD BE STRENGTHENED, OR THE DISTRICT SHOULD ADEQUATELY EXPLAIN THE BASIS OF THE PROPOSED CONDITIONS.

A. The Commissioning Time Should Be Reduced.

The District's analysis of the commissioning time does not demonstrate why a shorter commissioning time is infeasible. *See* SOB at 47-50. Rather, the data presented demonstrate that a shorter commissioning time is feasible. *Id.* at 49-50 (stating that another similar turbine was commissioned in 96 and 207 hours).

B. The District Should Ensure that, for Each Condition, Monitoring, Recordkeeping and Reporting Requirements Exist to Ensure Compliance.

The District's proposed permit contains monitoring and verification provisions that do not adequately assure that the emissions requirements in the permit will be met at all times.

Sulfur Dioxide: For sulfur dioxide, the District states that it will only require the applicant to monitor the sulfur percentage from the natural gas monthly. *See* SOB at 71. This frequency concerns CAP because the sulfur percentage in natural gas can vary significantly. For example, recent measurements by PG&E show great fluctuation from one quarter to the next. *See* Sulfur Information, *available at* http://www.pge.com/pipeline/operations/sulfur/sulfur_info.shtml (Exhibit 9). Sulfur dioxide is a precursor to PM2.5, for which the District is currently in non-attainment. *See* http://www.epa.gov/pmdesignations/2006standards/documents/2008-12-2/FR_Final_24hr_PM2.5_Designations_010609.pdf (Dec. 22, 2008 federal register notice designating the Bay Area as non-attainment for PM2.5). Thus, the need for increased accuracy is essential. We request that the content of sulfur in the fuel be measured weekly to assure the accuracy of the sulfur dioxide emissions estimates.

In addition, the District has proposed to allow RCEC to use PG&E's monthly measurements if Russell City can show the measurements are "representative." *See* SOB at 71. And yet there is no objective criteria specified in the permit conditions as to what qualifies as "representative."

Nor is it clear whether RCEC should be able to use PG&E's numbers when PG&E adds chemicals to its natural gas and does not assure the accuracy of its published information. *See* Sulfur Information, *available at* http://www.pge.com/pipeline/operations/sulfur/sulfur_info.shtml (Exhibit 10).

PM: The District's monitoring requirements for PM are also inadequate. The only measurement that appears to be required for PM is for the heat input, coupled with an emissions factor generated from one annual source test. *See* SOB at 71, 76. This limited information will not accurately predict the PM emissions resulting from this facility. PM generated from natural gas combustion can increase from "poor air/fuel mixing or maintenance problems." *See* EPA, AP-42 Factors for Natural Gas Combustion, *available at* http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf. The District should require more stringent monitoring requirements for particulate matter due to this operational variability and the fact that the District is currently in non-attainment for particulate matter.

C. The District Should Evaluate Control Options for Ammonia Emissions.

The total project ammonia emissions are predicted to be 15.2 lbs/hr, which exceeds the acute trigger level of 7.1 lbs/hr. Table 6, SOB at 14. Inhalation of ammonia can lead to respiratory symptoms such as coughing, wheezing or shortness of breath and decreased lung function. *See* ATSDR, Toxicological Profile for Ammonia, *available at* http://www.atsdr.cdc.gov/toxprofiles/tp126.html. The minimal risk level developed by the ATSDR is 0.1 ppm for chronic exposure. *Id.* The District should translate the high level of ammonia emissions anticipated from this project into projected concentrations to thoroughly analyze potential health impacts from the ammonia emissions. The limited information presented in Table 7 does not assure the community that adverse health effects will not occur from ammonia exposure. *See* SOB at 16. To help reduce these emissions, the District should explore all the potential control options for these emissions, which can include wet scrubbers, condensate systems and recovery systems. The EPA evaluated these types of technology as applied to ammonia emissions in 1995. *See* U.S. EPA Control and Pollution Prevention Options for Ammonia Emissions, *available at* http://www.epa.gov/ttn/catc/dir1/ammonia.pdf.

D. The District Should Evaluate Emission Reduction Levels for POCs and HAPs from Specific Oxidation Catalysts for Reducing CO Emissions.

The District evaluates the option of using an oxidation catalyst to reduce CO emissions. SOB at 30-33. The identification of particular types of oxidation catalysts are, however, missing in this analysis, which could be important for reducing POCs and HAPs emissions. For example, the SCONOx system has been shown to reduce VOCs and HAPs emissions, while reducing CO emissions. *See* Memorandum from Sims Roy, EPA, re Hazardous Air Pollutant (HAP) Emissions Control Technology for New Stationary Combustion Turbines (Apr. 3, 2002), *available at* http://www.epa.gov/ttn/atw/combust/turbine/cttech8.pdf. Due to the high levels of HAPs and VOCs emissions involved (*see* Table 6, SOB at 14), the District should evaluate the effect of using different oxidation catalysts on emissions of VOCs and HAPs when it selects BACT for CO. *See* Guzy Memorandum at 12 (Exhibit 7), (in establishing BACT for criteria pollutants, alternative technologies could be analyzed based on their ability to control HAPs; permitting authority can take into account effects of HAPs that are VOCs).

E. Diesel Fire Engines Should Only Be Used During True Emergencies.

Under the proposed permit, the Fire Diesel Engine's harmful emissions will be uncontrolled. *See* SOB at 78-79. Therefore, the District should reduce the allowable operating time of this engine as much as possible and limit its use to only emergencies. While the District states that it would allow the diesel fire engine to be operated to prevent fires, *see* SOB at 9, there are no permit conditions to ensure that it would in fact be operated in that manner.

The current permit condition allows the Fire Diesel Engine to be used for reliability, which means that the engine could operate during the "maintenance of a primary motor." *See* BAAQMD Regulation 9-8-232. There are at least four primary motors for the proposed facility. *See* SOB at 10-11. Rather than having the diesel engine be a back up for any one of these primary motors, these motors themselves should be back ups to each other. That is because the primary motors can generate more power than the diesel engines. The four primary motors have MMBtu/hr ratings of 2038.6 MMBtu/hr, 200 MMBtu/hr, 2038.6 MMBtu/hr and 200 MMBtu/hr, while the fire pump engine has a rating of 2.02 MMBtu/hr. *See* SOB at 10. Thus, the small amount of power generated by the fire pump diesel engine does not make it a real back up to these primary motors. This way, the fire pump diesel engine will only be used in a real emergency.

We look forward to your responses to our comments. Thank you for considering them.

Very truly yours,

Ethan Wimert

Helen Kang
Deborah Behles
Ashling McAnaney
James Barringer
Ethan Wimert*

* Ethan Wimert is a student waiting for recertification under the State Bar Rules governing the Practical Training of Law Students, working under the supervision of Professor Helen Kang.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IX
75 Hawthorne Street
San Francisco, CA 94105-3901

January 24, 2006

Mr. Jack Broadbent
Air Pollution Control Officer
Bay Area AQMD
939 Ellis Street
San Francisco, CA 94109-7799

RE: PSD Re-delegation Agreement

Dear ~~Mr. Broadbent~~ Jack:

EPA appreciates the efforts of your staff to work with us in amending your Prevention of Significant Deterioration (PSD) Delegation agreement between the District and EPA. Under the amended delegation agreement, the District is responsible for the PSD permitting of two new facilities—Ameresco Half Moon Bay LLC and ConocoPhillips - San Francisco Refinery, in addition to the nine power plant projects listed in the previous delegation agreement. I am pleased to enclose a signed copy of the revised PSD delegation agreement. The agreement is effective immediately.

Please contact Laura Yannayon at (415) 972-3534 if you have any other questions related to this matter.

Thanks, Jack!

Sincerely,

Deborah Jordan
Director, Air Division

Enclosure

cc: Brian C. Bunger, Bay Area Air Quality Management District, w/enclosure
Catherine Witherspoon, Executive Officer, California Air Resources Board w/enclosure

EXHIBIT 1

Printed on Recycled Paper

U.S. EPA - Bay Area Air Quality Management District

Agreement for Limited Delegation of Authority to Issue and Modify Prevention of Significant Deterioration Permits Subject to 40 CFR 52.21

The undersigned, on behalf of the Bay Area Air Quality Management District (District) and the United States Environmental Protection Agency (EPA), hereby agree to the limited delegation of authority for the initial issuance or "administrative" or "minor" modification[1] of the Prevention of Significant Deterioration (PSD) permits identified below, subject to the terms and conditions of this agreement. This limited delegation is executed pursuant to 40 CFR 52.21(u), Delegation of Authority.

I. BACKGROUND RECITALS

1. EPA had delegated authority to implement the federal PSD regulations at 40 CFR 52.21 for all sources and modifications to the District on April 23, 1986. On December 31, 2002, EPA finalized revisions to the regulations at 40 CFR 52.21, which became effective on March 3, 2003. 67 FR 80186. The revisions to 40 CFR 52.21 did not significantly alter those portions of 40 CFR 52.21 that concern the issuance of permits for newly constructed "greenfield" sources. See id. at 80187.

2. The District may need to revise its local regulations to fully implement the federal regulations at 40 CFR 52.21, effective March 3, 2003, Accordingly, on March 3, 2003,

[1] The terms "administrative" and "minor" modifications are defined the same as in the EPA memorandum entitled "Revised Draft Policy on Permit Modifications and Extensions" July 5, 1985, by Darryl Tyler, Director, Control Programs Development Division of US EPA Office of Air quality Planning and Standards.

EPA withdrew the delegation of PSD authority from the District. See 68 FR 19371 (April, 21, 2003).

3. Because the federal regulations concerning permit issuance for new sources were not significantly altered effective March 3, 2003, existing District regulations continue to allow the District to implement 40 CFR 52.21 pursuant to a delegation agreement to issue the initial PSD permit(s), or an administrative or minor modification of a PSD permit(s). EPA has determined that District Regulation 2, Rule 2 generally meets the requirements of 40 CFR 52.21; therefore, District permits issued in accordance with the provisions of Regulation 2, Rule 2 will be deemed to meet federal PSD permit requirements pursuant to the provisions of this delegation agreement.

II. APPLICABILITY

1. Pursuant to this delegation, the District shall have primary responsibility for initial issuance or administrative or minor modification of the PSD permit(s) identified below:

Facility:

a. Delta Energy Center
b. Los Medanos Energy Center
c. Metcalf Energy Center
d. East Altamont Energy Center
e. Tesla Power Plant
f. Russell City Energy Center
g. Delta Power Plant
h. Potrero Power Plant
i. Ameresco Half Moon Bay LLC
j. ConocoPhillips - San Francisco Refinery

2. Permitting History for Delta Energy Center (Delta #12095). The District issued a Preliminary Determination of Compliance (PDOC) on August 12, 1999. Subsequently,

the District issued the Final Determination of Compliance (FDOC) on October 22, 1999. The Prevention of Significant (PSD)/Authority to Construct (ATC) was issued on March 28, 2000. The Title IV/V permit was issued on March 19, 2003 and reissued on November 12, 2003. The Permit to Operate was issued on January 8, 2003, and modified on November 14, 2003.

3. Permitting History for Los Medanos Energy Center (Los Medanos #11866). The District issued a PDOC on March 18, 1999. Subsequently, the District issued the FDOC on June 10, 1999. The PSD/Authority to Construct was issued on September 10, 1999 and the Authority to Construct was superceded on July 2, 2001. The Title IV/V permit was issued on September 1, 2001 and modified on January 13, 2004. The District Permit to Operate was issued on May 19, 2002.

4. Permitting History for Metcalf Energy Center (Metcalf # 12183). The District issued the FDOC on August 24, 2000. The final PSD permit was issued on May 4, 2001. The Authority to Construct was issued on February 13, 2002 and a modification was granted on September 10, 2002.

5. Permitting History for East Altamont Energy Center (East Altamont # 13050). The District issued a PDOC on April 12, 2002. Subsequently, the District issued the FDOC on July 10, 2002. The Western Area Power Administration (WAPA) formally requested that US Fish and Wildlife (US FWS) initiate formal Section 7 consultation on February 11, 2002. The Authority to Construct has not been issued as of May 7, 2004.

6. Permitting History for Tesla Power Plant (Tesla # 13424). The District issued a PDOC on August 6, 2002. Subsequently, the District issued the FDOC on January 22, 2003.

The EPA formally requested that US FWS initiate formal Section 7 consultation on February 21, 2002. The final PSD permit is not issued because of a delay in the issuance of the Biological Opinion associated with Section 7 process. The California Energy Commission conducted an Evidentiary Hearing from September 8 to September 12, 2003. The Commissioners have not made a final determination as of May 7, 2004.

7. Permitting History for Russell City Energy Center (Russell City # 13161). The District issued a PDOC on October 25, 2001. Subsequently, the District issued the FDOC in March 2002 and an Authority to Construct on May 14, 2003. The EPA formally requested that US FWS initiate formal Section 7 consultation on March 11, 2002. The final PSD permit has not been issued because of a delay in the issuance of the Biological Assessment associated with the Endangered Species Act Section 7 process.

8. Permitting History for Delta Power Plant (Delta #18, Unit 8). The District issued a FDOC on February 2, 2001. The final PSD permit and Authority to Construct were issued on July 24, 2001. The Permit to Operate has not yet been issued as of May 7, 2004.

9. Permitting History for Potrero Power Plant (Potrero #26, Unit 7). The FDOC was issued on December 12, 2001. On July 25, 2003, Mirant of California (owner of the Potrero Power Plant) revised their application (#7951) to include a cooling tower system and reduce the annual hours of operation. A draft Biological Opinion and Incidental Take Statement were provide to EPA and the Army Corps of Engineers on April 2, 2003. NOAA Fisheries received comments on the draft Biological Opinion from EPA on May 6, 2003. The comments pertained to a revised description of EPA's federal action regarding the issuance of the air quality permit. EPA comments also stated that the Corps

has agreed to place all terms and conditions contained in the Incidental Take Statement of the April 2, 2003, draft Biological Opinion, in the Corps Section 404 Clean Water Act and in any Rivers and Harbor Act permits. The amended PDOC has not been issued as of May 7, 2004.

10. Proposed permit for Ameresco Half Moon Bay LLC (Plant # 17040). Amerecso is proposing a landfill gas-to-energy facility at the Ox Mountain Landfill located in Half Moon Bay. The applicant proposes to burn landfill gas in spark ignited lean burn reciprocating internal combustion engines. The engine-driven generators will recover energy from landfill gas in the form of electricity.

11. Proposed permit for ConocoPhillips - San Francisco Refinery (Plant # 16). ConocoPhillips is proposing the "Rodeo Clean Fuels Expansion Project," which will increase capacity of hydrocracking, deisobutanizing, reforming, and sulfur recovery units. The project will include construction of a new hydrogen plant, a new flare, a new furnace for hydrocracking and two new tanks.

12. To allow the District to continue to issue initial PSD permits and/or process administrative and minor modifications to the PSD permit(s) for Delta Energy, Los Medanos, Metcalf, East Altamont, Tesla, Russell City, Delta Power, Potrero, Amerecso and ConocoPhillips, EPA and the District have agreed to this delegation of PSD authority to issue initial permits or make administrative or minor modifications. If any of the facilities subject to this agreement requests a permit modification to incorporate conditions for a plantwide applicability limit, as provided in 40 CFR 52.21(aa), EPA shall process and issue any applications for a permit modification. EPA may review the PSD

permit to ensure that the District's implementation of this agreement is consistent with federal regulations (40 CFR 52.21).

13. The District shall send to EPA a copy of all public notices required by 40 CFR 124.

III. GENERAL CONDITIONS:

1. The District shall request and follow EPA guidance on any matter involving the interpretation of Sections 160-169 of the Clean Air Act or 40 CFR 52.21, relating to the PSD permits for Delta Energy, Los Medanos, Metcalf, East Altamont, Tesla, Russell City, Delta Power, Potrero, Amerecso and ConocoPhillips.

2 The District shall issue PSD permits under this Agreement in accordance with the PSD elements of the District's Regulation 2, Rule 2 and 40 CFR 52.21 as amended on December 31, 2002. Elements of Regulation 2, Rule 2 relating to state law requirements inconsistent with the Clean Air Act and 40 CFR 52.21 and 124, including, but not limited to, elements of Regulation 2, Rule 2 relating to the California Environmental Quality Act, shall not apply to PSD permits under this Agreement.

3. This delegation agreement may be amended at any time by the formal written agreement of both the District and the EPA, including amendment to add, change, or remove conditions or terms of this agreement.

4. If the U.S. EPA determines that the District is not administering the PSD permit identified in this agreement in accordance with the terms and conditions of this limited delegation, the requirements of 40 CFR 52.21, 40 CFR 124, or the Clean Air Act, this delegation, after consultation with the District, may be revoked in whole or in part. Any

such revocation shall be effective as of the date specified in a Notice of Revocation to the District.

5. If the District determines that administering the permits identified in this agreement in accordance with the terms and conditions of this agreement, the requirements of 40 CFR 52.21, 40 CFR 124, or the Clean Air Act conflicts with State or local law, or exceeds the District's authority or resources to fully and satisfactorily carry out such responsibilities, the District after consultation with EPA, may remand administration of these permits to EPA. Any such remand shall be effective as of the date specified in a Notice of Remand to EPA.

6. The permit appeal provisions of 40 CFR 124, including subpart C thereof, pertaining to the Environmental Appeals Board (EAB), shall apply to all appeals to the Administrator on permits and modifications to permits issued by the District under this delegation. For purposes of implementing the federal permit appeal provisions under this delegation, if there is a public comment requesting a change in a draft preliminary determination or draft permit conditions, the final permit issued by the District shall contain a statement that for Federal PSD purposes and in accordance with 40 CFR 124.15 and 124.19, (1) the effective date of the permit shall be 30 days after the date of the final decision by the District to issue, modify, or revoke and reissue the permit; and (2) if an appeal is made to the EAB through the Administrator, the effective date of the permit shall be suspended until such time as the appeal is resolved. The District shall inform EPA Region IX in accordance with conditions of this delegation when there is public comment requesting a change in the preliminary determination or in a draft permit condition. Failure by the

District to comply with the terms of this paragraph shall render the subject permit invalid for Federal PSD purposes.

7. Pursuant to the provisions of 40 CFR 52.21(u)(2), the District shall consult with the appropriate State or local agency primarily responsible for managing land use prior to making any determinations under this Agreement.

8. Nothing in this agreement shall prohibit EPA from enforcing the PSD provisions of the Clean Air Act, the PSD regulations or any PSD permit issued by the District pursuant to this agreement. In the event that the District is unwilling or unable to enforce a provision of this delegation with respect to a source subject to the PSD regulations, the District will immediately notify the Air Division Director. Failure to notify the Air Division Director does not preclude EPA from exercising its enforcement authority.

9. This limited delegation of PSD authority becomes effective upon the date of the signatures of both parties to this Agreement.

1/5/06
Date

Jack P. Broadbent
Jack P. Broadbent
Executive Officer/APCO
Bay Area Air Quality Management District

1/20/06
Date

Deborah Jordan
Deborah Jordan
Director, Air Division
U.S. EPA, Region IX

morning

11/6/08

Candido Veiga
Benjamin Beaver
Bob Nishimura
Madhave Patel
Wayne Lee

teleconference

No Flex 10 or 30 in operation

10 peaking / intermediate
30 base load

for more recent changes in operation
- more s/u & s/d

10/30
integrating all components in combined offering
want to have control of all components
all equipment must be designed to specifications

combination of hardware & software
Flex 10 - 49% 47-48%
Flex 30 - 57%

existing turbine cannot be retrofitted
will kill project because of cost

ctg will be updated prior to ~~the time~~ installation

EXHIBIT 2

Same attendees
+ Brian Lusher

11/6/08

S/U sequence
Flex (10)
5 minutes - synchronize to grid
10 minutes - 150 MW on line

exhaust to air-cooled condenser
12 min. coupling w/ GTG
20 min stack compliance

efficiency 39% first hour (simple cycle)

then 48-49% @ full load

bidding flex 10 on several projects now
~~will an~~ anticipate bidding on flex 30 in future

Weyman Lee

From: Veiga, Candido (E AS31) [candido.veiga@siemens.com]
Sent: Thursday, November 06, 2008 10:42 AM
To: Weyman Lee
Cc: Beaver, Benjamin R (E AS31)
Subject: Flex Plant Cycle.ppt

It was a pleasure speaking with you. Here is the slide I was refering to we will look forward to meeting with you again. In the meantime if you have any question please contact myself or Benjamin Beaver. Benjamin will forward his V-card in separate e-mail.

Best Regards,
Candi

SIEMENS

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Siemens Power System Sales
Candido Veiga
Region Vice President
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Cell (925) 328-1084

e-mail: candido.veiga@siemens.com

Weyman Lee

From: Beaver, Benjamin R (E AS31) [benjamin.beaver@siemens.com]
Sent: Thursday, November 06, 2008 3:57 PM
To: Weyman Lee
Cc: Veiga, Candido (E AS31)
Subject: Follow Up to Today's Flex Plant Discussion

My pleasure speaking with you earlier this morning. As discussed, I'm investigating availability of our Flex-Plant product experts for support of a technology update webcast sometime over the few weeks. Once I get a few potential dates from HQ, I'll submit them to you and your team for consideration. If possible, if you are aware of any dates/times that are not good for BAAQMD, please advise. Thank you.

We appreciate your interest in Siemens and our technology offerings. I've attached my contact information below. Please do not hesitate to contact me for any additional information and/or support.

I look forward to meeting with you soon.
Best regards,
Benjamin

SIEMENS **Siemens Energy**

Benjamin R. Beaver Siemens Power Generation, Inc.
Sales Manager 2303 Camino Ramon Suite 150
Pacific Northwest San Ramon, Ca. 94583

Phone: (925) 242

STATE OF CALIFORNIA —THE RESOURCES AGENCY ARNOLD SCHWARZENEGGER, Governor

CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO, CA 95814-5512

May 29, 2007

Mr. Jack P. Broadbent
Executive Officer/Air Pollution Control Officer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Dear Mr. Broadbent,

AMENDED PRELIMINARY DETERMINATION OF COMPLIANCE FOR THE RUSSELL CITY ENERGY CENTER, APPLICATION 15487

Thank you for the opportunity to comment on the Amended Preliminary Determination of Compliance (PDOC) for the proposed Russell City Energy Center (RCEC), a 600 MW combined cycle project located in the city of Hayward. In the Amended PDOC the District finds that, subject to specified permit conditions, the proposed project will comply with all applicable federal, state and Bay Area Air Quality Management District (District) rules and regulations.

In considering this project, we believe there may be better and more direct ways to reduce or avoid the cumulative impacts from ozone precursor emissions than those proposed by the project owner. We believe that there is current technology that the District should consider requiring as Best Available Control Technology (BACT) that will significantly limit the ozone precursor emissions that result from start-up and load following transitions. We believe that impact avoidance (i.e., preventing emissions) is generally a better approach than impact mitigation of air emissions through the provision of offsets when complying with the requirements of the California Environmental Quality Act.

<u>OFFSETS</u>

The planned operating profile of the project, frequent start-up and shutdown cycles, is creating a significant disparity between the daily emissions and the average daily offsets. The project owner is requesting that no District or Energy Commission conditions be attached to the project that would restrict the number of start-up and shutdown cycles or the annual hours of operation. They would, instead, accept a condition that would limit the facility's annual emissions to 134 tons per year (TPY) of oxides of nitrogen (NOx) and 28.5 TPY of precursor organic compounds (POC).

The Amended PDOC, per the District New Source Review (NSR) regulations, identified That RCEC will surrender emission reduction credits (ERC) in the amounts of 103 TPY of NOx and 80 TPY of POC to offset new emissions of 134 TPY of NOx and 28.5 TPY of POC. On a daily basis, including days that experience ozone violations, staff estimates that the project could emit up to 2,213 lbs of NOx, while the proposed

EXHIBIT 3

emission reduction credits provided would amount to only 844 lbs per day. This offset amount mitigates approximately 38 percent (844 lbs/2,213 lbs) of the project's potential emissions for NOx on any given day. Thus on those days when violations of the ozone air quality standards occur, the project's emissions would contribute to violations of the standard.

BACT

According to the Amended PDOC, each unit of the RCEC must be equipped with BACT for NOx, carbon monoxide (CO), POC, particulate matter less than 10 microns (PM10), and oxides of sulfur (SOx). The Amended PDOC states that BACT for each unit is the use of selective catalytic reduction (SCR) and CO oxidation catalyst systems to control NOx, POC and CO emissions, and the use of natural gas as BACT for PM10 and SOx.

The SCR system will maintain a normal operation NOx emissions limit of 2.0 parts per million (ppm) averaged over a one-hour period. The District determined that this meets District guidelines for BACT. Missing from this determination is consideration of the facility's potential high daily NOx emissions from multiple start-up and shutdown cycles. Energy Commission staff estimates that the facility can potentially emit 2,213 pounds per day of NOx. The hourly emissions during start-up and shutdown events are much greater than during normal operation since the SCR and ammonia injection system are not at optimal conditions. The resulting daily emissions could have a significant effect on ozone and air quality in the Bay Area air basin because the proposed NOx emission reduction credits are approximately equivalent to 844 pounds per day, well below the potential emissions of 2,213 pounds per day of NOx.

Energy Commission staff recommends that the district consider requiring, as part of their BACT analysis, hardware and software modifications to the project that can shorten start-up and shutdown events and optimize emission control systems. There is evidence that start-up and shutdown emissions from the facility can be reduced significantly with design changes to the heat recovery steam generator (HRSG) units that can include the use of the once-through HRSG (Benson Boiler). The start-up time for each turbine/HRSG unit could be reduced from the proposed 6 hours to approximately one hour, resulting in a significant reduction in start-up emissions. If the project is built with the aforementioned Fast-Start technology, the project start-up NOx emissions are expected to be reduced from the proposed 480 lbs to 22 lbs for each cold start-up event, and from 240 lbs to 28 lbs for hot or warm start-up events. This represents 95 and 88 percent reductions in NOx emissions per cold and hot or warm start-up events, respectively. In addition to reducing the facility's NOx emission liabilities, the use of Fast-Start technology at the RCEC project would result in cost savings from less fossil fuel use to create steam that is vented during start-ups. Staff has not estimated the actual fuel saving because this cost will tie directly to how many start-up and shutdown cycles the facility has during a year. According to one manufacturer (Siemens), the cost for the design changes is not significantly higher than the cost of the standard, off the shelf, HRSG.

Alternatively, the 600 MW combined cycle Palomar Project in Escondido has installed a proprietary control system, OpFlex from General Electric, and injects ammonia earlier to shorten start-up times and reduce start-up emissions at the facility. Preliminary, non-optimized results from their March 7, 2007, Petition for Variance 4703 Extension indicated that they have reduced NOx emissions from 120 lbs to 28 lbs for hot or warm start-up events.

If design or process control changes to reduce the facility's start-up and shutdown emissions are implemented, the RCEC daily emissions can be reduced. These design changes could be found to be cost-effective and included as BACT for the proposed facility.

GENERAL COMMENTS

- Page 2 and page 36 of the Amended PDOC identifies the source S-5, the cooling tower, "with efficiency drift eliminators make and model to be determined" while on page 14 the drift is specified as 0.0005%.
- Page 4, Item 3.c. identifies the POC limit of 1 ppmvd @15% O_2. However, Table 1 on the same page identifies POC limit of 2 ppmv.
- Page 5, Table 2 identifies PM10 emissions from the cooling tower, although drift elimination efficiency was not specified on page 2 and the TDS limits are not provided.
- Page 13 and Condition 20(g) specifies that the project will burn natural gas in the turbine and heat recovery steam generator with an annual average of 0.25 grains sulfur per 100 standard cubic feet. What is the basis for this value and how will it be enforced?

Thank you for the opportunity to provide comments on the District Amended PDOC for the Russell City Energy Center. We believe that design changes to the project could significantly reduce the facility's daily potential to emit, and at the same time address the effectiveness of the applicant's proposed offset mitigation. If you have any questions regarding our comments, please contact Matt Layton at (916) 654-3868.

Sincerely,

Paul C Richins Jr.

PAUL C. RICHINS, JR
Environmental Protection Office Manager

cc: Docket (01-AFC-7)
Proof of Service List
Agency List

2007 Pacesetter Plant Award

Palomar Energy Center

Escondido, Calif
San Diego Gas & Electric Co

Central stations return to the city

A hundred years or so ago, about half of the country's electricity was produced onsite by businesses that used it for competitive advantage. Electric utilities were born to urban areas as demand created by commercial, street, and residential lighting and appliances grew exponentially in the first quarter of the 20th century. They built "central stations" within the load pockets served because electricity couldn't be distributed efficiently very far from the generators that produced it.


Ted Walton

1. Palomar Energy Center, gets "A" grades for architectural design and noise mitigation

But as cities grew, so did the powerplants—fueled mostly by coal—and there were concerns about the pollutants released. The concerns were justified; outbreaks of respiratory illnesses attributed to, or exacerbated by, airborne emissions are fairly well documented. Powerplants got a bad name, as did coal.

One solution was to locate large plants outside cities and build high-voltage transmission lines to deliver electricity to load centers. The strategy worked for several decades—and still does, generally. But not everyone agrees with it.

Some vocal citizens tired of the visual impact associated with transmission towers; others became frightened by the weird science of electromagnetic fields that identified high-voltage lines as a health hazard. Long-distance transmission lost its white hat and licensing of new lines, even on existing towers, became difficult in certain areas—some might say virtually impossible.

The new robber barons. More recently, a few enterprising energy executives who believed regulated utilities could be run more efficiently if the industry were deregulated got their wish. And the federal government did its part during the open season on meddling with electricity supply by deciding to restructure the wires side of the business and create a national grid.

Generation and transmission assets were bought, sold, and traded by people who knew little other than how to increase their personal net worth. Several of the largest utilities were left holding the proverbial bag, retaining their "obligation to serve" but stripped of their generat-

EXHIBIT 4


one engineer.
start.
1
one contractor.
finish.
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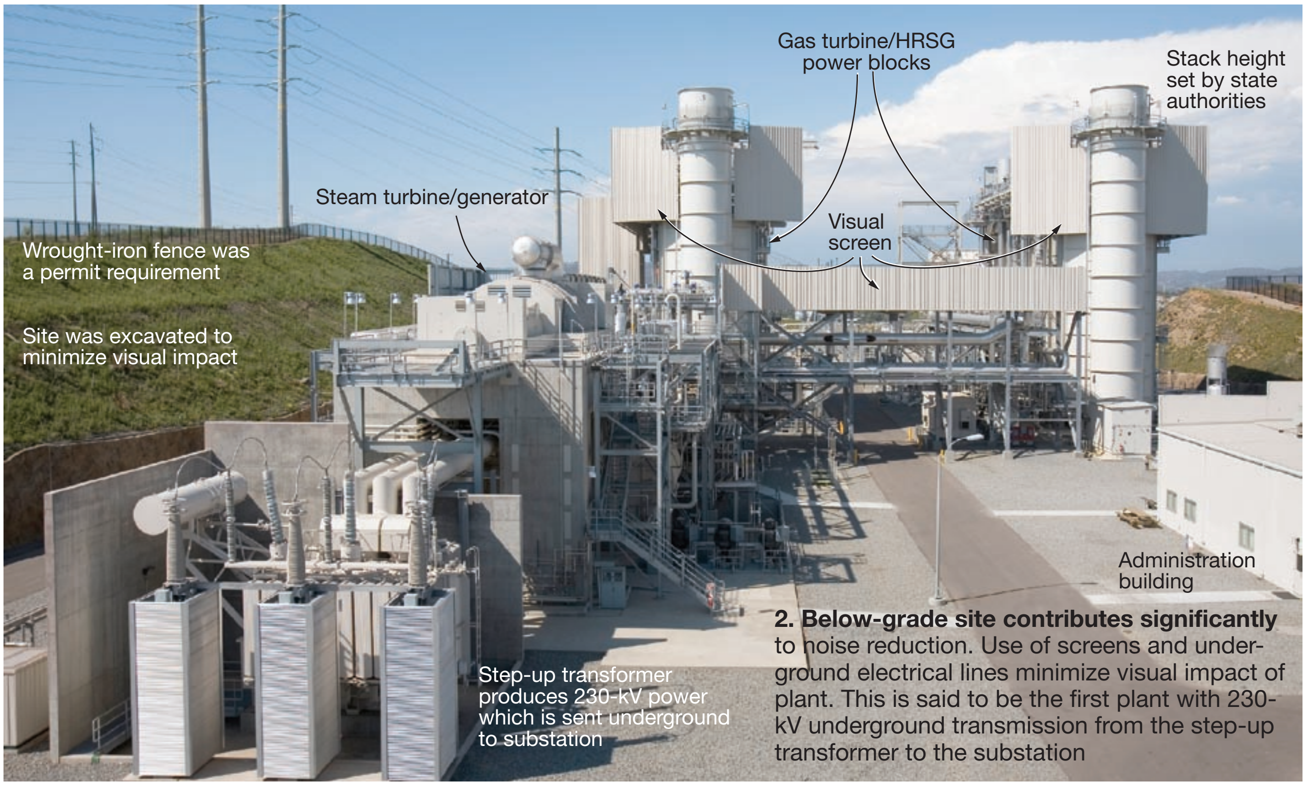
Bibb and associates

ing plants as well as control over the electrical networks they built.

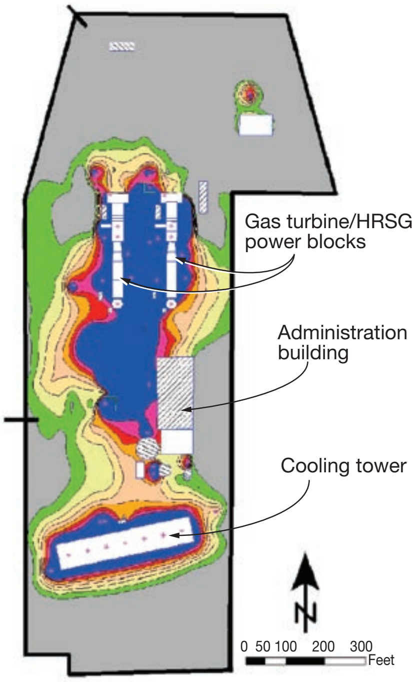
Most readers probably recall the California electricity crisis shortly after the millennium, when three of the country's most successful investor-owned utilities (IOUs)—Pacific Gas & Electric Co, Southern California Edison Co, and San Diego Gas & Electric Co (SDG&E)—were almost driven out of business by a perfect storm of bad ideas and actions on the part of others. The unprecedented "mess" was a major contributing factor behind the recall of Governor Gray Davis. It was only the second time in the history of the country that a governor had been recalled.



2. Below-grade site contributes significantly to noise reduction. Use of screens and underground electrical lines minimize visual impact of plant. This is said to be the first plant with 230-kV underground transmission from the step-up transformer to the substation

3. Sound-absorbing walls reduce noise generated by the gas turbines (left)

4. Acoustic model produced a noise profile for the Palomar site that looked like this after all attenuation enhancements were incorporated into the design (right)



5. Vent silencers are of a squat design to restrict their height to 1 ft above the visual screen

But nothing lasts forever, and the electric power industry in California has re-emerged from its darkest days with a new vitality. At least that's the feeling the editors came away with after visiting the half-dozen California plants profiled in the Class *of* 2006 report. Rules governing the licensing and operation of generating plants, and the obligations of owners, seem clearly defined, as do the roles and responsibilities of all market participants—private and public power producers, the transmission system operator, and regulatory authorities.

Hopefully, the plant profiles convey this positive outlook. They also offer a birds-eye view of what it takes to license a plant in California. Suggestion: Pay attention to the rules governing water use and the treatment of blowdown and other liquid waste streams, and how owner/operators are meeting them. They offer lessons learned that might prove valuable to you in the future.

Palomar's significance

Two positive impacts of California's "new beginning" in electric power are these:

- A re-emergence of IOUs as owner/operators of regulated generating plants in the state.
- The siting of central stations in urban locations to serve native load.

Palomar Energy Center (Fig 1), owned and operated by SDG&E, exemplifies both. The utility's leadership and achievement, which serve as models for others, earn Palomar the 2007 Pacesetter Plant Award. SDG&E is a unit of Sempra Energy Utilities, the umbrella organization for Sempra's regulated business units.

The 550-MW, natural-gas-fired facility—a 2 × 1 7FA-powered combined cycle—is the first major powerplant built in San Diego County in three decades. It is located on a hillside in the Escondido Research & Technology Center, a stone's throw from private homes.

Residents *might* know they have a powerplant as a neighbor, but why would they care? The facility, generally quieter than the traffic on surrounding freeways, has architectural features that enable it to blend in with its surroundings. Plus, it has an emissions profile that places Palomar among the cleanest generating stations in the world.

Jim Avery, SDG&E's senior VP electric (generation and T&D), says Palomar was built on a turnkey basis to mitigate construction risk. Its developer was Sempra Generation, an unregulated Sempra affiliate, which could not own and operate the plant and sell its output to the regulated utility because that would have been viewed as a conflict of interest.

SDG&E produced most of the power it sold before being ordered to divest of the generating plants in its electric service territory during the California meltdown described earlier. With the addition of Palomar, it now produces about 20% of the power it sells. The utility also owns an LM6000 peaker at Miramar and a small percentage of a nuclear plant.

Quiet, first-class appearance

Considerations such as stack emissions, water use, and wastewater treatment are table stakes for powerplant development most places. If you can't ante-up you have no chance of obtaining permits for construction and operation. In California, the stakes are higher, particularly if a plant will be built near offices and homes. The facility must operate quietly and appear as if it belongs in the neighborhood.

Joint-venture EPC contractor Kiewit/Bibb was responsible for building a functional facility that also followed noise regulations and didn't resemble a typical powerplant. Kiewit is Kiewit Industrial Co, Lenexa, Kan, the constructor; Bibb is Bibb and Associates Inc, Lenexa, Kan, and like Kiewit Industrial, a subsidiary of Peter Kiewit & Sons, Omaha.

Bibb's Palomar project manager, Kevin Needham, says that the permit approved by the California Energy Commission identified about a half-dozen so-called "sensitive receptors" around the plant and prescribed noise limitations for each. Failure to "nail the numbers" on the inspector's test after startup would put plant operation at risk and undoubtedly require very expensive retrofit work.

To ensure success, Bibb built a noise model with help from Michael Theriault, who heads up the specialized noise consultancy MTAcoustics, South Portland, Maine. This effort began with a plot plan of the long, narrow 20-acre site, which was carved into a hillside. Removal of 1.2 million cubic yards of dirt and rock

member in 50th country!

With the recent addition of The Power Generation Co. of Trinidad & Tobago LTD, the HRSG User's Group now supports members in 50 countries around the globe! Our 1500-plus colleagues come in all shapes, sizes, and professions within the combined-cycle/cogen community — owner/operators, manufacturers, engineering consultants, water-treatment specialists, repair contractors, insurance carriers, and so on.

Since 1993, the HRSG User's Group has provided educational events and publications, focused not just on how to improve the HRSG, but how to improve the entire, integrated steam system at gas-turbine-based plants. We cover all steam equipment, from Attemperators to ZLD systems!

To join this vibrant, productive, and international association, visit www.HRSGusers.org or send an email to info@HRSGusers.org

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India
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Iran
Ireland
Israel
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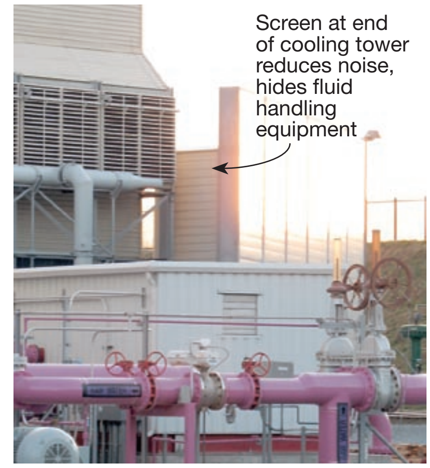


6. Screen at top of cooling tower primarily is for noise reduction. However, it also acts as a visual screen

7. Cooling tower's fluid handling equipment is hidden by end screen provided for noise reduction

allowed for most of the plant to sit below grade in a granite "bathtub," benefiting noise-attenuation efforts.

Using noise-emissions data gathered from manufacturers, and from tests conducted at plants with similar equipment, engineers ran the model to identify areas of concern—including HRSG (heat-recovery steam generator) stack and casing noise.

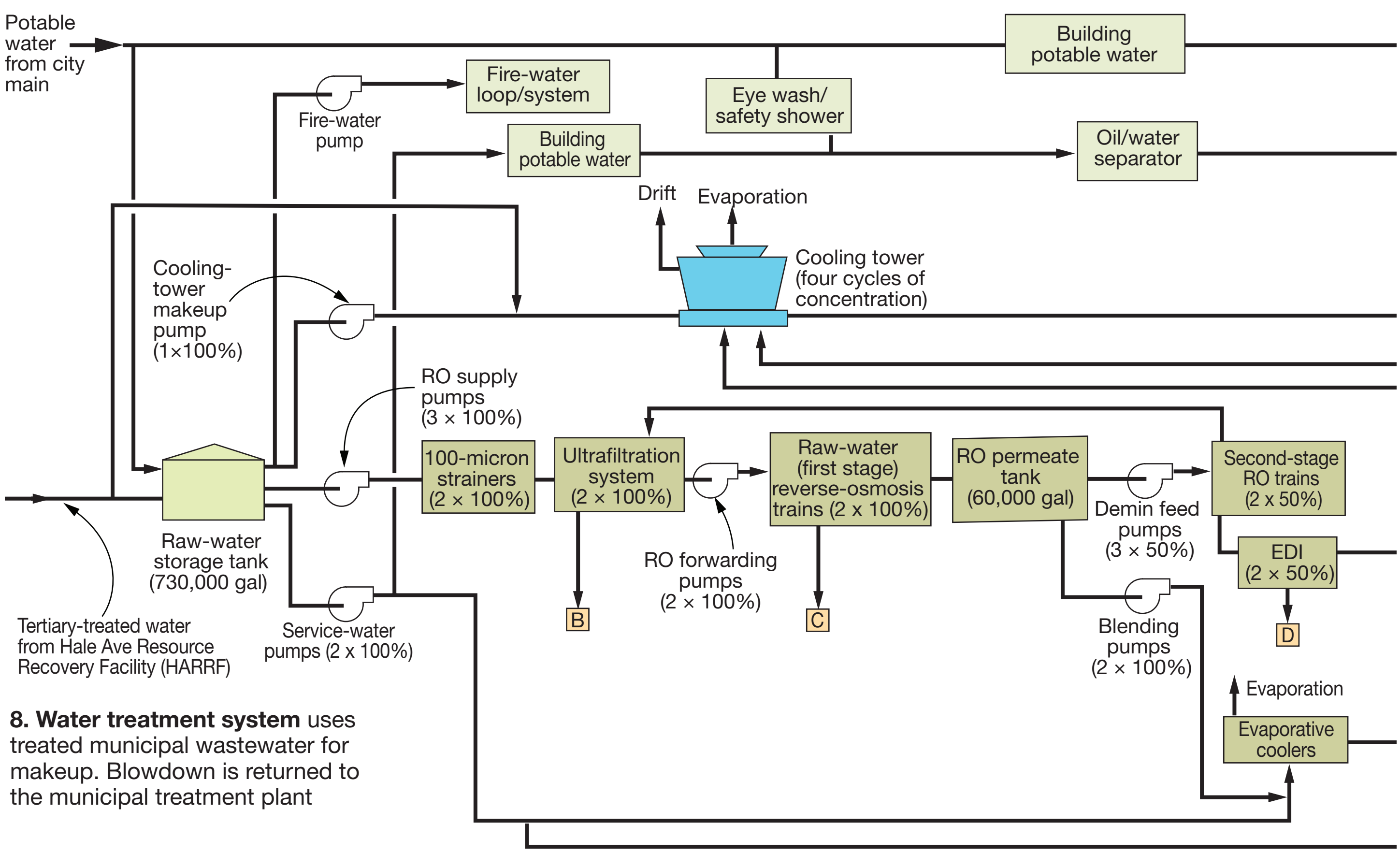
Next step: Modify the standard equipment offerings to reduce noise. To illustrate: For each HRSG, the thickness of the casing in the inlet duct area was increased to 0.875 in. Regarding the stacks, conventional silencers were not an option because of the 110-ft stack height limit to minimize visibility. The solution: Extend the length of the HRSG by 10 ft and add sound-attenuation baffles downstream from the last bank of tubes and upstream from the stack.

For gas turbines (GTs), the solution generally incorporates sound-absorbing walls to reduce the noise level (Fig 3).

The iterative process acoustical engineers use leads to a noise profile for the plant vicinity (Fig 4) that will produce the desired dB(A) readings at all of the receptors.

The editors can attest to the effectiveness of the noise mitigation program at Palomar. It's rare that you can walk between two operating 7FA/HRSG power blocks and carry on a normal conversation, but you can do it there. About the only thing you could hear were the boiler-feed pumps. Director of Electric Generation Dan Baerman says the noise level at the first residence is less than 40 dB(A).

Permits also govern the visual impact of the plant, Needham adds. Fig 2 shows some of the architectural screens on the HRSGs used to make them appear like commercial buildings from the road. Fig 5 illustrates restrictions on vent height at the top of the boilers. Steam vents are not



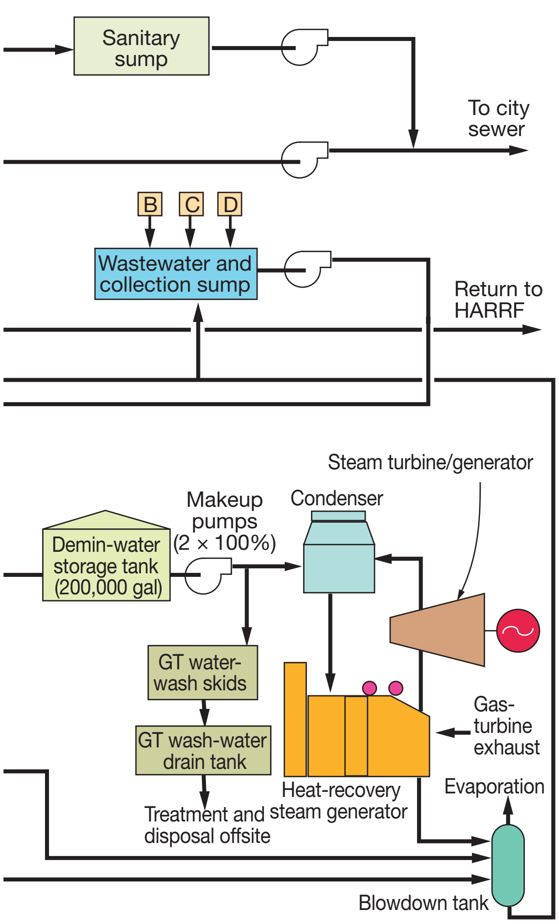
8. Water treatment system uses treated municipal wastewater for makeup. Blowdown is returned to the municipal treatment plant allowed to extend more than 1 ft above the height of the screen. To accommodate both the noise-attenuation and visual-impact requirements, special vent silencers have been installed. Note that they have a squat profile.

Visual impact of the cooling tower also was of concern. A screen around the top of the mechanical-draft tower reduces noise and hides the fan deck (Fig 6); an end screen hides piping and other fluid handling equipment (Fig 7).


Baerman

Plume visibility presents a problem at certain times of the year for a couple of hours in the morning. To address this issue, Marley-SPX Cooling Technologies, Overland Park, Kan, designed a plume abatement system into the tower. It relies upon a system of louvers and heat-transfer coils to eliminate or greatly reduce the formation of fog.

If the plant were located anywhere else in the country, the enhancements noted above to minimize the plant's visual impact probably would have been sufficient—but not in California. For Palomar to meet the requirements of its permit, the entire plant had to be finish-painted. It was a first-class job that specified the color of the paint and the type of wrought-iron fence used for the plant perimeter. Finally, the cooling towers also contained fiberglass sections in the specified color.



Plant operations

Palomar began commercial operation on April 1 and hasn't rested very often. Capacity factor for the last three quarters of 2006 was just about 70%, according to Baerman, which is relatively high for a combined-cycle plant today.

The plant essentially is in continuous operation, adds Operations Manager Pete Smithson. It follows load right through the night. Every now and again, he continues, the plant operates as a 1 × 1 at night, but that's not very often. Year-to-date availability was over 97% when the editors visited in mid December.

Total staff at Palomar, which also is responsible for the Miramar peaker, is 30. Baerman says one of the biggest challenges he had was to make everyone aware of the importance of environmental tracking. It's an integral part of everyone's day, he adds. Necessary inspections and tests—there are scores—are integrated into normal work processes; many PMs are compliance PMs as well, Baerman continues.


Smithson

So important is environmental compliance that Baerman's lieutenants are not just the operations and/or maintenance managers that you find at most combined-cycle plants of this size. Palomar also has a compliance manager, Kelly Hunt, at the same level as Maintenance Manager Carl LaPeter and Smithson.

Cold starts. Palomar is yet another plant in the Class *of* 2006 challenged on cold starts by permit requirements (see profiles for Mankato and Cosumnes). The SDG&E facility couldn't bring its GTs into emissions compliance on cold starts within the four-hour permit allowance because of the long startup time associated with the GE Energy (Atlanta) D11 steam turbine. The utility has filed for a permit change to extend the cold-startup time for emissions compliance to six hours.

Another concern was that high pollutant emissions during startups were rapidly consuming Palomar's annual NO_x allocation on a total weight basis. The DLN2.6 combustion system was meeting the 2-ppm NO_x and 6-ppm CO limits for normal operation, but startup emissions were well above that expected.

Palomar took two actions that ultimately reduced NO_x emissions by 75% on a pounds-per-startup basis. They were:


LaPeter


Hunt

- The GT OEM tuned the combustion system for all operating modes. One of the benefits is that the engines are now in NO_x compliance when operating at less than 50% of their full-load rating. In powerplant lingo, the GTs are in 6Q mode (full DLN) much sooner than they were initially.
- Initially, Palomar was starting its SCR (selective catalytic reduction) ammonia injection (reagent is 19% aqueous ammonia) when the catalyst reached 550F—as recommended by catalyst supplier Cormetech Inc, Durham, NC. Working together, plant staff and Cormetech found ammonia injection could begin at 485F and still be in full compliance on ammonia slip. This means the SCR could be started 90 minutes earlier than it had been, thereby reducing NO_x emissions significantly.

Water supply, wastewater treatment. California is tough on powerplant water use and on wastewater discharges (learn about the state's rules in the Riverside profile). Palomar's approach was simple: (1) Install two 1.1-mi pipelines from the plant to what is known locally as HARRF (the Hale Ave Resource Recovery Facility); (2) transport the tertiary treated municipal wastewater needed for plant cooling, cycle makeup, and fire and service water systems through one pipe; and (3) return all blowdown to HARRF via the second line.

In effect the plant has what amounts to a zero-liquid-discharge arrangement because it returns all of the wastewater to HARRF. Rather than explain system arrangement in words here, consult Fig 8. Note that the provided 780,000-gal raw-water surge tank has sufficient capacity for a system shutdown should HARRF be unable to supply water temporarily. CCJ

Santan Generating Station

Gilbert, Ariz
Salt River Project

Environmental upgrades focal point of plant expansion

Santan's 1 x 1 combined cycle, at right in photo, features a high-efficiency A14 steam turbine. Triangular arrangement of stacks was considered by neighbors to be more visually pleasing than individual stacks

It wasn't that the majority of people living near Salt River Project's Santan Generating Station just outside Phoenix in Gilbert, Ariz, didn't want the plant to expand, they just didn't want to see the facility, or hear it, or be subject to increased pollutant emissions.

The plant dates back to the early 1970s when SRP built four single-shaft (1 × 1) combined-cycle units on the 120-acre Santan site. These so-called STAG units, supplied by GE Energy, Atlanta, were powered by Frame 7B gas turbines (GTs). Originally, the units burned distillate and did not have emissions controls. In the early 1980s, the GTs were converted to dual-fuel firing because of the lower price of gas compared to oil.

Burgeoning power needs in the Southwest demanded that SRP plan to increase its generating capability as the 1990s came to a close. That plan called for adding two combined-cycle units at Santan with a total capacity of 825 MW. Unit 5, which began commercial operation in April 2005, is a 2 × 1 arrangement powered by Frame 7FA+e GTs. Unit 6, a 1 × 1, consisting of a 7FA+e and GE's new, high-efficiency A14 steam turbine, went commercial in 2006 (photo). Although this was only the second A14 steamer to enter service when it started up, the plant reports it has met OEM performance objectives and is operating as expected.

Bill Rihs, SRP's manager of major projects says that the permits for the new units had several significant conditions related to environmental control, including the following:

- The original GTs were upgraded to Frame 7Es and dry low-NO_x combustion systems were installed to reduce emissions. Controls were replaced with the Mark VI systems required for DLN combustion. Upgrades also were required for the cooling towers and heat-recovery steam generators (HRSGs). In addition to the environmental benefits, heat rate improved by about 10% and unit output increased by about 20 MW.
- Natural gas was specified as the only fuel acceptable for power production.
- Visible and noise pollution were high on the public's agenda. One reason: Residential development has expanded outward from Phoenix to the plant location in the last 30 years. To help reduce noise and hide the plant from view, the new generating facilities are located behind a manmade 25-ft-tall berm. Plus, the foundations for the HRSGs are set about 15 ft below grade. To make the stacks less noticeable, they are arranged in an aesthetic triangular pattern as shown in the photo. More than 1000 mature trees were planted on the berm to further mask visibility.

Water, a major concern of every power project in the West, comes from the Colorado River and other sources via the Central Arizona Project. Consumption is carefully monitored and controls are in place to assure optimum use. Makeup water for the reduced-plume cooling towers and other requirements is ordered a day ahead. Underground water storage facilities are provided at the plant.

Santan wastewater is treated to exacting specifications and delivered under contract to the Roosevelt Water Conservation District for irrigation purposes. In effect, the plant is a zero liquid discharge (ZLD) facility because all wastewater is reused. But satisfying the conservation district's specs has been challenging. In fact, the changing nature of plant water has dictated the installation of a new "front-end" treatment for the plant.

When water physical and chemical characteristics were determined prior to plant design, the area had been in a drought condition for a few years and surface water was relatively free of suspended solids. But 2005, when the 2 × 1 combined cycle began operating, was a wet year with lots of runoff from the mountains—and suspended solids. Plant is installing a clarifier to deal with the issue. CCJ

Shaheerah Kelly/R9/USEPA/US

07/02/2008 12:24 PM

To bryan.sixberry@ge.com

cc

bcc Shaheerah Kelly/R9/USEPA/US@EPA

Subject Rapid Response and OpFlex

Hi, Bryan.

Thanks for taking the time to discuss the Rapid Response and OpFlex systems with me. I really appreciate it. Below is a summary of my understanding of these systems based on our discussion. Please let me know if any of this is incorrect. Again, thanks.

Rapid Response:
- It is a total power plant system that allows combined-cycle gas turbine (CCGT) plants to get through low efficiency, high emission periods (i.e., SU periods) very quickly.
- The system generally reduces SU time from 110 minutes to 65 minutes for CCGT plants and from 45 minutes to 10 minutes for gas turbines (GTs); it also allows SCR injection to start at 50 to 60% load.
- It uses an auxiliary boiler to assist with heating up the steam turbine (ST) while the ST ramps up.
- It requires a specially designed HRSG and steam turbine for each power block.
- It is more suited for load-following and intermediate power plants which have several/daily startups and shutdowns; it is not beneficial to baseload plants since these plants do not startup/shutdown frequently and would only reduce a very small portion of SU emissions for these plants.
- It can reduce NOx emissions by 30-40% annually.
- It allows GTs to achieve 9 ppm NOx at 50-60 % load w/ SCR (typically 100 ppm between 50 - 60% load for conventional power plants).
- Its cost ranges between $100K and a few million dollars.

OpFlex Turndown:
- It is a software solution in which a controller is added to the CCGT power plant to optimize the combustion process.
- For 7FA GTs, uses Mark 5E or 6K. (Bryan, can you tell me what this means?).
- GTs can go down to 40% load and meet less than 9 ppm NOx and CO.
- It allows plants to reduce fuel use and and results in lower NOx and CO emissions during low load periods.
- It allows a CCGT power plants to cycle at low loads overnight instead of completely shutting down.
- Its costs range between $500 and $500K.
- It is available for new plants and as a retrofit for existing plants.

****

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EXHIBIT 5

ALAMEDA COUNTY HEALTH CARE SERVICES AGENCY
PUBLIC HEALTH DEPARTMENT

David J. Kears, Director
Anthony Iton, Director & Health Officer

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Oakland, CA 94607

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"RACE, CLASS, AND THE PATTERNS OF DISEASE DISTRIBUTION IN HAYWARD: DECISION-MAKING THAT REINFORCES HEALTH INEQUITY"

Testimony of Sandra Witt, DrPH, Director of Planning, Policy and Health Equity for the Alameda County Public Health Department

My name is Dr. Sandra Witt, Deputy Director of Planning, Policy and Health Equity for the Alameda County Public Health Department. For the last 7 years, I have directed the Community Assessment, Planning, Evaluation and Education Unit of the Public Health Department. This Unit includes 8 epidemiologists and is responsible for monitoring the health status of all County residents. Over the past 3 years we have produced over 14 technical reports analyzing data from a variety of sources including mortality, births, hospitalizations, health survey data, communicable disease, and census data to identify broad areas of health concern and to monitor the health of our residents, particularly the most socially and economically vulnerable populations in our County. Several of these reports are cited as scientific evidence in the Eastshore Energy Center staff report.

"A condition of environmental justice exists when environmental risks and hazards and investments and benefits are equally distributed with a lack of discrimination, whether direct or indirect, at any jurisdictional level; and when access to environmental investments, benefits, and natural resources are equally distributed; and when access to information, participation in decision making, and access to justice in environment-related matters are enjoyed by all." [1]

In monitoring and analyzing health outcomes for Alameda County residents, one resounding theme stands out: poor health and premature death are by no means randomly distributed in Alameda County. Low-income communities and communities of color in certain specific geographic neighborhoods suffer from substantially worse health outcomes and die earlier. Studies reveal that these inequitable health outcomes are not adequately explained by genetics, access to health care, or risk behaviors, but instead are to a large extent the result of profoundly adverse social and environmental conditions. These adverse environmental conditions are too often an indelible reflection of the way decision-making power is shared with low-income communities.[2] Historical exclusion from decision-making venues has resulted in communities of

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[1] European Workshop on Environmental Justice (Budapest, December 2003)
[2] Marmot MG and Wilkinson R, eds. 2003. *Social Determinants of Health: The Solid Facts, 2nd ed.* World Health Organization Regional Office for Europe, Copenhagen, Denmark.
Sampson, RJ. "The neighborhood context of well-being." *Perspectives in Biology and Medicine*; Summer 2003; 46(3):S53.

EXHIBIT 6

color and low-income communities that are disproportionately burdened by an abundance of environmental hazards, including toxin-emitting power plants and other sources of noxious pollution. It is incumbent upon public health officials to analyze health data to validate pro-equity policies that will lower the disproportionate burden of pollution and improve health outcomes among all populations.

1. **Illness and Death from Air Pollution Associated Conditions is Already Disproportionately Concentrated in the area of Hayward that is in Proximity to the Proposed Power Plant**

An environmental justice framework requires examination of the specific impacts of the project on low-income communities and communities of color. In its cursory three-page Final Staff Assessment, the California Energy Commission (CEC) concludes that Eastshore Power Plant project will not contribute significantly to morbidity or mortality in any race or ethnic group residing in the project area, and therefore would not have a disproportional impact on an environmental justice population. However, this seemingly blythe conclusion neglects consideration of published and publicly-accessible Alameda County Public Health Department evidence of the geographic distribution of disease in the area of Hayward within proximity to the proposed power plant site.

In its environmental justice examination, the CEC staff also fail to reference any analysis of the existing burden of toxic pollution in the area of the proposed power plant site and thus effectively ignore the compounding effects of various sources of toxicity (including non-airborne sources) to which residents in the surrounding Hayward community are already exposed. When these two points are appropriately examined, as they are below, it becomes inescapably clear that by approving the Eastshore Power Plant at 25101 Clawiter Road, nearby predominantly low-income communities of color, disproportionately burdened by exposure to environmental toxicity and suffering from higher rates of premature death and chronic diseases known to be exacerbated by air pollution, the California Energy Commission is running the risk of exacerbating conditions that are fundamentally the legacy of discrimination.

- **Hayward is more ethnically diverse than Alameda County**

The City of Hayward is home to a significantly larger non-white population than Alameda County as a whole. Over one-third (34.2%) of Hayward residents are Latino compared to 19.0% countywide, and the proportion of Latino residents is even higher within a three-mile radius of the proposed plant (37.8%). Additionally, Hayward is comprised of 10.6% African Americans, 18.7% Asians, and 29.2% White. In Alameda County, Whites make up 40.9% of the population.

- **Within three miles of the proposed site are several high poverty, high minority, low life expectancy census block groups**

Overall, 10.0% of Hayward residents live in poverty, a slightly lower percentage than the 11.0% countywide. And within a three-mile radius of the proposed plant, 10.4% of residents live in poverty. However, within this three-mile radius, there are three low-income census block groups where at least 20% of residents live in poverty and 80% are non-white (see map in attachments).

The mortality rate within these three block groups was 50% higher in 1999-2001 than the rate of the remaining block groups in the three-mile radius of the proposed plant site: 1,328 per 100,000 compared to 865 per 100,000. In addition, the life expectancy at birth in these three block groups was 73.3 years, five years less than the 78.3 years observed countywide. These three low-income areas also receive a high level of Public Health Department services (see map in attachments).

- **Death rates from air-pollution associated diseases are substantially higher in the three mile radius around the proposed site**

There are numerous scientific studies that document the relationship between air pollution and human disease.[3] Common acute non-cancer health effects include asthma, chronic obstructive pulmonary disease, and cardiovascular disease, particularly congestive heart failure. The exacerbation of these existing chronic conditions result in unnecessary morbidity, missed work days, preventable hospitalizations, and premature death. A disproportionate burden of the cost of these preventable hospitalizations, particularly among the uninsured, is borne by Alameda County government.

In order to examine mortality from specific causes, death rates within the three-mile radius around the proposed site were compared to Alameda County rates (combining the low-income block groups with the other block groups in the radius). Rates of death from all causes, coronary heart disease, and chronic lower respiratory disease were all significantly higher within the three-mile radius than those rates for Alameda County, representing an ongoing excess burden of mortality (see attached tables).

The rate of death from all causes within the three-mile radius was 888.4 per 100,000 from 1999 to 2001, statistically significantly higher than the county rate of 792.3 per 100,000. Similarly, the rate of death from chronic lower respiratory diseases was 54.8 per 100,000 within the three-mile radius, significantly higher (by 43%) than the county rate of 38.4. And finally, the coronary heart disease death rate was 216.4 per 100,000 within the three-mile radius, also significantly higher than the county rate of 185.7 per 100,000.

- **Hospitalization due to air pollution associated diseases is substantially higher in the zip codes close to the proposed site**

In order to examine measures of illness (morbidity as opposed to mortality) in the area of the proposed plant, rates of hospitalization for specific diseases in the combined zip codes, 94544 and 94545, were compared to Alameda County rates. From 2003 to 2005, the hospitalization rate for coronary heart disease in the two zip codes was 810.4 per 100,000 people, 60% higher than the county rate of 507.5 per 100,000. Similarly, the rate of chronic obstructive pulmonary disease

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[3] Epidemiology of chronic obstructive pulmonary disease: health effects of air pollution. Viegi G, Maio S, Pistelli F, Baldacci S, Carrozzi L, *Respirology.* 2006 Sep;11(5):523-32.
Particulate air pollution and hospital admissions for congestive heart failure in seven United States cities. Wellenius GA, Schwartz J, Mittleman MA. *Am J Cardiol.* 2006 Feb 1;97(3):404-8.
Identifying subgroups of the general population that may be susceptible to short-term increases in particulate air pollution: a time-series study in Montreal, Quebec. Goldberg MS, Bailar JC 3rd, Burnett RT, Brook JR, Tamblyn R, Bonvalot Y, Ernst P, Flegel KM, Singh RK, Valois MF. *Res Rep Health Eff Inst.* 2000 Oct;(97):7-113; discussion 115-20.
Identification of persons with cardiorespiratory conditions who are at risk of dying from the acute effects of ambient air particles. Goldberg MS, Burnett RT, Bailar JC 3rd, Tamblyn R, Ernst P, Flegel K, Brook J, Bonvalot Y, Singh R, Valois MF, Vincent R. *Environ Health Perspect.* 2001 Aug;109 Suppl 4:487-94

(COPD) hospitalization was 316.2 per 100,000 in the two zip codes, 20% higher than the county rate of 264.3. For congestive heart failure the hospitalization rate in the two zip codes was 397.7 per 100,000, 35% higher than the county rate of 295.3. Finally, the asthma hospitalization rate was 179.8 per 100,000, 14% higher than the county rate of 157.3.

All of these differences between the area of the proposed site and Alameda County as a background or reference were found to be statistically significant, which means they did not occur by chance. Based on Census 2000, the population of the two zip codes, as well as Hayward, had an age composition very similar to that for Alameda County—about one-fourth of the population was under age 18 and ten percent was over age 65. Thus the fact that rates of illnesses due to respiratory and circulatory system diseases (most often diseases of the elderly) are significantly higher in the proposed plant area than in the rest of the county suggests a level of vulnerability in this population that is not explained by age.

An environmental justice approach requires an analysis of the relative burden of disease in the population most directly affected by the decision to site this power plant. The presence of a disproportionate concentration of persons with asthma, chronic lung disease, congestive heart failure, and other chronic conditions that are exacerbated by air pollution must factor into the decision of where to site this power plant. These populations are the actual "sensitive receptors" referred to in the *Air Toxics Hot Spots Program Risk Assessment Guidelines*.[2] They are not distributed through the population randomly but instead are concentrated disproportionately in proximity to the proposed Hayward site. Siting the Eastshore Power Plant in Hayward will disproportionately impact a geographic area not only home to a comparatively high non-white population, but also already burdened by existing poor health outcomes.

2. **The CEC environmental justice analysis does not adequately factor in the uneven distribution of exposure to various sources of toxicity in the area in proximity to the proposed power plant site**

In its environmental justice examination, the CEC staff fail to reference any analysis of the existing burden of toxic pollution in the area of the proposed power plant site and effectively ignore the compounding effects of various sources of toxicity (including non-airborne sources) to which residents in the surrounding Hayward community are already exposed. CEC staff rely on established risk assessment models to predict health impacts from the proposed power plant. However, there is substantial uncertainty associated with the process of risk assessment. The uncertainty arises from lack of "real world" data in many areas necessitating a heavy reliance upon experimental animal models and a set of basic assumptions. Among the key assumptions underlying the health risk assessment are[4]:

1. Human toxicity from air pollution is additive rather than synergistic.
2. Animal toxicity data can be readily extrapolated to humans.

- **Human disease due to exposure to multiple toxic pollutants may be synergistic**

[4] Air Toxics Hot Spots Program Risk Assessment Guidelines. *The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments.* August 2003. California EPA.

The potential for multiple and varied air pollutants to act synergistically, rather than additively as assumed by the CEC health risk assessment, requires that an analysis of the overall toxic burden associated with this Hayward location be performed. Low-income minority populations have historically been exposed to a much higher burden of environmental toxicity. The brief CEC environmental justice analysis does not quantify or otherwise assess the cumulative burden of toxicity in the vicinity of the proposed site.

- **Animal toxicity data may be a poor proxy for human health effects**

There are very few in vivo studies that are designed to establish a safe threshold for human exposure to air pollution, in fact, a recent study by Harvard cardiovascular researchers looking at seven U.S. cities documents a direct association between particulate air pollution and acute hospitalizations for congestive heart failures.[5] *This effect is seen below the current levels set by US EPA.* Relative exposure limits established in animal models must be interpreted with a great deal of caution when deciding whether new sources of pollution should be sited in low income minority communities.

- **Detailed, publicly available and published data exists with which CEC staff could conduct a more complete and appropriate environmental justice analysis**

Alameda County Public Health Department maintains and publishes detailed age- and race-specific geographic morbidity and mortality data on asthma, chronic obstructive pulmonary disease, cardiovascular disease, and lung cancer for the county, the city of Hayward and for smaller geographic areas including zip code and census tract. CEC staff did not contact Alameda County Public Health Department to obtain critical data on chronic obstructive pulmonary disease, cardiovascular disease, or congestive heart failure. CEC staff did cite Alameda County Public Health Department data on asthma in its public health section, however, the CEC staff report ignores data related to these other serious respiratory and cardiovascular conditions that are known to be associated with ambient air pollution and help more fully characterize the vulnerability of the population residing in the shadow of this proposed site.

"An environmental injustice exists when members of disadvantaged, ethnic, minority or other groups suffer disproportionately at the local, regional (sub-national), or national levels from environmental risks or hazards, and/or suffer disproportionately from violations of fundamental human rights as a result of environmental factors, and/or denied access to environmental investments, benefits, and/or natural resources, and/or are denied access to information; and/or participation in decision making; and/or access to justice in environment-related matters."[6] The CEC staff analysis largely ignores profoundly important questions of environmental justice and in so doing contributes to the unfortunate and widely repudiated legacy of racial and class-based discrimination that continues to shape the pattern and burden of disease that compromise the quality of life of residents in the vicinity of the proposed power plant site. Alameda County Public Health Department strongly opposes decision-making based on such an inadequate analysis of critical environmental justice considerations.

[5] Particulate air pollution and hospital admissions for congestive heart failure in seven United States cities. Wellenius GA, Schwartz J, Mittleman MA. *Am J Cardiol.* 2006 Feb 1;97(3):404-8.
[6] European Workshop on Environmental Justice (Budapest, December 2003)

Attachments

Mortality rates, 1999-2001
Within a 3-mile radius of proposed site with Alameda County comparisons

Cause of Death	Area	3-Yr Count	Rate**	
All Causes	3 Mile Radius	2,492	888.4	*
	Alameda County	29,525	792.3	
Chronic Lower Respiratory Disease	3 Mile Radius	155	54.8	*
	Alameda County	1,387	38.4	
Coronary Heart Disease	3 Mile Radius	589	216.4	*
	Alameda County	6,769	185.7	

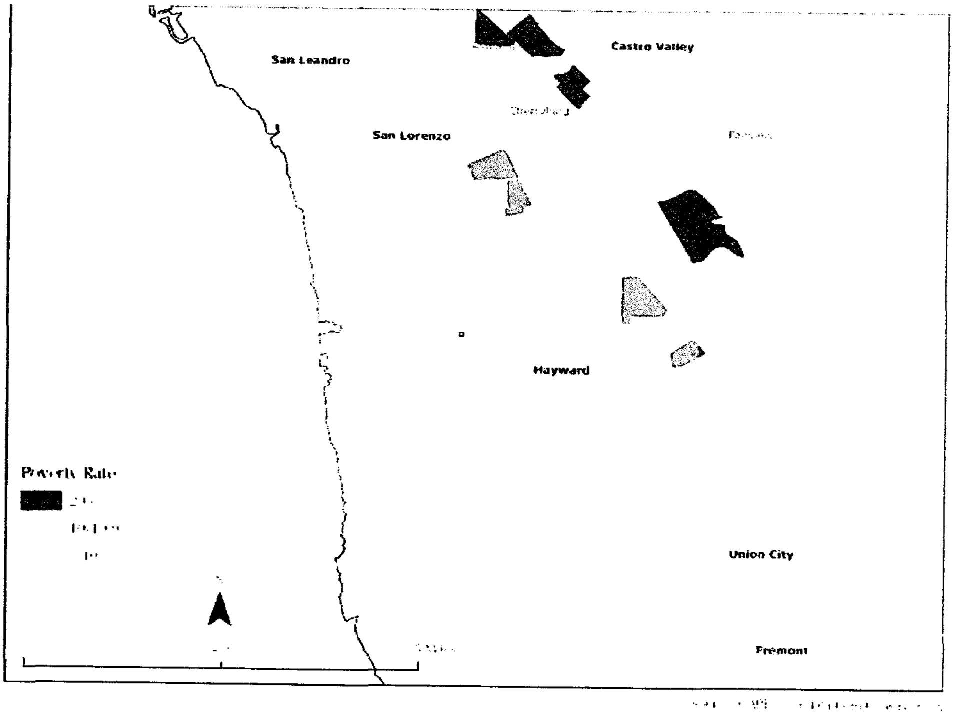
*Statistically significant difference at the p<=.05 level.
**Rates are age adjusted by the direct method to the 2000 US standard population.

Hospitalization Rates, 2003-2005
94544 and 94545 combined with Alameda County comparisons

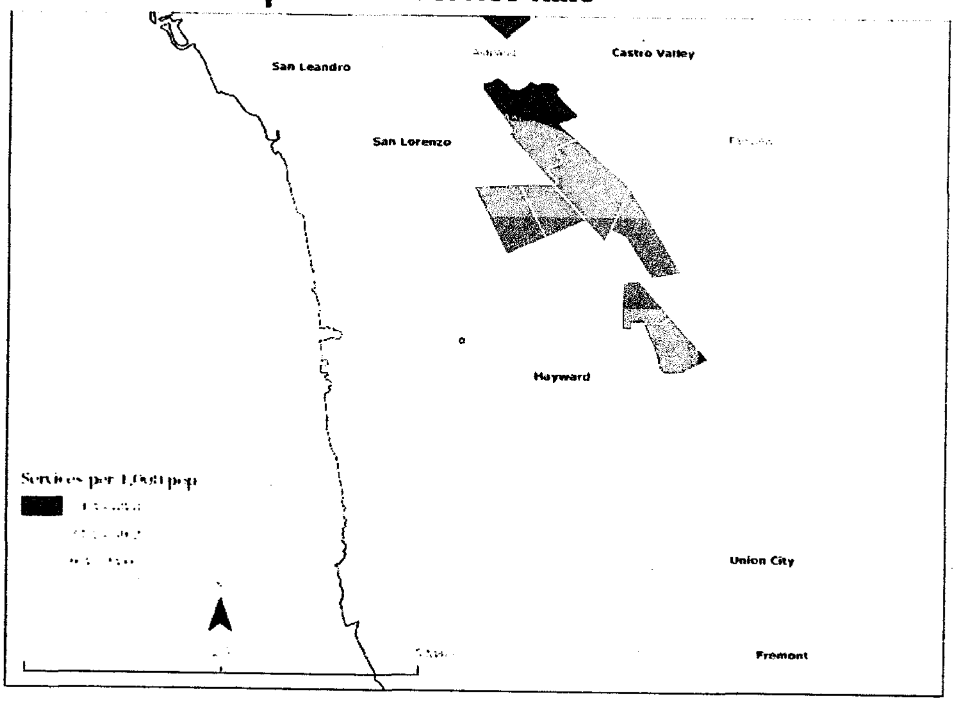
Primary Diagnosis	Area	3-Yr Count	Rate**	
Coronary Heart Disease	94544 & 94545	2,133	810.4	*
	Alameda County	20,780	507.5	
Chronic Obstructive Pulmonary Disease	94544 & 94545	891	316.2	*
	Alameda County	11,116	264.3	
Congestive Heart Failure	94544 & 94545	1,024	397.7	*
	Alameda County	11,914	295.3	
Asthma	94544 & 94545	531	179.8	*
	Alameda County	6,792	157.3	

*Statistically significant difference at the p<=.05 level.
**Rates are age adjusted by the direct method to the 2000 US standard population.

Poverty Rate



Public Health Department Service Rate



Dec. 1, 2000

MEMORANDUM

SUBJECT: EPA Statutory and Regulatory Authorities Under Which Environmental Justice Issues May Be Addressed in Permitting

FROM: Gary S. Guzy *//signed//*
General Counsel
Office of General Counsel (2310A)

TO: Steven A. Herman
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This memorandum analyzes a significant number of statutory and regulatory authorities under the Resource Conservation and Recovery Act, the Clean Water Act, the Safe Drinking Water Act, the Marine Protection, Research, and Sanctuaries Act, and the Clean Air Act that the Office of General Counsel believes are available to address environmental justice issues during permitting. The use of EPA's statutory authorities, as discussed herein, may in some cases involve new legal and policy interpretations that could require further Agency regulatory or interpretive action. Although the memorandum presents interpretations of EPA's statutory authority and regulations that we believe are legally permissible, it does not suggest that such actions would be uniformly practical or feasible given policy or resource considerations or that there are not important considerations of legal risk that would need to be evaluated. Nor do we assess the relative priority among these various avenues for addressing environmental justice concerns. We look forward to working with all your offices to explore these matters in greater detail.

EXHIBIT 7

I. Resource Conservation and Recovery Act (RCRA)

RCRA authorizes EPA to regulate the generation, transportation, treatment, storage, and disposal of hazardous wastes and the management and disposal of solid waste. EPA issues guidelines and recommendations to State solid waste permitting programs under RCRA sections 1008(a), 4002, or 4004 and may employ this vehicle to address environmental justice concerns. The primary area where environmental justice issues have surfaced, however, is in the permitting of hazardous waste treatment, storage, and disposal facilities (e.g., incinerators, fuel blenders, landfills). Pursuant to RCRA section 3005, EPA is authorized to grant permits to such facilities if they demonstrate compliance with EPA regulations.

Upon application by a State, EPA may authorize a State's hazardous waste program to operate in lieu of the Federal program, and to issue and enforce permits. The State's program must be equivalent to the Federal program to obtain and retain authorization. When EPA adopts more stringent RCRA regulations (including permit requirements), authorized States are required to revise their programs within one year after the change in the Federal program or within two years if the change will necessitate a State statutory amendment. 40 CFR § 271.21(e). EPA and most authorized States have so-called "permit shield" regulations, providing that, once a facility obtains a hazardous waste permit, it generally cannot be compelled to comply with additional requirements during the permit's term.

The scope of EPA's authority to address environmental justice issues in RCRA hazardous waste permits was directly addressed by the Environmental Appeals Board (EAB) in Chemical Waste Management, Inc., 6 E.A.D. 66, 1995 WL 395962 (1995) <**http://www.epa.gov/eab/disk11/cwmii.pdf**>The Board found "that when the Region has a basis to believe that operation of the facility may have a disproportionate impact on a minority or low-income segment of the affected community, the Region should, as a matter of policy, exercise its discretion to assure early and ongoing opportunities for public involvement in the permitting process." Id. at 73. It also found that RCRA allows the Agency to "tak[e] a more refined look at its health and environmental impacts assessment in light of allegations that operation of the facility would have a disproportionately adverse effect on the health or environment of low-income or minority populations." Id. at 74. Such a close evaluation could, in turn, justify permit conditions or denials based on disproportionately high and adverse human health or environmental effects, while "a broad analysis might mask the effects of the facility on a disparately affected minority or low-income segment of the community." Id. However, while acknowledging the relevance of disparities in health and environmental impacts, the Board also cautioned that "there is no legal basis for rejecting a RCRA permit application based solely upon alleged social or economic impacts upon the community." Id. at 73.

Consistent with this interpretation, there are several RCRA authorities under which EPA could address environmental justice issues in permitting:

A. **Hazardous Waste Treatment, Storage and Disposal**

1. RCRA section 3005(c)(3) provides that "[e]ach permit issued under this section shall contain such terms and conditions as the Administrator (or the State) determines necessary to protect human health and the environment." EPA has interpreted this provision to authorize denial of a permit to a facility if EPA determines that operation of the facility would pose an unacceptable risk to human health and the environment and that there are no additional permit terms or conditions that would address such risk. This "omnibus" authority may be applicable on a permit-by-permit basis where appropriate to address the following health concerns in connection with hazardous waste management facilities that may affect low-income communities or minority communities:

a. Cumulative risks due to exposure from pollution sources in addition to the applicant facility;

b. Unique exposure pathways and scenarios (e.g., subsistence fishers, farming communities); or

c. Sensitive populations (e.g., children with levels of lead in their blood, individuals with poor diets).

2. RCRA section 3013 provides that if the Administrator determines that "the presence of any hazardous waste at a facility or site at which hazardous waste is, or has been, stored, treated, or disposed of, or the release of any such waste from such facility or site may present a substantial hazard to human health or the environment," she may order a facility owner or operator to conduct reasonable monitoring, testing, analysis, and reporting to ascertain the nature and extent of such hazard. EPA may require a permittee or an applicant to submit information to establish permit conditions necessary to protect human health and the environment. 40 CFR § 270.10(k). In appropriate circumstances, EPA could use the authority under section 3013 or 40 CFR § 270.10(k) to compel a facility owner or operator to carry out necessary studies, so that, pursuant to the "omnibus" authority, EPA can establish permit terms or conditions necessary to protect human health and the environment.

3. RCRA provides EPA with authority to consider environmental justice issues in establishing priorities for facilities under RCRA section 3005(e), and for facilities engaged in cleaning up contaminated areas under the RCRA corrective action program, RCRA sections 3004(u), 3004(v), and 3008(h). For example, EPA could consider factors such as cumulative risk, unique exposure pathways, or sensitive populations in establishing permitting or clean-up priorities.

4. EPA adopted the "RCRA Expanded Public Participation" rule on December 11, 1995. See 60 Fed. Reg. 63417. RCRA authorizes EPA to explore further whether the RCRA

permit public participation process could better address environmental justice concerns by expanding public participation in the permitting process (including at hazardous waste management facilities to be located in or near low-income communities or minority communities).

5. In expanding the public participation procedures applicable to RCRA facilities, EPA also would have authority to expand the application of those procedures to the permitting of: (a) publicly owned treatment works, which are regulated under the Clean Water Act; (b) underground injection wells, which are regulated under the Safe Drinking Water Act; and (c) ocean disposal barges or vessels, which are regulated under the Marine Protection Research and Sanctuaries Act. These facilities are subject to RCRA's permit by rule regulations, 40 CFR § 270.60, and are deemed to have a RCRA permit if they meet certain conditions set out in the regulations. 40 CFR § 270.60.

6. EPA's review of State-issued permits provides additional opportunities for consideration of environmental justice concerns. Where the process for a State-issued permit does not adequately address sensitive population risks or other factors in violation of the authorized State program, under the regulations EPA could provide comments on these factors (in appropriate cases) during the comment period on the State's proposed permit on a facility-by-facility basis. 40 CFR § 271.19(a). Where the State itself is authorized for RCRA "omnibus" authority and does not address factors identified in EPA comments as necessary to protect human health and the environment, EPA may seek to enforce the authorized State program requirement. 40 CFR § 271.19(e) Alternatively, if the State is not authorized for "omnibus" authority, EPA may superimpose any necessary additional conditions under the "omnibus" authority in the federal portion of the permit. These conditions become part of the facility's RCRA permit and are enforceable by the United States under RCRA section 3008 and citizens through RCRA section 7002.

7. RCRA section 3019 provides EPA with authority to increase requirements for applicants for land disposal permits to provide exposure information and to request that the Agency for Toxic Substances and Disease Registry conduct health assessments at such land disposal facilities.

8. RCRA section 3004(o)(7) provides EPA with authority to issue location standards as necessary to protect human health and the environment. Using this authority, EPA could, for example, establish minimum buffer zones between hazardous waste management facilities and sensitive areas (e.g., schools, areas already with several hazardous waste management facilities, residential areas). Facilities seeking permits would need to comply with these requirements to receive a permit.

9. RCRA-permitted facilities are required under RCRA section 3004(a) to maintain "contingency plans for effective action to minimize unanticipated damage from any treatment, storage, or disposal of . . . hazardous waste." Under this authority, EPA could require facilities to prepare and/or modify their contingency plans to reflect the needs of

environmental justice communities that have limited resources to prepare and/or respond to emergency situations.

10. RCRA additionally provides EPA with authority to amend its regulations to incorporate some of the options described in 1 through 6 above so they become part of the more stringent federal program that authorized States must adopt.

II. Clean Water Act (CWA)

The CWA was adopted "to restore and maintain the chemical, physical, and biological integrity of the Nation's waters." To achieve this goal, Congress prohibited the discharge from a point source of any pollutant into a water of the United States unless that discharge complies with specific requirements of the Act. Compliance is achieved by obtaining and adhering to the terms of an NPDES permit issued by EPA or an authorized State pursuant to section 402, or a dredge and fill permit issued by the Army Corps of Engineers or an authorized State pursuant to section 404.

NPDES permits must contain: (1) technology-based limitations that reflect the pollution reduction achieved through particular equipment or process changes, without reference to the effect on the receiving water and (2) where necessary, more stringent limitations representing that level of control necessary to ensure that the receiving waters achieve water quality standards. Water quality standards consist of (1) designated uses of the water (e.g., public water supply, propagation of fish, or recreation); (2) criteria to protect those uses including criteria based on protecting human health and aquatic life; and (3) an antidegradation policy. EPA requires that States designate all waters for "fishable/swimmable" uses unless such uses are not attainable. EPA issues water quality criteria guidance to the States pursuant to CWA section 304(a).

Permits issued under CWA section 404 authorize the discharge of "dredged or fill material" to waters of the United States. The types of activities regulated under section 404 include filling of wetlands to create dry land for development, construction of berms or dams to create water impoundments, and discharges of material dredged from waterways to maintain or improve navigation. Section 404 permits issued by the Corps of Engineers must satisfy two sets of standards: the Corps' "public interest review" and the section 404(b)(1) guidelines promulgated by EPA. The public interest review is a balancing test that requires the Corps to consider a number of factors, including economics, fish and wildlife values, safety, food and fiber production and, public needs and welfare in general. 33 CFR § 320.4(a). The section 404(b)(1) guidelines provide that no permit shall issue if: (1) there are practicable, environmentally less damaging alternatives, (2) the discharge would violate water quality standards or jeopardize threatened or endangered species, (3) the discharge would cause significant degradation to the aquatic ecosystem, or (4) if all reasonable steps have not been taken to minimize adverse effects of the discharge. 40 CFR § 230.10.

There are several CWA authorities under which EPA could address environmental justice issues in permitting:

A. State Water Quality Standards

States are required to review their water quality standards every three years and to submit the results of their review to EPA. CWA section 303(c)(1). EPA Regional offices must approve or disapprove all new or revised State water quality standards pursuant to section 303(c)(3). EPA will approve State standards if they are scientifically defensible and protective of designated uses. 40 CFR § 131.11. If a State does not revise a disapproved standard, EPA is required to propose and promulgate a revised standard for the State. Section 303(c)(4)(A). The Administrator is also required to propose and promulgate a new or revised standard for a State whenever she determines that such a standard is necessary to meet the requirements of the Act and the State does not act to adopt an appropriate standard. CWA section 303(c)(4)(B).

1. State water quality standards currently are required to provide for the protection of "existing uses." 40 CFR § 131.12(a)(1). These are defined as uses actually attained in the water body on or after November 28, 1975. 40 CFR § 131.3(e). To the extent that minority or low-income populations are, or at any time since 1975 have been, using the waters for recreational or subsistence fishing, EPA could reinterpret the current regulations to require that such uses, if actually attained, must be maintained and protected. The CWA provides EPA with authority to require, through appropriate means, that high rates of fish consumption by these populations be considered an "existing use" to be protected by State water quality standards. Under the current regulations, existing uses cannot be removed.

2. EPA regulations provide that all waters must be designated for the protection and propagation of fish, shellfish, and wildlife and for recreation in and on the water ("fishable/swimmable") unless the State documents to EPA's satisfaction that such uses are not attainable. 40 CFR §§ 131.6(a), 131.10(j).

   EPA interprets "fishable" uses under section 101(a) of the CWA to include, at a minimum, designated uses providing for the protection of aquatic communities and human health related to consumption of fish and shellfish. In other words, EPA views "fishable" to mean that not only can fish and shellfish thrive in a waterbody, but when caught, can also be safely eaten by humans (stated in 10/24/00 "Dear Colleague" letter from Geoffrey H. Grubbs, Director Office of Science and Technology, and Robert H. Wayland, III, Director Office of Wetlands, Oceans and Watersheds). Therefore, EPA currently recommends that in setting criteria to protect "fishable" uses, that the State/Tribe adjust the fish consumption values used to develop criteria to protect the "fishable" use, including fish consumption by subsistence fishers (USEPA 2000, Methodology for Deriving Ambient Water Quality Criteria for the Protection of Human Health, EPA-822-B-00-004, Chapter 2.1). For example, in deriving such criteria, states or tribes could select their fish consumption value based on site-specific information or a national default value for subsistence fishing (Chapter 4).

In the future, EPA could reinterpret it regulations to mean that any human health use must have a criterion that would protect consumption by subsistence fishers unless there is a showing that water is not used for subsistence fishing.

3. The CWA provides EPA with authority to recommend that State CWA section 303(c)(1) triennial reviews of water quality standards consider the extent to which State criteria provide for protection of human health where there exists subsistence fishing. EPA Regional offices may disapprove a criterion that does not provide protection to highly-exposed populations. The Administrator further has the discretionary authority to determine that such criteria are necessary to meet the requirements of the CWA and then must promptly propose and promulgate such criteria.

4. Consistent with CWA section 101(e), EPA could encourage States to improve public participation processes in the development of State water quality standards through greater outreach and by translating notices for limited English speaking populations consistent with Executive Order 12898 on environmental justice.

B. Issuance of NPDES Permits

1. Assuming EPA adopts the interpretation described in paragraph A.1., above, NPDES permits issued for discharge to waters where a high level of fish consumption is an "existing use" should contain limitations appropriate to protect that use. The CWA provides EPA authority to take this approach when it issues NPDES permits in States not authorized to run the NPDES program, and to object to or ultimately veto State-issued permits that are not based on these considerations. CWA section 402(d).

2. Consistent with CWA section 101(e), where EPA issues NPDES permits, environmental justice concerns can also be taken into account in setting permitting priorities and improving public participation in the permitting process (greater outreach to minority communities and low-income communities including translating notices for limited English speaking populations consistent with Executive Order 12898 on environmental justice).

3. CWA section 302 authorizes EPA to propose and adopt effluent limitations for one or more point sources if the applicable technology-based or water quality-based requirements will not assure protection of public health and other concerns. This determination requires findings of economic capability and a reasonable relationship between costs and benefits. The Agency has never used this authority, but could evaluate whether this authority could be used with respect to pollutants of concern to minorities or

low-income communities. Prior to adopting such limitations by regulation, EPA could use its authority under CWA section 402(a)(1) to incorporate such limitations in specific NPDES permits issued by EPA. The Clean Water Act does not appear to provide any general authority to impose conditions on or deny permits based on environmental justice considerations that are unconnected to water quality impacts or technology-based limitations.

4. Pursuant to CWA section 104 and other authorities, EPA may provide technical assistance to Indian Tribes, where appropriate, in the development of water quality standards and the issuance of NPDES permits.

C. CWA Section 404

1. The broadest potential authority to consider environmental justice concerns in the CWA section 404 program rests with the Corps of Engineers, which conducts a broad "public interest review" in determining whether to issue a section 404 permit. In evaluating the "probable impacts . . . of the proposed activity and its intended use on the public interest," the Corps is authorized to consider, among other things, aesthetics, general environmental concerns, safety, and the needs and welfare of the people. 33 CFR § 320.4(a). This public interest review could include environmental justice concerns.

2. EPA has discretionary oversight authority over the Corps' administration of the section 404 program (i.e., EPA comments on permit applications, can elevate Corps permit decisions to the Washington, D.C. level, and can "veto" Corps permit decisions under section 404(c) that would have an unacceptable adverse effect on "municipal water supplies, shellfish beds and fishery areas, wildlife, or recreational areas"). The CWA thus authorizes EPA to use these authorities to prevent degradation of these public resources that may have a disproportionately high and adverse health or environmental effect on a minority community or low-income community. Such effects can be addressed when they result directly from a discharge of dredged or fill material (e.g., the filling of a waterbody), or are the indirect result of the permitted activity (e.g., the fill will allow construction of an industrial facility that will cause water pollution due to runoff).

III. Safe Drinking Water Act (SDWA)

The SDWA includes two separate regulatory programs. The Public Water Supply program establishes requirements for the quality of drinking water supplied by public water systems. This program contains no federal permitting. The Underground Injection Control (UIC) program establishes controls on the underground injection of fluids to protect underground sources of drinking water.

Under the UIC program, the Administrator must establish requirements for State UIC programs that will prevent the endangerment of drinking water sources by underground injection.

EPA has promulgated a series of such requirements beginning in 1980. The SDWA also provides that States may apply to EPA for primary responsibility to administer the UIC program. EPA must establish a UIC permitting program in States that do not seek this responsibility or that fail to meet the minimum requirements established by EPA.

There are several SDWA authorities under which EPA could address environmental justice issues in UIC permitting:

A. EPA-issued Permits

Underground injection must be authorized by permit or rule. The SDWA provides that EPA can deny or establish permit limits where such injection may "endanger" public health. "Endangerment" is defined to include any injection that may result in the presence of a contaminant in a drinking water supply that "may...adversely affect the health of persons." 40 CFR § 144.52(b)(1). As a result, in those States where EPA issues permits and an injection activity poses a special health risk to minority or low-income populations, the SDWA provides EPA with authority to establish special permit requirements to address the endangerment or deny the permit if the endangerment cannot otherwise be eliminated. As in its Chemical Waste Management RCRA permit appeal decision discussed in Part I above, the EAB has addressed EPA's authority to expand public participation and to consider disproportionate impacts in the UIC permitting program. Envotech, 6 E.A.D. 260, 281, 1996 WL 66307 (1996) <http://www.epa.gov/eab/disk10/envotech.pdf>.

B. Pending regulatory action

The Office of Water is currently revising the regulations under this program governing "Class V" injection wells (i.e., shallow wells where nonhazardous waste is injected). In determining which wells to regulate and the standards for those where EPA determines regulations are necessary to prevent "endangerment," the SDWA provides EPA with authority to take into account environmental justice issues such as cumulative risk and sensitive populations.

C. Other regulatory actions

Likewise, the SDWA provides EPA with authority to address environmental justice issues related to potential endangerment of drinking water supplies by injection for all types of wells. For example, EPA could revise its regulatory requirements for siting Class 1 (hazardous waste) wells to address cumulative risk and other risk-related environmental justice issues.

IV. Marine Protection, Research, and Sanctuaries Act (MPRSA)

The MPRSA, commonly known as the Ocean Dumping Act, 33 USC § 1401 ff., establishes a permitting program that covers the dumping of material into ocean waters. The ocean disposal of a variety of materials, including sewage sludge, industrial waste, chemical and biological warfare agents, and high level radioactive waste, is expressly prohibited.

EPA issues permits for the dumping of all material other than dredged material. 33 U.S.C. § 1412(a). The Army Corps of Engineers issues permits for the dumping of dredged material, subject to EPA review and concurrence. 33 U.S.C. § 1413(a). (As a practical matter, EPA issues very few ocean dumping permits because the vast majority of material disposed of at sea is dredged material.) EPA also is charged with designating sites at which permitted disposal may take place; these sites are to be located wherever feasible beyond the edge of the Continental Shelf. 33 U.S.C. § 1412(c)(1).

When issuing MPRSA permits and designating ocean dumping sites, EPA is to determine whether the proposed dumping will "unreasonably degrade or endanger human health, welfare, amenities, or the marine environment, ecological systems, or economic potentialities." 33 USC § 1412(a), (c)(1). EPA also is to take into account "the effect of... dumping on human health and welfare, including economic, esthetic, and recreational values." 33 U.S.C. § 1412(a)(B), (c)(1). Thus, in permitting and site designation, EPA has ample authority to consider such factors as impacts on minority or low-income communities and on subsistence consumers of sea food that would result from the proposed dumping. In addition, the MPRSA provides specifically that EPA is to consider land-based alternatives to ocean dumping and the probable impact of requiring use of these alternatives "upon considerations affecting the public interest." 33 U.S.C. § 1412(a)(G). This authorizes EPA to take impacts on minority populations or low-income populations into account in evaluating alternative locations and methods of disposal of the material that is proposed to be dumped at sea.

V. Clean Air Act (CAA)

There are several CAA authorities under which EPA could address environmental justice issues in permitting:

A. New Source Review (NSR)

NSR is a preconstruction permitting program. If new construction or making a major modification will increase emissions by an amount large enough to trigger NSR requirements, then the source must obtain a permit before it can begin construction. The NSR provisions are set forth in sections 110(a)(2)(C), 165(a) (PSD permits), 172(c)(5) and 173 (NSR permits) of the Clean Air Act.

Under the Clean Air Act, states have primary responsibility for issuing permits, and they can customize their NSR programs within the limits of EPA regulations. EPA's role is to approve State programs, to review, comment on, and take any other necessary actions on draft permits, and to assure consistency with EPA's rules, the state's implementation plan, and the Clean Air Act. Citizens also play a role in the permitting decision, and must be afforded an opportunity to comment on each construction permit before it is issued.

The NSR permit program for major sources has two different components–one for areas where the air is dirty or unhealthy, and the other for areas where the air is cleaner. Under the Clean Air Act, geographic areas (e.g., counties or metropolitan statistical areas) are designated as "attainment" or "nonattainment" with the National Ambient Air Quality Standards (NAAQS)–the air quality standards which are set to protect human health and the environment. Permits for sources located in attainment (or unclassifiable) areas are called Prevention of Significant Deterioration (PSD) permits and those for sources located in nonattainment areas are called NSR permits.

A major difference in the two programs is that the control technology requirement is more stringent in nonattainment areas and is called the Lowest Achievable Emission Rate (LAER). On the other hand, in attainment or PSD areas, a source must apply Best Available Control Technology (BACT) and the statute allows the consideration of cost in weighing BACT options. Also, in keeping with the goal of progress toward attaining the national air quality standards, sources in nonattainment areas must always provide or purchase "offsets"–decreases in emissions which compensate for the increases from the new source or modification. In attainment areas, PSD sources typically do not need to obtain offsets. However, PSD does require an air quality modeling analysis of pollution that exceeds allowable levels; this impact must be mitigated. Sometimes, these mitigation measures can include offsets in PSD areas.

1. Under the Clean Air Act, section 173(a)(5) provides that a nonattainment NSR permit may be issued only if: "an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification." For example, this provision authorizes consideration of siting issues. Section 165(a)(2) provides that a PSD permit may be issued only after an opportunity for a public hearing at which the public can appear and provide comment on the proposed source, including "alternatives thereto" and "other appropriate considerations." This authority could allow EPA to take action to address the proper role of environmental justice considerations in PSD/NSR permitting.

2. In addition to these statutory provisions, EPA directly issues PSD/NSR permits in certain situations (e.g., in Indian country and Outer Continental Shelf areas) and, through the EAB, adjudicates appeals of PSD permits issued by States and local districts with delegated federal programs. In such permit and appeal decisions, it is possible to consider environmental justice issues on a case-by-case basis, without waiting to issue a generally applicable rule or guidance document. EPA already considers environmental

justice issues on a case-by-case basis in issuing PSD permits consistent with its legal authority.

3. The EPA Environmental Appeals Board (EAB) has addressed environmental justice issues in connection with PSD permit appeals on several occasions. The EAB first addressed environmental justice issues under the CAA in the original decision in Genessee Power (September 8, 1993). In that decision the EAB stated that the CAA did not allow for consideration of environmental justice and siting issues in air permitting decisions. In response, the Office of General Counsel filed a motion for clarification on behalf of the Office of Air and Radiation (OAR) and Region V. OGC pointed out, among other things, that the CAA requirement to consider alternatives to the proposed source, and the broad statutory definition of "best available control technology" (BACT), provided ample opportunity for consideration of environmental justice in PSD permitting. In an amended opinion and order issued on October 22, 1993, the EAB deleted the controversial language but did not decide whether it is permissible to address environmental justice concerns under the PSD program. 4 E.A.D. 832, 1993 WL 484880, <http://www.epa.gov/eab/disk4/genesee.pdf>. However, in subsequent decisions, Ecoeléctrica, 7 E.A.D. 56, 1997 WL 160751 (1997) <http://www.epa.gov/eab/disk11/ecoelect.pdf>, and Puerto Rico Electric Power Authority, 6 E.A.D. 253, 1995 WL 794466 (1995) <http://www.epa.gov/eab/disk9/prepa.pdf>, the EAB stated that notwithstanding the lack of formal rules or guidance on environmental justice, EPA could address environmental justice issues. In 1999 in Knauf Fiber Glass, 8 E.A.D. PSD Appeal Nos. 98-3 through 98-20, 1999 WL 64235 (Feb. 4, 1999) <http://www.epa.gov/eab/disk11/knauf.pdf>, the EAB remanded a PSD permit to the delegated permitting authority (the Shasta County Air Quality Management District) for failure to provide an environmental justice analysis in the administrative record in response to comments raising the issue.

4. In the 1990 CAA Amendments, Congress provided that the PSD provisions of the Act do not apply to hazardous air pollutants (HAPs), see CAA section 112(b)(6), so the role of hazardous air pollutant impacts as environmental justice issues in PSD permitting is not straightforward. Thus, BACT limits are not required to be set for HAPs in PSD permits. However, the Administrator ruled prior to the 1990 Amendments that in establishing BACT for criteria pollutants, alternative technologies for criteria pollutants could be analyzed based on their relative ability to control emissions of pollutants not directly regulated under PSD. EPA believes that the 1990 Amendments did not change this limited authority, and EPA believes it could be a basis for addressing environmental justice concerns. In addition, EPA may have authority to take into account – and to require States to do so in their PSD permitting – effects of HAPs that are also criteria pollutants, such as VOCs.

B. Title V

Title V of the CAA requires operating permits for stationary sources of air pollutants and prescribes public participation procedures for the issuance, significant modification, and renewal of Title V operating permits. Unlike PSD/NSR permitting, Title V generally does not impose substantive emission control requirements, but rather requires all applicable requirements to be included in the Title V operating permit. Other permitting programs may co-exist under the authority of the CAA, such as those in State implementation plans (SIPs) approved by EPA.

1. Because Title V does not directly impose substantive emission control requirements, it is not clear whether or how EPA could take environmental justice issues into account in Title V permitting – other than to allow public participation to serve as a motivating factor for applying closer scrutiny to a Title V permit's compliance with applicable CAA requirements. EPA believes, however, that in this indirect way, Title V can, by providing significant public participation opportunities, serve as a vehicle by which citizens can address environmental justice concerns that arise under other provisions of the CAA.

2. Under the 40 CFR Part 70/71 permitting process, EPA has exercised its CAA authority to require extensive opportunities for public participation in permitting actions. State permitting authorities also have the flexibility to provide additional public participation.

3. Other permitting processes under the CAA such as SIP permitting programs can include appropriate public participation measures, and these can be used to promote consideration of environmental justice issues. For example, EPA regulations require that "minor NSR programs" in SIPs provide an opportunity for public comment prior to issuance of a permit (40 CFR § 51.161(b)(2)). (Note, however, that many state programs do not at present meet this requirement.)

C. Solid Waste Incinerator Siting Requirements

The CAA provides specific authority to EPA to establish siting requirements for solid waste incinerators that could include consideration of environmental justice issues. CAA section 129(a)(3) provides that standards for new solid waste incinerators include "siting requirements that minimize, on a site specific basis, to the maximum extent practicable, potential risks to public health or the environment." These would be applicable requirements for Title V purposes. The new source performance standards (NSPS) for large municipal waste combustors (40 CFR part 60, subpart Eb) and hospital/medical/infectious waste incinerators (40 CFR part 60, subpart Ec) both currently contain such requirements. In the large municipal waste combustor NSPS, the specific requirement in section 129(a)(3) was incorporated and requirements for public notice, a public meeting and consideration of and response to public comments were added. However, to reduce the burden on the much smaller entities which typically own and operate hospital/medical/infectious waste incinerators, that NSPS only incorporates the specific section 129(a)(3) requirement. EPA is subject to a court ordered deadline for taking final action on NSPS for commercial/industrial waste incinerators, and has proposed to follow the approach to the siting analysis adopted in the hospital/medical/infectious waste NSPS in that rule.

D. 40 CFR Part 71 Tribal Air Rule

The Part 71 federal operating permit rule establishes EPA's Title V operating permits program in Indian country. Where sources are operating within Indian country, and Tribes do not seek authorization to implement Title V programs, the Part 71 rule clarifies that EPA will continue to implement federal operating permit programs. These Title V permit programs are limited to Title V and other applicable federal CAA requirements and are not comprehensive air pollution control programs. Thus, the opportunities for addressing environmental justice issues may be similar to those discussed in section B above.

cc: Michael McCabe
Barry Hill
Lisa Friedman
Susan Lepow
Alan Eckert
James Nelson

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BAY AREA AIR QUALITY MANAGEMENT DISTRICT

RESOLUTION No. 2008- 10

A Resolution of the Board of Directors of the Bay Area Air Quality Management District to Continue Reducing Air Contaminants in Impacted Communities

WHEREAS, it is the intent of the Bay Area Air Quality Management District (District) to achieve clean and healthful air for all who live and work in the Bay Area, including segments of the population that bear disproportionately high and adverse health impacts from air pollution;

WHEREAS, the governing Board of Directors (Board) of the District recognizes that while most criteria and toxic air contaminants have been substantially reduced in the Bay Area, these contaminants continue to pose serious health risks;

WHEREAS, the Board further recognizes that these health risks are not equally distributed throughout the region and that some areas, where pollution levels are higher than others and where residents are particularly vulnerable to the adverse effects of air pollution, are more impacted;

WHEREAS, the Board has expressed its strong commitment to reduce toxic air contaminants in the Bay Area through its creation of the Community Air Risk Evaluation (CARE) program;

WHEREAS, the District has demonstrated its commitment to focus efforts to reduce toxic air contaminants in communities with high emissions and large populations of sensitive people through its implementation of the CARE Mitigation Action Plan that calls for

* Identifying impacted communities
* Focusing grant and incentive funding in impacted communities
* Increasing outreach efforts in impacted communities
* Developing land use guidance for local decision makers
* Updating CEQA guidelines
* Increasing collaboration with public health officials;

WHEREAS, the District has begun focusing grants and incentive funds from the Carl Moyer Program, the Transportation Fund for Clean Air, and the Goods Movement Bond on impacted areas as identified by the CARE program;

WHEREAS, the District has created and staffed a Community Outreach Program to increase and improve outreach and collaboration with community groups in impacted areas;

EXHIBIT 8

WHEREAS, the District recognizes that ongoing collaboration with impacted communities, including input to the CARE Mitigation Action Plan, is desirable;

WHEREAS, the Board has adopted a rule (Regulation 2, Rule 5) for new source review for toxic air contaminants, requiring best available control technology of toxic contaminants to reduce risks from new sources and from existing sources when they are modified or replaced;
WHEREAS, the District has developed enhanced complaint response programs, working with community groups to improve the District's reporting and response times;

WHEREAS, the District has collaborated with the California Air Resources Board and the Port of Oakland in the West Oakland Health Risk Assessment to identify health risks from diesel emissions in and around West Oakland and encourage community participation in the study;

WHEREAS, the District has participated in the implementation of the memorandum of understanding between the California Air Resources Board and the Union Pacific and Burlington Northern Santa Fe Railroads to ensure that rail emissions are reduced and their health impacts are clearly identified, and ensure that the public may actively participate in these processes;

WHEREAS, the District considers these activities to be a furtherance of its long-standing commitment to address disproportionate impacts of air pollution;

NOW, THEREFORE, BE IT RESOLVED that the Board commits to continue to address the cumulative impact of new and existing mobile and stationary sources of air pollution—particularly in disproportionately impacted communities—for sources that on a relative basis contribute most to health risk at a local and regional level;

BE IT FURTHER RESOLVED that the Board will continue its commitment to reduce air quality impacts throughout the Bay Area and will continue to implement the CARE Mitigation Action Plan to address health risks related to air quality in impacted communities.

BE IT FURTHER RESOLVED, that the Board will continue to explore and consider additional actions to reduce cumulative impacts throughout the Bay Area and that these actions will include, but not be limited to

* Participation in Statewide processes to address cumulative impacts; and
* In partnership with community groups, industry, health officials, and other agencies, development of new tools and methods, potentially including regulatory approaches, to consider and reduce cumulative impacts for sources that contribute most to health risk at a local and regional level,
* Promotion of interagency collaboration in impacted communities.

The foregoing resolution was duly and regularly introduced, passed and adopted at a regular meeting of the Board of Directors of the Bay Area Air Quality Management District on the Motion of Director ROSS, seconded by Director DUNNIGAN, on the 30th day of JULY, 2008 by the following vote of the Board:

AYES: BROWN, DUNNIGAN, GIOIA, HAGGERTY, KLATT, KNISS, LOCKHART, McGOLDRICK, MILEY, ROSS, SHIMANSKY, SILVA, UILKEMA, WAGENKNECHT, YEAGER, HILL

NOES: NONE.

ABSENT: BATES, DALY, GARNER, KISHIMOTO, SMITH, TORLIATT

Jerry Hill
Chairperson of the Board of Directors

ATTEST:

Brad Wagenknecht
Secretary of the Board of Directors

grains per 100 standard cubic feet (gr/100 scf). PG&E's gas supply typically qualifies as "pipeline quality natural gas" as shown in the Gas System Survey Results table below.

Gas System Sulfur Survey Results

PG&E has a program of periodically surveying representative locations on the system to determine the sulfur containing compound concentrations in the gas stream. PG&E tests for sulfur using ASTM D 5504 "Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence." Our detection limit is approximately 10 PPBv for each compound. PG&E odorizes our gas with a 50/50 blend of Tetrahydothiophene (THT) and Tertiary Butyl Mercaptan (TBM) and they are typically present at approximately 1 PPMv each in the natural gas on our system. The values shown in the table below provide a representative sample of the gas flowing on the PG&E system.

Date	Total Sulfur Average all sites		Total Sulfur Maximum	
	gr/100 scf	PPMv	gr/100 scf	PPMv
Fourth Quarter 2008	0.182	3.06	0.608	10.25
Third Quarter 2008	0.231	3.89	0.442	7.45
Second Quarter 2008	0.224	4.12	0.463	7.80
First Quarter 2008	0.227	3.82	0.475	8.01
Fourth Quarter 2007	0.225	3.79	0.462	7.79
Third Quarter 2007	0.204	3.44	0.421	7.10
Second Quarter 2007	0.197	3.31	0.326	5.50
First Quarter 2007	0.226	3.81	0.664	11.20
Fourth Quarter 2006	0.223	3.86	0.522	8.80
Third Quarter 2006	0.241	4.05	0.466	7.88
Second Quarter 2006	0.160	2.70	0.408	6.90
First Quarter 2006	0.145	2.45	0.318	5.37

EXHIBIT 9

PPMv is expressed as parts per million by volume.

The total readings include 0.400 PPMv of sulfur to account for compounds not measured by the existing equipment. This amount has been determined by supplemental testing at selected locations on the gas system.

Disclaimer

The data points shown above are from representative samples of sulfur content only. The data points are provided solely for informational purposes, and not for billing or odorant level monitoring purposes. PG&E makes no claim or representation that the data points provided are accurate. Data may be subject to adjustments and corrections.

Laboratory Services

PG&E's in-house laboratory, located in San Ramon, can collect a sample and perform sulfur analyses of your gas for a fee. Please contact 1

Pacific Gas and Electric Company®
California Gas Transmission
Pipe Ranger

EXHIBIT 10

Sulfur Information

Much of the sulfur contained in the gas delivered by PG&E consists of compounds that naturally occur in the gas, but PG&E also adds sulfur compounds to odorize the gas. The gas is odorized as a safety measure so that leaks can be detected by consumers.

Common sulfur compounds that may be found in the gas supply are Tetrahydrothiophene (THT), Tertiary Butyl Mercaptan (TBM), Dimethyl Sulfide (DMS), and Hydrogen Sulfide (H2S). A more comprehensive listing of typical sulfur compounds that may be found in the PG&E gas supply is shown at the end of this page. These compounds are harmless at low levels but can cause customer complaints due to excessive gas odor or in the case of Hydrogen Sulfide become dangerous at very high levels.

PG&E continuously monitors the gas stream for specific sulfur compounds at several points on its system as part of its program to ensure that the gas is properly odorized and that sulfur levels are within established limits. The monitoring equipment works well for the intended purpose but it does not provide comprehensive data on all potential sulfur compounds flowing in the gas supply. To supplement the continuous monitoring equipment PG&E has started a program to collect and analyze samples from representative parts of the system to provide an estimate of the total sulfur contained in the PG&E gas supply expressed as parts per million by volume or grains per 100 Standard Cubic Feet.

PG&E's Gas Rule 21, Section C contains specifications on the quality of the gas received into the system and these specifications include limits for sulfur compounds as well as for other constituents contained in the natural gas. Gas Rule 21 can be found in the PGE.com Web tariff book and the sulfur limits are summarized below.

Rule 21, Section C

Section C of Gas Rule 21 provides quality specifications for gas delivered into the PG&E pipeline system from California gas wells and generally governs the gas quality received from interconnecting pipelines. However, gas quality specifications, contained in the interconnection agreement may supersede the Gas Rule 21 C specifications.

- **Total Sulfur**: The gas shall contain no more than one grain (17 ppm) of total sulfur per one hundred standard cubic feet.
- **Mercaptan Sulfur**: The gas shall contain no more than 0.5 grain (8 ppm) of mercaptan sulfur per one hundred standard cubic feet.
- **Hydrogen Sulfide**: The gas shall contain no more than 0.25 grain (4 ppm) of hydrogen sulfide per one hundred standard cubic feet.

Pipeline Quality Gas

Many air quality compliance reporting requirements can be met by certifying that the fuel used in the process was "pipeline quality natural gas." The EPA criteria for pipeline quality natural gas from [40CFR72.2] is as follows:

"Pipeline natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological

BAYVIEW HUNTERS POINT COMMUNITY ADVOCATES

Post Office Box 24582, San Francisco, CA 94124-0582
ID# 94-3221152

February 4, 2009

Via E-Mail and U.S. Mail

weyman@baaqmd.gov
Weyman Lee, P.E.
Senior Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Re: Draft PSD Permit for Russell City Energy Center

Dear Mr. Lee:

The Bayview Hunters Point Community Advocates ("BHPCA") submits the following comments, in support of the Hayward Community, on the proposed permit for the construction of a power plant at the Russell City Energy Center in Hayward ("Permit"). The Permit is currently under consideration by the Bay Area Air Quality Management District ("District").

BHPCA has successfully worked to improve air quality for years within the San Francisco Bay Area. In particular, we were one of the groups that successfully worked to shut down the Hunters Point Power Plant in 2006. Currently, we are monitoring issues related to the Potrero Generating Plant located in San Francisco ("Potrero facility").

In the recent permitting action related to the Hayward facility, the District states that, "[t]he proposed project will supply electricity to Northern California. The electricity from the new plant is expected to displace older, less efficient sources of electricity elsewhere in the region." Page 93 of the Statement of Basis for the Russell City Energy Center.

If the District is referring to the Potrero facility in discussing "older, less efficient sources of electricity," the District may have little basis for the claim. The Potrero facility is currently proposing a retrofit of units 4, 5 and 6, which would have the effect of extending the life of the facility.

Mirant currently operates Potrero Units 4, 5 and 6 with diesel turbine engines. According to an analysis by CH2MHILL, Mirant's proposed retrofit would consist of diesel turbine engines and baseplates being converted to a system that can run on either natural gas or diesel fuel. The estimated cost for this retrofit is approximately $78,730,000. *See* CH2MHILL "Potrero Retrofit Feasibility Study", at 3. 5 and 7. When Mirant discussed this proposed retrofit it did not commit to a concrete shutdown date. Based on this information, we have no reason to believe that the proposed Hayward facility will lead to a shutdown of the Potrero facility.

Even if the District's statements are true and the Russell City Facility could lead to closure of other facilities, BHPCA supports the Hayward community's efforts to ensure that the District completes a proper and thorough analysis before granting the Permit. This effort necessarily includes compliance with all laws, a full assessment of the cumulative air quality impacts of the facility to the surrounding neighborhoods and of the effect the proposed emissions have on prevention of significant deterioration of air quality, and minimization of the facility's harmful air emissions.

Thank you for your consideration of these comments and do not hesitate to contact me at any time if you have any questions or concerns.

Very truly yours,

/s/ Karen Pierce
Karen Pierce
President of the Board of Directors,
Bayview Hunters Point Community
Advocates

January 23, 2009

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BAY AREA AIR QUALITY
MANAGEMENT DISTRICT

Mr. Weyman Lee, P.E.
Senior Air Quality Engineer
BAAQMD
939 Ellis Street
San Francisco, California 94109

Dear Mr. Lee,

This letter is a response to the issue of permit for the construction and operation of the Russell City Energy Center (RCEC) planned to be located at 3862 Depot Road in Hayward, on the shores of San Francisco Bay.

I was in attendance at the meeting held in Hayward on Wednesday, January 21, 2009 at Hayward City Hall. I listened intently as many citizens spoke passionately about the concerns of this power plant being built in the proposed area. As I looked around the room at the attending crowd, including children, I wondered how many of us would end up a cancer statistic.

From 1988 through 2005, 474,406 new cases of invasive cancer were diagnosed in the SF Bay Area. Also, 183,234 deaths occurred due to cancer during this period. As mentioned, the Bay Area is already at risk for its air quality, or lack thereof. The California EPA Air Resources Board has just provided a Health Update stating that the impacts of exposure to fine particulate matter from residential wood burning are an increased risk for mortality and asthma exacerbations. "Yet, the components of particulate matter that may be most responsible for these health effects are not known." There is much to learn.

In the Statement of Basis for Draft Amended Federal "PSD" Permit, the Health Risk Assessment Results state that the RCEC emissions will cause less than (>0.7) one risk in one million for cancer, which is stated to not be significant. However, if you are the one in a million, then my guess is that would be pretty significant to you. Take that >0.7 and ADD it into the 474.406 new cases of cancer and NOW you have a very significant number. How dare anyone pretend that emissions from RCI significant risk to the Bay Area and to the valleys east and north. Also, on top of that, the risk to the environment ai which is already failing at a drastic and critical rate, can only underscore the severity of this project's impact. There i learn.

The National Institute for Occupational Safety and Health has just extended their public comment period for t Hexavalent Chromium Document. NIOSH considers all CR(VI) compounds to be potential occupational carcinoge increased risk of lung cancer has been demonstrated in workers exposed to compounds. There is much to learn.

Researchers in Los Angeles have just released information stating that over the past two decades, "cleaner air adds 5 months to lives." Reducing pollution translates to longer lives. The law is widely credited with improving the nation's air quality. There is much to learn.

The information regarding RCEC power plant emissions is just for this one plant. Take those emissions, and ADD them into the industrial area of Hayward, which is already overdosed with toxins, particulate matter, and who knows what all. The Bay Area has trucking companies, chrome plating businesses, painting and finishing businesses, numerous oil refineries, dumpsites, etc. Our air is loaded with thick black sooty grit. This is what we are forced to breathe in every moment. I clean up this grit weekly from my home, my yard and plants, and my vehicle. It blows in my open windows. There are three large airports, major

-ways, shipping ports, trains, and a host of pollution producing engines, all following a western wind into a major metropolis. I guess this is why we can't burn wood in our fireplaces.

With this planned energy center to be located in the San Francisco Bay Area, there is also great concern for the at least 11 well-known bird sanctuaries and nature preserves that exist along the delicate shores of San Francisco Bay. Trails, Interpretive Centers, and a host of other educational facilities will be at risk from this project. It has yet to be discovered how much of a risk is at stake. There is much to learn.

The RCEC would not be operated using renewable energy. What good is a power plant if it is using up natural resources? There is not a critical timeline on this project. Communities will learn to cut back, use less, need less, and use wisely the resources California does have. Imagine how the funds for this project could be redirected in the education field, teaching the world about control of overpopulation, the main cause of our environmental downfall. If anyone is really concerned about the environment, they should start dealing with the real problem first.

Governor Schwarzenegger just sent a letter to President Obama stating that California and a growing number of farsighted states have sought to enforce a common-sense policy to reduce global-warming pollution. The EPA made what is believed to be a fundamentally flawed decision to deny California's request for the Clean Air Act waiver necessary to enforce regulation. It appears that by trying to authorize permit for the RCEC, you are placing the "cart before the horse." Air quality regulations and standards MUST be researched and updated BEFORE a project like RCEC can be permitted. There is much to learn.

With all the technology and research available, and agencies that are responsible to permit, there should be a way to prevent any further harm to California, its environment, its population, and its credibility as a leader. See if you can find a way to help move us in the right direction. Do not permit the RCEC until the current Presidential Administration has time to reinstate the necessary regulations to prevent further deterioration of our environment. I breathe to live and live to breathe. Please view the following: http://www.youtube.com/watch?v=42E2fAWM6rA

Respectfully,

D. Weiss

Debra Weiss
P.O. Box 11
Alameda, CA 94501

Cc: California EPA
Congressman Pete Stark
Al Gore
Speaker Nancy Pelosi
Senator Diane Feinstein
Senator Barbara Boxer
SF Mayor Gavin Newsome
Governor Arnold Schwarzenegger
President Obama

-----Original Message-----
From: MATHIAS THIEL [mailto:mvthiel@sbcglobal.net]
Sent: Thursday, January 22, 2009 6:05 PM
To: Weyman Lee
Cc: kansgirl16@aol.com
Subject: Air Quality Permit for Russell City E Center comment

Weyman Lee,P.E. 1/22/09
,Senior Air Quality Engineer
B.A.A.Q.M.D.

Comment on Proposed Air Quality Permit for the Russell City Energy Center in Hayward, CA.

Dear Sir:

The amended PSD permit for the above project was generated under the policies of the previous administration and therefore inconsistent with current administration policies. As President Elect 6bama has stated that his administration will function on the basis of scientific consensus, and not under the unregulated approach of the Bush administration.

It is unfortunate that in April, 2008, president Bush called for a "voluntary target" of "halting the growth of U.S. greenhouse gas emissions by 2025." But a report released 24 July 2008, by the Inspector General of the Environmental Protection Agency (EPA) said that such voluntary pollution-reduction programs have "limited potential" to reduce greenhouse gases (GHG); at most 19 percent. EPA should therefore consider additional policy options.

I must therefore warn you that that the list of pollutants in the proposed Air Quality permit is incomplete. The current administration has a strong focus on Global Warming as presented by the Intergovernmental Commission on Climate Change (IPCC) and the current policies of the new administration do include carbon dioxide as a pollutant. The adequacy of the PSD Permit may therefore be challenged before the first shovel is put into the ground.

The above contention is based on reported news items that can be obtained among others from :"The Progress Report" progress@mx3.americanprogressaction.org, of 19 Nov 2007 11:01:32, 25 Jul 2008 12:29:22 and December 11, 2008 9:09 AM.

The following quotations illustrate the urgency the current administration places on the criteria to be followed if the worst predictions for the future are to be mitigated.

In 2007 the Intergovernmental Panel on Climate Change (IPCC) warned that (quoting the N.Y. Times of Nov 18 2007,
http://www.nytimes.com/2007/11/18/science/earth/18climatenew.html?_r=1&hp=&oref=slogin&pagewanted=print
1. . By 2100, global average surface temperatures could rise by between 1.1 and 6.4 degrees Celsius,
2. and carbon dioxide in the atmosphere could lead to an eventual rise in sea levels of up to 1.40 meters. (quoting the New York times of Nov 18

IPCC chairman Dr. Rajendra Pachauri.

declared: “What we do in the next two to three years will determine our future. This is the defining moment,"

Recently, the IPCC reported that the last three decades have seen "a spring/summer warming of 0.87 degrees Celsius

The IPCC concluded that "reductions in greenhouse gases had to start immediately to avert a global climate disaster,"

Obama has shown that he intends to fill the void created by Bush and will allow science to dictate policy. Today, reports indicate that Obama will select Dr. Steven Chu as Secretary of Energy, Carol Browner as head of the new National Energy Council, and Lisa Jackson as Environmental Protection Agency (EPA) Administrator
 Browner would coordinate administration policy across departments and advocate for policies on Capitol Hill. Browner, a former aide to Al Gore, was the longest-serving administrator of the EPA, where she successfully beat back conservative efforts to gut safeguards from pollution. She is currently on the Board of Directors of CAP, Gore's Alliance for Climate Protection,

As the government's chief regulator of air quality, the EPA plays a pivotal role in formulating global warming policy.

The amended PSD needs, therefore, to be reconsidered.

Sincerely

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January 22, 2009

VIA ELECTRONIC MAIL AND HAND DELIVERY

Mr. Weyman Lee, P.E.
Senior Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis St.
San Francisco CA 94109
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Dear Mr. Lee:

The Sierra Club submits these comments to address the Bay Area Air Quality Management District's (the "District") BACT analysis in the re-noticed draft Statement of Basis ("SOB") and PSD permit[1] for the Russell City Energy Center ("RCEC").

The RCEC will generate up to 600 MW[2] net of electricity using two Westinghouse 501F combustion turbine generators, firing 2,038.7 MMBtu/hr of natural gas. The hot turbine exhaust gases are routed to two heat recovery steam generators ("HRSGs"). The HRSGs, or boilers that recover waste heat from the turbine exhaust, are each equipped with duct burners that burn 200 MMBtu/hr of natural gas. The HRSG and duct burners convert water into steam which drives a 235 MW steam turbine ("the Project").

This same project was proposed by the applicant, Calpine, and licensed by the California Energy Commission ("CEC") in 2002. The proposed facility location was

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[1] Statement of Basis for Draft Amended Federal "Prevention of Significant Deterioration" Permit, Russell City Energy Center, Bay Area Air Quality Management District Application Number 15487, December 8, 2008.

[2] We note that the Permit assumes 622 MW, presumably gross, while the CEC licensed a project rated at only 600 MW, presumably net. We assume that the difference is the auxiliary power load. See Russell City Energy Center, Amendment No. 1 (01-AFC-7C), Final Commission Decision, October 2007, p. 2. http://www.energy.ca.gov/2007publications/CEC-800-2007-003/CEC-800-2007-003-CMF.PDF.

subsequently moved 1,300 feet to the northwest of the approved location and thus required a modification to its CEC license and a new PSD permit.[3]

I. BACT for Carbon Dioxide (CO2)

The applicant asked the District to undertake a top-down BACT analysis for greenhouse gases.[4] The District conducted a BACT analysis and concluded that if BACT is required for CO2 emissions, an enforceable limit of 1,100 lb/MWh would suffice. Compliance would be demonstrated by an enforceable fuel throughput limit of 2,944.3 MMBtu/hr of heat input.[5]

We agree that the permit should include a BACT limit for CO_2. While the U.S. Environmental Protection Agency has wavered as to whether CO_2 is a "pollutant subject to regulation," within the meaning of the Clean Air Act's BACT definition, both the Clean Air Act and EPA's governing interpretations indicate that CO_2 falls within the pollutants demanding a BACT limit. *See* Ex. 1 (**In the Matter of: EPA Final Action Published at 73 Fed. Reg. 80300 (December 31, 2008), titled "Clean Air Act Prevention of Significant Deterioration (PSD) Construction Permit Program; Interpretation of Regulations That Determine pollutants Covered by the Federal PSD Permit Program," Petition for Reconsideration (January 6, 2009)**). However, the District's CO_2 limit and compliance provision as currently written do not satisfy BACT requirements, for the reasons below.

A. Failed To Consider More Efficient Options

The District acknowledges that an effective means to reduce CO2 emissions is to use the most efficient generating technology available; increased efficiency allows more of the fuel's energy content to be used to generate electricity, reducing emissions of CO_2 (and other pollutants). The District has not, however, conducted a full BACT analysis of efficient generating technologies. Instead, the District concludes (without supporting analysis) that the proposed "combined-cycle natural gas turbine technology" is "among the most efficient electrical generating technology created to date."[6]

BACT requires an emission limit based on the maximum degree of reduction that is achievable; limiting the District's review to a technology that is "among the most" effective fails to satisfy those "strong, normative terms." *Alaska Dep't of Envtl. Conservation* 540 U.S. 461, 485-86 (2004). As discussed in Section II, below,

[3] Statement of Basis for Draft Amended Federal "Prevention of Significant Deterioration" Permit, Russell City Energy Center, Bay Area Air Quality Management District Application Number 15487, December 8, 2008.
[4] SOB, p. 58.
[5] SOB, p. 63.
[6] SOB, pp. 60-61.

the proposed generating technology is not the most efficient available. It is not sufficient to stop one's inquiry with the a broad classification of the thermodynamic cycle, combined-cycle, but rather, one must look deeper, at the components of the cycle – the gas turbine, HRSG, duct burners, and steam turbine.[7] There are many different turbines that could be used in the same combined-cycle configuration and more efficient ways to generate peaking power. The technology proposed by the applicant was selected eight years ago. BACT is determined as of the date of issue of the PSD permit. By failing to examine more efficient means to generate electricity, the District has failed to properly fulfill its duty, under the BACT requirements, to examine all methods and processes of pollution-reduction, including "innovative combustion processes." 42 U.S.C. § 7579(3).

B. Failure to Set Proper CO2 BACT Limit

After improperly concluding that the applicant had selected the most efficient power generation technology, the District next considered a range of CO2 emissions expressed in units of pounds per megawatt hour ("lb/MWh") of net (presumably) electric generation. The values considered were regulatory levels proposed by various states (675 lb/MWh in Oregon to 1,900 lb/MWh in Delaware)[8] and certain California test data (794 to 1,058 lb/MWh).[9]

From this data, the District concluded that CO2 BACT is 1,100 lb/MWh. The lower values were rejected without technical explanation, arguing that "a reasonable compliance margin" is required to assure the limit is met.[10] The selected limit is conveniently the minimum emission performance standard that certain gas fired power plants in California must meet. This limit is 39% higher than the lowest reported CO2 emission level identified by the District. No justification is provided for a "reasonable compliance margin" of 39% or for the concept that such a "compliance margin" applies to BACT.

Generally, when there is uncertainty as to what can be achieved, an optimization period is built in to a permit with a requirement to design the system to meet the goal and time to achieve the goal. The permit should require the system to be designed to meet a much lower CO2 level. The design basis should be submitted to the District to establish that the intent was met. The permit should also establish protocols that identify (a) test methods that will be used to measure CO2 and MWh net; (b) frequency of testing; (c) length of optimization period; (d) averaging period for limit; and (e) methods and criteria that will be used to

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[7] David Gordon Wilson and Theodosios Korakianitis, The Design of High-Efficiency Turbomachinery and Gas Turbines, 2nd Ed., 1998; Kam W. Li and A. Paul Priddy, Power Plant System Design, 1985.
[8] SOB, p. 59, Table 20.
[9] SOB, pp. 62.
[10] SOB, p.63.

determine the lowest achievable CO2 limit. The permit should be drafted to require as BACT the lowest achievable limit, based on this testing demonstration.

The District tosses out all measured data, characterizing it as no more than a "snapshot" of turbine performance and not a continuous demonstration of compliance with an enforceable limit. The District also tosses out the lower end of the regulatory range and sets CO2 BACT at 1,100 lb/MWh,[11] based on California's interim performance standard for complying with a Senate Bill.

The 1,100 lb/MWh value was adopted by the California Public Utilities Commission under the Electricity Greenhouse Gas Emission Standards Act (SB 136812) as a performance standard for the state's investor owned utilities. It applies to new investments in existing plants, new or renewed contracts with plants outside of California, and new base load plants. Thus, it had to broadly apply across the existing gas-fired fleet that serves California.

The 1,100 lb/MWh value was not selected in a top-down BACT analysis, but rather through a political negotiation. It was a compromise between a value of 800 lb/MWh, which could then be achieved by the most efficient combined cycle plant, and 1,400 lb/MWh, which would envelop the majority of natural gas burning technologies (e.g., steam cycle boiler, simple cycle turbine).[12] Such a standard does not satisfy BACT, but (at most) serves as a floor for BACT.

Modern, efficient combined-cycle power plant in 2009 can cost-effectively achieve far lower emissions. The District failed to acknowledge that CO2 emissions from similar facilities have been continuously monitored for many years under the Acid Rain Program and publicly reported.[13] These data show that similar combined cycle power plants routinely meet CO2 emission levels of less than 800 lb/MWh.

Further, some of this data has been certified and reported to the California Climate Action Registry.[14] This data shows that Elk Hills, a similarly configured combined cycle project licensed by the CEC in 2000, reported CO2 emissions of 796 lb/MWh in 2006 and 794 lb/MWh in 2007. Calpine, the RCEC applicant who owns a number of similar gas-fired combined cycle projects in California, reported system-wide CO2 emissions from all fossil fuel generation of 891 lb/MWh in 2005 and 850 lb/MWh in 2006. This fleet includes many less efficient gas-fired facilities than proposed at RCEC.

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[11] SOB, pp. 62-63.
[12] Gary Collord, Implementation of SB 1368 Emission Performance Standard, Staff Issue Identification Paper, November 2006, p. 13.
[13] Clean Air Markets, Emissions Monitoring, http://www.epa.gov/airmarkets/emissions/.
[14] Climate Action Registry Reporting Online Tool, https://www.climateregistry.org/CARROT/public/Reports.aspx.

Similar facilities are also currently being licensed by the CEC with lower CO2 emissions. These include Avenal (500 lb/MWh);[15] Willow Pass Generating Station (933 lb/MWh);[16] and Lodi Energy Center (829 lb/MWh).[17] The State of Florida concluded that in 2007, new natural gas fired combined cycle plants could achieve 800 lb/MWh.[18] Based on this evidence, BACT should be an enforceable CO2 emission limit no higher than 800 lb/MWh.

C. Output-Based Limit Should Be Established

The District opted to determine compliance with the output-based CO2 emission limit, 1,200 lb/MWh, by setting an input-based fuel limit. In effect, this renders the limit input-based. Output-based measurements link the emissions from a power plant to the energy they produce. In 1998, the NSPS for utility and industrial boilers was changed from input to output based. Further, EPA has published an output-based guidance document under the NOx SIP Call as an option for states in the NOx Budget Trading Program.[19]

The use of an output-based CO2 limit is particularly critical here as the only currently feasible control option is more efficient energy production.[20] The District used a CO2 emission calculation to demonstrate that a heat input limit assures emissions remain below 1,100 lb/MWh. The Permit, however, does not cap electric output at 622 MW (a key assumption of the calculation). The calculations are, moreover, based on input rather than output, and utilize the wrong natural gas heat content (1050 instead of 1023 Btu/scf). The heat input method of determining compliance, for example, would not detect a decrease in efficiency due to aging of the equipment or due to changes in the equipment at a future time.

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[15] From Avenal Energy Application for Certification 08-AFC-01, February 2008, Vol. II, Appx. 6.2-1, Table 6.2-1.1. The highest values, calculated from CO2 in lb/hr divided by plant net output in MW. Table 6.2-41, the facility would emit 1.71 MT/yr of CO2, is 499.7 lb/MWh, based on case 12 (137,055 lb/hr/304.8 MW = **499.7 lb/MWh**). See: http://www.energy.ca.gov/sitingcases/avenal/documents/applicant/afc/

[16] From the Willow Pass AFC 08-AFC-6, Table 7.1-19, the facility would emit 987,970 MT/yr of CO2. From Figure 2.5-3, it would generate 266.5 MW net under worst-case conditions, 100% load and 94 F, 32% RH. This works out to: (987,970 MT/yr)(2204.6 lb/MT)/(266.7 MW)(8760 hr/yr) = 932.98 **lb/MW-hr** net and 905.8 lb/MWh gross. This is an air cooled plant so auxiliary power loads are higher than for a water cooled plant, such as RCEC. See:
http://www.energy.ca.gov/sitingcases/willowpass/documents/applicant/afc/index.php.

[17] Lodi Energy Center Application for Certification 08-AFC-10, September 2008, Table 5.1-22. See: http://www.energy.ca.gov/sitingcases/lodi/documents/applicant/afc/.

[18] Florida Department of Environmental Protection, Electric Utility Greenhouse Gas Emissions Reductions, Initial Rule Development Workshop, August 22, 2007.

[19] Susan Freedman and Suzanne Watson, Output-Based Emission Standards, Northeast-Midwest Institute, 2003, http://www.nemw.org/output_emissions.pdf.

[20] SOB, pp. 60-61.

Net electrical output and CO_2 can both be monitored continuously using widely used, standard measurement technology. Thus, the Permit should be revised to set an explicit limit on CO_2 emissions in pounds per megawatt-hour.

D. Other Greenhouse Gases and Sources

The District only performed a BACT analysis for CO_2 emissions from the gas turbines and duct burners. Other sources emit greenhouse gases, including diesel generators and heaters. Further, other Greenhouse Gases are emitted by gas-fired power plants, including methane (CH_4) and nitrous oxide (N_2O) (from combustion sources) and sulfahexafluoride (SF_6) (which is used in circuit breakers). The BACT analysis should be revised to include these other gases and sources.

II. The BACT Analysis Did Not Consider More Efficient Processes

The BACT analysis for NOx, CO, and PM emissions from the gas turbine/HSRG equipment considered only two classes of control options – combustion controls and post combustion controls. However, the amount of pollution that is generated by combustion sources depends upon the efficiency of power generation. The more fuel that is burned to produce a megawatt of electricity, the more NOx, CO, and PM10 that is emitted. Similarly, the less fuel burned, the lower the emissions. The District did not consider the efficiency of the power generation cycle in making its BACT determination for NOx, CO, or PM (though it paid lip service to efficiency considerations in its BACT determination for CO_2).

Consideration of more efficient generating technologies is required under BACT, which requires a case-by-case, comprehensive assessment that includes "*production processes* and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or *innovative fuel combustion techniques* for control of each . . . pollutant" regulated under the PSD program. 42 U.S.C. § 7479(3) (emphases added). A BACT analysis should, accordingly, not be limited to a comparative assessment of combustion controls and add-on controls, but must consider "'inherently lower-polluting process[es]/practice[s]' that prevent[ ] emissions from being generated in the first instance." *In re Knauf Fiber Glass, BMBH,* 8 E.A.D. 121, 129 (EAB 1999) (citing NSR Manual at B.10, B.13). *See also In re CertainTeed Corp.*, 1 E.A.D. 743, 746 (EAB 1982) (Affirms BACT is an emission limitation achievable through application of "production processes and available methods, systems, and techniques" for control of pollutants, denying applicant review of permit based on argument that BACT does not include production and process requirements). Furthermore, the history of the Clean Air Act amendment adding the term "innovative fuel combustion techniques" shows that the amendment was intended to include all actions taken by the fuel user, such as selecting the combustion process. 123 Cong. Rec. S9421, S9434-35.[21]

Russell City will use two Westinghouse 501 FD combustion turbines with fired heat recovery steam generators to generate 600 MW net of electric power. This is not the most efficient combination to generate said power and thus does not satisfy BACT for at least three reasons.

First, the efficiency of the unfired system (without duct burners) is reported to be 55%.[22] While that may have been an efficient mark eight years ago, when the turbines were selected, there are far more efficient turbines on the market today. These include the Westinghouse 501G, a more advanced turbine by the same manufacturer and its successors. It has a combined cycle net efficiency of 58%.[23] This turbine is in widespread commercial operation, including at the Charlton Power Plant, MA (since 2001); Lakeland McIntosh Unit 5, FL (Ex. 12);[24] West County, FL; Lower Mount Bethel, PA; Ennis Power, TX; Wolf Hollow, TX; and Port Westward, OR, among others.[25]

Other more efficient turbines have entered the market since 2001, with efficiencies up to 60%.[26] If turbines with a net combined cycle efficiency of 60% were selected, RCEC would emit over 8% less NOx, CO, and PM than the selected turbines when operated in unfired mode. In fact, the same applicant, Calpine, is scheduled to complete construction of Inland Empire Unit 1 in January 2009 and Unit 2 in July 2009. These two turbines were licensed in 2003 at 56.5% lower heating value without duct firing[27] compared to only 55% for RCEC which is being

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[21] "*It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account* - be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, *gasification*, or liquefaction." (emphases added). 123 Cong. Rec. S9421, S9434-35.

[22] Russell City Energy Center Application for Certification, 01-AFC-7, May 2001 ("RCEC AFC"), p. 10-3, http://www.energy.ca.gov/sitingcases/russellcity/documents/applicant_files/afc/ and Russell City Energy Center, Application for Certification 01-AFC-7, Commission Decision, p. 74. http://www.energy.ca.gov/sitingcases/russellcity/documents/2002-09-12_COMMISSION_DECIS.PDF

[23] Gerard McQuiggan and others, Westinghouse's Advanced Turbine Systems Program.

[24] Gregory R. Gaul, Ihor S. Diakunchak, and Alfred M. Dodd, The W501G Testing and Validation in the Siemens Westinghouse Advanced Turbine Systems Program, Paper 2001-GT-399, International Gas Turbine & Aeroengine Congress & Exhibition, June 4-7, 2001.

[25] Universal Energy UEI LLC, Management Services for Power, Petrochemical, Offshore, and Industrial Facilities, Experience List, February 2006. http://www.univenergy.com/PDFs/Industrial%20Capabilities%20020306.pdf.

[26] Gas Turbine World 2007 -08 Handbook, Combined Cycle Ratings; GE Energy, News Release, GE's H System Achieves Technology Milestone: 8,000 Operating Hours at Baglan Bay; GE Power Systems, GE Combined-Cycle Line and Performance. http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger3574g.pdf.

[27] Inland Empire Application for Certification 01-AFC-17, Commission Decision, November 14, 2003, p. 74. http://www.energy.ca.gov/sitingcases/inlandempire/documents/2003-12-22_COM_DECISION.PDF.

permitted in 2009. Inland Empire will use the higher efficiency GE PG7252(FB) turbines.

Second, RCEC will use an inefficient method to generate peaking power. When the duct burners are not operating, the gas turbines will produce 184.3 MW each and the steam turbine 198.4 MW, for a net plant output of 552.6 MW. The heat rate, or amount of energy in BTUs per kilowatt hour of electricity produced, for this mode of operation is 6,177 BTU/kWh based on the lower heating value.[28] During periods of peak demand, the duct burners are turned on to generate more steam. The heat rate for this condition is not reported in documents we reviewed.

Duct burners are inefficient compared to gas turbines. The files we reviewed do not report the efficiency of incremental power generation by the duct burners, nor does it include a heat/mass balance diagram that could be used to estimate the impact of duct firing on fuel efficiency. However, such estimates have been made in other similar cases. Based on these, the incremental heat rate of peaking capacity could range from about 8,890 to 9,000 Btu/kWh, corresponding to an efficiency of about 40%.[29] The peaking heat rate is higher than can be achieved by some simple cycle gas turbines. (Ex. 18)[30] Thus, peaking power generation by simple cycle gas turbine should have been considered in the BACT analysis as an alternative to duct burners. Further, the inclusion of duct burners in a combined cycle plant reduces the overall efficiency of the combined cycle plant as the steam cycle has to be sized to provide base load plus peaking load. This adds a fuel efficiency penalty during baseload unfired operation.

Third, as cited in Knauf (8 E.A.D, 129), the NSR Manual explicitly recognizes that "[c]ombinations of inherently lower-polluting processes/practices (or a process made to be inherently less polluting) and add-on controls are likely to yield more effective means of emissions control than either approach alone...These combinations should be identified in Step 1 of the top down process for evaluation in subsequent steps." NSR Manual, p. B.14. The BACT analysis for NOx, CO, and PM did not identify any inherently lower-polluting processes or practices and thus failed to consider whether combinations of these and add-on controls could further reduce NOx, CO, and PM.

The EPA's RACT/BACT/LAER Clearinghouse indicates that lower emission limits have been permitted for other facilities, including 1.5 ppm NOx at IDC Bellingham and numerous facilities at less than 4 ppm CO. These lower CO limits include Kleen Energy Systems, CT (0.9 ppmvd); CPV Warren, VA (1.3 and 1.8 ppmvd); and 2 ppmvd at: Goldendale Energy, WA; Garnet Energy, ID, Wallula

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28 RCEC AFC, Figure 2.2-3b.

29 CPV Vaca Station Application for Certification 08-AFC-11, October 2008, p. 2-2; Presiding Members Decision for Inland Empire 01-AFC-17, November 14, 2003, p. 75.

30 Gas Turbine World 2007-08 Handbook, Simple Cycle Ratings.

Generation, WA; Lawrence Energy, OH; Linden Generating Station, NJ; COB Energy Facility, OR; Vernon City Light & Power, CA; Magnolia Power Project, CA, and many others.

The BACT analysis should be revised to consider the efficiency of the energy production process and the draft SOB and Permit re-circulated for public review.

III. BACT for Carbon Monoxide (CO)

The District concluded that BACT for CO is an emission limit of 4 ppmvd at 15% oxygen based on a 1 hour average, achieved using an oxidation catalyst.[31] This is not BACT for several reasons.

A. The District Used an Illegal Process

The District argues that NOx and CO are inversely related, that is, when NOx is reduced, CO increases. Thus, the District prioritizes NOx and VOC reductions over CO reductions because the Bay Area is not in compliance with ozone standards but does comply with CO standards. The District requires applicants to minimize NOx to the greatest extent feasible, and then optimize CO and VOC emissions for that level of NOx control.[32]

This process is inconsistent with BACT, which requires that an emission limit be set for each pollutant based on the maximum degree of reduction for that pollutant. Further, even assuming this process were legal, it was improperly implemented. The emissions of both NOx and CO can be simultaneously reduced by using a higher efficiency power production system or more efficient post combustion controls. This flawed process resulted in picking a CO BACT level of 4 ppm based on a 1 hour average. As discussed below, CO BACT is lower than 4 ppmvd.

B. Power Production Cycle

As discussed in Comment I, a higher efficiency power production cycle coupled with the proposed controls would lower all emissions, including CO.

First, the applicant's emissions data show that with duct firing, an inefficient method to produce peaking power, uncontrolled CO emissions increase from 0.1 lb/MMBtu to 0.25 lb/MMBtu,[33] or by a factor of 2.5. Requiring a more efficient method of producing peaking power, such as a small aero-derivative turbine or more efficient duct burners, would allow a lower CO emission limit to be achieved.

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[31] SOB, p. 34.

[32] SOB, pp. 22, 31.

[33] Russell City Energy Center Application for Certifications (AFC) 01-AFC-7, Amendment No. 1, November 2006, Appendix 3.1A, Table 3.1A-2.

Second, the turbines chosen for this project, Westinghouse 501Fs generally emit more CO than comparable GE turbines. The Westinghouse 501F turbine outlet CO is about 10 ppm, compared to 9 ppm from a typical GE Frame F turbine. Further, the Westinghouse 501F is not as stable across loads and at low loads up to about 50-60% as GE Frame F turbines, requiring more catalyst to achieve the same CO outlet as for other turbines. Thus, the District should have considered alternative combustion processes to reduce CO emissions.

C. Maximum Degree of Removal

The District selected an oxidation catalyst as satisfying BACT, but fails to disclose the assumed CO control efficiency or the CO concentration at the inlet to the device, both required to complete the Step 3 top-down BACT ranking. Instead, the District jumps to a list of permitted exhaust gas CO concentrations. This leap of faith skips a critical step in the top-down process, the ranking of technologies according to their control effectiveness.[34]

The top technology can achieve over 98% CO control (Ex. 19)[35] and has been commonly specified at 90+% CO control on numerous projects in the past 5 years. (Ex. 20 [36] and 21[37]) Assuming an oxidation catalyst design basis of 0.25 lb/MMBtu during duct firing (112 ppm),[38] a 98% CO control efficiency would result in a CO concentration of 0.005 lb/MMBtu or 2.2 ppmvd at 15% oxygen. This is much lower than the proposed CO BACT limit of 4 ppmvd. The District should determine the design basis of the proposed oxidation catalyst, revisit its CO BACT determination, modify the SOB to disclose the design basis of the oxidation catalyst, and re-circulate it for public comment as meaningful review is not possible without this information.

D. Test Data

In selecting the 4.0 ppmvd limit, the SOB states that the District only reviewed CEMS data for a single facility, Metcalf. There are many other similarly controlled gas-fired Frame F turbines operating in combined cycle mode in California and elsewhere, including the Delta Energy Center and Sutter, similar Calpine projects.[39] In 2001, for example, there were 87 such units in California.[40] Stack

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[34] NSR Manual, pp. B.6, B.7

[35] BASF, Oxidation Catalyst - Power Generation.

[36] Engelhard Oxidation Catalyst Experience List, 2003 (Engelhard is now BASF).

[37] Mike Durilla, Fred Booth, Ken Burns, and William Hizny, Engelhard, The Use of Oxidation Catalysts for Controlling Emissions from Gas Turbines: A Historical Perspective with a View Towards the Future, Power-Gen International 2001.

[38] Russell City Energy Center Application for Certifications (AFC) 01-AFC-7, Amendment No. 1, November 2006, Appendix 3.1A, Table 3.1A-2.

[39] See California projects at: http://www.energy.ca.gov/sitingcases/all_projects.html and

tests for many of these facilities indicate that lower CO emissions are being routinely achieved. The Metcalf data alone should not determine BACT for RCEC. The District should be required to look more broadly.

The District misapplied the Metcalf data. The District concluded BACT is 4 ppmvd as the Metcalf CEMS data suggested it could only meet 2 ppm during some operations. During transient loads, CO emissions increased to 4 ppm.[41] Most of the exceedances of 2 ppmvd at Metcalf were in the first year of operation during optimization of the system and thus not relevant to what can be achieved during optimized operation.

Our review of the Metcalf CO data indicate that during the first year of operation, a CO concentration of 2 ppmvd was exceeded 54 times out of 730 measurements (2 turbines x 365 days) during the first year of operation (6/1/05 – 5/1/06), or about 8% of the time. However, during the next two plus years of operation (6/1/06 – 8/08), a CO concentration of 2 ppmvd was exceeded only 6 times out of 822 measurements, or only about 0.4% of the time. This small number of very small exceedances in the post-shakedown period could easily be accommodated by requiring a more efficient oxidation catalyst than the one installed on Metcalf.

This is excellent performance, given the Metcalf design basis and permit limit. Metcalf was permitted in 2000 with a CO limit of 6 ppmvd based on a 3-hour average, *without an oxidation catalyst.* According to the Permit, if stack tests and CEMS data indicated a lower CO limit could be achieved on a consistent basis, the District could reduce the limit to 4 ppmvd.[42] The District should only have considered the data collected after the optimization period.

Both Metcalf and RCEC are Calpine projects based on the same power generation system, a 2-on-1 combined cycle configuration using the same turbines and duct burners. Thus, the achievable CO limit, given the same pollution generation equipment, ultimately depends only upon the presence or absence of an oxidation catalyst and its CO control efficiency. The District disclosed neither. However, our research indicates that an oxidation catalyst was installed in the as-built Metcalf HSRG,[43] guaranteed to remove 76% of the CO. The District's analysis indicates that this facility has met its permit limit. However, this is not credible evidence that RCEC, eight years later, cannot do better.

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http://www.energy.ca.gov/sitingcases/alphabetical.html.

[40] Durilla et al. 2001

[41] SOB, p. 32.

[42] Final Determination of Compliance (FDOC), Metcalf Energy Center, August 24, 2000, Condition 20(d). http://www.baaqmd.gov/pmt/public_notices/1999_2001/27215/index.htm.

[43] The CEC ultimately required an oxidation catalyst to control VOCs. See: The Metcalf Energy Center, Application for Certification 99-AFC-3, Commission Decision, p. 166, Condition AQ-55.

Arguendo, if Metcalf could meet a CO limit of 6 ppmvd, 3 hour average uncontrolled in 2000, as reflected by the Metcalf permit and SOB, RCEC should be able to meet at a CO limit of less than 1 ppmvd with a 90% efficient oxidation catalyst today (0.1x6.0 = 0.6 ppmvd). Alternatively, assuming the 6 ppmvd could only be met with a 76% efficient oxidation catalyst, a 2 ppm limit could have been met with a 92% efficient catalyst.

Regardless, just because Metcalf meets a BACT limit established over eight years ago does not mean that in 2009, the RCEC cannot do better. BACT is determined as of the date of issue of the Permit. There is now a large amount of CO test data from which to make a more informed decision. The District should evaluate it, taking into consideration the installed controls, and make a new CO BACT determination. Further, there are at least three oxidation catalyst vendors in the market who are willing to guarantee 98%+ CO reduction from natural gas fired combustion turbine exhaust. There is simply no excuse for not requiring a CO BACT limit that is comparable to those in many permits that have been issued at 2 ppmvd or lower.

E. Lower Permitted Limits

The District compiled recent BACT determinations for CO from similar gas turbine projects. This tabulation included many BACT determinations that are lower than the 4 ppmvd 1 hour average required for RCEC. These include Turner Energy Center, BP Cherry Point, Wanapa, Morro Bay, Goldendale Energy, Sumas Energy, Bellingham, Magnolia, McDonough, and CPV Warren. Most of these were permitted at 2 ppmd.[44]

In spite of this impressive list of plants with lower CO limits, the District argues a limit in the 2-3 ppm range "may not be achievable for the proposed Russell City Energy Center."[45] The District advances several arguments in support of that limit, none of which have merit.

First, the District tosses out all lower CO limits that are permitted to emit NOx at higher levels on the theory that NOx and CO are inversely related and NOx is more important to reduce. As discussed above, higher NOx is not a valid reason to reject a lower CO limit. Further, once the pollution generating equipment has been selected, which is common to all subject facilities, the degree of CO reduction and NOx reduction are independent of the underlying combustion processes and depend only on the control efficiency of the SCR and oxidation catalyst. The control efficiency of these devices is not related. The lower NOx limit selected as BACT for RCEC does not in any way restrict the efficiency of the oxidation catalyst used to control CO. In fact, the District's tabulation proves the point. It includes one unit,

[44] SOB, pp. 32-33, Table 11.
[45] SOB, p. 34.

IDC Bellingham, that was permitted with both lower NOx (1.5 ppm, 1 hour average) and lower CO (2 ppm, 1 hour average).

Second, the District tosses out lower numeric limits that have longer averaging times. The RCEC limit is based on a 1 hour average, while some of the numerically lower limits are based on 3 hour averages. The District argues these longer averaging times are less stringent as emissions can be averaged over a longer period of time. However, the District fails to point out that a numerically higher limit, regardless of averaging time, represents more pollution than a lower limit. Thus, a 4 ppmvd limit based on a 1 hour average, as proposed for RCEC, will emit twice as much CO as a 2 ppmvd limit based on a 3-hour average. Regardless, averaging time is irrelevant for an oxidation catalyst, which achieves the same level of control on a continuous basis. Averaging time is not specified in an oxidation catalyst quote for this reason, the guarantee is assumed to be met continuously.

Third, the District argues that the majority of facilities with equivalent NOx limits (2 ppm, 1 hour average) have not been built and thus there is no operational data with which to evaluate performance.[46] However, this is not correct. The District shows that two units that have 2 ppm NOx limits and 2 ppm CO limits are operational – Goldendale Energy and Magnolia . The District did not analyze the CO data from these two facilities. Further, there are others that are operational with lower limits that the District did not consider. The District did not evaluate the CO CEMS data for these other facilities. Regardless, another agency's determination that a given CO level is achievable is by itself sufficient to conclude that it is feasible for RCEC, absent a clear demonstration that circumstances exist at RCEC which distinguish it from the other sources with lower limits.[47]

The District argues that operational data is required to make a CO BACT determination. If operational data were required, BACT would present a chicken and egg problem. BACT is intended to be technology forcing, and thus requires the exercise of engineering judgment as to the applicability of transferable or new methods of pollution control. The large number of CO BACT determinations made by many other agencies indicates that a much lower CO limit is achievable, and the District is required to assess the achievability of such lower limits.

Finally, the District's list of recent BACT determinations is incomplete. It omits Kleen Energy Systems, CT (0.9 - 1.7 ppmvd); CPV Warren, VA (1.3 and 1.8 ppmvd); Malburg Generating Station, CA (2.0 ppm), and several Massachusetts plants that were permitted and are operating with a NOx limit of 2 ppm, based on a 1 hour average, and a CO limit of 2 ppm, based on a 1-hour average, including Sithe Mystic

[46] SOB, p. 34.
[47] See, e.g. NSR Manual, p. B.29

(Ex. 26[48]) and Sithe Fore River (Ex. 27[49]). These similar operating facilities with lower CO limits and identical NOx limits establish CO BACT for RCEC.

If you have any questions or concerns, please do not hesitate to contact me at (415) 977-5769 or sanjay.narayan@sierraclub.org. Thank you for your time and attention.

Sincerely,

Sanjay Narayan / SB

Sanjay Narayan

[48] SCAQMD, Section II: Non-AQMD LAER/BACT Determinations, Application No. MBR-99-COM-012, Sithe Mystic Development LLC. http://www.aqmd.gov/bact/MBR-99-COM-012-Mystic2.doc.
[49] Massachusetts Department of Environmental Protection, PSD Permit, Sithe Four River Station, March 10, 2000.

Exhibits

Exhibit 23: http://www.energy.ca.gov/sitingcases/alphabetical.html..................

Exhibit 24: Final Determination of Compliance (FDOC), Metcalf Energy Center, August 24, 2000, Condition 20(d). http://www.baaqmd.gov/pmt/public_notices/1999_2001/27215/index.htm ....

Exhibit 25: The Metcalf Energy Center, Application for Certification 99-AFC-3, Commission Decision, p. 166, Condition AQ-55...

Exhibit 26: SCAQMD, Section II: Non-AQMD LAER/BACT Determinations, Application No. MBR-99-COM-012, Sithe Mystic Development LLC. http://www.aqmd.gov/bact/MBR-99-COM-012-Mystic2.doc

Exhibit 27: Massachusetts Department of Environmental Protection, PSD Permit, Sithe Four River Station, March 10, 2000

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In the Matter of: EPA Final Action Published at 73 Fed. Reg. 80300 (December 31, 2008), entitled "Clean Air Act Prevention of Significant Deterioration (PSD) Construction Permit Program; Interpretation of Regulations That Determine Pollutants Covered by the Federal PSD Permit Program"

AMENDED PETITION FOR RECONSIDERATION

Pursuant to Section 307(d)(7)(B) of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B), the undersigned organizations petition the Administrator of the Environmental Protection Agency ("the Administrator" or "EPA") to reconsider the final action referenced above. This final action constitutes a *de facto* final rule because it purports to establish binding requirements under the Clean Air Act's Prevention of Significant Deterioration ("PSD") program and create new substantive law regarding the applicability of that program, the obligations of permitting authorities, and the rights of citizens, states, and regulated entities. Because EPA did not conduct a proper rulemaking proceeding prior to implementing this final action, as required by Section 307(d), Petitioners had no opportunity to raise objections to it through public comment. The objections raised in this petition are of central relevance to the outcome of the final action because they demonstrate that the action is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 42 U.S.C. § 7607(d)(9)(A). With respect to each objection, moreover, the regulatory language and EPA interpretations that render the rule arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law appeared for the first time in the final action published on December 31, 2008, 73 Fed. Reg. 80300. The Administrator must therefore "convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed." 42 U.S.C. § 7607(d)(7)(B).

The original Petition for Reconsideration was served on EPA on December 31, 2008. This Amended Petition differs from the original only in that it requests, in Section III, below, that EPA stay the effect of this agency action during the pendency of this

Petition for Reconsideration and during any challenge to this action filed in the U.S. Court of Appeals for the District of Columbia Circuit.

INTRODUCTION

On December 18, 2008, EPA issued a document that purports to establish binding requirements under the Clean Air Act's PSD program and create new substantive law regarding the applicability of that program, the obligations of permitting authorities, and the rights of citizens, states, and regulated entities. Memorandum from Stephen L. Johnson, *EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program* (December 18, 2008) (the "Johnson Memo" or "Memo"). EPA published notification of the Johnson Memo in the Federal Register on December 31, 2008. 73 Fed. Reg. 80300.

As discussed below, this final agency action was impermissible as a matter of law, because it was issued in violation of the procedural requirements of the Administrative Procedures Act ("APA"), 5 U.S.C. § 101 et seq., and the Clean Air Act ("CAA"), 42 U.S.C. § 7607, it directly conflicts with prior agency actions and interpretations, and it purports to establish an interpretation of the Act that conflicts with the plain language of the statute. Accordingly, the undersigned organizations request that EPA immediately reconsider and retract the Johnson Memo.

BACKGROUND

In 2007, EPA Region 8 issued a PSD permit for a proposed new 110 MW unit at Deseret Power Electric Cooperative's existing Bonanza coal-fired power plant in Utah. Although Section 165 of the Act requires Best Available Control Technology ("BACT") for "each pollutant subject to regulation under this Act," and although CO_2 is regulated under the Act, the permit contained no BACT limits for CO_2.

In response to comments filed by Sierra Club, EPA contended for the first time in issuing the permit that it was precluded from requiring BACT limits for CO_2 based on a "longstanding interpretation" of the CAA that limited pollutants "subject to regulation" to those subject to actual control of emissions, as opposed to the CO_2 monitoring and reporting regulations in Subchapter C of Title 40 of the CFR. Sierra Club appealed the final permit to EPA's Environmental Appeals Board ("EAB" or "Board").[1]

The EAB rejected EPA's theory, vacated the permit and remanded it to Region 8: "[W]e conclude that the Region's rationale for not imposing a CO_2 BACT limit in the Permit – that it lacked authority to do so because of an historical Agency interpretation of the phrase 'subject to regulation under the Act' as meaning 'subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant' – is not supported by the administrative record." *In re Deseret Power Electric Cooperative*, PSD Appeal 07-03, slip op. at 63 (EAB Nov. 13, 2008), 13 E.A.D. __ *("Bonanza")*. To the contrary, the Board found that the **only** relevant interpretation of the applicable statutory and regulatory language was to be found in EPA's 1978 PSD rulemaking. That interpretation directly contradicted EPA's theory, and in fact "augurs in favor of a finding" that "subject to regulation under this Act" encompasses any pollutant covered by a regulation in Subchapter C of Title 40 of the CFR, such as CO_2. *Bonanza* at 41.

In addition, the Board also required an additional public notice and comment process addressing the question of CO_2 BACT limits for the Bonanza facility: "On remand, the Region shall reconsider whether or not to impose a CO_2 BACT limit in the Permit. In doing so*, the Region shall develop an adequate record for its decision, including reopening the record for public comment*." *Id*. at 64 (emphasis added).

Due to the importance of the issue, the EAB suggested that EPA might want to undertake a proceeding of national scope to deal more broadly with the question of how to address CO_2 in the context of PSD permitting. Regardless of the chosen procedural

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[1] The EAB has exclusive jurisdiction within EPA to review PSD permit decisions. 40 C.F.R. § 124.2(a) ("The Administrator delegates authority to the Environmental Appeals Board to issue final decisions in RCRA, PSD, UIC, or NPDES permit appeals filed under this subpart, including informal appeals of denials of requests for modification, revocation and reissuance, or termination of permits under Section 124.5(b). An appeal directed to the Administrator, rather than to the Environmental Appeals Board, will not be considered.").

mechanism, however, the Board was clear that additional notice and comment proceedings were necessary before EPA could adopt changes to the PSD program.

EPA responded to *Bonanza* by issuing the Johnson Memo, which states, "As of the date of this memorandum, EPA will interpret this definition of 'regulated NSR pollutant' to exclude pollutants for which EPA regulations only require monitoring or reporting but to include each pollutant subject to either a provision of the Clean Air Act or regulation adopted by EPA under the Clean Air Act that requires actual control of emissions of that pollutant." Johnson Memo at 1. EPA published a notice in the Federal Register on December 31, 2008, stating that the Johnson Memo "contains EPA's 'definitive interpretation' of 'regulated NSR pollutant.'" 73 Fed. Reg. 80300.

OBJECTIONS

I. BECAUSE THE JOHNSON MEMO IS NOT AN "INTERPRETIVE RULE," ITS ISSUANCE VIOLATES PROCEDURAL REQUIREMENTS THAT MANDATES AGENCY RECONSIDERATION

The Johnson Memo purports to be "establishing an interpretation clarifying the scope of the EPA regulation that determines the pollutants subject to" the PSD program. Johnson Memo at 1. Whatever else the Johnson Memo is, it is definitely not an "interpretive rule." As the D.C. Circuit has explained:

> Interpretative rules "simply state[ ] what the administrative agency thinks the statute means, and only *remind[ ] affected parties of existing duties*." *General Motors Corp. v. Ruckelshaus,* 742 F.2d 1561, 1565 (D.C. Cir. 1984) (en banc) (internal quotation marks omitted). Interpretative rules may also construe substantive *regulations*. *See Syncor Internat'l Corp. v. Shalala,* 127 F.3d 90, 94 (D.C. Cir. 1997).

Assoc. of Amer. RR v. Dept. of Transp., 198 F.3d 944 at 947 (D.C. Cir. 1999) (emphasis added). It is clear that EPA has so characterized it solely to avoid the procedural requirements – most importantly, public notice and comment – that would otherwise be imposed by the Clean Air Act, the Administrative Procedures Act, and the *Bonanza* decision. The Johnson Memo is a substantive rule, and not an interpretive one, because it reverses a formal agency interpretation, overturns an EAB decision, and amends the substance of the PSD program.

A. <u>The Johnson Memo Reverses a Formal Agency Interpretation</u>

In 1978, EPA determined in a Federal Register preamble that the phrase "'subject to regulation under this Act' means any pollutant regulated in Subchapter C of Title 40 of the Code of Federal Regulations for any source type." 43 Fed. Reg. 26,388, 26,397 (June 19, 1978). This earlier interpretation – which has never been withdrawn or modified – directly conflicts with the interpretation the Memo purports to adopt. As discussed more fully below (pp. 8 *et seq.*), because the Subchapter C regulations include, *inter alia*, regulations that require monitoring and reporting of CO_2 emissions, the EAB held that this language offers *no* support for an interpretation applying "BACT only to pollutants that are 'subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant.'" *Bonanza* at 41. The logical implication of the 1978 Preamble is that BACT applies to CO_2 emissions. At a minimum, the 1978 Preamble accords agency permitting offices discretion under the Act and under EPA's regulations (which merely parrot the language of the Act) to require CO_2 BACT limits in PSD permits. Either way, the Johnson Memo impermissibly seeks to change that interpretation so as to *preclude* consideration of CO_2, thereby significantly modifying the nature and scope of the PSD program without notice and comment rulemaking.

The D.C. Circuit has held that when an agency's purported interpretation of a statute or regulation "constitutes a fundamental modification of its previous interpretation," the agency "cannot switch its position" without following appropriate procedures. *Paralyzed Veterans of Am. v. D.C. Arena L.P.,* 117 F.3d 579, 586 (D.C. Cir. 1997). Once an agency provides an interpretation of a statute – as EPA did here, in 1978 – "it can only change that interpretation as it would formally modify the regulation itself: through the process of notice and comment rulemaking." *Id.*

In an effort to bypass the procedures required by *Paralyzed Veterans*, the Memo claims that it is not actually refuting the 1978 Preamble's interpretation. It suggests, first, that because the 1978 Preamble did not itself "amplify the meaning of the term 'regulated in,'" EPA remains free to insert a wholly new definition of that term. Johnson Memo at 19. The Agency may not, however, evade the procedures mandated by *Paralyzed Veterans* by disguising a revision of governing law as an interpretation of its previous interpretation. *Paralyzed Veterans*, 117 F.3d at 586 (refusing to allow revisions or modifications of agency interpretations without notice and comment).

Second, the Memo contends that "the 1978 statement referred to the language in the statute which said 'pollutant subject to regulation under this Act,'" while "the 2002 regulation I am interpreting here uses the phrase 'pollutant that otherwise is subject to regulation under the Act.'" Johnson Memo at 19. The latter phrase, however, is a component of the former, so that the Memo's interpretation of "pollutant[s] . . . otherwise . . . subject to regulation under the Act" necessarily limits its interpretation of "pollutant[s] subject to regulation under this Act." 40 C.F.R. § 52.21(b)(50)(iv).

B. The Johnson Memo Overturns the EAB's *Bonanza* Decision.

While the Johnson Memo states that it "is not intended to supersede the Board's decision," Johnson Memo at 2, that is exactly what it does, even though the Administrator has no jurisdiction to undo a statutory interpretation adopted in an EAB ruling or substitute his judgment for that of the Board. *See* 40 C.F.R. § 124.2(a). The Board held that to adopt a new interpretation of the PSD regulatory program, EPA *must* undertake a new notice and comment process. *Bonanza* at 64 ("On remand, the Region *shall* reconsider whether or not to impose a CO_2 BACT limit in the Permit. In doing so, the Region *shall* develop an adequate record for its decision, including reopening the record for public comment.") (emphasis added).

Thus, the EAB – the final agency decision-maker as to PSD permits – has already addressed whether a notice and comment process is required for EPA to change its position regarding the appropriate scope of analysis in PSD permits, and concluded that it is. Significantly, the Board also ruled that the existing record was inadequate to support the agency's attempted reinterpretation of the Act – directing the agency on remand to "develop an adequate record for its decision." *Id.*[2]

[2] The EAB also specifically *rejected* EPA's argument that its interpretation was supported by "historic practice," finding it insufficient to undo "the authority the Region admit[ed] it would otherwise have under the statute." *Bonanza* at 46. In its attempt to circumvent the Board's conclusion, the Memo appears to introduce new evidence that

While the Board suggested that "[t]he Region should consider whether interested persons, as well as the Agency, would be better served by the Agency addressing the interpretation of the phrase 'subject to regulation under this Act' in the context of an action of nationwide scope, rather than through this specific permitting proceeding," *id.*, the Board clearly anticipated a process involving public notice and comment. EPA simply can not excuse itself from its legal obligation to pursue additional notice and comment before finalizing a change to its PSD regulations merely by seeking to adopt its new interpretation of the Act through an "interpretive rule".

To the extent that the Johnson Memo attempts to rely on public participation in the specific adjudicatory proceeding regarding the Bonanza plant, or public participation in an advanced notice of proposed rulemaking ("ANPRM") (which broadly addressed the implications of any and all potential EPA regulatory actions regarding greenhouse gases, 73 Fed. Reg. 44353 (July 30, 2008)), such reliance is legally insufficient to cure the procedural failures of this illegal rulemaking. Among other things, the *Bonanza* proceeding addressed only a single facility, and the adjudicatory process associated with an individual permit proceeding cannot substitute for notice and comment on a legislative rule of broad national significance. Even the parties to that proceeding did not have the benefit of the agency's fully-developed litigation position until EPA filed its supplemental brief that the Board ordered after oral argument. As the Board's final order requiring notice and comment on remand clearly indicates, that proceeding did not provide sufficient public process to support a decision to omit a CO_2 BACT limit from that particular permit, much less serve as an adequate substitute for notice and comment on a rule of nationwide scope.

Similarly, in the ANPRM, EPA never indicated its intention to take imminent final action establishing new parameters for the PSD regulatory program. To the contrary, the ANPRM by its very nature was probing and exploratory, not a vehicle intended to result in a final and binding agency policy. Indeed, as the Administrator's preface to the ANPRM explained: "None of the views or alternatives raised in this notice represents

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has never been subject to scrutiny of any kind. Johnson Memo at 11 (referring to "the record of permits compiled to support this memorandum").

Agency decisions or policy recommendations. It is premature to do so." 73 Fed. Reg. at 44355. Moreover, neither the adjudicatory proceeding nor the ANPRM provided any notice of EPA's specific intent to reinterpret the agency's policy articulated in the 1978 preamble. Accordingly, these activities cannot serve to dispose of the agency's obligation to undertake notice and comment processes before adopting a final legislative rule amending the CAA's PSD program.

C. The Johnson Memo Substantively Amends the PSD Program

The Johnson Memo seeks to substantively amend EPA regulations to establish new legal rights, restrictions, and/or obligations under the Act's PSD program, without any associated notice and comment process. This 19-page memo also takes a large number of other regulatory steps, including establishing specific exceptions to this rule (*e.g.,* exempting pollutants that are subject to regulation under the Act through state implementation plans ("SIPs") (Johnson Memo at 15));[3] establishing Regional Office responsibilities with regard to future SIP submittals (*Id*. at 3 n.1); determining how pollutants will become subject to PSD permitting in the future on enactment of new congressionally-mandated emission limits (*Id*. at 6 n.5); imposing requirements that address when pollutants for which EPA has made a regulatory endangerment determination must be treated as PSD pollutants (*Id*. at 14); and defining when and how import restrictions will trigger PSD for a pollutant. The sheer breadth of issues addressed, regarding numerous and disparate regulatory programs, defies EPA's claim that this is a mere "interpretive rule."

Thus, EPA's action constitutes an unlawful rulemaking under the APA and the CAA. EPA's action in the Johnson Memo, according to its own terms, treats the conclusions in the Memo as binding on EPA itself, and on states implementing the federal PSD program through delegation agreements with EPA, and leads "private parties or . . . permitting authorities to believe that it will declare permits invalid unless

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[3] We note, as EPA points out, that it has adopted a similar approach in at least one other regulatory program, *see* Johnson Memo at 15-16 (regarding the treatment of ammonia as $PM_{2.5}$ precursors), but that it did so – as it should have here – by notice and comment rulemaking. *See* 70 Fed. Reg. 65984; 73 Fed. Reg. 28321.

they comply with [its] terms." *Appalachian Power Co. v. EPA,* 208 F.3d 1015, 1021 (D.C. Cir. 2000). The Johnson Memo states that its newly established substantive parameters governing EPA's regulatory program, which significantly modify the federal PSD program, represent the agency's "settled position." *Id.* at 1022. It "reads like a ukase." *Id.* at 1023. Finally, the Memo certainly creates and/or changes the "rights," "obligations," and scope of authority of various parties, including EPA itself, citizens, regulated entities, and possibly delegated State permitting authorities, and "commands," "requires," "orders," or "dictates" a particular regulatory approach that will affect the rights of parties in currently pending and future permitting actions. *Id.* at 1023; *see also General Elec. Co. v. EPA,* 290 F.3d 377, 380 (D.C. Cir. 2002) (EPA risk assessment document was a legislative rule, "because on its face it purports to bind both applicants and the Agency with the force of law").

In sum, the Johnson Memo is a new regulation that adopts a substantially new interpretation of the Act and seeks to implement that interpretation through uncodified substantive changes to the PSD regulatory program. The D.C. Circuit has made clear that agencies may not avoid the procedural requirements by this sort of subterfuge:

> Although [our] verbal formulations vary somewhat, their underlying principle is the same: ***fidelity to the rulemaking requirements of the APA bars courts from permitting agencies to avoid those requirements by calling a substantive regulatory change an interpretative rule***.

U.S. Telecom Ass'n v. F.C.C., 400 F.3d 29, 35 (D.C. Cir. 2005) (emphasis added and citations omitted). Accordingly, EPA must withdraw the Johnson Memo, and proceed, if at all, through appropriate notice and comment procedures.

II. THE POSITIONS ASSERTED IN THE JOHNSON MEMO ARE IMPERMISSIBLE UNDER THE CLEAN AIR ACT

The Johnson Memo purports to adopt a binding interpretation of a regulation that parrots the Clean Air Act phrase, "pollutant subject to regulation under this Act." That interpretation would "exclude pollutants for which EPA regulations only require monitoring or reporting but . . . include each pollutant subject to either a provision in the Clean Air Act or regulation adopted by EPA under the Clean Air Act that requires actual control of emissions of that pollutant." Johnson Memo at 1. The Memo thus attempts to revive a definition that the EAB found was not supported by any prior EPA interpretation of the statute. The Memo misconstrues the plain language of the Act, adopts impermissible interpretations of existing regulations, and ignores the distinct purpose of the PSD program in a vain attempt to forestall CO_2 emissions limits. In so doing, the Memo runs contrary to the Clean Air Act's clear mandate and flouts the Supreme Court's direction to use the regulatory flexibility that Congress provided to address new threats, such as climate change. *Massachusetts v. EPA,* 127 S. Ct. 1438, 1462 (2007).

A. The Johnson Memo Ignores the Plain Language of the Clean Air Act Requiring BACT for CO_2 Emissions.

EPA must impose emissions limitations on CO_2 in PSD permits for new coal-fired power plants. Section 165(a)(4) of the Clean Air Act requires BACT "for each pollutant subject to regulation under this chapter emitted from . . . such facility." 42 U.S.C. § 7475(a)(4). As even EPA now acknowledges, CO_2 is a pollutant under the Clean Air Act. *Massachusetts* , 127 S. Ct. at 1462. It is emitted abundantly by coal-fired generators and is currently regulated under the Clean Air Act through the Delaware SIP, as well as under monitoring and reporting requirements established by Section 821 of the 1990 Clean Air Act Amendments and the CO_2 monitoring requirements established by Congress' 2008 Appropriations Act.[4]

1. The Delaware SIP

On April 29, 2008, EPA approved a State Implementation Plan revision submitted by the State of Delaware that establishes emissions limits for CO_2, effective May 29, 2008. AR 123.3, 12.3, 73 Fed. Reg. 23101. The SIP revision imposes such CO_2 limits on new and existing distributed generators. Delaware Department of Natural Resources and Environmental Control, Division of Air and Waste Management, Air Quality Management Section, Regulation No. 1144. AR 123.2, Ex. 12.2., § 3.0.

In EPA's proposed and final rulemaking notices, EPA stated that it was approving the SIP revision "under the Clean Air Act," 73 Fed. Reg. 11,845, and "in accordance

[4] To the extent the EAB declined to hold that the PSD provision requires use of BACT for CO_2 emissions, the undersigned disagree with the Board's decision in that case. *American Bar Ass'n v. F.T.C.*, 430 F.3d 457, 468 (D.C. Cir. 2005) (reviewing courts "owe the agency no deference on the existence of ambiguity").

with the Clean Air Act," 73 Fed. Reg. at 23,101. EPA's approval made these CO_2 control requirements part of the "applicable implementation plan" enforceable under the Act, 42 U.S.C. § 7602(q), and numerous provisions authorize EPA to so enforce these SIP requirements, *e.g.*, 42 U.S.C. § 7413 (authorizing EPA compliance orders, administrative penalties and civil actions). In addition, EPA's approval makes these emission standards and limitations enforceable by a citizen suit under Section 304 of the Act. 42 U.S.C. § 7604(a)(1), (f)(3).

The Delaware SIP Revision constitutes regulation of CO_2 under the Clean Air Act because it was adopted and approved under the Act and is part of an "applicable implementation plan" that may be enforced by the state, by EPA, and by citizens under the Clean Air Act. Thus CO_2 is a pollutant "subject to regulation" under the Act for BACT purposes, **even under the definition put forth in the Johnson Memo** because it is "subject to . . . [a] regulation adopted by EPA under the Clean Air Act that requires actual control of emissions." Johnson Memo at 1.

Nevertheless, in an effort to evade the consequences of the Delaware SIP, the Memo purports to create an exception specifically designed to exclude the SIP from its definition of "regulation under the Act." *Id.* at 15. As support for its novel (and incorrect) interpretation, the Memo purports to rely on *Connecticut v. EPA*, 656 F.2d 902 (2d Cir. 1981). It construes that case as holding that the "Congress did not allow individual states to set national regulations that impose those requirements on all other states." Johnson Memo at 15. But *Connecticut* does not support that conclusion; indeed, it has nothing to do with the issue here, namely whether a particular pollutant is "subject to regulation" under the Act. Clean Air Act § 165(a)(4). Rather, *Connecticut* discusses only whether the quantitative limits imposed by one state on a particular pollutant apply to neighboring states under the "good neighbor" provision in § 110. *See Connecticut*, 656 F.2d at 909 (Section "110(a)(2)(E)(i) is quite explicit in limiting interstate protection to federally-mandated pollution standards.") (emphasis added). *Connecticut* provides no support to the Johnson Memo's arbitrary limitation on the scope of what constitutes a regulation under the Act – and demonstrates that the Memo's interpretation is driven not by the language or purpose of the statute, but rather by the agency's intractable refusal to address CO_2 emissions.

Nothing illustrates this better than the Memo's conclusion that "EPA does not interpret section 52.21(b)(50) of the regulations to make CO2 'subject to regulation under the Act' for the nationwide PSD program based solely on the regulation of a pollutant by a single state in a SIP approved by EPA." Johnson Memo at 15. In other words, conceding that the Delaware SIP constitutes "regulation under the Act", the Memo takes the position that such regulation by a single state is not enough. Neither the Act nor its regulations provide a basis for this position – indeed, the Memo makes no attempt to provide a basis.

Thus the Johnson Memo replaces the simple statutory test of whether a pollutant is "subject to regulation under the Act" with a test of whether the pollutant is "subject to regulation under the Clean Air Act in a sufficient number of states or, alternatively, in the state (or Region) where the facility is to be constructed."[5] But that is not what the Act says, nor does the Memo offer any support for the contention that regulation of CO_2 in another part of the country does not count as "regulation." Under the plain language of Section 165(a)(4), if CO_2 emissions are restricted under the Clean Air Act, whether in one state or all 50, they are "subject to regulation under the Act" – even under the Memo's improperly narrow definition of "regulation."

Finally, SIP regulations appear in "Subchapter C of Title 40 of the Code of Federal Regulations." 43 Fed. Reg. at 26,397. *See, e.g.,* 40 C.F.R. § 52.420 (2008) (incorporating by reference provisions of Delaware SIP). They are, accordingly, within the scope of the Agency's governing 1978 interpretation, even if that interpretation meant to say "regulated by requiring actual control of emissions" when it said "regulated." If the EPA wished to exclude SIP-based regulations, it would be required to modify its current interpretation, and provide the public with notice and an opportunity to comment upon that modification. *See Paralyzed Veterans,* 117 F.3d at 586.[6]

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[5] The Memo does not disclose how many states Administrator Johnson believes would suffice. Two? Three? Six? Fourteen?

[6] The EAB did not reach the issue of whether CO_2 is regulated under the Clean Air Act because it is regulated in the Delaware SIP, instead directing EPA to consider this issue "along with other potential avenues of regulation of CO_2." *Bonanza* at 55 n.57.

2. Section 821

In addition to being regulated under the Delaware SIP, CO_2 is regulated under Section 821 of the Clean Air Act Amendments of 1990. Section 821 requires EPA to "promulgate regulations" requiring major sources, including coal-fired power plants, to monitor carbon dioxide emissions and report their monitoring data to EPA:

> The Administrator of the Environmental Protection Agency *shall promulgate regulations* within 18 months after the enactment of the Clean Air Act Amendments of 1990 *to require that all affected sources subject to Title [IV] of the Clean Air Act shall also monitor carbon dioxide emissions* according to the same timetable as in Sections [412](b) and (c). *The regulations shall require that such data be reported to the Administrator*. The provisions of Section [412](e) of title [IV] of the Clean Air Act shall apply for purposes of this Section in the same manner and to the same extent as such provision applies to the monitoring and data referred to in Section 412.

42 U.S.C. § 7651k note; Pub. L. 101-549; 104 Stat. 2699 (emphasis added). In 1993, EPA promulgated these regulations, which require sources to monitor CO_2 emissions, 40 C.F.R. §§ 75.1(b), 75.10(a)(3), prepare and maintain monitoring plans, *id.* § 75.33, maintain records, *id.* § 75.57, and report monitoring data to EPA, *id.* § 75.60-64. The regulations prohibit operation in violation of these requirements and provide that a violation of any Part 75 requirement is a violation of the Act. *Id*. § 75.5. Not only do the regulations require that polluting facilities "measure . . . CO_2 emissions for each affected unit," *id*. § 75.10(a), they also prohibit operation of such units "so as to discharge or allow to be discharged, emissions of . . . CO_2 to the atmosphere without accounting for all such emissions . . . . " *Id*. § 75.5(d).

In *Bonanza*, EPA argued that monitoring regulations are not actually regulation and that Section 821 did not actually amend the Clean Air Act. The EAB having rejected EPA's attempt to banish Section 821 from the Act, the Johnson Memo now depends solely on the flawed argument that regulation requiring monitoring and reporting is not regulation. On the contrary, monitoring and reporting requirements clearly constitute regulation. Against the backdrop of Section 165's use of "regulation," Congress explicitly used that exact same word in Section 821 to refer solely to monitoring and reporting requirements. Just like regulations restricting emissions quantities, the regulations EPA promulgated implementing Section 821 have the force of law, and violation results in severe sanctions. 40 C.F.R. § 75.5; 42 U.S.C. § 7413(c)(2) (punishable by imprisonment of up to six months or fine of up to $10,000 for making false statement or representation or providing inaccurate monitoring reports under Clean Air Act).[7] Indeed, as the Region and OAR admitted in the supplemental brief (and exhibits) they filed with the EAB in *Bonanza*, EPA has enforced section 821 in a number of consent decrees that require the installation of CO_2 monitoring equipment.

In support of the interpretation of "regulation" to mean only a restriction on emissions quantity, the Johnson Memo recites the assorted dictionary definitions of "regulation" from the *Bonanza* briefing without any discussion of Section 821 and its use of this exact same word. Nor does the Memo appear to recognize that each of those definitions would include monitoring. Its preferred definition – "the act or process of controlling by rule or restriction" – encompasses regulations to monitor emissions just as easily as regulations that limit emissions quantities. Pursuant to Section 821, CO_2 is "controlled" by a "rule or restriction" because EPA's regulations require that emissions be monitored, which cannot be done if those emissions are freely emitted; by definition, monitoring requires that the flow of emissions be controlled. Indeed, monitoring creates more direct control over emissions of a pollutant than import restrictions, which involve only indirect control over emissions. Moreover, "control" is not synonymous with "cap" or "limit." The Memo clearly recognizes that distinction because it repeatedly supplements the original language of its interpretation ("actual control of emissions") by adding "limitation" ("actual control or limitation of emissions"). *See, e.g.,* Johnson Memo at 8. Finally, *Black's* defines "control" as "the power or authority to manage, direct, or

[7] In addition to the monitoring requirements imposed by Section 821, Congress has specifically required monitoring of all greenhouse gases, including CO_2, economy-wide, in the 2008 Consolidated Appropriations Act. H.R. 2764; Public Law 110-161, at 285 (enacted Dec. 26, 2007). As a result, CO_2 monitoring and reporting is required under the Act separate and apart from Section 821. The Johnson Memo attempts to evade the consequences of the Appropriations Act requirement by, among other things, opining that a pollutant is not "subject to regulation" when Congress specifically tells EPA to regulate it, but only when EPA actually adopts regulations. Johnson Memo at 14. The deadline has passed for EPA to issue the proposed regulations required by the Appropriations Act with no action by EPA.

oversee." *Black's Law Dictionary* (8th ed. 2004). Monitoring and reporting regulations certainly constitute oversight.

The Johnson Memo serves to confuse rather than clarify the definition of regulation. EPA should withdraw it and comply with the plain language of the Act, which requires BACT limits for pollutants subject to monitoring and reporting regulations.

B. The Interpretation in the Johnson Memo is Inconsistent with the Only Relevant Regulatory History.

1. The 1978 Preamble

The Johnson Memo repudiates the only Agency interpretation of the words "subject to regulation under this Act" that the EAB identified as "possess[ing] the hallmarks of an Agency interpretation that courts would find worthy of deference" – the preamble to the Agency's 1978 Federal Register rulemaking, 43 Fed. Reg. 26,388, 26,397 (June 19, 1978). *Bonanza* at 39. In the 1978 Federal Register preamble, the Administrator established that "'subject to regulation under this Act' means any pollutant regulated in Subchapter C of Title 40 of the Code of Federal Regulations for any source type." 43 Fed. Reg. at 26,397. As the Board recognized, that preamble offers *no* support for an interpretation applying "BACT only to pollutants that are 'subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant.'" *Bonanza* at 41. Instead (again, as expressly noted by the Board) it implies that "CO_2 became subject to regulation under the Act in 1993 when the Agency included provisions relating to CO_2 in Subchapter C." *Id.* at 42 n.43.

Under the 1978 preamble definition, CO_2 is "subject to regulation" for BACT purposes because it is regulated under Subchapter C of Title 40 of the Code of Federal Regulations. In its 1993 rulemaking to revise the PSD regulations, EPA did not withdraw its 1978 interpretation of "subject to regulation." *See Bonanza* at 42; *see also* Acid Rain Program: General Provisions and Permits, Allowance System, Continuous Emissions Monitoring, Excess Emissions and Administrative Appeals, 58 Fed. Reg. 3,590, 3,701 (Jan. 11, 1993) (final rule implementing § 821's CO_2 monitoring and reporting regulations). Nor has any subsequent rulemaking, including the 2002 rulemaking on which the Johnson Memo relies, disturbed the 1978 interpretation. *See*

Bonanza at 46. Thus, the only existing EPA interpretation of the phrase “subject to regulation” in Section 165(a)(4), 42 U.S.C. § 7465(a)(4), affirms that BACT is required for CO_2 emissions because it is regulated under the Act’s implementing regulations.

The Johnson Memo seeks to change this interpretation. It purports to establish that henceforth, BACT will be required for “only those pollutants for which the Agency has established regulations requiring actual controls on emissions,” Johnson Memo at 12 precisely the interpretation to which, according to the Board, “the 1978 Federal Register preamble *does not lend support.”* *Bonanza* at 41 (emphasis added).

EPA seeks to elide its amendment of the 1978 interpretation via two routes. First, it asserts that “the specific categories of regulations identified in the second sentence of the passage quoted above are all regulations that require control of pollutant emissions.” Johnson Memo at 12. *Bonanza* directly refutes that claim: “Nothing in the 1978 preamble . . . indicates that the Agency intended to depart from the normal use of ‘includes’ as introducing an illustrative, and non-exclusive, list of pollutants subject to regulation under the Act.” *Bonanza* at 40 (holding that “we must reject” the “conten[tion] that only the pollutants identified in the preamble by general category defined the scope of the Administrator’s 1978 interpretation).

Second, the Memo claims that the phrase “regulated in” as it appears in the 1978 Preamble is ambiguous and thus subject to clarification by the Agency, such that the 1978 Preamble may be understood to mean “regulated by actual control of emissions” by use of the term “regulated.” Johnson Memo at 12. (“[I]t is still not clear that a monitoring or reporting requirement added to subchapter C would make that pollutant ‘regulated in’ Subchapter C because of the alternative meanings of the term regulation, regulate, and regulated discussed earlier”).

This newly proposed understanding of the words “regulated in” fits so unnaturally with the text of the 1978 Federal Register preamble as to defy credibility. That understanding would, entirely *sub silentio,* impose an enormously substantive and restrictive qualification by use of the words “regulated in,” while dismissing the far more prominent reference to “Subchapter C of Title 40 of the Code of Federal Regulations” as irrelevant verbiage. Like Congress, agencies cannot be presumed to hide such "elephants in mouseholes." *Whitman v. American Trucking Ass'n*, 531 U.S. 457, 468 (2001). The words "regulated" and "regulation," appear pervasively throughout the 1978 Federal Register preamble, uniformly meaning (as they always do) *any* act of regulating or regulation. *See, e.g.*, 43 Fed. Reg. 26,389 ("The regulations made final today apply to any source . . ."), 26,398 ("In the regulations adopted today, EPA's assessment of the air quality impacts of new major sources and modifications will be based on" certain EPA guidelines), 26,401 ("Such offsets have always been acceptable under the agency's PSD regulations . . . ."), 26,402 ("Environmental groups pointed out that the proposed regulations did not specifically require Federal Land Managers to protect "affirmatively" air quality related values . . . .").

Those references demonstrate that the Agency in 1978 used "regulation" and "regulate" as they are generally used: to encompass all forms of regulation. In explaining the meaning of the phrase "subject to regulation," the Agency offered no hint that, merely by employing the words "regulated in," it was departing from that standard-English definition – much less that it was adopting the Johnson Memo's "alternative" definition. Under any plausible reading, the 1978 Federal Register preamble used "regulated in" to describe *all* the regulations contained "in Subchapter C of Title 40 of the Code of Federal Regulations." *See Bonanza* at 41-42 & n.43 (noting that "plain and more natural reading of the preamble's interpretative statement suggests a different unifying rule" than a rule that would limit "regulation" to actual control of emissions).[8]

The Johnson Memo's proposed interpretation of the term "subject to regulation" via the "regulated in" subterfuge is not only disingenuous, but absurd. The Memo claims that the Agency can freely substitute its new definition of "regulation" as "regulation requiring actual control of emissions" for the word "regulation" in whatever form the latter appears, apparently in any regulatory document. Johnson Memo at 11.

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[8] Indeed, in *Bonanza* EPA assumed that the 1978 Preamble used the word "regulated" in this most natural sense, hence its reliance on the enumerated examples as limiting "the scope" of the reference to the Code of Federal Regulations, and its citation of the preamble to the 1993 rulemaking as reflecting an intent to avoid including CO_2 among the pollutants regulated under the Act. *Bonanza* at 41-42.

Nor, logically, does it stop there: not only “regulation”, but also “regulate” and “regulated” are now up for grabs; they now mean anything Administrator Johnson wants them to mean, wherever they might appear in any environmental statute or EPA regulation.

2. The 2002 Regulation

The Johnson Memo attempts to narrow the plain language of the Clean Air Act and EPA’s 1978 interpretation of that language by purporting to interpret a 2002 implementing regulation rather than the statute itself. That regulation states:

> *Regulated NSR pollutant,* for purposes of this section, means the following:
>
> (i) Any pollutant for which a national ambient air quality standard has been promulgated and . . . any constituent[s] or precursors for such pollutant[s]. . . . identified by the Administrator [e.g., volatile organic compounds are precursors for ozone];
>
> (ii) Any pollutant that is subject to any standard promulgated under section 111 of the Act;
>
> (iii) Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act; [or]
>
> (iv) **Any pollutant that otherwise is subject to regulation under the Act;** except that any or all hazardous air pollutants either listed in section 112 of the Act or added to the list pursuant to section 112(b)(2) of the Act, which have not be delisted pursuant to section 112(b)(3) of the Act, are not regulated NSR pollutants unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Act.

40 C.F.R. § 52.21(b)(50) (emphasis added). The Memo declares that it is interpreting the phrase “any pollutant that otherwise is subject to regulation under the Act” in this definition when it excludes pollutants subject to monitoring regulations and pollutants regulated “solely . . . by a single state in a SIP approved by EPA.” Johnson Memo at 15.

In reality, the Johnson Memo is interpreting the language of the statute. The agency’s interpretation of its regulation is not entitled to deference because the regulation simply parrots the language of the statute.

> [T]he existence of a parroting regulation does not change the fact that the question here is . . . the meaning of the statute. An agency does not acquire special authority to interpret its own words when, instead of using its expertise and experience to formulate a regulation, it has elected merely to paraphrase the statutory language.

Gonzales v. Oregon, 546 U.S. 243, 257 (2006). Moreover, because the regulation merely paraphrases statutory language that EPA already interpreted in 1978, that earlier interpretation applies to the language of both the statute and rule absent an indication in the 2002 rulemaking that EPA was abandoning it; as EAB found, that rulemaking contained no such indication. *Bonanza* at 46. EPA cannot now change its prior interpretation in a memo issued with complete disregard for the public notice and comment that the law requires. *See* pp. 4-9, *supra.*

The Johnson Memo rationalizes its narrow interpretation by relying on a canon of statutory construction known as *ejusdem generis*, which provides that "where general words follow the enumeration of particular classes of things, the general words are most naturally construed as applying only to things of the same general class as those enumerated." *Am. Mining Cong. v. EPA*, 824 F.2d 1177, 1189 (D.C. Cir. 1987) (quoted in *Bonanza* at 45). It reasons that EPA can construe "otherwise subject to regulation" in subsection (iv) to apply to the same class of pollutants allegedly covered by subsections (i) – (iii) of the "regulated NSR pollutant" definition—those "pollutants subject to a promulgated regulation requiring actual control of a pollutant." Johnson Memo at 8.

Numerous defects undermine this reasoning. Most importantly, it directly conflicts with the *Bonanza* decision because the EAB explicitly held that it is not appropriate to use *ejusdem generis* to interpret a parroting regulation "[w]ithout a clear and sufficient supporting analysis or statement of intent *in the regulation's preamble.*" *Bonanza* at 46 (emphasis added). The Memo attempts to remedy this omission by belatedly supplying "additional analysis and statement of intent regarding the regulation." Johnson Memo at 9. Analysis in a memo, however, is an inadequate substitute for the missing analysis in the rulemaking itself. The EAB held that the analysis should be in the preamble, and the failure to include it deprives the public of proper notice and the opportunity to comment.

Indeed, *ejusdem generis* is entirely inapplicable in this situation. The fundamental dispute here concerns the meaning of a broadly-worded provision of the Clean Air Act, not the nearly identical language of a subsection of the regulation. The Act does not contain a list; it contains a single broad category of pollutants "subject to regulation." The Supreme Court has cautioned against narrowly interpreting the broad language of the Clean Air Act. *Massachusetts*, 127 S.Ct. at 1462. EPA may not restrict that language through the back door by interpreting a parroting regulation with a narrowing canon of construction not suited to the statute itself.

Even looking at only the regulation, applying *ejusdem generis* is inappropriate because "the whole context dictates a different conclusion." *Norfolk & W. Ry. Co. v. Am. Train Dispatchers' Ass'n*, 499 U.S. 117, 129 (1991). The first three subsections of the regulation refer to pollutants subject to a "standard" that has been promulgated, while the fourth covers "[a]ny pollutant that is *otherwise* subject to *regulation* under the Act." 40 C.F.R. 52.21(b)(50) (emphasis added). The use of "otherwise" and "regulation" indicates that it applies to pollutants regulated in some other way than by a standard. Moreover, subsections (i) through (iii) are not so alike, since subsection (i) refers to ambient air quality standards that in and of themselves do not require control of emissions, (ii) refers to standards governing emissions from sources, and (iii) refers to standards that only indirectly control emissions. Tellingly, the "general class" that the Johnson Memo identifies ("pollutants that are subject to a promulgated regulation requiring actual control of a *pollutant*") differs from the other iterations of the interpretation (pollutants subject to a regulation "that requires actual control of *emissions* of that pollutant)," in a way evidently designed to minimize the differences among the three pollutant categories enumerated. Memo at 8, 1 (emphasis added).

C. The Johnson Memo Contravenes the Purpose and Structure of the Clean Air Act By Prohibiting BACT for CO_2 Emissions.

Limiting BACT as described in the Johnson Memo ignores the broad, protective purpose of the PSD program. Congress explicitly stated that the purpose of the PSD program was to "protect public health and welfare from **any** actual or **potential adverse effect** which in the Administrator's judgment may reasonably be anticipate[d] to occur from air pollution . . . notwithstanding attainment and maintenance of all national ambient air quality standards." 42 U.S.C. § 7470(1) (emphasis added). In stark contrast, Congress required EPA to make an endangerment finding before establishing generally applicable standards such as the NAAQS, New Source Performance Standards, or motor vehicle emissions standards. Each of these programs expressly require EPA to find that emissions of a pollutant "cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare" as a prerequisite to regulation. *Id.* § 7408(a)(1)(A); *id.* § 7521(a)(1); *see also id.* § 7411(b)(1).

In the PSD program, Congress used language showing that it clearly intended that BACT apply regardless of whether an endangerment finding had been made for that pollutant. Thus Congress – which was quite familiar with the "endangerment trigger" – deliberately established a much lower threshold for requiring BACT than an "endangerment finding." Thus requiring BACT for "each pollutant subject to regulation under the Act" meshes perfectly with the purpose of the PSD program to guard against any "potential adverse effect" as opposed to "endangerment of public health or welfare." And because the BACT analysis entails a case-by-case inquiry, it is more dynamic in assimilating new information than other statutory standards, such as New Source Performance Standards.

As the Johnson Memo's focus on endangerment demonstrates, *see, e.g.*, Johnson Memo at 18, the interpretation it adopts improperly limits the scope of the PSD program and the BACT requirement. It ignores the broader purpose of the PSD program by limiting the BACT requirement to pollutants already subject to limitations on emissions. *Id.* at 13. Strangely, it attempts to justify this interpretation by stating: "The fact that Congress specified in the Act that BACT could be no less stringent than NSPS and other control requirements under the Act indicates that Congress expected BACT to apply to pollutants controlled under these programs." *Id.* But, quite obviously, the fact that BACT *applies* to pollutants controlled under those programs does not mean that it is *limited* to them. Instead, the congressional directive that BACT be no less stringent than those other control requirements is a further indication that BACT is meant to be ***more*** protective and apply more broadly. The Johnson Memo demonstrates a fundamental misperception of the role of the PSD program and its BACT requirement within the Act.

D. The Need to Study Pollutants Does Not Justify Prohibiting BACT for CO_2.

The Johnson Memo defends the decision to prohibit BACT limits for CO_2 by asserting that it would "frustrate the Agency's ability to gather information using Section 114 and other authority and make informed and reasoned judgments about the need to establish controls or limitations on individual pollutants." *Id.* at 9. This rationale is nothing but a red herring. Throughout the *Bonanza* proceeding, EPA has not identified a single pollutant other than CO_2 that would be affected by an interpretation of "regulation" in Section165 to include monitoring and reporting regulations. EPA is free to gather information about pollutants under Section 114 without adopting regulations. And Congress explicitly singled out CO_2 as a pollutant of special concern in Section 821. Nothing in that provision indicates that Congress intended CO_2 to be considered regulated under the Act for some purposes but not for other purposes. If Congress directs EPA to adopt monitoring regulations under the CAA for particular pollutants, it can choose to expressly exclude those pollutants from BACT requirements, but it did not do so in Section 821.

The Johnson Memo opines that "[t]he current concerns over global climate change should not drive EPA into adopting an unworkable policy of requiring emissions controls under the PSD program any time that EPA promulgates a rule under the Act that requires a source to gather or report emissions data under the Act for any pollutant." *Id.* at 10. But EPA has not demonstrated that anything is unworkable about requiring BACT for pollutants subject to monitoring regulations when Congress has expressly singled out specific pollutants for regulation without excluding them from BACT. And it has not demonstrated that BACT would be required in any other situation. EPA has pointed to nothing in the Act that supports its position that requiring BACT for pollutants subject to monitoring conflicts with Congress' information-gathering objectives under the Act. *See Massachusetts,* 127 S.Ct. at 1460-61 ("And unlike EPA, we have no difficulty reconciling Congress' various efforts to promote . . . research to better understand climate change with the agency's pre-existing mandate to regulate 'any air pollutant' that may endanger the public welfare.") (footnote and citation omitted). As the Supreme Court has held, EPA cannot ignore its duties under the Clean Air Act to address pollutants that cause global climate change, and the statute offers the regulatory flexibility needed to do so. *Id.* at 1462.

The plain language of the Clean Air Act, its structure, and authoritative regulatory history of the phrase, "subject to regulation under this Chapter" all support the conclusion that BACT is required for *each* pollutant subject to any sort of regulation under the Act. The EAB has held that EPA has never established a contrary position in any action entitled to deference, and it may not now do so in an internal agency memorandum.

III. EPA SHOULD STAY THE EFFECT OF THE JOHNSON MEMO

By its own terms, the Johnson Memo purports to go into effect "immediately." Johnson Memo at 2. Because the Memo so clearly violates both the procedural requirements of the Administrative Procedure Act, the Clean Air Act, and the *Bonanza* decision, as well as the substantive requirements of the Clean Air Act, EPA should stay implementation of the Memo during the pendency of this Petition for Reconsideration and during the pendency of any challenge to the Memo in the U.S. Court of Appeals for the District of Columbia Circuit.

CONCLUSION

EPA must reconsider its final action for all of the reasons stated above.

DATED: January 6, 2009

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The Design of High-Efficiency Turbomachinery and Gas Turbines

Second Edition

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Upper Saddle River, New Jersey 07458

Library of Congress Cataloging-in-Publication Data
Wilson, David Gordon.
The design of high-efficiency turbomachinery and gas turbines / by David Gordon Wilson and Theodosios Korakianitis. -- 2nd ed.
p. cm.
ISBN 0-13-312000-7
1. Turbomachines--Design and construction. 2. Gas-turbines--Design and construction. I. Korakianitis, Theodosios. II. Title.
TJ267.W47 1998 97-46540
621.406--dc21 CIP

Acquisition Editor: Bill Stenquist
Editor-in-Chief: Marcia Horton
Production Manager: Bayani Mendoza de Leon
Production Service: ETP Harrison
Director of Production and Manufacturing: David W. Riccardi
Creative Director: Jayne Conte
Cover Designer: Bruce Kenselaar
Full Service Coordinator/Buyer: Donna Sullivan
Editorial Assistant: Meg Weist
Composition: ETP Harrison

Prentice Hall

Pearson Education
Upper Saddle River, NJ 07458

Printed in the United States of America

10 9 8 7 6 5 4 3 2

ISBN 0-13-312000-7

Prentice-Hall International (UK) Limited, *London*
Prentice-Hall of Australia Pty. Limited, *Sydney*
Prentice-Hall Canada, Inc., *Toronto*
Prentice-Hall Hispanoamericana, S.A., *Mexico*
Prentice-Hall of India Private Limited, *New Delhi*
Prentice-Hall of Japan, Inc., *Tokyo*
Prentice Hall Pte. Ltd., *Singapore*
Editora Prentice-Hall do Brasil, Ltda., *Rio de Janeiro*

Contents

Chapter 3

Thermodynamics of gas-turbine cycles

Gas-turbine engines are rotors and stators with blading, combustors, casings, heat exchangers and so forth. Each molecule of gas that enters the engine undergoes a sequence of processes that is called a "cycle". In a theoretical cycle, and in actual so-called "closed-cycle" gas turbines, the gas molecule returns to its original state. Most gas turbines work on the "open" cycle, in which ambient air enters the compressor, fuel is burned in the air, and the products of combustion emerge from the engine exhaust at above-atmospheric temperature. The regeneration of this gas by cooling and by the conversion of carbon dioxide to oxygen is then carried out in the atmosphere by natural processes.

The cycle to be used for a gas-turbine engine must be chosen before any component design can be started. The thermodynamic analysis of the cycle will yield the potential efficiency, power output and approximate size of the engine.

Gas turbines, in contrast to steam turbines, spark-ignition and compression-ignition engines, can operate on a wide variety of different cycles. In this chapter we develop the performance of "simple" (compressor, burner, expander; or "CBE") cycles; similar cycles that incorporate an exhaust-gas heat exchanger ("CBEX"); and heat-exchanger cycles that use an intercooled, instead of a nonintercooled, compressor (e.g., "CICBEX" cycles)[1]. We will also describe and briefly discuss some other cycles (for instance, turbojet and turbofan cycles for jet propulsion, and combined and steam-injection cycles for industrial power generation) among the many that have been designed or considered.

This chapter is concerned with the start of the design process. The first decisions the designer must make before the start of a stand-alone piece of turbomachinery or of a gas-turbine engine is the choice of the thermodynamic conditions, including the temperatures, pressures, pressure losses, component efficiencies and so forth. The designer might, in fact, have only limited freedom in many of these respects. The customer or someone at a more-senior level might already have chosen the overall component specifications or the engine cycle. The component efficiencies, pressure losses and so on may be very

[1]This is a slightly modified version of the cycle-designation system apparently developed by E. S. Taylor at MIT. We have substituted the generic "expander, E" for "turbine, T".

restricted choices. The designer is more likely to choose a type of compressor, for instance (from the principal types: axial-flow, radial-flow or axial-centrifugal combinations) and accept whatever efficiency is produced by either a very conservative or a very aggressive approach to the type chosen. If you, the reader, are being exposed to turbomachinery for the first time you will not have the experience to choose appropriate values, and you will need to be guided by the typical numbers used in the examples in this chapter. You will be able to choose some values for yourself after going through chapters four and five, which cover the performance of diffusing components and the preliminary design of fans, compressors, pumps, and turbines. Much more precise estimates of component efficiencies, including those of heat exchangers, can be made after the material in chapters 7 through 10 is absorbed.

3.1 Temperature-entropy diagrams

By definition, a gas turbine uses a gas as a working fluid. In the great majority of gas-turbine applications, the working fluid is air, or is a gas that is well removed from its liquefaction temperature in the cycle conditions chosen (for instance, hydrogen or helium). Under these conditions, it is a good approximation to treat the working fluid as a perfect or semi-perfect gas, defined as a substance that obeys the equation of state:

$$pv = RT$$

where p is the pressure, v is the specific volume, R is a constant (the "gas constant"), and T is the (absolute) temperature. It is convenient to perform initial analyses of cycles assuming that the working fluid is a perfect gas simply because the calculations are greatly simplified, and because the resulting ease of analysis makes it possible to gain a deeper insight into the variations that may be expected from changes in cycle conditions. Final calculations may then be made using real-gas properties in the knowledge that conditions will not be greatly changed. We shall give examples of calculations made using different assumptions for working-fluid properties.

Property diagrams are particularly useful for giving the conditions of, and relationships among, the end points of processes making up gas-turbine cycles. Perfect gases are simple substances, for which the state can be found from the value of any two independent properties. Therefore we could make cycle diagrams on charts with axes of p and v, or v and h, for instance.

More suitable choices for the axes of a diagram to represent the ideal gas-turbine cycle, which is known as the Brayton or Joule cycle in one form, and the Ericsson cycle in another form, are T and s or h and s. The fluid stagnation temperatures at compressor and turbine inlets are normally part of the cycle specifications. The ideal compression and expansion processes are isentropes in the Brayton cycle, and isothermals in the ideal Ericsson cycle (for compression which in practice could be approached by using many intercoolers and expansion by using many reheat combustors). Both are easily drawn on $T - s$ diagrams. The thermodynamic or material limits for gas-turbine cycles are lines of constant temperature, again easily drawn. Atmospheric temperature is one limit

This cryogenic application is one case where the use of reheaters between expansion stages would be easily practicable and would increase the power output and the efficiency. Many stages of compression and expansion are needed to produce a change of temperature sufficient for the use of intercoolers or reheaters when hydrogen is used, because of the very high specific heat. Whether or not the high additional cost of intercoolers and reheaters would be justified would depend on the value of the additional power produced.

Cycles that incorporate water or steam

The combined cycle is the most-used variation of the basic gas-turbine cycle in the last part of the twentieth century. The simplest form is the combined-heat-and-power plant, or CHP. A gas-turbine engine, usually one working on the "simple cycle" (CBE), exhausts hot gas into a heat-recovery steam generator (HRSG). In the case of CHP, the steam from the HRSG is led to a process application (for instance, a paper-making plant), or to building or district heating (figure 3.48). In a true combined-cycle plant the steam operates a steam-turbine plant (figure 3.49), and the plant is sometimes called a "CCGT" plant, for "combined-cycle gas turbine", although manufacturers like to devise their own names for their particular offerings. GE uses "STAG", for "steam and gas". Sometimes the gas-turbine part is called the "topping cycle" and the steam-turbine portion the "bottoming cycle". Most of the new generating plants being built around the world are designed to this cycle. Efficiencies of the small plants are in the range of 50%, while for the larger plants it can go as high as 60% (figure 3.50). (This is forecast for the GE Power Systems "H" technology, which uses steam in another way, blade cooling, to allow turbine-inlet temperatures of 1430 °C (2600 °F), to be reached in heavy-duty gas turbines. The 60-percent figure is for the so-called STAG 109H, a 480-MW combined-cycle plant.) The efficiencies rise with power output partly because Reynolds-number effects and tip-clearance losses become relatively smaller as gas-turbine plants become larger, and partly because the incorporation of efficiency-improving measures in steam-turbine plant (feed-water heating for instance) is economic only for the largest plants.

There is sufficient oxygen in the exhaust of a simple-cycle gas turbine to support additional combustion. However, most combined-cycle plants do not have supplementary

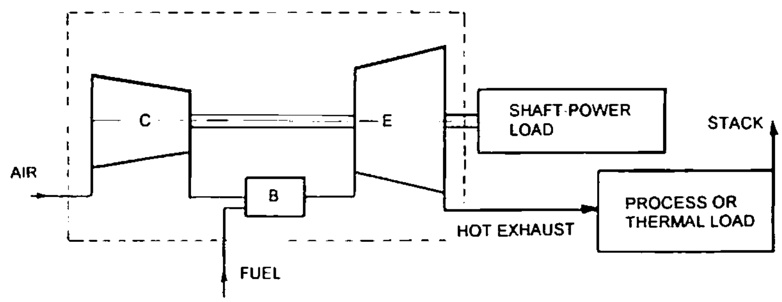

Figure 3.48. Combined heat and power (CHP) plant

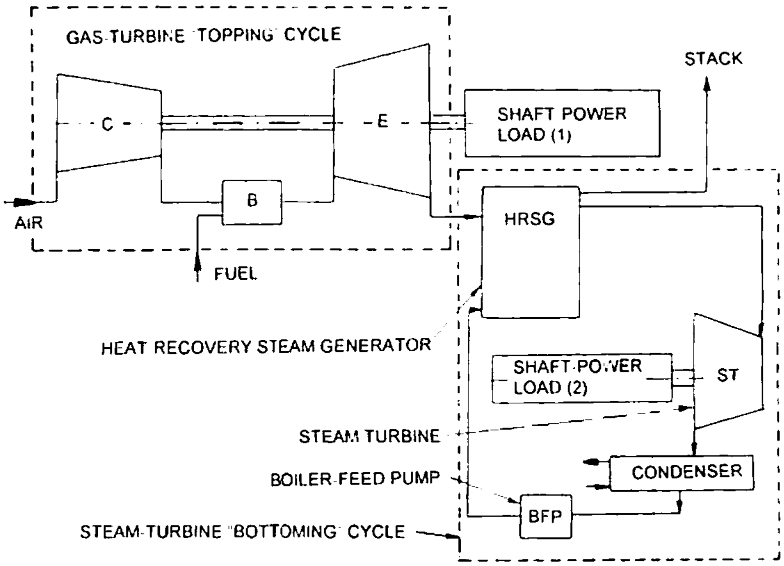

Figure 3.49. Combined-cycle plant

firing. The temperature of the steam at the stop-valve of large steam turbines is around 566 °C (1050 °F), a temperature limit set by hydrogen embrittlement of superheater tubes (at high pressures and temperatures water dissociates to OH^- and H^+). It is desirable that the steam reach, but not exceed, this temperature. The increasing turbine-inlet temperatures of modern gas-turbine plant match the required steam conditions without the need for further combustion. There is also benefit in increasing the output of the gas-turbine by incorporating intercooling and reheat.

Another variation is the integrated-gasification combined cycle (IGCC) that incorporates a system producing gas from coal. Where the gasifier is oxygen-fed, the system must include an oxygen plant in addition to the gasification plant, leading to a capital cost reported as approximately three times that of a CCGT fired by natural gas. The ability to use a low-cost fuel, coal, in an environmentally benign manner will justify the additional capital cost in certain circumstances today, and presumably in more circumstances in the future when natural-gas prices are certain to rise. The 250-MWe Demkolec plant in the Netherlands started trial operation in 1994, and the Wabash River plant in Indiana started trials in 1995. The capital cost of larger plants is estimated at about $1600/kW; several other IGCC plants are in the advanced planning stage (Stambler, 1996).

Coal is also being used to power combined-cycle gas turbines by using pressurized fluidized beds for combustion, initially in Spain, Japan, and the US. The beds contain limestone and other sorbents that, together with slag-melting on the walls and base of the bed, produce a hot gas that can pass through a gas turbine expander without causing more than minor erosion, corrosion, or deposition. The prices forecast for the plants are 75 percent of those for the IGCC plants.

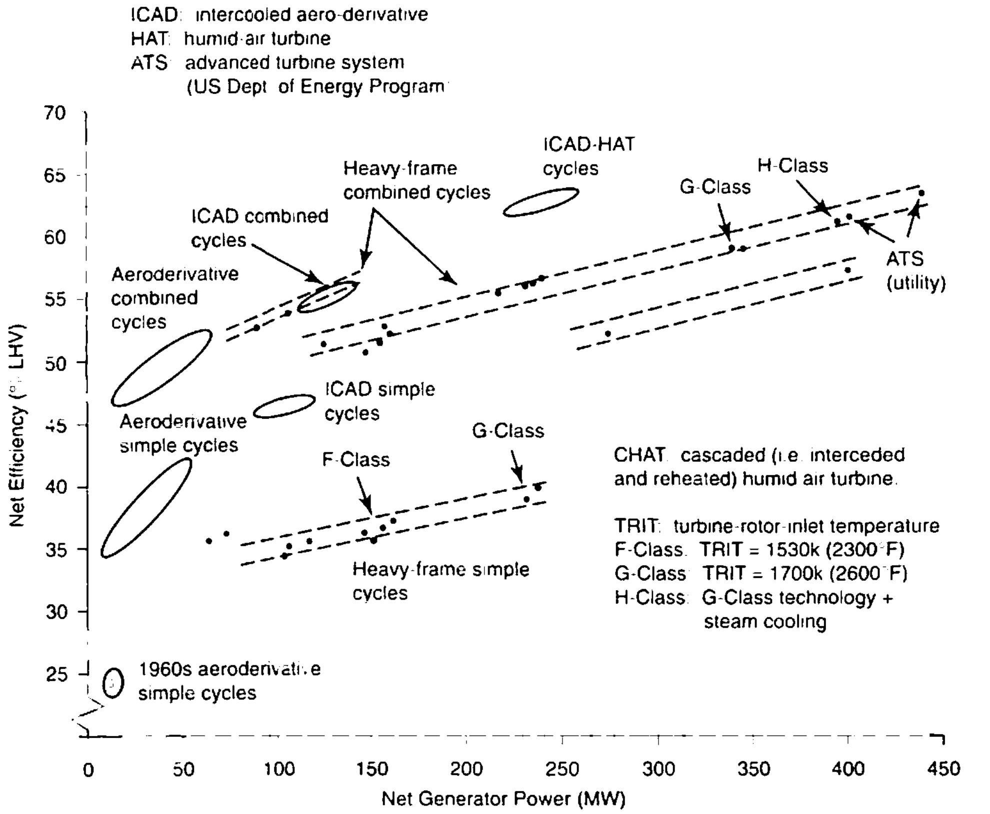

Figure 3.50. Thermal efficiency versus power output and type. From Touchton (1996)

Steam injection in a location where it will expand through the turbine blading with the combustion gases is a third use of the steam generated in a HRSG (figure 3.51). It is a modern version of the system pioneered by Lemale and Armengaud in the first decade of this century (see the historical introduction). Steam may be injected upstream of or into the combustion chamber, or into the turbine nozzles anywhere along the expansion. The steam does less work the further along the expansion it is injected. In comparison with the combined cycle, the steam-injected cycle has the following advantages. A substantial increase in power can be obtained from the gas-turbine engine with no modification in the configuration of the expansion turbine itself. The part-load efficiency is improved. The production of NO_x is reduced. In a review of the status of steam-injected gas turbines, Tuzson (1992) states that combined-cycle turbines have demonstrated the highest power-generation efficiencies and the lowest cost in sizes above 50 MW (although he also quotes a study giving the power level below which steam-injection systems become more attractive than combined cycles as 150 MW). At lower power levels the steam-injected

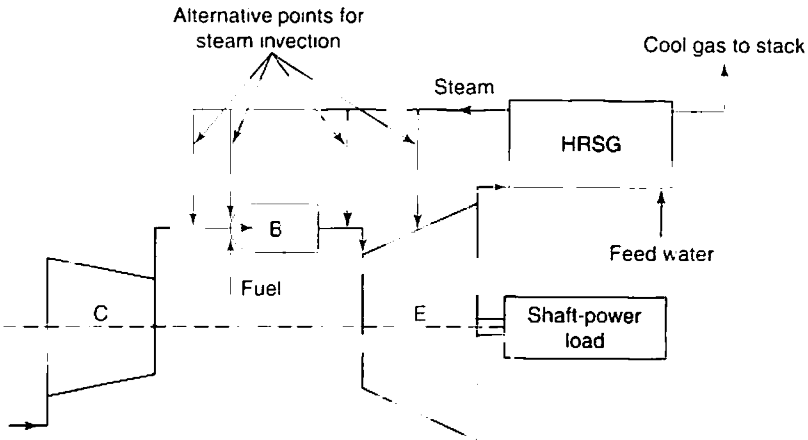

Figure 3.51. Steam-injection gas turbine

gas turbine becomes attractive because of the avoidance of the large cost of the steam turbine. A typical power gain from steam injection for a GE LM5000 gas-turbine engine was quoted as increasing the engine output from 34 MW to 49 MW, together with an efficiency increase from 37 percent (simple cycle) to 41 percent. GE analyzed the gains that would be obtained from a combination of intercooling and steam injection for the LM5000: a power increase from 34 MW to 110 MW and an efficiency improvement from 37 to 55 percent. The water-purification requirements are more demanding for steam injection than for the combined cycle because virtually all the water is normally lost in the exhaust rather than being circulated in a closed system, and because the specifications are more stringent. Any dissolved solids that become deposited on the turbine blades or elsewhere could form corrosion sites or potential blockages. However, Tuzson states that water-purification cost is of the order of five percent of the fuel cost and is not, therefore, a decisive factor. The reliability of early steam-injected units has been high, for instance 99.5 percent. Rather surprisingly, combustor-liner durability has been found to increase.

One of the advanced gas-turbine systems being developed in Japan uses an intercooled-reheated gas turbine (the intercooler is a water-spray direct-contact type) in which the steam raised in the HRSG can power a conventional steam turbine, or the steam can be injected into the gas turbine (Takeya and Yashui, 1988). The configuration shown in figure 3.52 is for the steam-injection system. The output, 400 MW, and the predicted efficiency, 54.3 percent, place it outside Tuzson's guidelines above.

A gas turbine is a good candidate for steam injection if the compressor has a wide range of operation (in particular, a good "surge margin"—see chapter 8) because the increased flow creates a higher back pressure. A high pressure ratio and a high turbine-inlet temperature are also desirable. These conditions seem to favor the aircraft-derivative turbine. However, Tuzson (1992) points out that heavy-duty industrial turbines can accommodate concentrations of contaminants about five times higher than can the aircraft-derivative turbines.

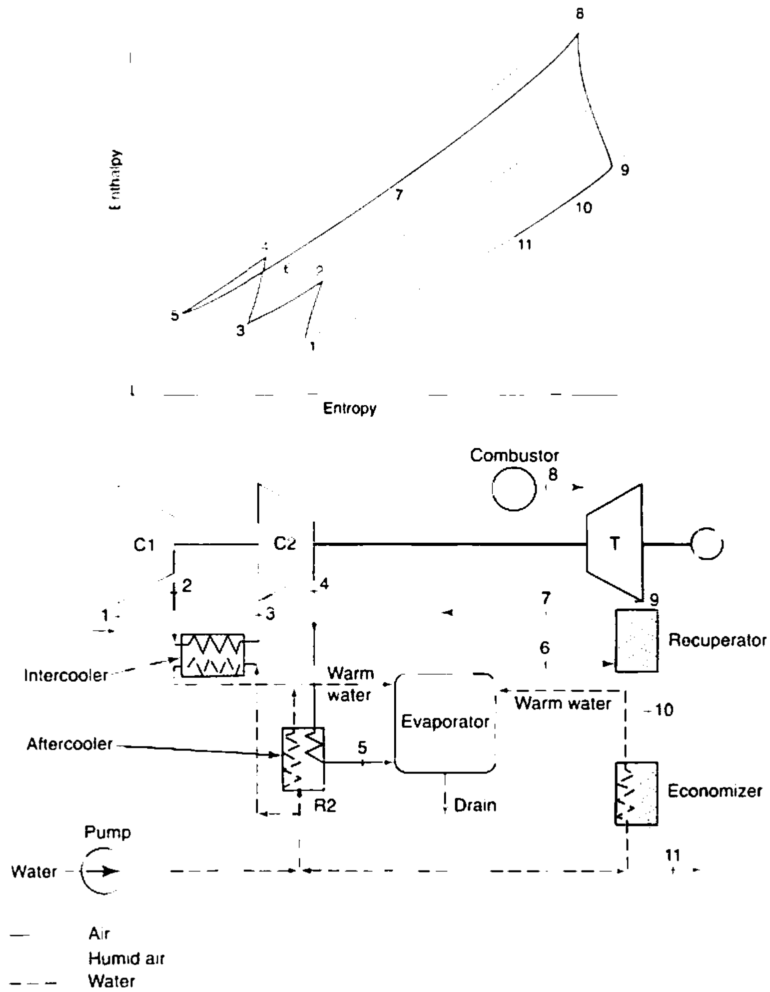

Figure 3.54. Humid-air cycle

rated water at exhaust temperature and at its partial pressure in the exhaust products of combustion is returned to the steam-turbine cycle). The flow rate of air at the gas-turbine inlet is ($\dot{m}_{15}$, station 15), and the flow rate of steam at the HP steam-turbine inlet is ($\dot{m}_3$, station 3). Energy available from condensation of the flue gas and from the steam-turbine condenser provide district hot-water heating ΔE at 110 °C. For typical values of CBE-cycle compressor pressure ratio and turbine-inlet temperature, they obtained figures such as 3.57 showing power-plant thermal efficiency versus specific power and effectiveness versus specific energy of district heating as functions of F2/F1, ratios of steam plant to

White Bluff Steam Electric Station Units #1 and #2 of Arkansas Power and Light Co., 1983. The plant consists of two coal-fired units, each rated at approximately 800 MW, complete with electrostatic precipitators and natural draft cooling towers. Steam conditions are 2400 psig, 1000 F superheat, and 1000 F reheat. Coal fuel is low-sulfur, western subbituminous, delivered by unit trains. (Courtesy of Arkansas Power and Light Co.)

Power Plant System Design

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John Wiley & Sons

New York Chichester Brisbane Toronto Singapore

Library of Congress Cataloging in Publication Data:

Li, Kam W.
Power plant system design.

Includes index.
1. Electric power-plants–Design and construction.
I. Priddy, A. Paul. II. Title.

TK1191.L5 1985 621.31'2132 84-22177
ISBN 0-471-88847-8

Printed and bound in the United States of America

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Preface

This textbook is the outgrowth of our consulting engineering work and teaching in electric power generation. It was written to meet the needs of mechanical engineering students and engineers. In the last 20 years, the changes in technology include substantial growth in unit size (from approximately 200 MW in the 1950s to 1100 MW in the 1970s) and the use of different steam conditions (from subcritical in the 1950s to supercritical conditions in the 1970s). In addition, the plant capital and fuel costs have escalated so rapidly that the plant system design has become a subject of increasing importance in the power industry.

The aim of this book is the design of optimum power plant systems. There are two basic concepts in power plant design that will be embodied in this book: component design and system design. The system generally consists of one or more components related to each other to perform one particular task. In power plants the system may be very simple, such as a section of steam pipe between the superheater and the high-pressure turbine, or very complex, such as the turbine cold-end system, which may consist of the turbine exhaust end, condenser, and cooling tower. This book will emphasize systems rather than components. The selection of components will be made in terms of its impacts on the system. However, basic knowledge of the components is a necessary ingredient for understanding the system.

Design is a decision-making process. The design process frequently results in a set of drawings, or a report that may include calculations and descriptions of equipment. In this textbook attention will be focused on the system design rather than the component design; on the thermal design rather than the mechanical design. When we write "thermal design" we mean that the calculations or decisions are based on the principles of thermodynamics, heat transfer, and fluid mechanics. The system design procedures will generate several optional solutions. Apparently, not all these solutions are equally acceptable. Some are better than others. The final decision as to which solution to use will be made by utilizing various simulation and optimization techniques.

This book serves as an introduction to power plant system design. Since the electric power generating system is complex, we do not intend to cover all aspects. Rather, attention is focused on the steam turbine, steam supply systems, condenser, and cooling tower, as well as their combined system. However, the design methodology introduced here is so general that it can be easily adapted to other system design problems.

The use of the digital computer in power plant design is another feature of this textbook. Several computer programs are introduced and may be obtained from us. These programs have been thoroughly verified and tested in a Boston consulting firm. The reason for including these programs is to provide students have to spend a lot of time in design calculation and not have enough time to appreciate the effects of various design parameters. These computer programs may also serve as models for the further development of computer programs for power plant system design. However, the computer materials were presented in such a way that omitting them would not in any way disturb the continuity of the text.

The book is intended for use at the undergraduate and beginning graduate levels. It should provide sufficient materials, including homework problems, for one four-credit course in universities and colleges. The prerequisites are the first course of thermodynamics, heat transfer, and fluid mechanics. This book is also suitable as a reference for engineers in consulting engineering firms and in utility and manufacturing companies.

The subject matter included in this text is arranged to provide the instructor with a certain degree of flexibility in developing a particular engineering course. When the text is used in a system course (such as power plant system design or thermal system design in general), some background and component materials should be omitted. For this purpose it is suggested that Chapters 2, 5, and 6 be quickly reviewed or entirely omitted. When the text is used in a low-level course such as "Energy Conversion" or "Introduction to Power Plant Systems," the design materials presented in the text should be de-emphasized to some extent. In either case the instructor must select the material to be covered according to the background of the student and the purpose of the course.

During the preparation of this book students were foremost in the our minds. The objective was to develop in students an awareness and understanding of the relationship between the power plant system design and thermal science courses. Efforts were made to demonstrate by examples the use of the principles and working procedures in system design. The book has been tested for two years at North Dakota State University. In 1982 it was also used as a text for the short course "Power Plant System Simulation and Design Optimization" at the Center for Professional Advancement in New Brunswick, New Jersey. We appreciated very much the constructive criticisms both from the practicing engineers and university students.

No claim is made for complete originality of the text. We have been influenced by the excellent publications of many organizations and individuals, especially *Steam/Its Generation and Use* by Babcock & Wilcox, *Combustion*, *Fossil Power Systems* by Combustion Engineering, and those by General Electric and Westinghouse. We feel that these excellent publications should be acknowledged separately in addition to their being listed in the reference sections in the text.

We are indebted to Northern States Power Company (Minneapolis), Chas. T. Main, Inc. (Boston), and North Dakota State University for the assistance rendered in their professional development. We also thank North Dakota State's Department of Mechanical Engineering and Applied Mechanics for their support in preparing the manuscript and to Brenda Stotser and Debbie Coon for their typing.

Kam W. Li

Contents

Power Plant System Design

The mean effective pressure is given by

$$\text{MEP} = \frac{w_{\text{net}}}{v_b - v_a} = \frac{\eta_{cy} \times q_h}{v_1 - v_2}$$

$$= \frac{(0.585)(850)(778)}{(13.1 - 1.46)(144)} = 230.8 \text{ psia}$$

EXAMPLE 2-8. An air-standard Diesel cycle has a compression ratio of 15 and a cutoff ratio of 3. At the beginning of the compression process the conditions are 14.7 psia and 60 F. Calculate the cycle efficiency, the mean effective pressure, and the cycle maximum temperature.

Solution: Designating the states as shown in Fig. 2-27, we first calculate the maximum temperature in the cycle as follows:

$$v_1 = \frac{RT_1}{P_1}$$

$$= \frac{53.34 \times 520}{14.7 \times 144} = 13.1 \text{ ft}^3/\text{lb}$$

$$v_2 = \frac{v_1}{r_v} = \frac{13.1}{15} = 0.873 \text{ ft}^3/\text{lb}$$

$$T_2 = T_1\left(\frac{v_1}{v_2}\right)^{k-1} = 520(15)^{0.4} = 1536 \text{ R}$$

$$T_3 = \alpha T_2 = 3 \times 1536 = 4608 \text{ R}$$

The temperature T_3 is the maximum temperature in the cycle. To calculate the cycle efficiency, we simply use Eq. (2-60) and have

$$\eta_{cy} = 1 - \frac{1}{r_v^{k-1}}\left[\frac{\alpha^k - 1}{k(\alpha - 1)}\right]$$

$$= 1 - \frac{1}{15^{0.4}}\left[\frac{3^{1.4} - 1}{1.4(3 - 1)}\right]$$

$$= 0.558 \quad \text{or} \quad 55.8\%$$

The cycle network is the product of the cycle efficiency and the heat transfer to the air. That is,

$$w_{\text{net}} = \eta_{cy} q_h = \eta_{cy} c_p (T_3 - T_2)$$

$$= 0.558 \times 0.24 \times (4608 - 1536)$$

$$= 411.4 \text{ Btu/lb}$$

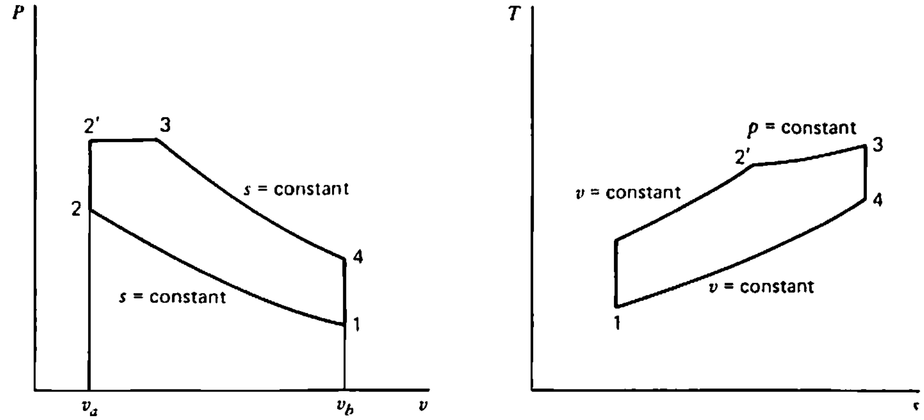

Figure 2-28. The air-standard dual cycle.

Finally, the mean effective pressure of the cycle is

$$\text{MEP} = \frac{w_{\text{net}}}{v_1 - v_2}$$

$$= \frac{411.4 \times 778}{(13.1 - 0.873) \times 144} = 181.8 \text{ psia}$$

It should be emphasized that the thermal efficiency calculated by the air-standard cycle approach is always greater than the actual efficiency. This is simply because the assumptions in the air-standard cycle analysis are not compatible with reality and very difficult to implement in practice. In an actual engine, the combustion may not be complete, and the compression and expansion processes are not isentropic because of friction and heat loss. The engine operation involves an inlet and an exhaust process, and certain amount of work is usually required to overcome the friction in the processes. However, as previously mentioned, the main value of the air standard cycle is to enable engineers to identify the important parameters and qualitatively determine their influence on the engine performance.

It should be noticed that the main difference between the Otto engine and the Diesel engine is in the combustion. The Otto engine has a constant volume process for combustion, while the Diesel engine has a constant pressure process. Consequently, there is an intermediate class of engine whose performance may lie between these two extremes. In this kind of engine, combustion initially takes place at constant volume and finishes at constant pressure process. The corresponding air standard cycle is frequently referred to as the dual cycle. Fig. 2-28 shows the P-v and T-s diagrams for a dual cycle. The thermal efficiency can be determined in the same fashion as that for the Otto and Diesel cycles.

2-6 COMBINED AND BINARY CYCLES

Improving the cycle efficiency has been an important objective in any cycle analysis. One convenient approach is to combine two different cycles to form a new

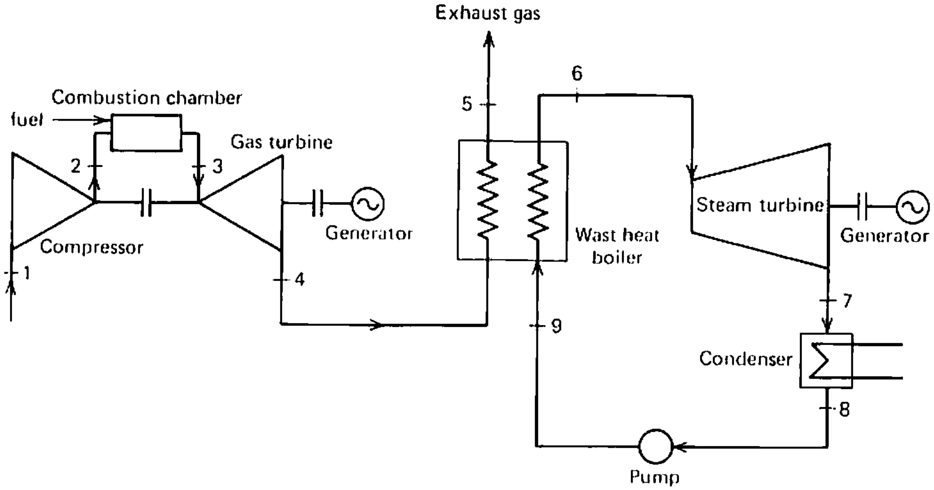

Figure 2-29. Schematic diagram for a combined-cycle system.

power-generating cycle. One of the most popular schemes is the combination of gas turbine cycle and steam turbine cycle as shown in Fig. 2-29. It is seen that the hot exhaust gas from the gas turbine is utilized to generate the steam that is in turn used to drive the steam turbine. In this system, combustion of the fuel is effected only at one point in the cycle, namely, in the combustion chamber of the gas turbine and the cycle work is produced at two different places. The overall thermal efficiency of the combined-cycle system is

$$\eta_{cy} = \frac{w_{gt} + w_{st}}{Q} \tag{2-62}$$

Let

η_{gt} = gas turbine plant efficiency

η_{st} = steam turbine plant efficiency

The gas turbine and steam turbine work, respectively, are

$$w_{gt} = \eta_{gt} \times Q \tag{2-63}$$

and

$$w_{st} = (1 - \eta_{gt}) \times Q \times \eta_{st} \tag{2-64}$$

Substituting these two terms into Eq. (2-62) gives us the combined-cycle efficiency in terms of the single-cycle efficiencies:

$$\eta_{cy} = \eta_{st} + (1 - \eta_{st})\eta_{gt} \tag{2-65}$$

Equation (2-65) shows that the thermal efficiency of the combined cycle is greater than the steam turbine plant efficiency by an amount equal to $(1 - \eta_{st})\eta_{gt}$. With $\eta_{st} = 0.33$ and $\eta_{gt} = 0.26$ as typical values, the combined-cycle efficiency will be approximately 0.5. This cycle efficiency represents an optimistic estimate. When detailed design of a combined-cycle plant is made, it usually shows the plant efficiency in the range of 38 to 42%.

The waste heat steam generator is the component that couples the gas part of the system with the steam part. The turbine exhaust gas enters the bottom of the heat exchanger, moves upward, and releases its energy. At the end of the process, the turbine exhaust gas will leave the plant through a short stack. Fig. 2-30 shows the temperature variation for both hot gas and steam. Water enters the steam generator in the form of compressed liquid. As water receives heat from the hot exhaust gas, it becomes saturated, evaporated, and eventually superheated. The temperature difference between these two streams varies throughout the waste heat steam generator. The minimum value $(T_x - T_s)$ is frequently defined as the pinch point. The pinch point selection is important and can greatly affect the physical size of the heat exchanger. For economic reasons, the pinch point usually ranges between 40 to 80 F. To determine the amount of steam generated in the heat exchanger, we take the evaporator and superheater as a control volume and apply the first law to it. That is,

$$m_g c_p (T_{hi} - T_x) = m_s (h_{ce} - h_1)$$

or

$$\frac{m_s}{m_g} = \frac{c_p (T_{hi} - T_x)}{h_{ce} - h_1} \tag{2-66}$$

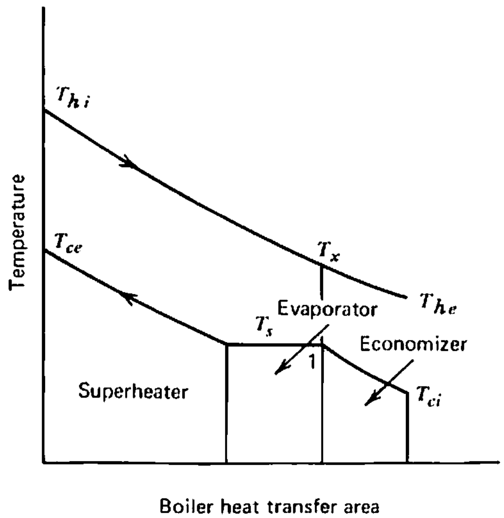

Figure 2-30. Temperature variation in a waste heat steam generator.

This equation gives the amount of steam generated by a unit mass of exhaust gas. In calculation, the pinch point is first selected; the temperature T_x is simply the pinch point plus the steam saturation temperature. The temperature of the gas entering the plant stack is also important and estimated by

$$m_g c_p (T_x - T_{he}) = m_s (h_1 - h_{ci})$$

or

$$T_{he} = T_x - \frac{1}{c_p} \frac{m_s}{m_g} (h_1 - h_{ci}) \tag{2-67}$$

To avoid corrosion from moisture formation in economizer and stack, the minimum gas temperature in the steam generator is always kept higher than the dew point temperature.

EXAMPLE 2-9. Consider the combined-cycle system as shown in Fig. 2-29. The gas side of the system is identical to that in Example 2-4. On the steam side steam enters the turbine at 1200 psia 800 F and exhausts to the condenser at a pressure of 4 in. Hg abs. The steam turbine and pump efficiency are, respectively, 88 and 85%. Calculate the combined-cycle efficiency and the temperature of the gas leaving the stack.

Assume that the boiler pinch point is 60 F.

Solution: Designating the states as shown in Fig. 2-29, we first calculate the amount of steam generated by a unit mass of the hot gas. Since the boiler pinch point is 60 F and the saturation temperature of steam at 1200 psia is 567.2 F, the intermediate gas temperature T_x must be

$$T_x = 60 + 567.2 = 627.2 \text{ F}$$

Also,

$$h_6 = 1379.7 \text{ Btu/lb}$$

$$h_1 = 571.9 \text{ Btu/lb (enthalpy of saturated water at 1200 psia)}$$

$$T_4 = 1410 \text{ R} \qquad \text{or} \qquad 950 \text{ F (from Example 2-4)}$$

Substituting these values into Eq. (2-66) gives us

$$\frac{m_s}{m_g} = \frac{0.25(950 - 627.2)}{1379.7 - 571.9} = 0.099 \text{ lb/lb}$$

Next, we calculate the steam turbine and pump work based on a unit mass of hot gas passing through the boiler. The turbine work is given by

$$w_{st} = \frac{m_s}{m_g} \eta_t (h_6 - h_{7s})$$

$$w_{st} = 0.099 \times 0.88(1379.7 - 894)$$

$$= 42.7 \text{ Btu/lb of gas}$$

and the pump work is

$$w_p = \frac{m_s}{m_g} \frac{1}{\eta_p} v(P_9 - P_8)$$

$$= \frac{0.099 \times 0.01623(1200 - 1.96) \times 144}{0.85 \times 778}$$

$$= 0.42 \text{ Btu/lb of gas}$$

It is seen that the pump work is negligibly small as compared with the steam turbine work. Therefore, it is omitted from the cycle analysis. In this system the combustion chamber of the gas turbine is only one place where the fuel is burned. The heat supplied is given by

$$g_h = c_p(T_3 - T_2)$$

$$= 0.25(2460 - 1096)$$

$$= 341 \text{ Btu/lb}$$

Then, the overall thermal efficiency of the combined cycle is

$$\eta_{cy} = \frac{(w_{gt} - w_c) + w_{st}}{q_h}$$

$$= \frac{118.4 + 42.7}{341} = 0.472 \qquad \text{or} \qquad 47.2\%$$

Finally, to determine the temperature of the gas entering the stack, we use Eq. (2-67) and have

$$T_{stack} = 627.2 - \frac{1}{0.25} \times 0.099 \times (571.9 - 93.7)$$

$$= 437.8 \text{ F}$$

The above calculations are based on the assumption of no pressure drop at the various cycle locations. When these pressure drops are taken into account, the efficiency of the combined cycle is greatly reduced.

In recent years, other arrangements of waste heat steam generator have been veloped. In addition to the unfired boiler just described, the supplemental fired ler and the exhaust-fired boiler are available. In the supplemental boiler, additional fuel is injected and burned in the furnace. Because of the additional firing, temperature of the steam is expected to be somewhat higher than that in the ired boiler and therefore to improve the performance of the steam side in the nbined cycle. The exhaust-fired boiler is similar to the conventional steam ierator equipped with a complete set of combustion equipment. Additional fuel is rned in the furnace, and the combustion air is supplied through the gas turbine npressor. In general, the combined system with exhaust fired boiler has higher ciency but the initial investment also costs much more. Chapter 13 discusses the ste heat boiler selection.

There is another approach in combining the gas turbine and steam turbine tem. Figure 2-31 shows the schematic diagram of this combined system. The air ply through the compressor is used to pressurize the combustion chamber of the m generator. The flue gases from the boiler would act as the working substance expand in the gas turbine. The steam generated in the boiler would go through turbine cycle as it does in the conventional steam plant. In this system ibustion of the fuel is effected only in the furnace of the boiler, and the useful k is produced by gas and steam turbine. The cycle efficiency can be calculated in same manner as that for the previous combined cycle.

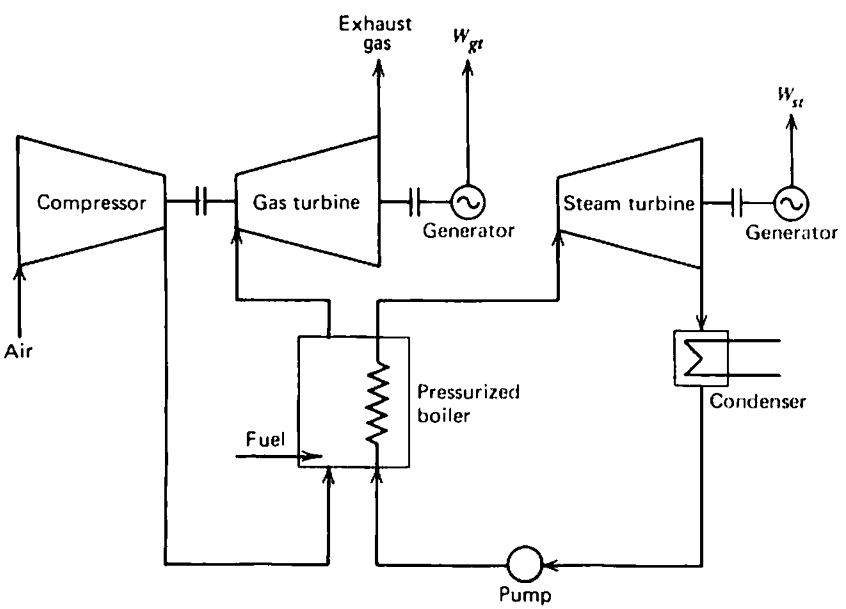

Figure 2-31. Schematic diagram for a combined-cycle system with pressurized boiler.

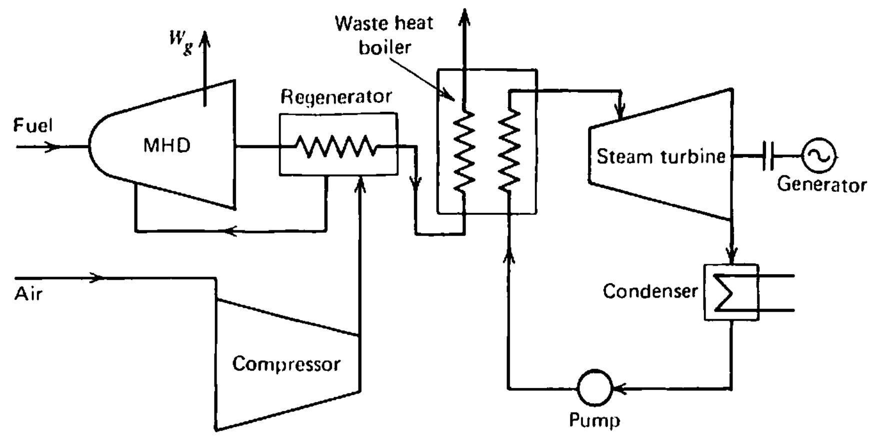

Figure 2-32. Schematic diagram for a combined-cycle system with MHD generator.

In recent years work has been initiated to develop the combined gas-steam plant with magnetohydrodynamic (MHD) generator. Figure 2-32 shows the simplified flow diagram for this system. It is seen that the MHD generator replaces the gas turbine and produces useful work in the gas circuit. Then the gas passes through a regenerator on the way to the steam generator. The steam side of this combined cycle is similar to the steam sides just described.

The principle of MHD operation is based on the Faraday effect, and may be best illustrated in Fig. 2-33. The electrically conducting gas at high temperature enters the

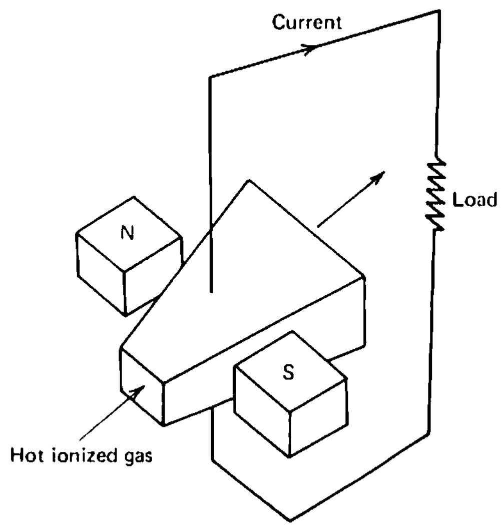

Figure 2-33. Principle of MHD operation.

MHD generator and passes through the diverging channel. An intense magnetic field is created in the direction perpendicular to the direction of gas flow. Interaction of the conducting gas with the magnetic field will then induce an electric field in a direction normal to both the magnetic field and the gas flow. When electrodes are placed in the channel walls that are in contact with the gas stream, the current will flow through the gas, the electrodes, and the external load. In this fashion thermal energy is extracted from the gas stream and electric energy is produced.

The combined system with a MHD generator presents no new problem in a cycle analysis. When the calculation on the MHD generator is completed, the remainder of cycle analysis is similar to those we have discussed before.

It has been demonstrated that the thermal efficiency of the combined cycle is generally greater than the individual cycle efficiency. This is mainly because the combined cycle can take advantage of the best features of each individual cycle. For instance, the high-temperature feature of gas turbine is utilized in the heat addition process of the combined cycle. To avoid high temperature of heat rejection encountered in the gas turbine system, the combined cycle replaces it by a steam turbine system that is characterized by heat rejection in a low temperature. The concept of utilizing the best features from more than one cycle system is easy to understand. In fact, this concept is also utilized in binary cycles. In a binary cycle, two different working substances go through two separate cycles and produce useful work. There is one coupling device (or equipment) in which heat is transferred from one working substance to another. One of the most popular schemes for binary cycles is the mercury-steam cycle as shown in Fig. 2-34. It is seen that a Rankine cycle using dry saturated mercury is superposed on another Rankine cycle using superheated steam. The device coupling these two Rankine cycles is the heat exchanger in which mercury is condensed and water is changed from liquid to vapor phase. To increase the efficiency of the steam side, steam is usually superheated and the superheater is frequently located in the mercury boiler. Not shown in Fig. 2-34 is the economizer of the steam side. The economizer usually placed in the mercury boiler is used to raise the water temperature before the water enters the steam generator (or mercury condenser). The thermal efficiency of mercury-steam binary cycle is given by

$$\eta_{cy} = \frac{w_{Hg} + w_{st}}{Q} \tag{2-68}$$

where

w_{Hg} = mercury turbine output

w_{st} = steam turbine output

Q = heat supplied to the binary cycle

For simplicity, the pump works are omitted from consideration. The amount of heat supplied to the binary cycle is divided into two portions; one (x) is given to the

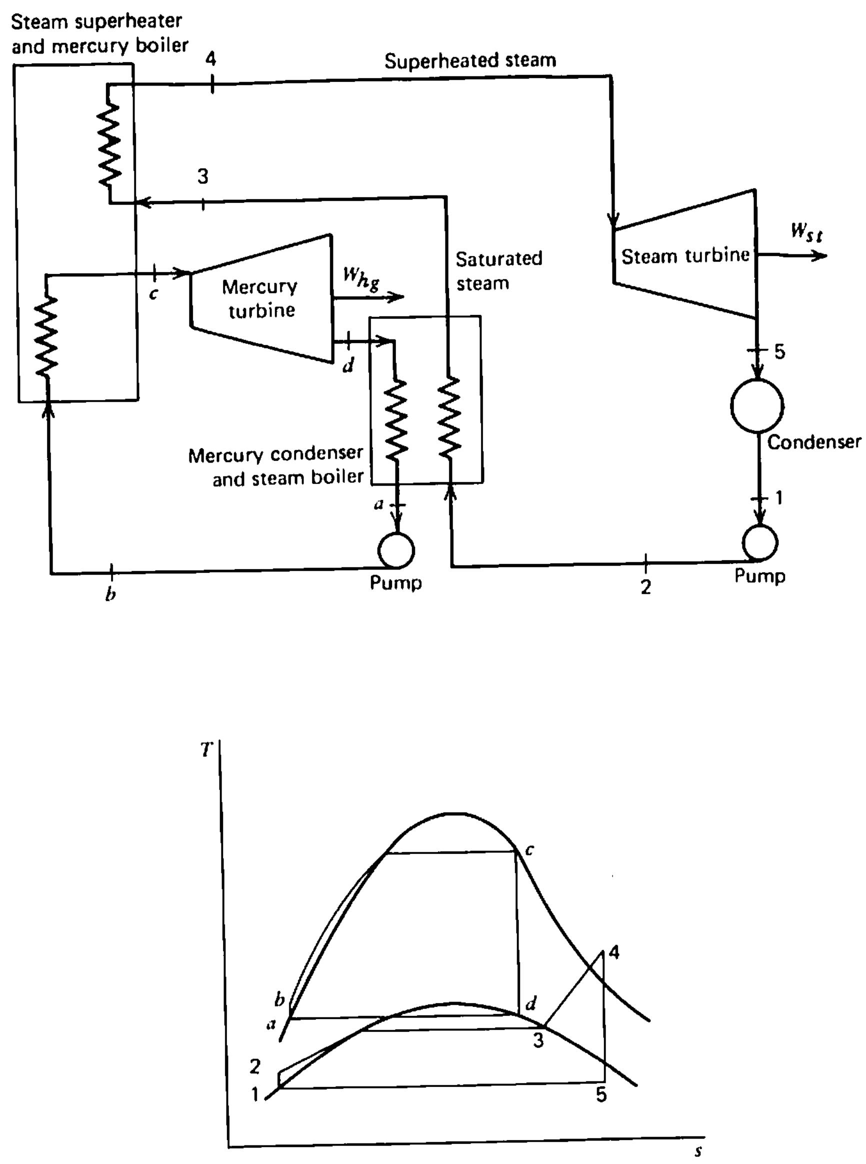

Figure 2-34. A mercury-steam binary cycle.

mercury, while another $(1 - x)$ is given directly to the steam in the superheater. Thus the mercury and steam turbine outputs are, respectively

$$w_{Hg} = xQ\eta_{Hg}$$

and

$$w_{st} = \left[(1 - \eta_{Hg})xQ + (1 - x)Q\right]\eta_{st}$$

where η_{Hg} is the thermal efficiency of the mercury side and η_{st} is the efficiency of the steam side. Substituting these two expressions into Eq. (2-68), we have

$$\eta_{cy} = x\eta_{Hg} + (1 - \eta_{Hg})x\eta_{st} + (1 - x)\eta_{st}$$

After rearranging, the thermal efficiency of the binary cycle becomes

$$\eta_{cy} = \eta_{st} + x\eta_{Hg}(1 - \eta_{st}) \tag{2-69}$$

Equation (2-69) indicates that the binary cycle has greater efficiency than the steam cycle by the amount equal to $x\eta_{Hg}(1 - \eta_{st})$. When there is no superheater and economizer in the mercury boiler, the fraction of heat supplied to the mercury will become a unity (i.e., $x = 1$). Then Eq. (2-69) becomes

$$\eta_{cy} = \eta_{st} + \eta_{Hg}(1 - \eta_{st}) \tag{2-70}$$

Mercury is one of the few working substances used in power plant cycles. For use in binary cycles mercury exhibits certain desirable characteristics that water may not have. These include a low specific heat of liquid mercury, large latent heat of vaporation, and low vapor pressure at high temperature. A low specific heat means a lesser need for feed heating in the mercury cycle. The low specific heat is also evident from the *T-s* diagram where the saturated liquid line for mercury has a very steep slope and is almost close to the vertical. A large latent heat means a heat addition process close to an isothermal. In other words, large latent heat will maximize the average temperature in which heat is added to the cycle and therefore improve the cycle efficiency. For a given power output the large latent heat also tends to reduce the equipment size. A low vapor pressure at high temperature is an important property for the working substance. It reduces not only the equipment cost, but also safety hazards generally associated with high-pressure operation.

EXAMPLE 2-10. Consider the binary cycle as shown in Fig. 2-34. Dry saturated mercury vapor enters the mercury turbine at 225 psia and exhausts at the pressure 4 psia. In the steam side superheated steam enters the turbine at 680 psia and 900 F and exhausts to the condenser at 1 psia. Both turbine processes are assumed isentropic, and pump works are negligible. Calculate the thermal efficiency of this binary cycle using the following mercury properties:

P (psia)	T (F)	h_f (Btu / lb)	h_v (Btu / lb)	s_f (Btu / lb-R)	s_v (Btu / lb-R)
225	1138	32.20	156.32	0.03565	0.11852
4	557.8	17.16	143.44	0.02373	0.14787

Solution: Designating the states as shown in Fig. 2-34, we find the me properties at various cycle locations as follows:

$$h_c = 156.32 \text{ Btu/lb}$$

$$s_c = 0.11852 \text{ Btu/lb-R}$$

$$s_d = s_c = x_d s_{vd} + (1 - x_d)s_{fd}$$

$$0.11852 = 0.14787x_d + 0.02373(1 - x_d)$$

$$x_d = 0.764$$

$$h_d = x_d h_{vd} + (1 - x_d)h_{fd}$$

$$= (0.764)(143.44) + (1 - 0.764)(17.16)$$

$$= 113.65 \text{ Btu/lb}$$

Neglecting the pump effects, we get

$$h_a = h_b = 17.16 \text{ Btu/lb}$$

The mercury turbine work is given by

$$w_{Hg} = h_c - h_d$$

$$= 156.32 - 113.65 = 42.67 \text{ Btu/lb}$$

and the heat supplied to the mercury is

$$q_1 = h_c - h_b$$

$$= 156.32 - 17.16 = 139.16 \text{ Btu/lb}$$

Next, we move to the steam side and find the steam properties as follows:

$$h_4 = 1460 \text{ Btu/lb}$$

$$s_4 = 1.6614 \text{ Btu/lb-R}$$

$$s_5 = s_4 = x_5 s_{v5} + (1 - x_5)s_{f5}$$

$$1.6614 = 1.9781x_5 + 0.1326(1 - x_5)$$

$$x_5 = 0.828$$

$$h_5 = x_5 h_{v5} + (1 - x_5)h_{f5}$$

$$= (0.828)(1105.8) + (1 - 0.828)(69.73)$$

$$= 927.6 \text{ Btu/lb}$$

Implementation of SB 1368 Emission Performance Standard

Gary Collord
Special Projects
Energy Facilities Siting Division
California Energy Commission

STAFF ISSUE IDENTIFICATION PAPER

NOVEMBER 2006
CEC-700-2006-011

Chapter 4: Emissions Performance Standard

The statute requires the emissions standard for the POU's to be consistent with that developed by the CPUC for its jurisdictional load-serving entities. Since this paper was prepared prior to the CPUC's adoption of a standard for load-serving entities, it raises issues that have been examined in the CPUC process and examines POU-specific issues which may provide a basis for modifying the Energy Commission's standard.

> *(e) (1) On or before June 30, 2007, the Energy Commission, at a duly noticed public hearing and in consultation with the commission and the State Air Resources Board, shall establish a greenhouse gases emission performance standard for all baseload generation of local publicly owned electric utilities at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation. <u>The greenhouse gases emission performance standard established by the Energy Commission for local publicly owned electric utilities shall be consistent with the standard adopted by the commission for load-serving entities. Enforcement of the greenhouse gases emission performance standard shall begin immediately upon the establishment of the standard.</u> All combined-cycle natural gas powerplants that are in operation, or that have an Energy Commission final permit decision to operate as of June 30, 2007, shall be deemed to be in compliance with the greenhouse gases emission performance standard.*

The CPUC staff proposed 1,100 pounds carbon dioxide per megawatt-hour as an Interim Emissions Performance Standard in its October 2, 2006 Final Workshop Report. The standard was selected from proposals ranging from 800 to 1,400 lbs CO2/MWhr, and the earlier Revised Staff Report's recommendation of 1,000 lbs CO2/MWhr (0.46 metric tons CO2/MWhr)[1]. The CPUC staff proposed EPS's of 1,000 or 1,100 lbs CO2/MWhr (0.50 metric tons CO2/MWhr) appear to be a compromise between the 800 lbs CO2/MWhr that the most efficient modern combustion turbine combined cycle plant could achieve, and the 1,400 lbs CO2/MWhr that might envelope the majority of natural gas burning technologies (e.g., steam cycle boiler, simple cycle combustion turbine, reciprocating engine, and a range of combustion turbine combined cycle units).

A proposed standard of 1,100, or 1,000, lbs CO2/MWhr is equivalent to a power plant unit with an effective heat rate, in higher heating value (HHV)[2], of:

	Typical Fuel CO2 emission factor	Effective Heat Rate @ an EPS of 1,000 lbs	Effective Heat Rate @ an EPS of 1,100 lbs

[1] Conversion: pounds to metric tons, multiply by 0.454×10^{3}.

[2] Heating Value: traditionally, heat rates in the USA and of boiler units is specified in higher heating value, while Europe and combustion turbines generally use lower heating value. For this discussion and more direct comparison, the higher heating value is used unless otherwise stated.

Natural gas HHV = 1.11 x LHV

Bituminous coal HHV = approx. 1.05 x LHV

Facility Level Emissions Quick Report
January 20, 2009

Your query will return data for 83 facilities and 188 units.

You specified: **Year(s):** 2007 **Program(s):** ARP **State(s):** CA

State	Facility Name	Facility ID (ORISPL)	Year	Program (s)	# of Months Reported	SO_2 Tons	NO_x Tons	CO_2 Tons	Heat Input (mmBtu)
CA	AES Alamitos	315	2007	ARP	12	5.0	86.2	994,778.8	16,741,572
CA	AES Huntington Beach	335	2007	ARP	12	5.7	58.1	905,556.7	15,239,761
CA	AES Redondo Beach	356	2007	ARP	12	1.7	17.7	343,210.4	5,776,117
CA	Agua Mansa Power	55951	2007	ARP	12	0.2	3.5	29,636.1	498,662
CA	Almond Power Plant	7315	2007	ARP	12	0.3	8.9	53,002.5	891,874
CA	Anaheim Combustion Turbine	7693	2007	ARP	12	0.1	4.6	29,389.7	494,485
CA	Blythe Energy	55295	2007	ARP	12	2.7	74.4	543,528.8	9,145,930
CA	Broadway	420	2007	ARP	12	0.0	1.8	9,391.4	158,042
CA	Cabrillo Power I Encina Power Station	302	2007	ARP	12	11.9	115.3	1,618,095.5	27,309,474
CA	CalPeak Power - Border LLC	55510	2007	ARP	12	0.1	2.1	23,254.6	391,312
CA	CalPeak Power - El Cajon LLC	55512	2007	ARP	12	0.1	1.9	19,764.5	332,576
CA	CalPeak Power - Enterprise LLC	55513	2007	ARP	12	0.1	1.4	16,142.0	271,639
CA	CalPeak Power - Panoche LLC	55508	2007	ARP	12	0.0	0.7	7,444.1	125,275
CA	CalPeak Power - Vaca Dixon LLC	55499	2007	ARP	12	0.0	0.6	7,719.5	129,917
CA	Calpine Gilroy Cogen, LP	10034	2007	ARP	12	0.7	81.1	136,415.8	2,295,417
CA	Calpine Sutter Energy Center	55112	2007	ARP	12	5.7	86.6	1,119,265.0	18,833,808
CA	Carson Cogeneration	7527	2007	ARP	12	2.2	29.3	240,734.3	3,799,976
CA	Carson Cogeneration	10169	2007	ARP	12	1.0	14.4	207,299.1	3,488,275

	Company								
CA	Chula Vista Power Plant	55540	2007	ARP	12	0.0	0.8	1,626.8	27,383
CA	Contra Costa Power Plant	228	2007	ARP	12	0.5	10.7	90,721.0	1,526,531
CA	Coolwater Generating Station	329	2007	ARP	12	2.1	350.9	421,624.0	7,094,649
CA	Cosumnes Power Plant	55970	2007	ARP	12	7.5	69.6	1,480,952.3	24,920,386
CA	Creed Energy Center	55625	2007	ARP	12	0.0	1.3	7,979.3	134,272
CA	Delta Energy Center, LLC	55333	2007	ARP	12	11.1	134.0	2,205,554.9	37,112,676
CA	Donald Von Raesfeld	56026	2007	ARP	12	1.4	15.9	268,881.9	4,524,443
CA	Dynegy South Bay, LLC	310	2007	ARP	12	2.7	46.3	509,294.3	8,569,590
CA	El Centro	389	2007	ARP	12	1.4	268.7	269,356.1	4,532,233
CA	El Segundo	330	2007	ARP	12	0.9	22.0	360,580.8	6,067,472
CA	Elk Hills Power	55400	2007	ARP	12	7.6	83.2	1,505,361.0	25,330,619
CA	Escondido Power Plant	55538	2007	ARP	12	0.0	0.6	2,473.9	41,624
CA	Etiwanda Generating Station	331	2007	ARP	12	2.2	24.3	444,830.3	7,485,126
CA	Feather River Energy Center	55847	2007	ARP	12	0.1	2.0	15,977.9	268,865
CA	Fresno Cogeneration Partners, LP	10156	2007	ARP	12	0.2	3.1	31,505.4	529,858
CA	Gilroy Energy Center, LLC	55810	2007	ARP	12	0.3	58.0	50,910.1	856,689
CA	Gilroy Energy Center, LLC for King City	10294	2007	ARP	12	0.1	1.2	11,615.1	195,579
CA	Glenarm	422	2007	ARP	12	0.1	4.8	24,331.2	409,416
CA	Goose Haven Energy Center	55627	2007	ARP	12	0.0	1.1	9,203.8	154,858
CA	Grayson Power Plant	377	2007	ARP	12	1.0	21.3	139,125.1	1,623,467
CA	Hanford Energy Park Peaker	55698	2007	ARP	12	0.1	2.4	23,232.1	390,918
CA	Harbor Generating Station	399	2007	ARP	12	0.7	25.6	140,435.0	2,363,342
CA	Haynes Generating Station	400	2007	ARP	12	10.2	92.7	2,019,801.5	33,992,772

CA	Henrietta Peaker Plant	55807	2007	ARP	12	0.1	2.4	13,329.7	224,296
CA	High Desert Power Project	55518	2007	ARP	12	9.7	159.4	1,921,877.2	32,339,084
CA	Humboldt Bay	246	2007	ARP	12	43.2	1,052.9	365,324.5	6,104,391
CA	Indigo Generation Facility	55541	2007	ARP	12	0.3	10.8	52,992.5	891,732
CA	Kings River Conservation District Malaga	56239	2007	ARP	12	0.4	5.8	76,028.5	1,279,384
CA	La Paloma Generating Plant	55151	2007	ARP	12	14.2	142.5	2,812,443.5	47,324,777
CA	Lake	7987	2007	ARP	12	0.0	0.9	4,992.2	83,986
CA	Lambie Energy Center	55626	2007	ARP	12	0.0	1.3	9,083.3	152,821
CA	Larkspur Energy Faciity	55542	2007	ARP	12	1.9	5.3	31,838.9	534,423
CA	Los Esteros Critical Energy Fac	55748	2007	ARP	12	0.2	8.8	40,168.5	675,919
CA	Los Medanos Energy Center, LLC	55217	2007	ARP	12	7.8	2,744.9	1,546,010.5	26,014,684
CA	Magnolia	56046	2007	ARP	12	1.7	15.5	328,970.7	5,535,839
CA	Malburg Generating Station	56041	2007	ARP	12	1.7	19.7	341,469.9	5,746,176
CA	Mandalay Generating Station	345	2007	ARP	12	1.4	9.4	275,926.6	4,643,002
CA	Metcalf Energy Center	55393	2007	ARP	12	6.8	77.9	1,337,584.8	22,507,479
CA	Miramar Energy Facility	56232	2007	ARP	12	0.0	0.4	4,281.2	72,036
CA	Morro Bay Power Plant, LLC	259	2007	ARP	12	1.5	86.9	305,629.4	5,142,682
CA	Moss Landing	260	2007	ARP	12	17.3	169.1	3,429,063.6	57,700,641
CA	Mountainview Power Company, LLC	358	2007	ARP	12	13.7	126.9	2,705,366.0	45,522,915
CA	NCPA Combustion Turbine Project #2	7449	2007	ARP	12	0.2	3.5	39,329.2	666,956

CA	Olive	6013	2007	ARP	12	0.0	0.1	1,664.2	28,005
CA	Ormond Beach Generating Station	350	2007	ARP	12	3.1	39.9	619,648.5	10,426,783
CA	Palomar Energy	55985	2007	ARP	12	7.1	76.3	1,403,805.3	23,621,779
CA	Pastoria Energy Facility	55656	2007	ARP	12	10.5	114.5	2,071,866.0	34,863,142
CA	Pittsburg Power Plant (CA)	271	2007	ARP	12	0.7	14.6	136,555.5	2,297,780
CA	Potrero Power Plant	273	2007	ARP	12	1.6	24.9	315,982.1	5,317,019
CA	Redding Power Plant	7307	2007	ARP	12	0.5	2.2	96,630.1	1,648,098
CA	Ripon Generation Station	56135	2007	ARP	12	0.1	2.2	20,980.5	353,028
CA	Riverside Energy Resource Center	56143	2007	ARP	12	0.1	2.3	23,584.1	396,861
CA	Riverview Energy Center	55963	2007	ARP	12	0.1	2.1	16,397.2	275,914
CA	Roseville Energy Park	56298	2007	ARP	6	0.4	3.4	70,844.1	1,192,059
CA	SCA Cogen II	7551	2007	ARP	12	1.9	50.4	380,906.8	6,409,475
CA	Sacramento Power Authority Cogen	7552	2007	ARP	12	2.6	41.9	524,239.4	8,821,321
CA	Scattergood Generating Station	404	2007	ARP	12	14.3	19.6	1,006,825.3	15,907,187
CA	Sunrise Power Company	55182	2007	ARP	12	7.7	74.8	1,528,392.0	25,718,239
CA	Tracy Peaker	55933	2007	ARP	12	0.1	15.3	10,111.1	171,404
CA	Valley Gen Station	408	2007	ARP	12	6.9	90.2	1,340,036.7	22,548,605
CA	Walnut Energy Center	56078	2007	ARP	12	3.3	35.9	663,350.2	11,162,241
CA	Wellhead Power Gates, LLC	55875	2007	ARP	12	0.0	0.7	5,695.9	95,845
CA	Wolfskill Energy Center	55855	2007	ARP	12	0.1	1.7	13,016.6	219,042
CA	Woodland Generation Station	7266	2007	ARP	12	1.0	15.9	203,357.7	3,421,792
CA	Yuba City	10349	2007	ARP	12	0.1	2.0	15,433.5	259,699

	Energy Center								
Total						**272.1**	**7,105.0**	**42,451,035.9**	**712,395,421**

Annual Emissions Report

Elk Hills Power

(Emissions from California operations)

Report Generated On: 01/20/2009 07:55 pm PT

4026 Skyline Road
PO Box: 460

Tupman, CA 93276 United States

(661) 763-2727

pramsey@elkhills.com

Legend

Blue = required

Orange = optional

Contact:	Patrick Ramsey
Industry Type:	Electric Power Producer
NAIC Code:	2211-Electric Power Generation, Transmission and Distribution
SIC Code:	4911-Electric Services
Description:	Independent Power Producer
Primary Calculation Methodologies:	The inventory was prepared using the CCAR General Reporting Protocol Version 2.2, March 2007 and the CCAR Power and Utility Reporting Protocol Version 1.0, April 2005. EMISSION EFFICIENCY METRICS Net Generation: 796 lbs CO2/MWh from net owned generation Net Fossil Generation: 796 lbs CO2/MWh from net owned Fossil Fuel Generation
Organizational structure disclosure:	

VERIFIED EMISSIONS INFORMATION

Reporting Year:	**2006**
Reporting Scope:	**CA**
Reporting Protocol:	General Reporting Protocol, Version 2.2 (March 2007); Power/Utility Reporting Protocol, Version 1 (April 2005)
Reporting Boundaries:	
Baseline Year (Direct Emissions):	
Baseline Year (Indirect Emissions):	

Direct Emissions	**CO2e**	**CO2**	**CH4**	**N2O**	**HFCs***	**PFCs***	**SF6**	**Unit**
Mobile Combustion	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
Stationary Combustion	**1,260,653.08**	1,248,733.95	92.29	32.20	0.00	0.00	0.00	metric ton
Process Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
Fugitive Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL DIRECT	**1,260,653.08**	1,248,733.95	92.29	32.20	0.00	0.00	0.00	metric ton

* HFCs and PFCs are classes of greenhouse gases that include many compounds. These columns may reflect the total emissions of multiple HFC and PFC compounds, each of which has a unique Global Warming Potential (GWP). Emissions of each gas are first multiplied by their respective GWP and then summed in the total CO2-equivalent column.

Indirect Emissions	**CO2e**	**CO2**	**CH4**	**N2O**	**Unit**
Purchased Electricity	**0.00**	0.00	0.00	0.00	-
Purchased Steam	**0.00**	0.00	0.00	0.00	-
Purchased Heating and Cooling	**0.00**	0.00	0.00	0.00	-
TOTAL INDIRECT	**0.00**	0.00	0.00	0.00	-

De Minimis Emissions	**CO2e**	**CO2**	**CH4**	**N2O**	**HFCs***	**PFCs***	**SF6**	**Unit**
TOTAL DEMINIMIS	**3,296.15**	3,275.81	0.03	0.02	0.01	0.00	0.00	metric ton

Percentage of Total Inventory: 0.26 %

This report includes emissions from California sources

Annual Emissions Report

Elk Hills Power

(Emissions from California operations)

Report Generated On: 01/20/2009 07:55 pm PT

VERIFICATION INFORMATION

Verification Body: Ryerson, Master & Associates, Inc.

Basis of Verification Opinion:

Elk Hills Power, LLC (EHP) submitted their California GHG Emission Inventory Report for Year 2006 to Ryerson, Master and Associates, Inc., (RMA) for review and certification against the Registry's General Reporting Protocol, Version 2.2 and the Power Utility Reporting Protocol (April 2005). RMA followed the procedures outlined in the Registry's General Certification Protocol (dated July 2003) and the Power Utility Certification Protocol (April 2005) to complete the certification process. The certification activities were conducted during January through March 2008.

On March 12, 2008, RMA issued a Certification Report to EHP documenting the certification activities and the immaterial misstatements in the EHP inventory. EHP accepted the Certification Report, and made revisions in CARROT and in the PUP spreadsheet to address the RMA findings. On March 20, 2008, RMA provided a Certification Opinion to EHP. RMA completed the Certification Activities Checklist and completed the certification in CARROT on March 20, 2008.

Date Submitted:

3/20/08 1:25 pm

OPTIONAL INFORMATION

Information in this section is voluntarily provided by the participant for public information, but is not required and thus, not verified under California Registry protocols.

Optional Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL OPTIONAL	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-

Emissions Efficiency metric: See comments on Certified Emissions Inventory, Fossil generation and Net generation

Emissions Management Programs:

Emissions Reduction Projects:

Emissions Reduction Goals:

REFERENCE DOCUMENTS

Title	Author	Document Status	Publish Date
2006 PUP Report	CCAR	Public	03/13/2008 12:00:00AM

This report includes emissions from California sources

Annual Emissions Report

Elk Hills Power

(Emissions from California operations)

Report Generated On: 01/20/2009 07:53 pm PT

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Legend

Blue = required

Orange = optional

Contact:	Patrick Ramsey
Industry Type:	Electric Power Producer
NAIC Code:	2211-Electric Power Generation, Transmission and Distribution
SIC Code:	4911-Electric Services
Description:	Independent Power Producer
Primary Calculation Methodologies:	The inventory was prepared using the CCAR General Reporting Protocol Version 3.0, April 2008 and the CCAR Power and Utility Reporting Protocol Version 1.0, April 2005. Emission Efficiency Metrics Net Generation: 793.99 lbs CO2/MWh net owned generation Net Fossil Generation: 793.99 lbs CO2/MWh net owned fossil generation only
Organizational structure disclosure:	

VERIFIED EMISSIONS INFORMATION

Reporting Year:	**2007**
Reporting Scope:	**CA**
Reporting Protocol:	General Reporting Protocol, Version 3.0, (April 2008); Power/Utility Reporting Protocol, Version 1 (April 2005)
Reporting Boundaries:	Management Control - Operational Criteria
Baseline Year (Direct Emissions):	
Baseline Year (Indirect Emissions):	

Direct Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
Mobile Combustion	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
Stationary Combustion	**1,347,966.36**	1,344,042.64	149.45	2.53	0.00	0.00	0.00	metric ton
Process Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
Fugitive Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL DIRECT	**1,347,966.36**	1,344,042.64	149.45	2.53	0.00	0.00	0.00	metric ton

* HFCs and PFCs are classes of greenhouse gases that include many compounds. These columns may reflect the total emissions of multiple HFC and PFC compounds, each of which has a unique Global Warming Potential (GWP). Emissions of each gas are first multiplied by their respective GWP and then summed in the total CO2-equivalent column.

Indirect Emissions	CO2e	CO2	CH4	N2O	Unit
Purchased Electricity	**0.00**	0.00	0.00	0.00	-
Purchased Steam	**0.00**	0.00	0.00	0.00	-
Purchased Heating and Cooling	**0.00**	0.00	0.00	0.00	-
TOTAL INDIRECT	**0.00**	0.00	0.00	0.00	-

De Minimis Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
TOTAL DEMINIMIS	**3,592.67**	3,572.78	0.03	0.02	0.01	0.00	0.00	metric ton

Percentage of Total Inventory: 0.27 %

This report includes emissions from California sources

Annual Emissions Report
Elk Hills Power
(Emissions from California operations)

Report Generated On: 01/20/2009 07:53 pm PT

VERIFICATION INFORMATION

Verification Body: Ryerson, Master & Associates, Inc.

Basis of Verification Opinion: Elk Hills Power, LLC (EHP) submitted their California GHG Emission Inventory Report for Year 2007 to Ryerson, Master and Associates, Inc., (RMA) for review and verification against the Registry's General Reporting Protocol, Version 3.0 and the Power Utility Reporting Protocol (April 2005). RMA followed the procedures outlined in the Registry's General Verification Protocol, Version 3.0 and the Power Utility Certification Protocol (April 2005) to complete the verification process. The verification activities were conducted during July through October 2008.

On September 30, 2008, RMA issued a Verification Report to EHP documenting the verification activities and the immaterial misstatements in the EHP inventory. EHP accepted the Verification Report, and no revisions in CARROT or in the PUP spreadsheet were made. On October 1, 2008, RMA provided a Verification Opinion to EHP. RMA completed the Verification Activities Checklist and completed the verification in CARROT on October 6, 2008.

Date Submitted:
10/6/08 2:08 pm

OPTIONAL INFORMATION

Information in this section is voluntarily provided by the participant for public information, but is not required and thus, not verified under California Registry protocols.

Optional Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL OPTIONAL	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-

Emissions Efficiency metric: See Comments on Certified Emissions Inventory

Emissions Management Programs:

Emissions Reduction Projects:

Emissions Reduction Goals:

REFERENCE DOCUMENTS

Title	Author	Document Status	Publish Date
Elk Hills Power, LLC 2007 PUP Report	Elk Hills Power, LLC	Public	05/28/2008 12:00:00AM

Annual Emissions Report

Calpine Corporation

(Emissions from California operations)

Report Generated On:	01/20/2009 07:56 pm PT

50 W. San Fernando Street

San Jose, CA 95113 United States

www.calpine.com
925-479-6729
bmcbride@calpine.com

Legend
Blue = required
Orange = optional

Contact:	Barbara McBride
Industry Type:	Electric Power Producer
NAIC Code:	2211-Electric Power Generation, Transmission and Distribution
SIC Code:	4911-Electric Services
Description:	Clean, Reliable Power

Calpine Corporation is helping meet the needs of an economy that demands more and cleaner sources of electricity. Founded in 1984, Calpine is a major U.S. power company, capable of delivering nearly 24,000 megawatts of clean, cost-effective, reliable and fuel-efficient electricity to customers and communities in 18 states in the U.S. The company owns, leases and operates low-carbon, natural gas-fired and renewable geothermal power plants. Using advanced technologies, Calpine generates electricity in a reliable and environmentally responsible manner for the customers and communities it serves.

Calpine Quick Facts

Calpine adheres to stringent standards for safe, efficient plant operations.
Calpine is North America's leading geothermal power producer. At The Geysers, about 100 miles northeast of San Francisco, Calpine harnesses naturally heated steam from the earth to create electrical power. This renewable "green" power is available to consumers throughout California.

Primary Calculation Methodologies:	Calpine is using the default Acid Rain CO2 emissions factor = 118.9 lbs CO2/mmbtu No changes to deminimus in 2006.
Organizational structure disclosure:	

VERIFIED EMISSIONS INFORMATION

Reporting Year:	**2006**
Reporting Scope:	**CA**
Reporting Protocol:	General Reporting Protocol, Version 2.2 (March 2007); Power/Utility Reporting Protocol, Version 1 (April 2005)
Reporting Boundaries:	
Baseline Year (Direct Emissions):	
Baseline Year (Indirect Emissions):	

Direct Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
Mobile Combustion	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
Stationary Combustion	**7,484,851.79**	7,484,851.79	0.00	0.00	0.00	0.00	0.00	metric ton
Process Emissions	**197,903.87**	197,903.87	0.00	0.00	0.00	0.00	0.00	metric ton
Fugitive Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL DIRECT	**7,682,755.65**	7,682,755.65	0.00	0.00	0.00	0.00	0.00	metric ton

* HFCs and PFCs are classes of greenhouse gases that include many compounds. These columns may reflect the total emissions of multiple HFC and PFC compounds, each of which has a unique Global Warming Potential (GWP). Emissions of each gas are first multiplied by their respective GWP and then summed in the total CO2-equivalent column.

Annual Emissions Report

Calpine Corporation

(Emissions from California operations)

Report Generated On: 01/20/2009 07:56 pm PT

Indirect Emissions	CO2e	CO2	CH4	N2O	Unit
Purchased Electricity	**0.00**	0.00	0.00	0.00	-
Purchased Steam	**0.00**	0.00	0.00	0.00	-
Purchased Heating and Cooling	**0.00**	0.00	0.00	0.00	-
TOTAL INDIRECT	**0.00**	0.00	0.00	0.00	-

De Minimis Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit

Percentage of Total Inventory:

VERIFICATION INFORMATION

Verification Body: Ryerson, Master & Associates, Inc.

Basis of Verification Opinion:

Calpine Corporation submitted their California GHG Emission Inventory Report for Year 2006 to Ryerson, Master and Associates, Inc., (RMA) for review and certification against the Registry's General Reporting Protocol, Version 2.2 and the Power Utility Reporting Protocol (April 2005). RMA followed the procedures outlined in the Registry's Certification Protocol (dated July 2003) and the Power Utility Certification Protocol (April 2005) to complete the certification process. The certification activities were conducted during November 2007 through April 2008.

On April 21, 2008, RMA issued a Certification Report to Calpine documenting the certification activities and the material and immaterial misstatements in the Calpine inventory. Calpine revised the emission inventory in CARROT, and RMA recertified the inventory. A Certification Opinion was provided to Calpine on April 28, 2008. RMA completed the Certification Activities Checklist and completed the certification in CARROT on April 28, 2008.

Date Submitted:

4/28/08 9:47 pm

OPTIONAL INFORMATION

Information in this section is voluntarily provided by the participant for public information, but is not required and thus, not verified under California Registry protocols.

Optional Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL OPTIONAL	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-

Emissions Efficiency metric: 644 lbs CO2/mwh

Emissions Management Programs: Total Energy Efficiency Metric = 644 lbs CO2/mwh
lbs of direct CO2 Emissions from stationary fossil fuel combustion/Net MWH from all energy sources.

Fossil Fuel Electricity Generation: 850 lbs CO2/MWH
lbs of CO2 emissions from stationary fossil fuel combustion/Net MWH from fossil fuel sources only.

Emissions Reduction Projects: Calpine will work to improve the fuel efficiency of its natural gas fueled power plants through a series of performance improvement programs, which will reduce CO2 emissions per megawatt hour throughout the fleet.

Annual Emissions Report

Calpine Corporation

(Emissions from California operations)

Report Generated On: 01/20/2009 07:56 pm PT

Emissions Reduction Goals: Calpine's goal is to minimize CO_2 emissions per megawatt hour from its power plants and to be recognized as the industry leader in minimizing CO_2 emissions from power generation.

REFERENCE DOCUMENTS

Title	Author	Document Status	Publish Date

This report includes emissions from California sources

Annual Emissions Report

Calpine Corporation

(Emissions from California operations)

Report Generated On:	01/20/2009 07:57 pm PT

50 W. San Fernando Street

San Jose, CA 95113 United States

www.calpine.com
925-479-6729
bmcbride@calpine.com

Legend
Blue = required
Orange = optional

Contact:	Barbara McBride
Industry Type:	Electric Power Producer
NAIC Code:	2211-Electric Power Generation, Transmission and Distribution
SIC Code:	4911-Electric Services
Description:	Clean, Reliable Power

Calpine Corporation is helping meet the needs of an economy that demands more and cleaner sources of electricity. Founded in 1984, Calpine is a major U.S. power company, capable of delivering nearly 24,000 megawatts of clean, cost-effective, reliable and fuel-efficient electricity to customers and communities in 18 states in the U.S. The company owns, leases and operates low-carbon, natural gas-fired and renewable geothermal power plants. Using advanced technologies, Calpine generates electricity in a reliable and environmentally responsible manner for the customers and communities it serves.

Calpine Quick Facts

Calpine adheres to stringent standards for safe, efficient plant operations.
Calpine is North America's leading geothermal power producer. At The Geysers, about 100 miles northeast of San Francisco, Calpine harnesses naturally heated steam from the earth to create electrical power. This renewable "green" power is available to consumers throughout California.

Primary Calculation Methodologies:	Calpine is using the default Acid Rain CO2 emissions factor = 118.9 lbs CO2/mmbtu No changes to deminimus in 2004.
Organizational structure disclosure:	

VERIFIED EMISSIONS INFORMATION

Reporting Year:	**2005**
Reporting Scope:	**CA**
Reporting Protocol:	General Reporting Protocol, Version 2.1 (June 2006); Power/Utility Reporting Protocol, Version 1 (April 2005)
Reporting Boundaries:	
Baseline Year (Direct Emissions):	
Baseline Year (Indirect Emissions):	

Direct Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
Mobile Combustion	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
Stationary Combustion	**7,374,694.12**	7,374,694.12	0.00	0.00	0.00	0.00	0.00	metric ton
Process Emissions	**204,500.12**	204,500.12	0.00	0.00	0.00	0.00	0.00	metric ton
Fugitive Emissions	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL DIRECT	**7,579,194.24**	7,579,194.24	0.00	0.00	0.00	0.00	0.00	metric ton

* HFCs and PFCs are classes of greenhouse gases that include many compounds. These columns may reflect the total emissions of multiple HFC and PFC compounds, each of which has a unique Global Warming Potential (GWP). Emissions of each gas are first multiplied by their respective GWP and then summed in the total CO2-equivalent column.

Annual Emissions Report

Calpine Corporation

(Emissions from California operations)

Report Generated On: 01/20/2009 07:57 pm PT

Indirect Emissions	CO2e	CO2	CH4	N2O	Unit
Purchased Electricity	**0.00**	0.00	0.00	0.00	-
Purchased Steam	**0.00**	0.00	0.00	0.00	-
Purchased Heating and Cooling	**0.00**	0.00	0.00	0.00	-
TOTAL INDIRECT	**0.00**	0.00	0.00	0.00	-

De Minimis Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit

Percentage of Total Inventory:

VERIFICATION INFORMATION

Verification Body: Ryerson, Master & Associates, Inc.

Basis of Verification Opinion:

Calpine Corporation submitted their California GHG Emission Inventory Report for Year 2005 to Ryerson, Master and Associates, Inc., (RMA) for review and certification against the Registry's General Reporting Protocol, Version 2.1 and the Power Utility Reporting Protocol (April 2005). RMA followed the procedures outlined in the Registry's Certification Protocol (dated July 2003) and the Power Utility Certification Protocol (April 2005) to complete the certification process. The certification activities were conducted during October through December 2006.

On December 28, 2006, RMA issued a Certification Report to Calpine documenting the certification activities and the material and immaterial misstatements in the Calpine inventory. Calpine revised the emission inventory in CARROT, and RMA recertified the inventory. A Certification Opinion was provided to Calpine on December 29, 2006. RMA completed the Certification Activities Checklist and completed the certification in CARROT on December 31, 2006.

Date Submitted:

12/31/06 9:38 am

OPTIONAL INFORMATION

Information in this section is voluntarily provided by the participant for public information, but is not required and thus, not verified under California Registry protocols.

Optional Emissions	CO2e	CO2	CH4	N2O	HFCs*	PFCs*	SF6	Unit
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-
TOTAL OPTIONAL	**0.00**	0.00	0.00	0.00	0.00	0.00	0.00	-

Emissions Efficiency metric: 667 lbs CO2/mwh

Emissions Management Programs: Total Energy Efficiency Metric = 667 lbs CO2/mwh
lbs of direct CO2 Emissions from stationary fossil fuel combustion/Net MWH from all energy sources.

Fossil Fuel Electricity Generation: 891 lbs CO2/MWH
lbs of CO2 emissions from stationary fossil fuel combustion/Net MWH from fossil fuel sources only.

Emissions Reduction Projects: Calpine will work to improve the fuel efficiency of its natural gas fueled power plants through a series of performance improvement programs, which will reduce CO2 emissions per megawatt hour throughout the fleet.

Annual Emissions Report

Calpine Corporation

(Emissions from California operations)

Report Generated On: 01/20/2009 07:57 pm PT

Emissions Reduction Goals: Calpine's goal is to minimize CO2 emissions per megawatt hour from its power plants and to be recognized as the industry leader in minimizing CO2 emissions from power generation.

REFERENCE DOCUMENTS

Title	Author	Document Status	Publish Date

This report includes emissions from California sources

APPENDIX 6.2

AIR QUALITY

APPENDIX 6.2-1

EMISSIONS AND OPERATING PARAMETERS

Table 6.2-1.1
Emissions and Operating Parameters for New Turbines
Avenal Energy Project

	Case 1	Case 5	Case 9	Case 2	Case 6	Case 10	Case 4	Case 8	Case 12
	101°F Full Load w/ DB[1]	63°F Full Load w/ DB[1]	32°F Full Load w/ DB[1]	101°F Full Load no DB	63°F Full Load no DB	32°F Full Load no DB	101°F 50% Load	63°F 50% Load	32°F 50% Load
Ambient Temp, °F	101	63	32	101	63	32	101	63	32
GT Load, %	100%	100%	100%	100%	100%	100%	50%	50%	50%
Both GTs Gross Power, MW	344.8	345.0	359.0	345.5	345.6	**359.5**	144.1	168.6	183.2
STG Gross Power, MW	290.8	273.3	254.7	171.6	176.1	177.7	118.3	127.6	130.6
Plant Gross Power Output, MW	635.6	**618.3**	613.7	517.2	**521.7**	537.2	262.5	296.2	313.9
Plant Net Power Output, MW	600.0	600.0	600.0	483.7	506.5	525.5	250.3	286.3	304.8
GTs Fuel Flow, kpph	156.4	156.4	161.8	156.4	156.4	161.8	87.2	96.2	102.2
DBs Fuel Flow, kpph	49.0	39.6	31.0	0.0	0.0	0.0	0.0	0.0	0.0
GTs Heat Input, MMBtu/hr (HHV)	1,794.2	1,794.3	1,855.4	1,795.6	1,795.4	1,856.3	1,001.4	1,104.3	1,171.9
DBs Heat Input, MMBtu/hr (HHV)	562.3	454.4	356.3	0.0	0.0	0.0	0.0	0.0	0.0
Total Heat Input, MMBtu/hr (HHV)	**2,356.5**	2,248.6	2,211.8	1,795.6	1,795.4	**1,856.3**	1,001.4	1,104.3	**1,171.9**
Stack Flow, lb/hr	3,653,000	3,650,000	3,759,000	3,628,000	3,630,000	3,743,000	2,232,700	2,336,800	2,413,300
Stack Flow, acfm	**1,044,365**	**1,025,495**	**1,059,836**	**1,051,531**	**1,037,822**	**1,071,653**	**620,528**	**644,316**	**666,146**
Stack Temp, °F	**195.3**	**184.9**	**189.0**	**207.4**	**198.8**	**200.9**	**180.2**	**175.8**	**177.4**
Stack exhaust, vol%									
O_2 (dry)	11.40%	11.87%	12.34%	13.76%	13.77%	13.78%	14.46%	14.11%	13.93%
CO_2 (dry)	5.42%	5.16%	4.89%	4.09%	4.08%	4.08%	3.70%	3.89%	3.99%
H_2O	10.54%	10.03%	9.12%	8.39%	8.28%	7.78%	8.07%	7.97%	7.63%
Emissions									
NO_x, ppmvd @ 15% O_2	**2.0**	2.0	2.0	2.0	2.0	**2.0**	2.0	2.0	2.0
NO_x, lb/hr[2]	**17.13**	**16.34**	**16.06**	**13.03**	**13.03**	**13.47**	**7.26**	**8.01**	**8.51**
NO_x, lb/MMBtu (HHV)	**0.0073**	0.0073	0.0073	0.0073	0.0073	**0.0073**	0.0073	0.0073	0.0073
SO_2, ppmvd @ 15% O_2 [3]	**0.139**	0.139	0.140	0.140	0.140	**0.140**	0.140	0.140	0.140
SO_2, lb/hr[2,3]	**1.66**	1.59	1.56	1.27	1.27	**1.31**	0.71	0.78	0.83
SO_2, lb/MMBtu (HHV)[3]	**0.0007**	0.0007	0.0007	0.0007	0.0007	**0.0007**	0.0007	0.0007	0.0007
CO, ppmvd @ 15% O_2	**4.0**	4.0	4.0	4.0	4.0	**4.0**	4.0	4.0	4.0
CO, lb/hr[2]	**20.86**	19.90	19.56	15.86	15.86	**16.39**	8.84	9.75	10.36
CO, lb/MMBtu (HHV)	**0.0089**	0.0088	0.0088	0.0088	0.0088	**0.0088**	0.0088	0.0088	0.0088
VOC, ppmvd @ 15% O_2[4]	**2.0**	2.0	2.0	1.4	1.4	**1.4**	1.4	1.4	1.4
VOC, lb/hr[2,4]	**5.96**	5.68	5.59	3.17	3.17	**3.28**	1.77	1.95	2.07
VOC, lb/MMBtu (HHV)[4]	**0.0025**	0.0025	0.0025	0.0018	0.0018	**0.0018**	0.0018	0.0018	0.0018
PM_{10}, lb/hr[2,5]	**11.81**	11.27	10.78	9.00	9.00	**9.00**	9.00	9.00	9.00
PM_{10}, lb/MMBtu (HHV)[5]	**0.0050**	0.0050	0.0049	0.0050	0.0050	**0.0048**	0.0090	0.0081	0.0077
PM_{10}, gr/SCF (dry)[5]	0.00189	0.00179	0.00165	0.00142	0.00142	0.00137	0.00230	0.00220	0.00212
NH_3, ppmvd @ 15% O_2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
NH_3, lb/hr[2]	35.39	33.57	32.66	26.28	26.25	26.98	14.60	16.08	17.02
CO_2, lb/MMBtu (HHV)[7]	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
CH_4, lb/MMBtu (HHV)[6]	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
N_2O, lb/MMBtu (HHV)[8]	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022
CO_2, lb/hr [5]	275,599	262,984	258,674	210,000	209,976	217,102	117,114	129,153	137,055
CH_4, lb/hr [5]	30.7	29.2	28.8	23.4	23.4	24.1	13.0	14.4	15.2
N_2O, lb/hr [5]	0.52	0.50	0.49	0.40	0.40	0.41	0.22	0.24	0.26

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APPENDIX

7.1 AIR QUALITY

This analysis of the potential air quality impacts of the Willow Pass Generating Station (WPGS) was conducted according to California Energy Commission (CEC) power plant siting requirements. Air pollutant sources belonging to this project will include two new gas-fired combined-cycle gas turbines with associated heat recovery steam generators (HRSGs), and a single natural-gas–fired fuel gas heater to treat the natural gas fuel stream to the turbines. The analysis also addressed U.S. Environmental Protection Agency (U.S. EPA) Prevention of Significant Deterioration (PSD) requirements and Bay Area Air Quality Management District (BAAQMD) permitting requirements for Determination of Compliance/Authority to Construct (DOC/ATC). The assessment of project air quality impacts is presented in nine sections, as summarized below.

Section 7.1.1 describes the local environment surrounding the project site that is relevant to evaluation of the air quality impacts. Section 7.1.2 evaluates the project's air quality impacts from emissions of NO_X, carbon monoxide (CO), sulfur dioxide (SO_2), precursor organic compound (POC) (also called volatile organic compound [VOC] in some regulations but used interchangeably herein), particulate matter less than 10 micrometers in diameter (PM_{10}), and particulate matter less than 2.5 micrometers in diameter ($PM_{2.5}$). Section 7.1.3 discusses the cumulative impacts analysis. Section 7.1.4 describes mitigation measures and the project's emission offset strategy. Section 7.1.5, Best Available Control Technology Analysis, discusses the detailed Best Available Control Technology (BACT) analysis conducted for the project. Section 7.1.6 describes all applicable laws, ordinances, regulations, and standards (LORS) pertaining to the project's emissions of air pollutants. Section 7.1.7 lists the agency personnel contacted during preparation of the air quality assessment. Section 7.1.8 lists the air quality permits required for the project and provides a permit schedule. Section 7.1.9 lists the references used to conduct the air quality assessment.

Some air quality data are presented in other sections of this Application for Certification (AFC), including an evaluation of toxic air contaminants (see Section 7.6, Public Health), information related to the fuel characteristics (see Chapter 5, Gas Supply), and expected capacity factor of the proposed facility and heat rates (see Chapter 2, Project Description).

7.1.1 Affected Environment

This section describes the regional climate and meteorological conditions that influence transport and dispersion of air pollutants, as well as the existing air quality within the project region. The monitoring data presented in this section are considered to be representative of the project site.

Figure 7.1-1 shows the WPGS project boundary and surroundings. The proposed project site is located on the southern side of Suisun Bay, approximately 2 miles from the center of the City of Pittsburg. The WPGS site is 26 acres situated within the approximately 1,000-acre Pittsburg Power Plant (PPP) located at 696 West 10th Street, Pittsburg, CA, 94565. The WPGS site will be located on a separate legal parcel to be created by adjusting the lot lines of two existing legal parcels at the PPP site, both of which are identified as Assessor's Parcel Number 085-010-014.

The WPGS site is currently occupied by the existing retired power generation PPP Units 1 through 4, an unused surface impoundment, an administration building, hazardous materials and hazardous waste materials buildings, Tank 7, temporary buildings, and other ancillary facilities. The project includes the demolition of Units 1 through 4, the administration building, and Tank 7 that are on the WPGS site, as well as replacement of the hazardous materials and hazardous waste buildings. The unused surface impoundment on the WPGS site (north of Tank 1) will be left in place. The new generating units will be located on the south 23.5 acres of the WPGS site. No land disturbance will occur within the north 2.5-acre portion of the WPGS site (adjacent to Suisun Bay). Pacific Gas & Electric Company (PG&E) owns a 36-acre switchyard adjacent to the PPP site, directly southwest of the WPGS site (Figure 2.2-1).

Table 7.1-19 Estimated Greenhouse Gas Emissions from the Project				
Emission Rate (metric tons/year)				
CO_2	**CH_4**	**N_2O**	**SF_6**	**Total CO_2 Equivalent**
987,970	72.65	25.34	0.003	997,438

Notes:
CH_4 = methane
CO_2 = carbon dioxide
N_20 = nitrous oxide
SF_6 = sulfur hexafluoride

Table 7.1-20 Surface Moisture Conditions for Years 2002-2005												
Surface moisture condition by month for the Antioch Pump Plant 3 Station												
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2002	dry	dry	avg	dry	dry	dry	dry	dry	dry	dry	avg	wet
2003	avg	dry	avg	wet	wet	dry	dry	wet	dry	dry	avg	wet
2004	avg	wet	dry	dry	avg	dry	dry	dry	dry	wet	avg	wet
2005	wet	avg	wet	avg	avg	wet	dry	dry	dry	dry	dry	wet

Note: Surface moisture conditions provided by BAAQMD.

Exhibit 9

The California ENERGY COMMISSION

Lodi Energy Center - AFC, Vol. 1 - 08-AFC-10

Name	last modified Color dates added today	
Parent Directory		
LEC 1.0 Executive Summary.pdf	Sep 12 2008	3.7
LEC 2.0 Project Description.pdf	Sep 12 2008	4.4
LEC 3.0 Electric Transmission.pdf	Sep 12 2008	26(
LEC 4.0 Natural Gas Supply.pdf	Sep 12 2008	66.
LEC 5.0 Environmental Info.pdf	Sep 12 2008	43.
LEC 5.10 Socioeconomics.pdf	Sep 12 2008	2.5
LEC 5.11 Soils.pdf	Sep 12 2008	3.2
LEC 5.12 Traffic and Transportation.pdf	Sep 12 2008	6 n
LEC 5.13 Visual.pdf	Sep 12 2008	4.6
LEC 5.14 Waste Management.pdf	Sep 12 2008	18(
LEC 5.15 Water Resources.pdf	Sep 12 2008	4.6
LEC 5.16 Worker Health and Safety.pdf	Sep 12 2008	20(
LEC 5.1 Air Quality.pdf	Sep 12 2008	73:
LEC 5.2 Biological Resources.pdf	Sep 12 2008	14.
LEC 5.3 Cultural.pdf	Sep 12 2008	1.9
LEC 5.4 Geologic Hazards and Resources.pdf	Sep 12 2008	3.2
LEC 5.5 Hazardous Materials.pdf	Sep 12 2008	29
LEC 5.6 Land Use.pdf	Sep 12 2008	15.
LEC 5.7 Noise.pdf	Sep 12 2008	3.9
LEC 5.8 Paleo Resources.pdf	Sep 12 2008	2.2
LEC 5.9 Public Health.pdf	Sep 12 2008	4.5
LEC 6.0 Alternatives.pdf	Sep 12 2008	1.4
LEC Acronyms.pdf	Sep 12 2008	10:
LEC Contents.pdf	Sep 12 2008	10(

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Decisions Pending and Opportunities for Public Participation

Last Modified:

18 hours of base load turbine operation and 12 hours of duct firing for NO_x, CO, and VOC. These assumptions are used as the basis for the calculations and are not intended to be proposed as limits.

Detailed calculations, including quarterly emissions calculations, are shown in Appendix 5.1A, Table 5.1A-6.

TABLE 5.1-21
Criteria Pollutant Emissions from New Equipment

Emissions/Equipment	NO_x	SO_2	CO	VOC	PM_{10}
Maximum Hourly Emissions[a]					
CTG/HRSG	160	6.0	900	16	11.0
Auxiliary Boiler	0.55	0.19	2.37	0.27	0.47
Cooling Tower	—	—	—	—	0.45
Total, pounds per hour	**160.5**	**6.2**	**902.4**	**16.3**	**11.9**
Maximum Daily Emissions[b]					
CTG/HRSG	864.9	136.4	5,641.9	179.8	240.0
Auxiliary Boiler	6.5	2.2	28.5	3.3	11.3
Cooling Tower	—	—	—	—	5.6
Total, pounds per day	**871.4**	**138.6**	**5,670.4**	**183.1**	**256.4**
Maximum Annual Emissions					
CTG/HRSG	71.3	24.3	254.4	17.4	41.9
Auxiliary Boiler	0.13	0.04	0.6	0.1	0.1
Cooling Tower	—	—	—	—	2.0
Total, tons per year	**71.5**	**24.3**	**254.9**	**17.5**	**44.0**

[a]Maximum hourly emissions include CTG in startup (for NO_x, CO and VOC), with auxiliary boiler and cooling tower in operation. Maximum hourly SO_2 and PM_{10} emissions from the CTG assume duct fired operation.

[b]Maximum daily emissions based on full-load turbine operation for 24 hours with 12 hours of duct firing for PM_{10} and SO_x; and 6 hours of cold start, 18 hours of base load turbine operation and 12 hours of duct firing for NO_x, CO, and VOC.

5.1.3.5 Greenhouse Gas Emissions

Greenhouse gas (GHG) emissions from the project have been calculated using calculation methods and emission factors from the California Air Resources Board's December 5, 2007, regulatory update.[6] Calculations are based on the maximum proposed annual fuel use and corresponding generation. The calculations are shown in detail in Table 5.1A-7, Appendix 5.1A and the results are summarized in Table 5.1-22.

[6] California Air Resources Board, "Regulation for the Mandatory Reporting of Greenhouse Gas Emissions," December 5, 2007 (Staff's Suggested Modifications to the Originally Proposed Regulation Order Released October 19, 2007). http://www.arb.ca.gov/cc/ccei/reporting/GHGReportRegUpdate12_05_07.pdf.

TABLE 5.1-22
Greenhouse Gas Emissions from New Equipment

Unit	CO_2, metric tonnes/yr	CO_2. metric tonnes/MWh	CO_2eq, metric tonnes/yr[a]
CTG/HRSG	902,487	0.376	—
Auxiliary Boiler	1,608	Not applicable	–
Total	904,095	0.376	904,971

*Includes CH_4, N_2O and SF_6.

5.1.3.6 Hazardous Air Pollutants

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[7] In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1). The SJVAPCD regulates toxic air contaminant emissions under the SJVAPCD's Integrated Air Toxic Program. This program integrates the state and federal requirements. Any pollutant that may be emitted from the LEC and is on the federal New Source Review list, the federal Clean Air Act list, and/or the SJVAPCD toxic air contaminant list has been evaluated as part of the AFC.

5.1.3.6.1 Toxic Air Contaminant Emissions: New Gas Turbine/HRSG and Auxiliary Boiler

Maximum hourly and annual TAC emissions were estimated for the gas turbine/HRSG and the auxiliary boiler based on the heat input rates (in MMBtu/hr and MMBtu/yr), emission factors (in lb/MMBtu), and the nominal fuel higher heating value of 1004 Btu/scf. Hourly and annual emissions were based on the heat input rates shown in Table 5.1-17. The ammonia emission factor was derived from an ammonia slip limit of 10 ppmv @ 15 percent O_2. At the request of the SJVAPCD [8], Ventura County emission factors were used to quantify other TAC emissions. The Ventura County AB2588 combustion emission factors do not include factors for hexane or propylene oxide or for speciated polyaromatic hydrocarbons (PAHs), so emission factors for these TACs were taken from the California Air Resources Board's CATEF database for natural gas-fired gas turbines. TAC emissions are summarized in Table 5.1-22. Detailed emissions calculations, including emission factors, are provided in Appendix 5.1A, Tables 5.1A-8 and 5.1A-9.

5.1.3.6.2 Toxic Air Contaminant Emissions: Cooling Tower

Maximum hourly and annual TAC emissions from the cooling tower are extremely low. As shown in Table 5.15-23, concentrations of most metals and salts in the water supply were below detection limits. Total TAC emissions from the cooling tower are shown in Appendix 5.1A, Table 5.1A-10.

7 These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission.

8 June 5, 2008, email message from Cheryl Lawler to Nancy Matthews, "District's Comments for Lodi Energy Center Modeling Protocol."

Exhibit 10

Electric Utility Greenhouse Gas Emissions Reduction

Initial Rule Development Workshop
August 22, 2007

Department of Environmental Protection
Division of Air Resource Management

Governor's Executive Order 07-127

"The Secretary of Environmental Protection shall immediately develop rules as authorized under Chapter 403, Florida Statutes, to achieve the following:

Adoption of a maximum allowable emissions level of greenhouse gases for electric utilities in the State of Florida. The standard will require at minimum three reduction milestones as follows: by 2017, emissions not greater than Year 2000 utility sector emissions; by 2025, emissions not greater than Year 1990 utility sector emissions; by 2050, emissions not greater than 20% of Year 1990 utility sector emissions (i.e., 80% reduction of 1990 emissions by 2050)"

Year 2000 & Year 1990 Utility Greenhouse Gas Emissions

First estimates:

- Year 2000: 135,080,858 tons CO_2
- Year 1990: 100,109,860 tons CO_2

Year 2000 value from eGrid (Emissions & Generation Resource Integrated Database) developed by EPA, Office of Atmospheric Programs, Climate Protection Partnerships Division. http://www.epa.gov/cleanenergy/egrid/index.htm

Year 1990 data estimated by applying ratio of 1990/2000 utility emissions from EPA State Inventory Tool to Year 2000 value.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Year 2004 Utility Greenhouse Gas Emissions

Coal	65,484,849 tons CO_2
Oil & petcoke	33,404,545 tons CO_2
Natural gas	44,846,881 tons CO_2
➢ Total fossil fuel	143,736,276 tons CO_2

All emissions data from eGrid. Does not include 1,265,244 tons CO_2 emissions from burning of non-biogenic solid waste such as plastics and tires in waste-to-energy facilities.

Fossil-fuel electricity generation accounts for about 45% of Florida's greenhouse gas emissions

Required Utility Greenhouse Gas Reductions from Year 2004 Levels

- By 2017 6%
- By 2025 30%
- By 2050 86%

- But, electric power usage in the state is growing…

Year 2004 Net Generation by Source

- Fossil-fuel generation
  - Coal 61,982,540 MWh
  - Oil & petcoke 37,232,873 MWh
  - Natural gas 76,624,773 MWh
  - Interchange power 18,649,000 MWh
  - Subtotal 194,489,186 MWh (83% of grand total)
- Other generation
  - Biomass 4,950,744 MWh
  - Nuclear 31,215,576 MWh
  - Hydroelectric 265,258 MWh
  - Other waste & phosphate* 2,862,650 MWh
- Grand Total **233,783,414 MWh**

Interchange data from Florida Reliability Coordinating Council; all other data from eGrid. eGrid assigns 70% of generation from solid waste to biomass; 30% to other waste (plastics, tires, etc.).
*Includes waste heat cogeneration in phosphate industry.

Projected Electricity Usage

Year 2016: 325,566,000 MWh

- Equates to 33% increase from actual 2006 net generation—same rate of increase as from 1996 to 2006

Year 2016 projection from "2007 Regional Load and Resource Plan" by Florida Reliability Coordinating Council, available on Public Service Commission website at: www.psc.state.fl.us/utilities/electricgas/10yearsiteplans.aspx.

No Year 2017, 2025 or 2050 projections available.

Year 2004 Average CO_2 Emission Rates for Florida Fossil-Fuel Units

Coal	2,113 lb/MWh
Oil & petcoke	1,794 lb/MWh
Natural gas	1,171 lb/MWh
➢ Weighted avg.	1,635 lb/MWh

CO_2 Emission Rates for Fossil-Fuel Generating Units Compared

- Year 2004 statewide average emission rate:

  1,635 lb/MWh

- Statewide average emission rate to meet 135 million ton cap with total generation of 325 million MWh, 83% of which supplied by fossil fuel (values selected for illustrative purposes; not a DEP-presumed scenario)

  1,000 lb/MWh

- Emission rates achievable by today's new units:
  - Natural gas combined cycle — 800 lb/MWh
  - Pulverized coal or IGCC (w/o carbon capture & storage) — 1,750 lb/MWh

Challenges in Meeting the Caps

- Slowing the state's growth in electricity usage
- Increasing generation from proven non-fossil sources
- Reducing statewide average fossil fuel emission rate
- Developing and deploying advanced technologies

Initial Rule Development Issues

- Definition of electric utility sector
- Nailing down Year 2000 and Year 1990 utility sector emission levels
- How to treat out-of-state interchange power
- Possible rule approaches

Comments

- Mail to:
  Mr. Larry George, Program Administrator
  Division of Air Resource Management, MS-5500
  Department of Environmental Protection
  2600 Blair Stone Rd.
  Tallahassee, FL 32399-2400

  cc: Ms. Lynn Scearce, Rules Coordinator (same address)

- Or e-mail to: larry.george@dep.state.fl.us and lynn.scearce@dep.state.fl.us

- All comments are public records and will be posted on the department's website at www.dep.state.fl.us/air

- To receive updates on this rule development project by e-mail, provide name, affiliation, and e-mail address to Ms. Lynn Scearce at lynn.scearce@dep.state.fl.us

Exhibit 11

[OUTPUT-BASED EMISSION STANDARDS]

ADVANCING INNOVATIVE ENERGY TECHNOLOGIES

By Susan Freedman and Suzanne Watson
Northeast-Midwest Institute

NORTHEAST-MIDWEST INSTITUTE

The Northeast-Midwest Institute is a Washington-based, private, non-profit, and non-partisan research organization dedicated to economic vitality, environmental quality, and regional equity for Northeast and Midwest states. Formed in the mid-1970s, it fulfills its mission by conducting research and analysis, developing and advancing innovative policy, providing evaluation of key federal programs, disseminating information, and highlighting sound economic and environmental technologies and practices.

The Institute is unique among Washington policy centers because of its close working relationship with the Northeast-Midwest Congressional and Senate Coalitions — co-chaired by Senators Susan Collins (R-ME) and Jack Reed (D-RI) and Reps. Marty Meehan (D-MA) and Jack Quinn (R-NY). The bipartisan coalitions seek to influence those issues of greatest importance to northeastern and midwestern states.

ISBN: 1-882061-95-0

This report was made possible by a grant from the U.S. Environmental Protection Agency. Opinions in the report, however, may not necessarily reflect the agency's view, and no official endorsement should be inferred. Reproduction of this report, with the customary credit to source, is permitted.

The authors want to extend particular thanks to Skip Laitner at the Environmental Protection Agency's Office of Atmospheric Programs, Joel Bluestein with Energy and Environmental Analysis, Inc., Neal Elliott with the American Council for an Energy-Efficient Economy, Tim Daniels with the U.S. Combined Heat and Power Association, and Dick Munson with the Northeast-Midwest Institute.

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EXECUTIVE SUMMARY

The United States needs a new means to regulate air pollution, one that will reward the more efficient operation of electricity-generating technologies and encourage the introduction of innovative energy processes. The nation's current regulatory approach — using "input-based emission standards" — provides no correlation between the amount of fuel used and the amount of electricity generated. In contrast, an "output-based" approach would reward those generators producing the same amount or more energy while emitting fewer pollutants.

Output-based standards could advance an array of innovative power technologies that offer enormous potential to improve efficiency and enhance the environment. One such technology, combined heat and power (CHP), produces two outputs — thermal and electric. CHP allows for the productive use of much of the waste heat from electricity production, which accounts for about two-thirds of the energy used to generate electricity.[1] Only output-based measurements can capture the total efficiency provided from such a single source of fuel producing both electricity and thermal energy.

This paper details the growing federal, state, regional, and international efforts to incorporate output-based standards in ways that reward increased energy efficiency and emissions reductions It highlights how those standards can advance innovative energy systems, such as combined heat and power, gas-fired turbines, efficient engines, fuel cells, microturbines, wind and solar, among others.

While **Section I** provides an overview, **Section II** offers a policy framework and explains how output-based standards fit into an environmental permitting strategy. Numerous ongoing policy debates, including electricity restructuring and Clean Air Act amendments, affect the electricity industry and the regulation of its pollutants. This section provides a brief history of these issues in order to frame where an output-based approach fits within current U.S. energy and environmental policy.

Section III, the heart of the report, describes state activities, federal efforts, and alternative models that promote output-based standards. It reviews air-quality regulations and legislation, including emissions performance standards (EPS) for power plants, multi-pollutant proposals, distributed generation permitting programs, and the NOx Budget Program. It pays particular attention to Texas, California, and northeastern and midwestern states, which have considered utility restructuring and pollution regulation alternatives. This section also examines models developed by several organizations for how output-based standards could promote innovative and efficient technologies.

This section also reports on how other countries are addressing air emissions for innovative technologies. Many European nations effectively reduce emissions through fiscal measures like carbon taxes (climate change levies), the removal of coal subsidies, and tax exemptions for renewables and/or combined heat and power technologies. In response to one European Union directive, the United Kingdom has implemented an output-based "quality assessment" for CHP. The European Union also is studying cap-and-trade options for regulating greenhouse gas emissions. Allocation allowances — determined on an output basis (or production based) — are one metric being considered.

Section IV offers policy recommendations and perspectives on the future for output-based standards.

The **Appendices** provide state-specific information resulting from communications with state agencies, interviews with experts and regional groups, and literature searches. They also contain a listing of air-quality policy contacts by state, an example of an output-based model referenced in the report, as well as additional details on the Clean Air Act as it applies to power plants and other combustion sources.

Output-based emission standards (also known as efficiency-based or performance-based) are gaining greater attention as states and the federal government address electricity restructuring and ways to mitigate pollutants responsible for acid rain, ground-level ozone, and climate change. By determining emission levels based on the amount of electricity and/or thermal energy generated, output-based standards support improved efficiency without regard to the type of fuel or technology used to achieve that improvement. Adopting such standards, therefore, could help advance the nation's mutual goals of cleaning the air; protecting public health and welfare; and providing affordable, reliable, and secure supplies of energy.

1: OVERVIEW

An array of innovative power technologies offers enormous potential to improve efficiency and enhance the environment. With a growing demand for electricity and the bulk of America's power plants at retirement age, the U.S. faces a unique opportunity to clean the air while providing major economic benefits. Unfortunately, these innovative technologies face regulatory, financial, and environmental barriers.

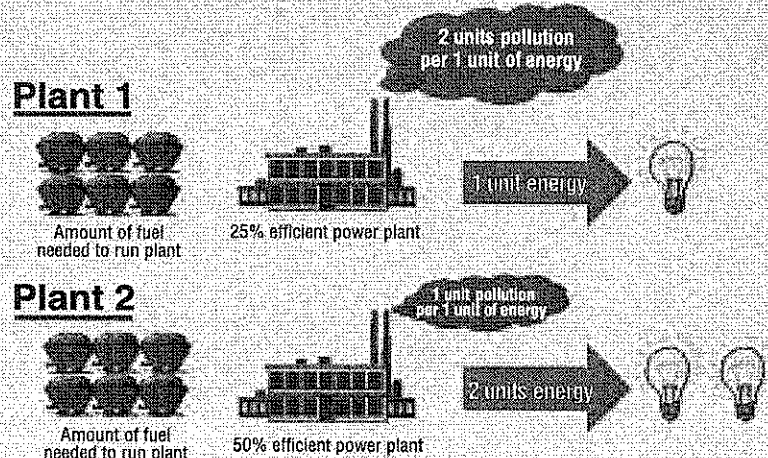
Output-based emission standards can be an effective way to address the environmental barriers since they reward the more efficient operation of energy-generating technologies. The nation's current regulatory approach to cleaning the air relies on "input-based standards" that measure emissions based on units of fuel delivered to the power plant, reported as pounds of pollutant per Btu of fuel. This method, unfortunately, does not recognize system efficiency, and it provides no correlation between the amount of fuel used and the amount of electricity and other energy generated by that fuel.

In contrast, output-based standards link emissions to the generator's final output. Such an approach can reward those generators having the highest "output" of megawatt-hours and the lowest "output" of pollutants.[2] Output-based standards calculate emissions based on the amount of electricity generated, which can be represented in pounds of pollutant per megawatt-hour. Using an output-based measurement encourages greater energy efficiency and pollution prevention.[3] It can minimize the environmental impact of the power sector while enhancing the amount of available power in the U.S.

Figure 1 contrasts the two regulatory approaches by offering a conceptual picture of two power plants, both using the same amount of fuel. Because Plant 2 is more efficient, it is able to produce more electricity and emit fewer pollutants per unit of energy into the air. Current air regulations for power plants do not recognize this air-quality benefit, while an output-based approach would. (Figure 3 on page 12 provides a more detailed example.)

FIGURE 1:

CURRENT INPUT-BASED STANDARDS DO NOT RECOGNIZE EFFICIENCY AND LOWER EMISSIONS*



A power plant producing more useful energy and less pollution for that energy is not rewarded using input-based standards.

Depiction for purposes of demonstrating difference between input and output measurements.

Output-based emission standards (which also have been known as efficiency-based or performance-based) are gaining greater attention as states and the federal government address electricity restructuring and ways to mitigate pollutants responsible for acid rain, ground-level ozone, and climate change. In September 1998, the U.S. Environmental Protection Agency (EPA) revised its New Source Performance Standards (NSPS) for utility and industrial boilers from a fuel-input to an electricity-output basis in order to regulate nitrogen oxide (NOx) emissions.[4] Combined heat and power systems (producing both thermal and electricity) also were to be treated on an output basis. In a memorandum issued October 2001, EPA's Office of Air Quality Planning and Standards advanced the use of output-based standards for combined heat and power (CHP) systems in order to determine whether they constituted a "new source" under certain permitting conditions.[5] In the case of CHP systems, only output-based measurements capture the total efficiency provided from producing both electricity and thermal load (heating and cooling) from a single fuel source.

Using an output-based approach is not a new concept. Such measurements already are used to limit emissions in other regulated sectors. In the transportation sector, for instance, vehicle emissions are monitored on a grams-per-mile basis.[6]

Many organizations and manufacturers of cleaner technologies advocate a shift from current methods to an output-based approach. Such groups include the State and Territorial Air Pollution Program Administrators (STAPPA), Association of Local Air Pollution Control Officials (ALAPCO),[7] Ozone Transport Commission,[8] Pew Center on Climate Change, U.S. Combined Heat and Power Association, and COGEN Europe.

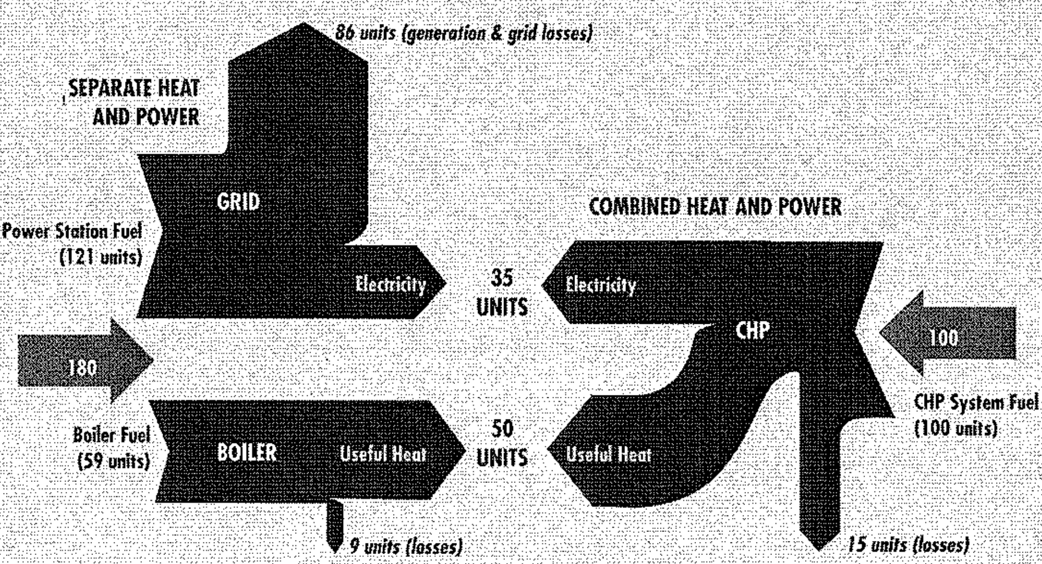
The Pew Center on Global Climate Change in a July 2002 publication stated, "Other reforms to the Clean Air Act also could significantly affect the ability of new highly-efficient generation technologies to enter the market. For instance, air regulations that express limits on an output basis (e.g., pounds per kilowatt-hour, or lbs/kWh) as opposed to input basis (e.g., lbs/Btu of fuel) would encourage investment in new efficient plants."[9]

If output-based standards could encourage the installation of newer and cleaner generating systems, the obvious question is why they are not used more widely in the U.S. The answer is not simple, but part of it relates to simple inertia. For more than 50 years, the U.S. has employed a "central power paradigm" in which

Source: Kaarsberg (1998)

FIGURE 2:

CHP PRODUCES BOTH ELECTRICITY AND THERMAL ENERGY USING LESS FUEL



utility monopolies built large central power plants many miles away from urban centers. That paradigm made sense for several years as larger power plants were more efficient, but by the late 1950s, the U.S. electricity industry was operating at only a 33 percent efficiency level, meaning that for every three units of burned fuel only one unit of useful energy was obtained. Figure 2 displays the difference in fuel needed to produce the same amount of energy by a combined heat and power system and conventional separate heat and power systems. Although the utility industry has delivered relatively reliable power and, therefore, gained an image of being as effective as possible, this dismal efficiency record has not improved. Power plants that stand to lose if output-based standards are adopted are the older, inefficient, coal-burning units; utilities owning those plants will use their political clout to maintain the status quo as long as possible.

Still, an output-based permitting approach falls in line with President Bush's goals for helping industry reduce criteria pollutant emissions under the Clean Air Act. In May 2001, the National Energy Plan (NEP) recommended that the president direct the administrator of the Environmental Protection Agency (EPA) to promote CHP through flexibility in environmental permitting. The EPA put forth draft output-based guidance for CHP in accordance with this recommendation.[10] The NEP recognized that,

> *A family of technologies known as combined heat and power (CHP) can achieve efficiencies of 80 percent or more. In addition to environmental benefits, CHP projects offer efficiency and cost savings in a variety of settings, including industrial boilers, energy systems, and small, building scale applications. At industrial facilities alone, there is potential for an additional 124,000 megawatts (MW) of efficient power from gas-fired CHP, which could result in annual emissions reductions of 614,000 tons of NOx emissions and 44 million tons of carbon equivalent. CHP is also one of a group of clean, highly reliable distributed energy technologies that reduce the amount of electricity lost in transmission while eliminating the need to construct expensive power lines to transmit power from large central power plants.*[11]

While output-based emissions standards would be the preferred environmental method to promote innovative technologies, the process could still be a barrier to combined heat and power systems if the added value from producing both thermal and electric energy is not accurately credited. Since a CHP system provides thermal energy, it can avoid the need for (or displace) a separate stand-alone boiler that has its own fuel demands and pollution. Unless special guidance recognizes and accounts for a CHP system's added efficiency benefit, the output-based standard will not be fully effective, nor truly reflect the market value of CHP, thereby stifling investment in highly-efficient, reliable, and low-emitting power technologies.

This report investigates the air quality policies of twenty states (18 northeastern and midwestern states, plus Texas and California); provides an expanded description of steps being taken to adopt output-based emissions standards; and highlights how those standards might increase more innovative energy systems, such as combined heat and power (CHP). Northeast-Midwest Institute staff communicated with state air regulatory agencies in order to assess their actions and/or interest in output-based standards. Special attention was given to Texas, California, and northeastern and midwestern states since most had adopted utility restructuring and seemed more willing to consider air pollution control alternatives.

Northeast-Midwest Institute staff also conducted a literature review on innovative emission standards, again focusing on output-based initiatives and market-based approaches. Highlighted models include emission performance standards, multi-pollutant regulations, and distributed generation permits. Different state, regional, and federal bodies use a variety of terms to represent output-based standards and applicable power generators; the varying terminology is detailed in Section III of this report. Also explored were international efforts to encourage the deployment of innovative and energy-efficient technologies. Several European countries, for instance, have aggressive programs to advance CHP systems, and the European Commission in 1997 argued for the promotion of CHP "through the setting of emission standards for combustion plants."[12]

II: POLICY FRAMEWORK

Policymakers will not consider output-based standards in a vacuum. Numerous ongoing debates, including electricity restructuring and the Clean Air Act amendments, affect the electricity industry and the regulation of its pollutants. This section provides a brief history of these issues in order to frame where an output-based approach fits within current U.S. energy and environmental policy.

A. ELECTRICITY RESTRUCTURING

Electricity industry restructuring has created an impetus to examine how emissions from power generators are regulated. With the potential of increased competition from a variety of power sources in the wholesale and retail electricity markets, the methods to regulate air pollution must be reviewed.

Although restructuring is moving in fits and starts, due largely to the calamitous events experienced in California's energy markets, the process continues in many states with more or less successful results.[13] Electric utilities have remained the nation's last holdout monopoly. The lack of competition has hindered innovation, as evidenced by the utility industry's stagnant efficiency.

The growing awareness of waste within today's electricity system has prompted a new round of energy debates. Americans, according to some estimates, pay roughly $100 billion too much each year for heat and power.[14] Two thirds of the fuel burned to generate electricity is lost. The utility industry's efficiency has not increased since the late 1950s. Because of this inefficiency, U.S. electric generators throw away more energy than Japan consumes.[15] They also are the nation's largest polluters, spewing tons of carbon dioxide, nitrogen oxides, sulfur dioxide, and other contaminants into America's air and water. The average generating plant was built in the early 1960s, using technology from the 1950s, whereas the factories constructing computers have been replaced and updated five times over that same period. More than one fifth of U.S. power plants are more than 50 years old.

The process of restructuring actually began in the late 1970s, in the midst of concerns about petroleum supplies. Congress in 1978 approved the Public Utilities Regulatory Policies Act (PURPA) in order to advance energy efficiency. The little-noticed Section 210 of that law, however, created the first competitive crack in the utility industry's monopoly structure. For the previous several decades, power companies had enjoyed freedom from competition in their service territories in exchange for regulatory oversight by state commissions.

PURPA opened the door for the first time in several decades to the generation of electricity by power plants not controlled by utility monopolies. The legislation required utilities to purchase the extra electricity from independent power producers at a cost equal to that utilities' avoided cost of new capacity additions. PURPA spurred the construction of wind farms and cogenerators, units producing both heat and electricity from a single fuel source — also known as combined heat and power (CHP).

By the late-1980s, non-utility, independent power producers, many as large as 400 megawatts, were entering the marketplace.[16] These large generators did not qualify to take advantage of the PURPA provisions, but their cheaper electricity production encouraged policymakers to believe that greater competition in the marketplace could reduce electricity prices to consumers.

The Energy Policy Act (EPAct) of 1992 tried to remove additional barriers to increased competition in the electric power sector. While PURPA moved regulatory authority toward the Federal Energy Regulatory Commission (FERC), especially at the transmission and wholesale level, EPAct further encouraged the use of a market-based approach to electricity generation and advanced the concept of customer choice.[17]

Since the mid-nineties, 24 states and the District of Columbia have either enacted utility restructuring legislation or issued regulatory orders to implement retail access. Texas has gone to actual retail competition with some success, while California is in full retreat and has suspended its restructuring process for the foreseeable future.

Several of the restructured states are developing output-based initiatives. Restructuring legislation in Massachusetts, New Jersey, and Connecticut called for the development of output-based (performance-based) standards for retail electricity suppliers if certain criteria are met. Massachusetts and New Hampshire also have set output-based regulations targeting emissions reductions from their dirtiest power plants. Texas has created a permit system for distributed generation systems on an output basis that also allows credit for recovered heat in CHP. In contrast, states that have avoided restructuring also have ignored output-based standards, leading to the conclusions that without the impetus of restructuring states may not take steps to address high power-plant emissions and utilities will resist changes that highlight the status quo's inefficiencies and waste.

B. CLEAN AIR ACT

The Clean Air Act (CAA), among other things, regulates air emissions from the nation's central power plants. At least two provisions of the law have inadvertently hindered the development of innovative and efficient electricity technologies. One is a "grandfather clause" under New Source Review (NSR) that allows less-efficient plants — those built prior to 1977 — to avoid the costs associated with more stringent environmental regulation and permitting. A second barrier to energy efficiency is the regulation of plant emissions on an input basis. As a result of the former, new facilities — even those that are significantly more efficient — are required to absorb the bulk of the required emission reductions. Although upgrades have occurred at grandfathered plants which many consider to be "significant modifications," few have been so characterized and the plants have not had to face stricter clean air rules under NSR. (That issue, however, has sparked several pending lawsuits.)

Since the nation's emissions are regulated on the basis of fuel inputs, power companies usually try to reduce emissions at the "end of the pipe" by installing pollution control equipment. That equipment, however, increases a plant's costs and further lowers its efficiency. Output-based standards, which determine emissions based on electricity generated, offer a more flexible and effective means to reduce emissions at the front end of the process.

The Clean Air Act (CAA), approved in 1970 and amended in 1977 and 1990, gives authority to protect ambient air quality in the U.S. to the Environmental Protection Agency (EPA), and it requires permitting of pollution sources at the state level through individual State Implementation Plans (SIPs). The states may enact stricter air-quality regulations and permitting requirements than required by the EPA, but they cannot adopt less-stringent ones. The extensive state-by-state permitting system regulates energy generating technologies, largely systems over one megawatt (MW) in size and considered major sources.

In September 1998, EPA issued a rule to reduce smog in the eastern United States. That rule, known as the NOx SIP Call, required 22 states and the District of Columbia to revise their state implementation plans in order to reduce emissions of nitrogen oxides, which react with other chemicals in the atmosphere to form ozone (smog). Under the NOx SIP call, NOx allowances were originally provided based on heat input. But EPA formed a stakeholder working group to address an output-based approach for allocating NOx allowances, which ended with the publishing of a May 2000 output-based guidance document.

The Clean Air Act also established New Source Review (NSR), the air pollution control program under which many new electric generation sources fall. The NSR includes two preconstruction permit programs governing the construction of new or modified major stationary sources. In nonattainment areas, NSR requires pollution control technologies to achieve the lowest achievable emissions rate (LAER), as well as emission reductions to offset any increases. In attainment areas (clean areas), best available control technology (BACT) is required.

The Clean Air Act excluded plants built before 1977 from strict air pollution restrictions. These "grandfathered" units come under New Source Review requirements only if the facility receives a major modification or upgrade. Congress included the exemption with the expectation that these electric and boiler plants would soon be retired. Yet such expectations have not been realized. In the 1980s, the EPA amended the definition of "modification" to exempt anything considered "routine maintenance," creating a loophole in which utilities could avoid NSR even when modifications are made under the pretense of "routine maintenance." By the 1990s, however, such utility actions spurred a number of EPA lawsuits against utilities and refineries. Debate continues over what constitutes a modification and routine maintenance.

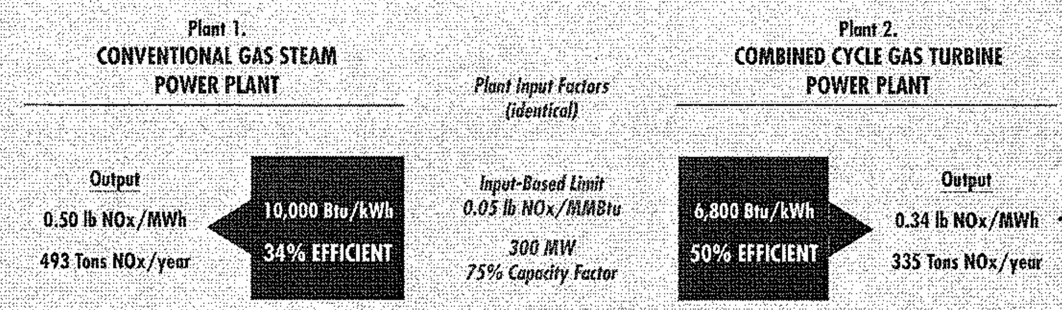
Emissions standards in NSR are based on the amount of fuel required as an input into the generation of electricity. For example, nitrogen oxide emissions have been measured as the pounds of NOx per million Btus of heat input. Currently, the BACT and LAER regulations set targets independent of a system's efficiency, which allows a less-efficient system to burn more fuel and emit more pollution. Output-based emissions regulations would more fairly recognize the environmental benefits of efficiency. For instance, Connecticut, in order to recognize a power system's efficiency, has revised its NSR regulations to credit the thermal output of CHP applications.

C. OUTPUT-BASED STANDARDS IN THE ENVIRONMENTAL PERMITTING STRATEGY

Output-based standards are a means to encourage energy efficiency improvements. Figure 3 (see next page) provides a more detailed contrast of the regulatory approaches, using data from two plants. Again, Plant 2 is more efficient, emits less pollution (in NOx), while producing the same amount of electricity. Yet Plants 1 and 2 are treated as equal in the current regulatory framework. If an output-based approach were used, Plant 1 would have to account for the added fuel used by making the plant more energy efficient, switching to a less polluting fuel, or by running the plant less. Regulations that measure emissions at the point of input do nothing to credit a facility for using energy more efficiently in production. Lower emissions and lower fuel use of highly efficient plants, like CHP, go unrecognized.

Source: Bluestein (2002)

FIGURE 3



This Figure illustrates the relevance of output-based regulation. It compares two 300 MW power plants — Plant 1, a conventional gas steam plant at 34 percent efficiency and Plant 2, a combined cycle gas turbine (CCGT) plant at 50 percent efficiency.

- They both run at the same capacity factor and generate the same amount of electricity.
- They both have the same input-based emission factor of 0.05 lb NOx/MMBtu.

Because of the efficiency difference, however, the less efficient plant creates 493 tons of NOx per year while the more efficient one creates only 335 tons of NOx.

When issuing revised New Source Performance Standards (NSPS) for boilers, EPA requires output-based standards as a way to promote energy efficiency and pollution prevention.[18] Box 1 (see next page) provides more detailed information on the revision to the boiler standard.

EPA also established a NOx Budget Trading Program that requires certain states, primarily in the Northeast and mid-Atlantic, to address stricter ground level ozone and regional haze problems. In May 2000, the EPA released a guidance document[19] for states joining the NOx Budget Trading Program under the NOx SIP Call. The document assists states in determining whether to use output-based NOx allocations for their state implementation plans (SIP) as part of the NOx SIP call. The guidance describes options for developing NOx allowance allocations for power plants, industrial boilers, and turbines using electric and thermal output. The guidance also provides sample regulatory language for state environmental agencies to use. Some states have followed this guidance and adopted output-based standards for their NOx Budget Programs, including Massachusetts, New Hampshire, and New Jersey.

Output-based standards inherently encourage energy efficiency by directly registering the emissions impact of a change in efficiency. Under an output-based standard, a decrease in efficiency would cause an increase in emissions per unit of output, and would require the power plant owner to respond by either restoring its baseline efficiency or reducing its emission rate. Moreover, increases in efficiency anywhere in the regulated process allow the owner to produce more of its salable product within the environmental limit. Thus, the output-based standard provides a built-in market incentive for efficiency. Conversely, a power plant owner currently has no environmental regulatory reason or incentive to respond to increased emissions. In fact, the owner faces a disincentive to respond with a "major" modification of the plant since such a change might trigger New Source Review and require a significant investment of limited capital.

Unlike current air regulations, output-based standards also account for the increased efficiency benefits that occur when heat is recovered in a generation system. They are, in short, essential to encourage the adoption of the cleanest and most efficient electricity generation technologies.

BOX 1

EPA USES OUTPUT-BASED STANDARDS FOR NEW UTILITY AND INDUSTRIAL BOILERS

In September 1998, EPA published revised new source performance standards (NSPS) for emissions of nitrogen oxides (NOx) from both new utility boilers and new industrial boilers. These revisions changed the NOx emission limit for new electric utility steam generating units from a heat input basis to an electrical output basis in order to promote energy efficiency. These standards were based on the performance of best control technologies used by comparable facilities.

In making the revisions, EPA stated that utility NOx emissions were traditionally controlled on the basis of boiler input energy (lb of NOx/million Btu heat input). However, input-based limitations allow units with low operating efficiency to emit more NOx per megawatt (MWe) of electricity produced than more efficient units. Considering two units of equal capacity, under current regulations, the less efficient unit will emit more NOx because it uses more fuel to produce the same amount of electricity. One way to regulate mass emissions of NOx & plant efficiency is to express the NOx emission standard in terms of output energy. Thus, an output-based emission standard would provide a regulatory incentive to enhance unit operating efficiency and reduce NOx emissions.

Pursuant to section 407(c) of the Clean Air Act in subpart Da (Electric Utility Steam Generating Units) and subpart Db (Industrial-Commercial-Institutional Steam Generating Units) of 40 CFR part 60, the EPA revised the NOx emission limits for steam generating units. Only those electric utility and industrial steam generating units for which construction, modification, or reconstruction commenced after July 9, 1997, were affected by these revisions.

The NOx emission limit in the final rule for newly constructed subpart Da units is 200 nanograms per joule (ng/ JO) (1.6 lb/megawatt-hour (MWh)) gross energy output regardless of fuel type. For existing sources that become subject to subpart Da through modification or reconstruction, the NOx emission limits are still regulated on an input basis.

III:
SURVEY OF INITIATIVES TO ADVANCE OUTPUT-BASED STANDARDS

Various federal, state, regional, and international agencies have adopted, or are proposing, output-based initiatives. This section reviews those efforts, which have been made under a variety of air quality policies: new source review, emissions performance standards (EPS) for power plants,[30] multi-pollutant legislation and regulations, distributed generation permitting programs, and the NOx Budget Program. Also examined in this section are several suggested models for developing and implementing output-based standards.

TABLE 1

Air Quality Policies with Output-based Standards:	*State Initiatives and Other Models:*	*Relevance to CHP and Thermal Energy Credited:*
Emissions Performance Standards	MA, CT, NJ, Northeast States for Coordinated Air Use Management (NESCAUM)	Limits emissions by suppliers of retail electricity. Could involve CHP facilities and recognize thermal benefits, but not the policy focus.
Targeted multi-pollutant strategies	MA, NJ, NH	Limits emissions of high-polluting power plants.
Distributed generation regulations	CT, TX, CA, EPA Draft Guidance for CHP, Regulatory Assistance Project (RAP), American Council for an Energy Efficient Economy (ACEEE), Ozone Transport Commission (OTC)	Credits thermal of "qualifying" CHP facilities by quantifying emissions for thermal and electric on output basis; various methods used.
NOx Budget Program allocations	MA, NH, NJ, DE, Ozone Transport Commission (OTC)	Guidance recognizes thermal benefit of CHP. Determines allocations for thermal and electric on an output basis.

Although the highlighted initiatives and models vary in their applications and the factors they employ, each suggests that output-based standards are the preferred way to recognize a power facility's energy efficiency and address the electricity sector's air emissions. Some models and state initiatives see output-based standards as a way to level the playing field among all fossil-fuel-burning power generators, old and new. Output-based standards also inherently showcase zero-emissions power supplies, such as wind, hydrogen, solar, and other renewable resources.

In order to complete its survey, the Northeast-Midwest Institute initially sent electronic-mail questionnaires to state air-permit contacts in search of output-based initiatives for distributed generation, and information on whether any initiatives credited CHP for its added thermal energy product. (Distribution generation technologies produce electricity or thermal energy at or near the point of use.) Recognizing that the use of output-based standards is relatively new to many state contacts, a final question sought to determine if the state air regulator was aware of any efforts in his/her state to recognize energy efficiency in power generation.

Since the initial questionnaires found that few distributed-generation permits were based on output measurements, the Institute conducted a wider survey by telephone and email to state air regulatory agencies on power plant emission policies. That survey identified a limited, but larger, set of air policies measuring emissions on an output basis. In documenting the variety of output-based efforts currently underway in the states and in other venues, this report identifies a slight shift in perception and policy toward an output-based approach.

A. THE STATE INITIATIVES

This section examines how selected states have advanced "output-based" or "efficiency-based" standards as a means to measure and encourage the reduction of power generation emissions. Its purpose is three-fold:

1. To describe where each state currently stands in terms of implementing output-based standards in air quality policies, such as permitting new and significantly-retrofitted power generation facilities;
2. To identify a contact or multiple contacts in each state on output-based air pollution policies and CHP permitting; and
3. To identify any special state-level treatment for permitting CHP, particularly related to output-based emission standards, in order to improve air quality and credit energy efficiency.

Appendix A provides a complete summary of output-based efforts in twenty states. Appendix B contains a listing of air-quality policy contacts by state.

Several states — particularly in the Northeast, California, and Texas — are taking steps to shift their air regulations. Texas and California, for instance, are using output-based measurements for air quality permitting of distributed generation units, and they have given special treatment to CHP. New Hampshire is shifting its air regulations to an output-based approach wherever possible.

Massachusetts's restructuring legislation directs the state Department of Environmental Protection to develop output-based regulations that apply to all power generators involved in the retail sale of electricity. Like Massachusetts, restructuring legislation in Connecticut and New Jersey call for the development of output-based emission standards that apply to retail sellers of electricity. Whereas Massachusetts will implement output-based standards for NOx by May 2003, the other states imposed some stipulations to their implementation. New Jersey's legislation, for instance, calls for output-based rules to be developed only if the state finds that existing federal and regional policies do not address air quality issues satisfactorily or if neighboring states adopt such standards.[31]

Connecticut is the only state to date to take action on New Source Review (NSR), calculating emissions on an output basis and crediting the thermal energy used. The state environmental protection agency completed a major revision to its NSR regulations on December 28, 2001, and those changes went into effect on March 15, 2002. Connecticut also has recognized the public health benefits that output-based standards can generate with regard to the electricity industry.

States have prepared rules for the adoption of output-based standards under three mechanisms/avenues.

1. By setting output-based emissions standards specifically for electric generating units (focusing on distributed generation); and/or
2. By setting output-based emissions standards for one or multiple pollutants and for some or all generating facilities involved in the retail sale of electricity; and
3. By setting output-based emissions standards for nitrogen oxide allocations within the NOx Budget Program.

The first approach sets limits on the amount of air pollution from distributed generators, in turn protecting public health from a potential influx of cheap and highly-polluting diesel generators, while providing incentives to CHP and renewable technologies. The second mechanism encourages energy efficiency on a wider scale and moves the retail electricity market to newer, cleaner technologies that emit less pollution for the same amount of fuel used. The third pertains to summertime NOx emissions and mostly to states in the Northeast that are in nonattainment. Below is a more detailed review of these state efforts. States found to have the most activity are presented here, while Appendix A provides the results of all twenty states surveyed.

Connecticut

Connecticut in December 2001 made major revisions to its New Source Review program in order to permit major sources on an output basis and to credit thermal energy used. Effective March 15, 2002, these revisions apply to all facilities seeking NSR permitting. The modifications are in Section 22a-174-3a of the Regulation of Connecticut State Agencies (RCSA), "Permit to Construct and Operate Stationary Sources."[22] The impetus for state action was twofold: 1) An understanding of the need to credit a facility's energy efficiency, and 2) the lead taken by the U.S. Environmental Protection Agency's release of draft guidance on permitting combined heat and power technologies in NSR.

Since Connecticut's NSR rule provides for CHP incentives, the output basis will reward more efficient projects. The language states that in determining whether to approve BACT (Best Available Control Technology), "The commissioner shall, among other items, not preclude the establishment of an output based emission limitation as BACT provided such application of BACT improves the overall thermal efficiency of the subject source or modification."[23] The permit requirements for nonattainment areas include a provision allowing the commissioner to take into account an output-based emission limitation as LAER (Lowest Achievable Emissions Rate), provided such application of LAER improves the overall thermal efficiency of the subject source or modification.[24]

On April 23, 2002, Connecticut issued its general permit for distributed generators that applies to multiple pollutants and has an annual emissions cap.[25] The permit is not output-based but will only be in effect until December 31, 2003. After that time, the state Department of Environmental Protection expects to adopt the output-based Regulatory Assistance Project Model Rule for distributed generators[26] (which is highlighted later).

In April 1998, Connecticut's electricity restructuring legislation directed the state Department of Environmental Protection to establish generation performance standards for five pollutants: sulfur dioxide (SO2), nitrogen oxides (NOx), carbon dioxide (CO2), carbon monoxide (CO), and mercury (Hg). The standards are to be implemented when "three of the states participating in the northeastern states' Ozone Transport Commission, as of July 1, 1997, with a total population of not less than 27 million, have adopted such a standard." The state electricity restructuring legislation and subsequent law refer to output-based standards as generation performance standards.

Connecticut's Performance Standard Law is Public Act No. 98-28, Sec. 24 and reads:

> *Sec.24. (NEW) Not later than January 1, 1999, the Commissioner of Environmental Protection shall, by regulations adopted in accordance with chapter 54 of the general statutes, establish uniform performance standards for electricity generation facilities supplying power to end use customers in this state. Such standards shall, to the greatest extent possible, be designed to improve air quality in this state and to further the attainment of the National Ambient Air Quality Standards promulgated by the United States Environmental Protection Agency. Such performance standards shall be based on the fuel used for generation of electricity and shall apply to Electric suppliers' generation facilities located in North America and shall limit the amount of air pollutants, including, but not limited to, nitrogen oxides, sulfur oxides, carbon dioxide, carbon monoxide and mercury, emitted per megawatt hour of electricity produced. Such performance standards may provide for a program for purchase of offsetting reductions in emissions and trading of emission credits. A performance standard established by the Department of Environmental Protection for an individual pollutant pursuant to this section shall go into effect when three of the states participating in the northeastern states' Ozone Transport Commission as of July 1, 1997, with a total population of not less than twenty-seven million at that time, have adopted such standard.*

Thus, the Department of Environmental Protection (DEP) is required to have an output-based standard in place, but that standard need not be implemented until other states in the region have adopted similar standards. The state's purpose was to improve air quality. The regulations target retail electricity suppliers, giving the state the ability to require compliance from out-of-state suppliers. As of September 2002, the state Department of Environmental Protection has produced a draft rule, Draft RCSA Section 22a-174-34, based on the NESCAUM regional model regulation (described later). The draft of "Section 34" has been reviewed by the Connecticut Department of Public Utility Control. As of this report's publication, a final rule was not released.

The Connecticut Department of Environmental Protection also has played an integral role in the development of several of the regional model rules to be discussed later in this report. These include the Regulatory Assistance Project's Model Rule for Distributed Generation and the NESCAUM Model Emissions Performance Standard.

Massachusetts

The Massachusetts legislature in late 1997 directed the state Department of Environmental Protection to adopt output-based standards[27] for all power facilities engaged in the retail sale of electricity to end users in the Commonwealth. The standards are for any pollutant of concern to public health. The legislation requires that the state implement the standards for at least one pollutant by May 2003, and it will begin with NOx. If other states in the Northeast implement output-based standards for electricity generation in the meantime, Massachusetts can follow suit. The state DEP has not acted on the generation performance standard to date.[28] The regulatory authority is under Massachusetts General Law c. 111, Sections 142A through 142N.

The state legislature and Department of Environmental Protection believe output-based standards will make it easier to regulate sources that are low-emitting and efficient, while high-emitting and inefficient facilities may need to reduce emissions or purchase allowances from low-emitting sources in order to comply with requirements. The Department of Environmental Protection's background document on the rule declares that "allocating the available state budget based on electrical output promotes pollution prevention in the electric sector by rewarding energy efficiency, and promotes fair competition in the energy market by leveling the environmental playing field for all generators of electricity."[29]

Chapter 111, Section 142N in Massachusetts General Law states that:

> *Section 142N. For the purpose of preventing, mitigating, or alleviating impacts on the resources of the Commonwealth and to the health of its citizens from pollutants emitted by fossil fuel-fired electric generation facilities serving retail customers in the commonwealth, the Department of Environmental Protection shall, in consultation with the office of the attorney general and the Department of Telecommunications and Energy, promulgate rules and regulations to adopt and implement for fossil fuel-fired electric generation facilities uniform generation performance standards of emissions produced per unit of electrical output on a portfolio basis for any pollutant determined by the Department of Environmental Protection to be of concern to public health, and produced in quantity by electric generation facilities. The Department of Environmental Protection shall have said uniform performance standards for at least one pollutant in effect on, but not before, May 1, 2003, unless three or more other northeastern states enact similar standards before that date, in which case the Department of Environmental Protection may adopt such standards prior to May 1, 2003. The Department of Environmental Protection shall issue annually, by March first of each year, an annual report detailing the implementation and compliance of said program, its standards, and its companion rules and regulations.*[30]

As Massachusetts has not developed these standards to date, it is not known whether stipulations for combined heat and power facilities would be included. The state in April 2001 made available a developer's guide to regulations, policies, and programs that affect renewable energy and distributed generation facilities in the Commonwealth. The guidebook references the generation performance standards required in the restructuring legislation.

On another front, in April 2001, Massachusetts took an aggressive step to improve local air quality by targeting reductions at its six dirtiest power plants. Regulation 310 CMR 7.29, "Emissions Standards for Power Plants," requires reductions of NOx, SO2, CO2, and mercury beginning in 2004 (or 2006 depending on reduction choices made by the individual plant). This is accomplished by establishing output-based emission rates for NOx, SO2, and CO2 and establishing an emissions cap on CO2 and Hg emissions from affected facilities. See Table 2 for a summary of the standards, compliance paths, and dates.

The regulation defines "output-based emission rate" as an emission rate for any pollutant, expressed in terms of actual emissions in pounds over a specified time period per megawatt-hour of net electrical output produced over the same time period. "Output-based emission standard" is defined as the emission standards for each applicable pollutant, expressed in terms of pounds of pollutant emitted per megawatt-hour of net elec-

TABLE 2

MASSACHUSETTS POWER PLANT CLEAN UP STANDARDS[31]

(MA DEP Regulation 310 CMR 7.29)

Pollutant	*Emission Standard*	*Standard Pathway Compliance Dates*	*Repowering Pathway Compliance Dates*
NOx	1.5 lbs/MWh	October 1, 2004	October 1, 2006
SO2	6.0 lbs/MWh	October 1, 2004	October 1, 2006
SO2	3.0 lbs/MWh	October 1, 2006	October 1, 2008
CO2	1800 lbs/MWh annual avg.	October 1, 2006	October 1, 2008

trical output produced. The regulation is available online at: http://www.state.ma.us/dep/bwp/daqc/files/regs/729final.doc.

The Massachusetts NOx SIP allocates allowances to generation sources on an output basis. To judge emissions on an output rather than input basis, the state must add data on electrical output, which the Ozone Transport Commission points out is widely available.[32] The state's NOx Allowance Trading Program for 2003 includes an output-based allocation for generating units with useful steam output. The Department of Environmental Protection provides a formula for calculating the steam allocation, which is then added to the electrical output allocation, thereby promoting energy efficiency and recognizing two useful energy outputs. Regulation 310 CMR 7.28 applies to any source greater than 25 MW or greater than 250 mmBtu/hr boiler size. If a source is a CHP facility, then the Department of Environmental Protection allows credit for the CHP portion.[33]

The Massachusetts Department of Environmental Protection also has played an integral role in the development of several of the regional model rules to be discussed later in this report. These include the Regulatory Assistance Project's Model Rule for Distributed Generation and the NESCAUM Model Emissions Performance Standard.

New Jersey

New Jersey's electricity restructuring legislation, approved in February 1999, addressed the potential need for an emissions performance standard, referred to as an environmental portfolio standard. The law directed the Board of Public Utilities, in consultation with the Department of Environmental Protection, to adopt and implement an emission performance standard if such standards became necessary to meet ambient air quality standards beyond current federal and regional actions. A stipulation in the New Jersey legislation also required the adoption of this emissions performance standard if two other states within the PJM interconnection area, comprising at least 40 percent of retail electricity sales, adopt similar standards.

The legislation allows the state Department of Environmental Protection to take action if existing air quality policies do not go far enough to protect citizens from pollution of power plants within the state and the region. In addition, the state will be required to take action if neighboring states adopt this type of emissions regulation. No state has done so to date, and New Jersey has made no decision to promulgate an emissions performance standard.[34]

The emissions portfolio standard language is found within the "Electric Discount and Energy Competition Act," and is as follows:

> *Public Law 1999, Chapter 23, Section C.48:3-87 Environmental disclosure requirements.*
>
> *38. c. (1) The board [of public utilities] may adopt, in consultation with the Department of Environmental Protection, after notice and opportunity for public comment, an emissions portfolio standard applicable to all electric power suppliers and basic generation service providers, upon a finding that:*
>
> > *(a) The standard is necessary as part of a plan to enable the State to meet federal Clean Air Act or State ambient air quality standards; and*
> >
> > *(b) Actions at the regional or federal level cannot reasonably be expected to achieve the compliance with the federal standards.*
>
> *(2) The board shall adopt an emissions portfolio standard applicable to all electric power suppliers and basic generation service providers, if two other states in the PJM power pool comprising at least 40 percent of the retail electric usage in the PJM Interconnection, L.L.C. independent system operator or its successor adopt such standards.*

The legislation's goal was to prevent large amounts of high-emission generation in the state. As part of New Jersey's restructuring legislation, generation companies also are required to disclose environmental characteristics, such as power plant fuels used and emissions generated. This environmental disclosure should allow consumers to understand what's being emitted to produce their electricity.

Certain states — including Connecticut, Massachusetts, New Hampshire, New York, and New Jersey — allocate the allowances available under the NOx Budget Program in ways that recognize energy efficiency. Their purpose is to reduce emissions from power plants and large stationary sources. The New Jersey NOx Budget Program is located in New Jersey Administrative Code, Title 7, Chapter 27, Subchapter 31 and available online at: www.state.nj.us/dep/aqm/rules.htm. The 2003 allocations will be in part on an output basis: both input-based and output-based emission rates are provided. New Jersey also is committed to adopting output-based standards for distributed generation, based on the Ozone Transport Commission's recommendations.[35]

Finally, New Jersey has reached agreement with power companies to reduce multi-pollutants at power plants in the state. This action does not result from regulation but rather is an enforcement action targeting NSR violations. From the state's greenhouse gas initiative came a settlement with Public Service Electric & Gas to reduce CO2 from New Jersey's fossil-fueled electric generating units by a certain amount of pounds per megawatt-hour (MWh) in 2006.[36]

New Hampshire

To the extent it can, the state of New Hampshire tries to regulate all air emissions on an output basis and is currently updating many of its regulations to reflect this approach.[37] New Hampshire has proposed output-based standards targeting four pollutants from the state's highest-polluting power plants. The state in January 2001 released its Clean Power Strategy, which calls for emissions caps based on electricity output for all large electrical generating facilities in the state; put another way, it does not "grandfather" any existing power plant. This action resulted in the Clean Power Act, House Bill 284, which was signed into law in May 2002 and took effect in July 2002.[38] The law requires emissions reductions in SO2, NOx, CO2, and mercury. Section 125-O:3 states that the multi-pollutant strategy shall be implemented in a market-based fashion that allows trading and banking of emission reductions in order to comply with the overall statewide annual emission caps. It also declares that allowances shall be allocated to each affected source based on its output.

In New Hampshire's NOx Budget Program[39] that will go into effect in 2005, allocations will be determined on an output-basis. The allocation language is in the New Hampshire Code of Administrative Rules, Part Env-A 3200. The rule extends New Hampshire's NOx Budget Trading Program for the period 2006 and beyond. This cap-and-trade program does not set output-based "standards," but instead establishes output-based allowance allocations.[40] The Department of Environmental Services followed EPA's guidance for output-based allocations, which includes provisions for thermal heat output for cogeneration; however, there currently are no applicable CHP sources in New Hampshire.

New Hampshire believes output-based standards are a way to encourage greater efficiency and pollution prevention. The state also argues that such standards would help create a level playing field and advance competitive markets.

The state also has a new rule regarding smaller electric generating units (EGUs), Env-A 3700, based on legislation passed during the 1999 legislative session. In House Bill 649,[41] the legislature found it necessary to address emissions from the growing number of smaller generators that were not subject to NOx requirements. The bill acknowledged that many businesses have sought to control their high electric costs by using internal combustion engines that run on fossil fuels to generate electricity. The legislature recognized that these generators have increased nitrogen oxide (NOx) emissions and that additional units could substantially increase such emissions and raise electric rates for customers purchasing electricity from sources subject to more stringent NOx regulations.

The state views this rule as market-based. Sources emitting NOx greater than 7 lb/MWh are subject to either paying fees, buying credits, or installing controls. A new provision was added to RSA 125-J, *NOx-Emitting Generation Source Requirements*, exempting emissions above 7 lb/MWh attributable to cogeneration.

The New Section 125-J:13 reads:

> *I. Each NOx-emitting generation source emitting more than 7 pounds of NOx per megawatt hour generated shall be required to supply to the department NOx emissions information, and the amount of kilowatt hours actually produced during each period listed in subparagraph II(b). Additionally, except as provided either by paragraph I or II of this section, each NOx-emitting generation source shall acquire NOx budget allowances, emissions reduction credits, or other emissions reduction mechanisms on the same basis as a NOx budget source for all of its NOx emissions. However. NOx-emitting generation sources shall not be required to acquire NOx budget allowances, emissions reduction credits, or use emissions reduction mechanisms for the first 7 pounds of NOx emitted for each megawatt-hour of electricity produced and any amounts of NOx above such first 7 pounds that are attributable to the provision of other, non-electric services provided by the generating source, including but not limited to, steam and heat. and any amounts of NOx emitted during any period when the NOx-emitting generation source is operating to provide power during a power shortage at the request of any governmental authority or provider of electrical power to the public generally.*[42]

The New Hampshire Department of Environmental Services also has played an integral role in the development of several of the regional model rules to be discussed later in this report. These include the Ozone Transport Commission Model Rules, and the NESCAUM Model Emissions Performance Standard.

Illinois

The Illinois Resource Development and Energy Security Act (HB 1599), approved on June 22, 2001, calls for a report on reducing multiple pollutant emissions from fossil-fuel-fired electric generating plants. The state Environmental Protection Agency must report on multi-pollutant strategies for NOx, SO2, and mercury to the House and Senate Committees on Environment and Energy before September 30, 2004, but not before September 30, 2003. Although output-based standards are not explicit in the legislative language, the state EPA plans to study this approach.[43] The new provisions applying to fossil-fuel-fired electric generating plants are contained in the Illinois Environmental Protection Act under Section 9.10, 415 ILCS 5/ (IL Compiled Statutes).[44]

Texas

Effective June 1, 2001, the Texas Commission on Environmental Quality (CEQ)[45] established a standard air-emissions permit for NOx from distributed generation in order to encourage the most energy-efficient configurations, such as combined heat and power. The *Air Quality Standard Permit for Electric Generating Units* (EGU),[46] Texas Administrative Code (TAC) Rule 106.511, is a standard permit that was designed to be an expedited method of authorizing clean electric generating units in the state.

The permit, issued under Texas Clean Air Act's Health & Safety Code Sections 382.011, provides a streamlined preconstruction authorization mechanism for electric generating units that are not prohibited by other state or federal permitting statute or regulation. The distributed generation standard is output-based (in lbs/MWh) and establishes pre-certification requirements for a power system.

The standard permit applies to all electric generating units that emit air contaminants, regardless of size, and it reflects BACT (Best Available Control Technology) for electric generating units on an output basis in pounds of NOx per megawatt hour, adjusted to reflect a simple cycle power plant.

For this air quality permit, the state has been divided into two regions — East Texas and West Texas — in order to address ozone nonattainment problem in the East Texas region. In 2005, the permit will require stricter emissions requirements, and the standards for units then will be determined by hours of operation.

The distributed generation permit recognizes that combined heat and power units produce two useful energy outputs, in the form of electricity and heat, and it gives credit for this dual output. The state CEQ produced a guideline, which can be found at: http://www.tnrcc.state.tx.us/permitting/airperm/nsr_permits/files/segu_permitonly.pdf. To meet the emission standards, CHP units may take credit for useful thermal output at the rate of one megawatt-hour for each 3.4 million BTUs of heat recovered. If a CHP unit is not pre-certified by the manufacturer, the owner or operator may submit documentation of the system to receive a CHP credit.

The CHP credit is designed to encourage users to install and use CHP in order to improve the efficiency of generating units where there is a valid need for the recovered heat. In a supplement document, the CEQ offers an example of how this credit works for a 10-megawatt CHP unit.

The Texas CEQ purports that the permit's standards will allow for the cleanest reciprocating engines as well as turbines, microturbines, and fuel cells. This approach should allow the use of more efficient equipment; give an incentive for using CHP without setting standards that would require it; and provide economic incentive for reliable power to be generated at the point of use, as opposed to relying on central plant power with emergency backup.

California

The California Air Resources Board (CARB) has established a distributed generation certification program using output-based emissions standards for NOx, CO, VOCs, and particulate matter. The regulation went into effect on October 4, 2002, and it applies to distributed generation units that had otherwise been exempt from air pollution control requirements.

California Senate Bill 1298[47] (which became Chapter 741 on September 27, 2000) mandated that the Air Resources Board adopt a certification program and uniform emission standards (in lbs/MWh) for electrical generation units that are exempt from other state air district permitting requirements. It also required that the emissions standards reflect the best performance achieved in practice by existing electrical generation technologies.

This law requires CARB to:

1. Adopt uniform emission standards for electrical generation technologies that are exempt from air pollution control or air quality management district permit requirements;
2. Establish a certification program for the distributed technologies subject to these standards; and
3. Issue guidance to the 35 state air districts on the permitting or certification of electrical generation technologies subject to the district's regulatory jurisdiction.

SB 1298 mandated that CARB establish two levels of emission standards for affected distributed generation technologies. The first set of standards had to become effective no later than January 1, 2003, and had to reflect the best performance achieved in practice by existing distributed generation technologies that are exempt from district permits. The law also required that, by the earliest practicable date, the standards be made equivalent to the level determined by CARB to be the best available control technology (BACT) for permitted central station power plants in California.[18] The emission standards must be expressed in pounds per megawatt-hour (lb/MWh) in order to reflect the efficiencies of various electrical generation technologies.

The distributed generation certification regulation is available from the Air Resources Board Distributed Generation Internet site at: http://www.arb.ca.gov/energy/dg/dg.htm. CARB also released its final guidance document for the distributed generation certification regulation in July 2002.[19] In that guidance, CARB set emissions standards for 2003 and 2007, and offered limits for units with and without combined heat and power. In 2005, the CARB will produce a technical review of the distributed generation technologies and emissions criteria in order to determine if any modifications to its certification standards are necessary.

The air quality benefits of combined heat and power (CHP) applications were given special consideration and reflected in their special treatment. Section VII, B. of the guidance states that "efficient" CHP systems will receive an emissions credit for thermal output. Efficient CHP applications must maintain a minimum efficiency of 60 percent in the conversion of the energy in the fossil fuel to electricity and process heat. Thus, the facility's overall lb/MWh can be determined by dividing the facility's emissions, on a pollutant-by-pollutant basis, by the facility's total energy production. The total energy production is the sum of the net electrical production, in megawatts, and the actual process heat consumed in a useful manner, converted to megawatts. More detailed methodologies for calculating the emissions performance standard, and for calculating the CHP credit on an output basis, are provided in the CARB Guidance document appendices C and D.

B. FEDERAL EFFORTS

At the federal level, Congress has begun a new round of debates on the Clean Air Act. Several bills addressing multiple pollutants (known as multi-pollutant bills) were introduced in the 107th Congress, one of which called for emissions to be measured on an output basis. The proposals differed markedly. For much of the 107th session, attention focused on the contrast between a four-pollutant bill from Senator James Jeffords (I-VT), then chairman of the Environment and Public Works Committee, and the Bush Administration's "Clear Skies" initiative, a three-pollutant proposal introduced by Senator Bob Smith (R-NH) in the Senate and Representative Joe Barton (R-TX) in the House.

Senator Thomas Carper (D-DE) in October 2002 introduced a third "multi-pollutant" bill to bridge the gap between the Jeffords and administration proposals. While both the Jeffords and Carper bills would regulate carbon dioxide, the most harmful of the greenhouse gases, the Carper bill regulates most pollutants on an output basis, while the Jeffords legislation considers this as one method but does not commit to a methodology. The Clear Skies proposal does not regulate carbon dioxide, and it does not regulate emissions on a performance basis that could improve air quality.

The Carper bill called for NOx and Hg allocations on a per-megawatt-hour output basis, which would be calculated on a three-year rolling average. It also stated that the EPA shall promulgate regulations that ensured CHP systems received "equitable issuance of allowances." As for CO2, allowances would also be allocated on an output basis, using a three-year rolling average. However, there was no specific mention of CHP or thermal crediting. SO2 retained the Acid Rain program structure with a few minor amendments; the current structure employs an input-based allocation system. The emission cap on annual tonnage of SO2 was to be tightened. Whether the Carper bill or other multi-pollutant initiatives will be introduced in the 108th Congress remains to be seen.

As for CHP, the technology focus of this report, the Bush Administration's National Energy Policy (NEP), released in May 2001, directed the Environmental Protection Agency (EPA) to provide flexibility in environmental permitting.[50] Although the NEP does not specifically mention output-based standards, the implication can be drawn that output-based standards could form the basis of a more fair and flexible system that rewards greater efficiency. The EPA, moreover, sites the NEP's directive as the impetus for a draft guidance it released in 2001 to streamline permitting of some CHP facilities; that guidance measures emissions on an output basis.

The EPA Office of Air Quality Planning and Standards has been finalizing its New Source Review (NSR) guidance in order to recognize output-based standards for CHP systems, siting the above NEP directive as one reason. In October 2001, EPA made available for public comment a draft guidance document that addresses the permitting of CHP systems under EPA's New Source Review and Title V programs.[51] That draft guidance sought to clarify EPA's interpretation of how regulations apply in determining the boundaries for a major stationary source with regard to CHP facilities. Under this draft guidance, CHP facilities may apply for a streamlined permit if the facility is constructed, owned, and operated by a party other than the host or customers. To qualify, a CHP system must meet certain energy-efficiency requirements based on its electric and thermal outputs. The draft guidance also allows the CHP facility to use credits from the shutdown of existing boilers in determining NSR applicability.

The intent of the draft guidance is to clarify how source determinations for CHP facilities should be made under the NSR and Title V permitting regulations. It acknowledges EPA's belief that net environmental benefits will result from CHP emissions replacing old boiler emissions, even if emissions from CHP facilities are not subject to BACT or LAER controls.

While lauding EPA efforts to provide flexibility and streamline environmental permitting process for CHP facilities, CHP advocates recommend certain modifications. For example, since the draft guidance applies to CHP facilities that are owned and operated separately from the host facility, it does not offer any streamlining for those systems under sole ownership. John Jimison, executive director of the U.S. Combined Heat and Power Association, contends that CHP units should be included in the guidance regardless of ownership.[52] Also of importance is the need to create incentives for all facility owners, particularly grandfathered plants that do not fall under NSR, to convert their old boilers and other facilities to more-efficient and less-polluting CHP systems.

Other concerns raised by some analysts have been that energy efficiency levels in the draft guidance are too high, requiring CHP facilities to be more efficient than state-of-the-art natural gas-fired turbine systems — systems that are already significantly more efficient than the industry's average of 33 percent. Critics also worry that the high efficiency measurement could preclude certain renewables, like biomass, from use in CHP since biomass cannot achieve the same level of efficiency as a natural gas-fired system. As of this report's publication, it was not known whether EPA will release a final CHP guidance document.

C. ALTERNATIVE MODELS

Several organizations have developed models for how output-based standards could promote energy efficiency and innovative technologies. Below is a review of those recommended model rules, including environmental permitting for distributed generation and CHP on an output basis and emissions performance standards.

American Council for an Energy-Efficient Economy (ACEEE)

An October 2001 report[53] by the American Council for an Energy-Efficient Economy (ACEEE), the Natural Resources Defense Council (NRDC), and the Center for Clean Air Policy (CCAP) endorses output-based regulation in order to encourage energy-efficient power technologies and to reflect the benefits of combined heat and power. The report provides a model for certifying CHP systems that recognizes the emissions produced in relation to the two usable energy products generated — thermal and electric. ACEEE is a nonprofit organization dedicated to advancing energy efficiency as a means of promoting both economic prosperity and environmental protection.

ACEEE's CHP certification report provides the technical justification for calculating compliance of an individual CHP unit with electric output-based standards. The ACEEE method of accounting for CHP's dual benefits merges the emission standards for electric generators and boilers.

> *When calculating compliance of an individual CHP unit with electric output-based emissions standards, the emissions from the unit should be discounted by the avoided emissions that a conventional system would have otherwise emitted had it provided the same thermal output. For example, a 35-megawatt electric (MWe) CHP system with a power-to-heat ratio of 0.7 produces 50 megawatt thermal (MWt). For this system, we assume that the CHP unit displaces a typical small industrial, commercial, or residential boiler with an efficiency of 80 percent. Using this assumption and the California emissions standard for boilers, we assume that the displaced boiler would emit 0.036 lbs/MMBtu on an input basis, equivalent to 0.154 lbs NOx/MWhe on an output basis (California Clean Air Act 1998). Based on a power-to-heat ratio of 0.7, the emission credit on an electric basis would be 0.220 lbs NOx/MWhe. In other words, a CHP unit could emit 0.72 lbs NOx/MWhe and still comply with California Air Resources Board's proposed 0.5 lbs/MWh standard (since 0.72 lbs NOx/MWhe - 0.220 lbs/MWhe = 0.5 lbs/MWhe).*[54]

Having determined an equitable method of valuing the thermal energy product, and making the conversion entirely to output and electric, a single emissions standard — in pounds per megawatt-hours of electricity for both stand-alone electric generators and CHP units — can be implemented through this method. Other model emissions rules have not fully recognized and accounted for the added benefits of combined heat and power systems or for their technical capabilities.

The ACEEE model also addresses the stringency of energy-efficiency requirements that would exclude any off-the-shelf, low-emitting technologies. Moreover, it realistically addresses the lead-time needed by industry research and development in order to improve these already-innovative technologies. These issues have been raised in public comments for California and Texas, as well as by the Regulatory Assistance Project's model rule for distributed generation.

Regulatory Assistance Project

The Regulatory Assistance Project (RAP) in October 2002 released a final-review-draft model emissions rule[55] for distributed generators. RAP is a non-profit organization, formed in 1992, that provides workshops and education assistance to state public utility regulators on electric utility regulation. RAP is committed to fostering a restructuring of the electric industry in a manner that creates economic efficiency, protects environmental quality, assures system reliability, and applies the benefits of increased competition fairly to all customers.

RAP's draft model rule for distributed generation contains output-based emissions standards in pounds per megawatt-hour for NOx, particulate matter, CO, and CO2 for power generating units too small to trigger new source review. RAP's supporting documentation contains a series of emission calculations and charts detailing pollutant levels for various distributed generation technologies. The rule calls for the pollutant standards to be phased in over three phases in a ten-year period. The emissions limits are for two generation categories: emergency and non-emergency.[56] Based on public comment to the first draft, RAP extended its proposed phase-in periods (beginning in 2004, 2008, and then 2012) in order to better accommodate manufacturer research and development cycles. NOx emission limits for Phases I and II are differentiated for attainment and nonattainment, after which time only one set of limits will apply. RAP will conduct a technological review of the rule by December 31, 2010, and make any changes determined appropriate to the Phase III standards.

The draft rule would impose an air permitting review process on certain power generating facilities not now subject to operating with a permit. It does not apply to existing sources. The rule's purpose is to ensure that air quality will not be unduly impacted by the wider introduction of smaller power generating units into any region. RAP's objectives in designing the rule were:

1. To regulate "the emissions output of distributed generation in a technology-neutral and fuel-neutral approach;"
2. To "facilitate the development, siting, and efficient use of distributed generation in ways that improve or, at least, do not degrade air quality;" and
3. To "encourage technological improvements that reduce emissions output."[57]

The principles guiding development of the rule were to promote technological improvements in efficiency and emissions output by encouraging the use of non-emitting resources and by accounting for the benefits of CHP and the use of otherwise flared gases. Another principle was that the rule be easy to administer so that it could facilitate the development, siting, and efficient use of distributed energy resources.[58]

Section VII, (B) of the rule, under Credit for Concurrent Emissions Reductions, pertains to combined heat and power facilities. For a CHP installation to qualify for a thermal credit, the October 2002 version of the rule lays out two requirements.

1. At least 20 percent of the recovered energy must be thermal and at least 13 percent must be electric.[59] (This corresponds to a power-to-heat ratio of between 4.0 and 0.15.)
2. The design system efficiency must be at least 55 percent.[60]

RAP has made other changes with regard to CHP based on comments to its March 2001 draft document. One change recognizes that CHP replaces a variety of power generation facilities. When determining the emission rates for a displaced boiler, RAP added language to address retrofit CHP facilities. In the case where retrofit-CHP facilities replace existing thermal systems for which actual emission rates can be documented, the CHP unit can receive credit for the actual emission rates (up to a prescribed limit).[61] Otherwise, the thermal credit is based on new natural-gas-fired boilers.

Revisions to the March 2001 draft model were ongoing through Spring and Summer 2002. A final draft model rule, dated October 31, 2002, incorporated the public review comments. As of this report's publication, an official final rule has not been publicly released, but will be available at http://www.raponline.org/

when ready. Regardless of its publication date, the state of Connecticut plans to adopt RAP's model distributed-generation standards to become effective in 2004.[62]

Northeast States for Coordinated Air Use Management (NESCAUM)

The Northeast States for Coordinated Air Use Management (NESCAUM) developed an output-based model emissions rule for power generators in December 1999. NESCAUM is an interstate association of air quality control divisions in northeastern states. It was originally formed to deal with the problem of emissions from large power plants located on or near state borders, but it has tackled other issues, including acid rain and ozone.

If adopted by a state, NESCAUM's proposed output-based standards, known as Emissions Performance Standards (EPS),[63] would apply to any retail electricity supplier's portfolio of generation resources. NESCAUM recognized the large variations in electricity costs and emissions control requirements for power generating facilities across the eastern U.S. It also acknowledged that electricity restructuring could shift retail choice to lower-cost but more-polluting resources unless environmental performance measures were required for all retail suppliers.

In developing its model, the group defined two objectives:

1. To prevent electric utility restructuring from resulting in a degradation of air quality in the Northeast by providing a mechanism to ensure that disparities in environmental regulation would not create a competitive advantage for more polluting resources (i.e., "leveling the environmental playing field"); and
2. To improve air quality in the Northeast and to reduce the adverse impacts of electricity generation on public health and the region's environment.[64]

Some states, like Massachusetts and Connecticut, have passed legislation calling for output-based emissions standards, while others could follow suit in their own restructuring legislation. In order to promote regional coordination and consistency, NESCAUM tried to adhere to objectives within existing state laws. The EPS framework was based on state electricity restructuring legislation, recognizing that generators serving in-state retail customers might be located out of state. The retail sale of electricity was chosen as the compliance trigger since it is tied to a state's authority to license providers of retail electric services.

Finally, the EPS covers NOx, SO2, CO2, and eventually mercury — as had been identified in Connecticut's restructuring legislation. A placeholder to regulate carbon monoxide is provided though no standard is set in the model. To determine compliance with the output-based standards, a retail supplier must use the model's measurement formula to calculate a weighted average emission of its electricity generation portfolio in pounds per megawatt-hour and then compare the result with the pollutant emission maximum level.

TABLE 3

NESCAUM MODEL EMISSION PERFORMANCE STANDARDS[65]

Pollutant	*Emission Performance Standards*
NOx	1 lb/MWh
SO2	4 lb/MWh
CO2	1100 lb/MW
Mercury	Actual Emission Rate

The intent of EPS is "to maintain, in the deregulated market, an equal or improved level of environmental performance relative to what would otherwise be required for electricity generation serving the Northeast market."[66] The workgroup plans to review the EPS in 2003, make any necessary revisions, and reconvene every five years thereafter.

With regard to emission attributes of combined heat and power installations, Section (g)(B)1.a. of the NESCAUM EPS Model Rule states that:

> *Combined heat and power system emissions shall be assigned an emission rate calculated by allocating emissions on a pro-rata basis between 1) electric energy output and 2) thermal energy output multiplied by a combined heat and power factor. The combined heat and power factor is initially set at 50%. Said factor shall be reviewed and revised on the schedule defined in subsection (f)(3) and any revision shall be consistent with regulations adopted by the Federal Energy Regulatory Commission pursuant to the Public Utilities Regulatory Policy Act.*

The emission performance standards model rule bases its thermal and electric emissions mix on a standard Public Utilities Regulatory Policies Act (PURPA) calculation, assigning 50 percent of emissions to electric output.[67] The model rule provides for periodic review of this assumption, consistent with future revisions to the PURPA calculation. Some reviewers encouraged NESCAUM to better credit thermal cogeneration and to adopt other modifications that acknowledge how CHP's efficiency levels will change over time with improvements in technology and depending on fuel mix used.

The NESCAUM model emissions performance standard can serve as a template for states interested in addressing air quality and competitiveness in their electricity restructuring efforts. States can modify the model as appropriate to their needs. One such modification could be to incorporate the ACEEE method for valuing CHP emissions on an output-basis. State air policy regulators from Connecticut and Massachusetts led the workgroup that developed the EPS and have used the NESCAUM work as a basis for the development of their state rules.

Ozone Transport Commission

The Ozone Transport Commission (OTC) has released models and reports on output-based standards as part of environmental performance standards for electricity generators, distributed generation permits, and NOx Budget Program allocations. The organization recognizes the air quality benefits that measuring emissions on an output basis can yield. The OTC was formed by Congress through the Clean Air Act (CAA) Amendments of 1990 in order to help coordinate control plans for reducing ground-level ozone in the Northeast and mid-Atlantic states. Since its inception, OTC has focused on a number of tasks, including assessing the nature and magnitude of the ozone problem in the region, evaluating potential control approaches, and recommending regional control measures. Twelve states and the District of Columbia are represented in the OTC.

The OTC Technology and Innovations Committee in September 2000 released a report on environmental performance standards[68] that states could use to encourage the development and use of clean power. The OTC identified output-based standards as one control measure to help reduce ozone pre-cursors. The standards would be applied to each electricity product sold to a retail customer in a particular state, and would not apply to specific generating units or wholesale transactions. As a model, the OTC directs states to the NESCAUM emissions performance standard.

The Technology and Innovations Committee in March 2001 released a report and draft model rule to streamline environmental permitting for small-scale distributed generators.[69] In order to foster low-emitting distributed generation technologies and limit the growth of high-emitting sources, OTC proposed that states could ease permit requirements for clean technologies while ensuring that high-emitting diesel engines receive careful review. Low-emitting sources would not need permits unless the units exceeded a given size threshold. The permit emissions thresholds would be reviewed within three years.

The OTC suggested that a draft model permit be required, with few exceptions, for existing, modified, and new electric generating equipment that emit NOx, CO, PM, and SO2 in pounds per megawatt-hour. Distributed generation equipment that would not require a permit in the OTC model included:[70]

- Fuel cells of any generating capacity size fueled by hydrogen;
- Fuel cells with less than 5,000 kW generating capacity fueled by methane;
- Fuel cells with less than 500 kW generating capacity fueled by fuels other than hydrogen and methane;
- Microturbines with less than 500 kW generating capacity fueled by natural gas, verified to emit less than 0.4 lbs/MWh NOx;
- Diesel engines with less than 37 kW generating capacity;
- Diesel engines equal to or greater than 37 kW generating capacity (50 horsepower (HP)) but less than 200 HP that are not located at a major stationary source of NOx emissions;
- Other electric generating equipment with less than 500 kW generating capacity, which is verified to emit less than:
  1. 0.4 lbs/MWh NOx;
  2. 0.25 lbs/MWh CO;
  3. 0.1 lbs/MWh PM;
  4. 0.01lbs/MWh SO2.

In order to reduce the impact of the anticipated influx of permit applications from distributed generation emission sources, the OTC report suggested that states could use a "verification program" approach for general permits or permits-by-rule, similar to the Texas and California distributed-generation permit programs. If the verification approach is taken by some states within the ozone transport region, consistent emission verification programs and standards should be developed and implemented within the region. The OTC distributed generation report mentioned that combined heat and power should be incentivized, but it did not add further detail.[71]

D. COMBINED HEAT AND POWER EFFORTS

The U.S. Combined Heat and Power Association (USCHPA) is a proponent of shifting air quality regulations from an input- to an output-based measurement. The organization brings together diverse market interests to promote the growth of clean, efficient CHP in the United States. It is a private, non-profit association, formed in 1999, to promote the merits of CHP and achieve public policy support.

USCHPA argues that air regulations should recognize and credit CHP systems for their increased efficiency and reduced emissions. The National CHP Roadmap identifies environmental permitting as one of the top barriers to siting more of these highly-efficient systems, and it recognizes the adoption of output-based standards as a solution. The CHP Action Agenda from the Roadmap calls for the development of output-based emissions standards by working with the Environmental Protection Agency in the analysis of alternative technical approaches, development of guidance to state and local air quality officials, and the offering of technical assistance.[72] Regional CHP initiatives, including the Midwest and Northeast, also are concerned with output based standards and receiving credit for the thermal output of CHP systems.

E. INTERNATIONAL EFFORTS

The Northeast-Midwest Institute conducted a literature search in order to learn how other countries have addressed air emissions for electricity producers, including innovative technologies like combined heat and power facilities. The research included data from the International Energy Agency (IEA), Organization for Economic Cooperation and Development (OECD), Commission of the European Communities (CEC), Cogen Europe, U.K.'s Combined Heat and Power Association, and other sources. Communications were engaged with the U.K. CHPA and the World Association for Decentralized Energy (WADE).

It was learned that:

- Energy security, climate change, and electricity and gas restructuring (liberalization) are key drivers behind the promotion of energy efficiency, renewables, and CHP;
- A number of policy directives at the European level apply to power generation and combined heat and power;
- In response to one directive, the U.K. has implemented an output-based "quality assessment" for CHP, and the European Union would like other member states to follow suit;
- The European Union (EU) is currently studying cap-and-trade program options for regulating greenhouse gas emissions. Allocation allowances determined on an output basis (or production based) is one metric being considered;
- Output-based emissions standards are not used for environmental permitting of industrial installations and/or power plants; and
- Many EU member states reduce emissions through fiscal measures like carbon taxes (climate change levies), the removal of coal subsidies, and tax exemptions for renewables and/or combined heat and power technologies.

In December 1997, in the framework of the Climate Change negotiations in Kyoto, the European Union (EU) committed itself to reduce its greenhouse gas emissions by 8 percent for the period between 2008-2010 in relation to its 1990 levels. This commitment is then distributed with different targets among the EU member states, which include Austria, Germany, Netherlands, Belgium, Greece, Portugal, Denmark, Ireland, Spain, Finland, Italy, Sweden, France, Luxembourg, and the United Kingdom. The Commission of the European Communities, or CEC, administers EU policy and ensures that EU legislation is fully implemented in all the member states.

Unlike the U.S., European environmental regulations have not only focused on ozone precursors and acid rain, but also on greenhouse gas emissions from carbon dioxide. European power generating facilities are subject to a series of regulatory requirements. Some of the most important requirements include a council resolution and proposed directive on CHP, the electricity and gas liberalization directives, a pollution prevention directive (IPPC), and a large combustion plant (LCP) directive. See Box 2 on next page for details. In the case of gas turbines, standards differ across Europe. In some countries, no standards exist for small units and standards for bigger installations depend mostly on the 1988 LCP Directive. In other countries, the principle of Best Available Technique (BAT) in the IPPC Directive is applied.

Still, European countries are recognizing the importance of whole system efficiency, and they emphasize pollution-prevention in combustion systems, which differs from the general U.S. approach of relying on add-on controls. Germany's TA-Luft standard, for instance, states that "all possible measures which reduce emissions through improved combustion shall be applied."[73] There has been a strong downward trend in most EU member states in pollutants due to the tightening of emission limits of power plants and the switch to gas.[74] Emission regulations are generally revised downward every few years, taking into account developments in technology.[75]

CHP — and renewables — have been widely recognized both at the European Community level and member state level as technologies that can make a major contribution to achieving targeted greenhouse gas reductions. In December 1997, the CEC formally adopted a resolution for a community strategy to promote CHP and to dismantle barriers to its development.[76] In the resolution, the CEC states that the efficient use of energy from combined heat and power can contribute positively not only to the environmental policies of the European Union, but also to the competitive situation of the EU and its member states and to security of supply. Specifics like recognizing energy efficiency in permitting requirements are not mentioned, but the resolution does state that such measures to promote the use of combined heat and power could include the internalization of external costs and environmental benefits, among other measures.

The proposed Directive on the Promotion of Cogeneration[77] was released on July 7, 2002, in order to provide a framework for achieving EU CHP targets. The Directive obliges member states to publish an analysis of the national potential for "high efficiency" cogeneration; to publish an analysis of the barriers to high efficiency

BOX 2

EUROPEAN COMMISSION DIRECTIVES RELATING TO CHP AND POWER GENERATION

The proposed Directive on the Promotion of Cogeneration was released on July 7, 2002 to provide a framework for achieving EU CHP targets. The Directive obliges Member States to publish an analysis of the national potential for "high efficiency" cogeneration, to publish an analysis of the barriers to high efficiency cogeneration, & to report on progress towards increasing the share of high efficiency cogeneration, including the measures taken to promote it. The high efficiency term is used in place of "quality cogeneration" as used in the UK CHP Assessment (detailed later).

The Directive to Liberalize the Electricity Market, Council Directive 96/92/EC, concerns common rules for the internal market in electricity, & became effective January 8, 1997. The Directive obliges an opening of at least 25% of the European Electricity market by February 1999, 28% by 2002 & 33% by 2005. This directive establishes common rules for the generation, transmission & distribution of electricity. Throughout the directive, preference is given to renewable energy sources & CHP. The level of implementation of this Directive varies among Member States. Energy sector liberalization in Europe is expected to be complete by 2010.

The Directive to liberalize the Gas market, Council Directive 98/30/EC, is to establish common rules for the transmission, distribution, supply & storage of natural gas. It is similar to that for electricity: Member States must gradually liberalize their gas market. The Directive addresses access to the market, operation of systems, & the criteria & procedures applicable to the granting of authorizations for transmission, distribution, supply & storage.

continued on next page

cogeneration; and to report on progress towards increasing the share of high efficiency cogeneration, including the measures taken to promote it. The high efficiency term is used in place of "quality cogeneration" as used in the U.K. CHP Assessment (detailed later).

The CHP Directive relies on output-based qualifying measurements for thermal and electric generation. "Heat efficiency" is defined as the annual useful heat output divided by the fuel input used for heat produced in a cogeneration process and for gross electricity production. In the case of cogeneration with district heating, useful heat output is measured at the point of outlet to the heat distribution network, decreased by a realistic estimation of losses in the distribution network. In the case of other cogeneration applications, useful heat output is measured at the point of use.[78] "Electrical efficiency" is defined as the annual electricity production measured at the point of outlet of the main generators, divided by the fuel input used for heat produced in a cogeneration process and gross electricity production. "Overall efficiency" is defined as the annual sum of electricity production and useful heat output, divided by the fuel input used for heat produced in a cogeneration process and gross electricity production. Annex III of the Directive (See Appendix C.) uses these definitions in the methodology of determining the efficiency of cogeneration production and details what it considers "high efficiency" cogeneration.

BOX 2

The Large Combustion Plant Directive,[82] Council Directive 88/609/EEC, limits the emissions of certain pollutants (including SO2 & NOx) into the air from large combustion plants (50 MW or more). Amendments to the LCP Directive include Council Directives 94/66/EC & 2001/80/EC on the limitation of air emissions of certain pollutants from existing large combustion plants. In June 2000 the EU environment ministers agreed to a set of air emission standards to restrict pollution from large power plants & also agreed to national emissions ceilings for 4 substances: sulfur dioxide (SO2), nitrogen oxides (NOx), volatile organic compounds (VOCs) & ammonia (NH3).[83] National & local authorities define final emission limits through national legislation & permit procedures.

The Integrated Pollution Prevention & Control (IPPC) Directive is Council Directive 96/61/EC. The IPPC has a set of common rules on permitting for industrial installations to minimize pollution from various point sources throughout the European Union. All installations covered by Annex I of the Directive are required to obtain an authorization (permit) from the authorities in the member countries. The IPPC directive contains rules for "integrated" permits that must take into account the whole environmental performance of the plant including emissions to air, water & land, generation of waste, use of raw materials, energy efficiency, noise, prevention of accidents, & risk management. New & esixting installations should comply by 2007.

Permits must be based on the concept of **Best Available Techniques (BAT)**, defined in Article 2 of the IPPC Directive. Sector-specific BAT reference documents (BREFs—guidance) are underway. All BREFs should be completed by the end of 2005; several have been finalized & are available from the European IPPC Bureau.[84] The directive requires the member states to ensure that the technical & economic feasibility of providing for CHP is examined, & where feasibility is confirmed, to develop installations accordingly.[85] CHP is BAT for industrial installations.

Furthermore, in the proposed Directive, high efficiency cogeneration is determined in terms of energy savings in comparison with separate heat and power production. Cogeneration production must provide energy savings of at least 10 percent to qualify as high-efficiency cogeneration (or 5 percent for existing facilities). Line losses of 5-10 percent also are counted in central system (in)efficiency.

A European team of experts analyzed the future for cogeneration in Europe stated in their findings that the most frequent barriers to cogeneration include "bureaucratic procedures for obtaining all required authorizations," and "emissions regulations (that) do not take the higher efficiency of cogeneration systems into account."[79]

The European nonprofit organization promoting combined heat and power, Cogen Europe, believes that emission legislation should reflect more clearly the high efficiency of energy conversion. Some countries have prepared specific legislation on CHP but currently only the Netherlands, Flanders (Belgium), and Denmark take efficiency of energy conversion into account in emission regulations.[80] A recent article in the international journal, *Cogeneration and On-Site Power Production*, called for the adoption of output-based emission standards for many combustion sources, including gas turbines used in CHP applications.[81]

In the **United Kingdom**, the regulatory system does not take into account whether heat is recovered from a prime mover, or whether steam from a boiler is used to drive a turbine; it is the fuel-burning components — the gas turbines, engines, and boilers — that are regulated as combustion processes.[86] But like at the EU level, the efficiency of a CHP installation is beginning to be recognized in other policy mechanisms such as the CHP Quality Assessment.

The U.K. has developed an output-based standard measurement for CHP in order to incentivize its installation. Termed the CHP Quality Assessment (or QA), it provides an emissions standard for determining "good quality" CHP in order for CHP facilities to qualify for financial incentives. (Box 3 details the U.K. CHP Quality Assessment.) The European Union recommends that other member states follow the U.K. lead and include a definition of quality (level of efficiency) for CHP. The QA came from a 1997 European Council directive that member states develop a means to distinguish good-quality CHP.

The standard was not created to streamline environmental permitting, but rather as a measure to qualify for special financial treatment in the electricity sector. The following benefits were available from April 1, 2001:

1. Exemption for good-quality CHP from the Climate Change Levy
2. Enhanced capital allowances for good-quality CHP
3. A level playing field for good-quality CHP within Business Rating.[87]

The aim of the CHP Quality Assessment program is to:

1. Provide a practical, reliable method for quality assessment and monitoring of various types and sizes of CHP scheme. This method is based on the energy efficiency and environmental performance of a CHP plant compared to good alternative energy supply options; and
2. Improve the quality of existing and new CHP schemes in order to enhance the "environmental and other benefits" of CHP.[88]

In its Environmental Action Plan, U.K. Office of Gas and Electricity Markets (OFGEM) supports the greater use of flexible, market-based mechanisms for environmental regulation. OFGEM's role includes issuing Levy Exemption Certificates (LECs) based on qualifying output from accredited generators. One LEC is issued for each qualifying megawatt-hour produced.[90] In the 2002 Budget, the government announced the extension of the exemption to the Climate Change Levy to all good-quality CHP. OFGEM plans to extend the Climate Change Levy exemption to good-quality CHP in the next year.[91]

Many other European countries have taken steps to promote emissions reductions and energy efficiency. Belgium has no explicit programs that support CHP development directly, but a number of incentives, including tax advantages and direct grants, are available for energy-saving investments based on federal government legislation. For instance, cogeneration that satisfies a "quality" standard, like the EC Directive, receives a better gas tariff.[92] "Quality cogeneration" is a gas-fired cogeneration installation whose functioning allows for savings of primary energy of 15 percent in relation to the separate generation of heat and electricity from a reference installation. Belgium has three regional regimes for environmental standards, notably in Flanders.[93]

In the Netherlands, over 50 percent of total electricity generation is from CHP plants.[94] For permitting, NOx limits for gas turbines are corrected for the electrical efficiency of the CHP installation: higher efficiencies are rewarded with a higher NOx standard.[95] The Dutch electricity sector is influenced by the government's

BOX 3

THE UK CHP QUALITY ASSESSMENT

The program involves a Quality Assessment based on a Quality Index (QI). A suite of definitions is being developed to cover the whole range of schemes, applications, sizes, technologies and fuels. It has been taken into account that, regardless of the electrical efficiency, a project that recovers heat will generally be more efficient than one that does not. The Quality Index (QI) methodology is built on the rationale that electricity supplied is more valuable than heat supplied. It compares CHP to separate electricity-only and heat-only alternatives. The QI therefore offers scope for a major improvement over conventional approaches simply based on overall efficiency.

The general form for QI calculation is: QI = X x Efficiencypower + Y x Efficiencyheat

Where: Efficiencypower = annual power supply (MWhe)/annual fuel use (MWh)

Efficiencyheat = annual heat supply (MWhth)/annual fuel use (MWh)

X is a coefficient for power, related to alternative electricity supply options. Similarly Y is a coefficient for heat generation, related to alternative heat generation options. These coefficients vary to reflect conditions affecting particular classes of CHP plant. For a scheme that supplies electricity only, Efficiencyheat is zero.

"Good Quality" CHP is defined as achieving a certain minimum efficiency of heat and electricity production from the CHP project. The required power efficiency is at least 20% (15% until 2005 for existing projects), with a required CHP efficiency that decreases as power output increases. For a small CHP scheme (1-10MW) producing power at 20% efficiency, the required CHP efficiency would by 69%.

Efficiencies are expressed in terms of Gross Calorific Values (GCV). Annual heat supply is the useful heat supplied by the scheme that displaces heat, which would otherwise have to be supplied by boilers or by direct heating.[96]

policies to reduce CO_2 emissions and improve energy sustainability. The 1989 Electricity Act strongly encouraged market entry by decentralized CHP for environmental reasons.[96] Incentives included government subsidies, tax benefits, and other financial perks. Environmental regulations were not an issue.

Denmark is another leader in CHP use. More than 60 percent of the country's electricity production comes from combined heat and power facilities.[97] The development of cogeneration in Denmark has been backed by promotional policies by the government, including a carbon tax containing incentives for cogeneration. The Danish Energy Agency has recently written a report, "Combined Heat and Power in Denmark," that contains a summary of recent government incentives to promote cogeneration in Denmark.[98]

Germany applies airborne pollutants regulations, known as the TA-Luft standards, to gas turbines that allow higher emission limits for higher-efficiency gas turbine systems in order to account for the lower emissions per unit of output achieved by these systems. These standards have been used in other EU countries as a guideline. May 1991 was the last update of the 1986 TA-Luft to conform with Best Available Technique (BAT) requirements.[99]

Greenhouse Gas Cap and Trade Program

In June 2000, the European Commission established the European Climate Change Program (ECCP) to help identify the most environmentally-beneficial and cost-effective additional measures to achieve the Kyoto Protocol target. The CEC has identified particular sectors that could be initially included in a trading program, including electric heat, pulp and paper, cement, iron and steel, refining, and chemicals.[100] Cap-and-trade options include grandfathering, auctions, and updating. The allocation metrics to measure facility-specific data could include using fuel inputs, product output, emissions, or a combination.

In October 2001, the EU adopted a proposal for a directive to establish a cap-and-trade system for various sources of greenhouse gas emissions as one means of meeting the EU emissions targets in the Kyoto Protocol.[101] Under a cap-and-trade program, individual trading entities are initially allocated emission allowances (the right to emit a ton of pollutant) that cumulatively equal the cap or target for the relevant sectors.

The establishment of cap-and-trade programs in Europe and the United States could be an effective way to recognize efficiency while reducing emissions globally and locally. Determining allocations on useful energy output is a potential mechanism to account for efficiency in a combustion system and credit efficient systems under such an emissions reduction program.

IV: SUMMARY AND RECOMMENDATIONS

This report summarizes actions that demonstrate a slight shift toward the use of output-based standards for regulating air emissions from power plants and distributed generation technologies. Output-based emission standards are being recognized at the state and federal levels, in Europe, as well as in models developed by regional organizations and environmental groups. Such standards:

- Create a level playing field for all power generators regardless of plant age or geographic location;
- Address multiple pollutants in one policy or regulation;
- Provide incentives for energy efficiency by linking air emissions to the end energy product; and
- Protect air quality.

The sooner the U.S. adopts output-based emission standards, the sooner the nation will see innovative energy-efficient technologies improve our air quality and enhance our economic trading position internationally. The change in emissions measurement from input-basedto output-based may occur slowly in the U.S. since owners of inefficient power-generation plants realize that they will be disadvantaged by a change in the status quo, yet such a change would increase the energy industry's efficiency and reduce the nation's pollution.

The movement toward output-based emission standards will continue as consumers learn more about how electricity generation affects the environment. Tracking emissions per megawatt or kilowatt-hour is a logical next step in monitoring air quality. Adoption of output-based standards also will reward and encourage the businesses bringing innovative technologies into the marketplace.

Since the use of output-based standards is still relatively new, states need to learn from each other how best to integrate those measures into future emissions-permitting and cap-and-trade programs. Federal direction also will be needed. Regulations must reflect the environmental benefits of more energy-efficient, cleaner technologies. The marketplace is ready for this change. Policymakers must change the means of regulating air emissions if the nation is to enjoy the benefits of innovative energy systems.

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APPENDIX A. STATE-BY-STATE SUMMARIES

State: CALIFORNIA **Restructured: SUSPENDED**

The California Air Resources Board (CARB) has established a distributed generation certification program using output-based emissions standards for NOx, CO, VOCs, and particulate matter. The regulation went into effect on October 4, 2002, and it applies to distributed generation units that had otherwise been exempt from air pollution control requirements.

California Senate Bill 1298 (which became Chapter 741 on September 27, 2000) mandated that the Air Resources Board adopt a certification program and uniform emission standards (in lbs/MWh) for electrical generation units that are exempt from other state air district permitting requirements. It also required that the emissions standards reflect the best performance achieved in practice by existing electrical generation technologies.

This law requires CARB to:

1. Adopt uniform emission standards for electrical generation technologies that are exempt from air pollution control or air quality management district permit requirements;
2. Establish a certification program for the distributed technologies subject to these standards; and
3. Issue guidance to the 35 state air districts on the permitting or certification of electrical generation technologies subject to the district's regulatory jurisdiction.

SB 1298 mandated that CARB establish two levels of emission standards for affected distributed generation technologies. The first set of standards had to become effective no later than January 1, 2003, and had to reflect the best performance achieved in practice by existing distributed generation technologies that are exempt from district permits. The law also required that, by the earliest practicable date, the standards be made equivalent to the level determined by CARB to be the best available control technology (BACT) for permitted central station power plants in California.[102] The emission standards must be expressed in pounds per megawatt-hour (lb/MWh) in order to reflect the efficiencies of various electrical generation technologies.

The distributed generation certification regulation is available from the Air Resources Board Distributed Generation Internet site at: http://www.arb.ca.gov/energy/dg/dg.htm. CARB also released its final guidance document for the distributed generation certification program in July 2002.[103] In that guidance, CARB set emissions standards for 2003 and 2007, and offered limits for units with and without combined heat and power. In 2005, the CARB will produce a technical review of the distributed generation technologies and emissions criteria in order to determine if any modifications to its certification standards are necessary.

The air quality benefits of combined heat and power (CHP) applications were given special consideration and reflected in their special treatment. Section VII, B. of the guidance states that "efficient" CHP systems will receive an emissions credit for thermal output. Efficient CHP applications must maintain a minimum efficiency of 60 percent in the conversion of the energy in the fossil fuel to electricity and process heat. Thus, the facility's overall lb/MWh can be determined by dividing the facility's emissions, on a pollutant-by-pollutant basis, by the facility's total energy production. The total energy production is the sum of the net electrical production, in megawatts, and the actual process heat consumed in a useful manner, converted to megawatts. More detailed methodologies for calculating the emissions performance standard, and for calculating the CHP credit on an output basis, are provided in the CARB Guidance document appendices C and D.

State: CONNECTICUT *Restructured:* YES

Connecticut in December 2001 made major revisions to its New Source Review program in order to permit major sources on an output basis and to credit thermal energy used. Effective March 15, 2002, these revisions apply to all facilities seeking NSR permitting. The modifications are in Section 22a-174-3a of the Regulation of Connecticut State Agencies (RCSA), "Permit to Construct and Operate Stationary Sources."[104] The impetus for state action was twofold: 1) An understanding of the need to credit a facility's energy efficiency, and 2) the lead taken by the U.S. Environmental Protection Agency's release of draft guidance on permitting combined heat and power technologies in NSR.

Since Connecticut's NSR rule provides for CHP incentives, the output basis will reward more efficient projects. The language states that in determining whether to approve BACT (Best Available Control Technology), "The commissioner shall, among other items, not preclude the establishment of an output based emission limitation as BACT provided such application of BACT improves the overall thermal efficiency of the subject source or modification."[105] The permit requirements for nonattainment areas include a provision allowing the commissioner to take into account an output-based emission limitation as LAER (Lowest Achievable Emissions Rate), provided such application of LAER improves the overall thermal efficiency of the subject source or modification.[106]

On April 23, 2002, Connecticut issued its general permit for distributed generators that applies to multiple pollutants and has an annual emissions cap. The permit is not output-based but will only be in effect until December 31, 2003. After that time, the state Department of Environmental Protection expects to adopt the output-based Regulatory Assistance Project Model Rule for distributed generators[107] (which is highlighted later).

In April 1998, Connecticut's electricity restructuring legislation directed the state Department of Environmental Protection to establish generation performance standards for five pollutants: sulfur dioxide (SO2), nitrogen oxides (NOx), carbon dioxide (CO2), carbon monoxide (CO), and mercury (Hg). The standards are to be implemented when "three of the states participating in the northeastern states' Ozone Transport Commission, as of July 1, 1997, with a total population of not less than 27 million, have adopted such a standard." The state electricity restructuring legislation and subsequent law refer to output-based standards as generation performance standards.

Connecticut's Performance Standard Law is Public Act No. 98-28, Sec. 24 and reads:

> *Sec.24. (NEW) Not later than January 1, 1999, the Commissioner of Environmental Protection shall, by regulations adopted in accordance with chapter 54 of the general statutes, establish uniform performance standards for electricity generation facilities supplying power to end use customers in this state. Such standards shall, to the greatest extent possible, be designed to improve air quality in this state and to further the attainment of the National Ambient Air Quality Standards promulgated by the United States Environmental Protection Agency. Such performance standards shall be based on the fuel used for generation of electricity and shall apply to Electric suppliers' generation facilities located in North America and shall limit the amount of air pollutants, including, but not limited to, nitrogen oxides, sulfur oxides, carbon dioxide, carbon monoxide and mercury, emitted per megawatt hour of electricity produced. Such performance standards may provide for a program for purchase of offsetting reductions in emissions and trading of emission credits. A performance standard established by the Department of Environmental Protection for an individual pollutant pursuant to this section shall go into effect when three of the states participating in the northeastern states' Ozone Transport Commission as of July 1, 1997, with a total population of not less than twenty-seven million at that time, have adopted such standard.*

Thus, the Department of Environmental Protection (DEP) is required to have an output-based standard in place, but that standard need not be implemented until other states in the region have adopted similar standards. The state's purpose was to improve air quality. The regulations target retail electricity suppliers, giving the state the ability to require compliance from out-of-state suppliers. As of September 2002, the state Department of Environmental Protection has produced a draft rule, Draft RCSA Section 22a-174-34, based on the NESCAUM regional model regulation (described later). The draft of "Section 34" has been reviewed by the Connecticut Department of Public Utility Control. As of this report's publication, a final rule was not released.

The Connecticut Department of Environmental Protection also has played an integral role in the development of several of the regional model rules to be discussed later in this report. These include the Regulatory Assistance Project's Model Rule for Distributed Generation and the NESCAUM Model Emissions Performance Standard.

State: DELAWARE Restructured: YES

The state's NOx Budget Program uses output-based NOx budget allocations.

State: ILLINOIS Restructured: YES

The Illinois Resource Development and Energy Security Act (HB 1599), approved on June 22, 2001, calls for a report on reducing multiple pollutant emissions from fossil-fuel-fired electric generating plants. The state Environmental Protection Agency must report on multi-pollutant strategies for NOx, SO2, and mercury to the House and Senate Committees on Environment and Energy before September 30, 2004, but not before September 30, 2003. Although output-based standards are not explicit in the legislative language, the state EPA plans to study this approach.[108] The new provisions applying to fossil-fuel-fired electric generating plants are contained in the Illinois Environmental Protection Act under Section 9.10, 415 ILCS 5/ (IL Compiled Statutes).[109]

Output-based standards were discussed during development of the state's NOx SIP, but agreement on the issue could not be reached.

State: INDIANA Restructured: NO

The state is currently not considering output-based standards in its air quality regulations.

State: IOWA Restructured: NO

The state is currently not considering output-based standards in its air quality regulations.

State: MAINE Restructured: YES

State has no regulations on an output basis. Lawmakers have discussed the options, seem to think it's a good idea, but have not moved forward on changing any regulations or permits.[110]

State: MARYLAND Restructured: YES

The state is currently not considering output-based standards in its air quality regulations.

Note: Information was gained from literature search and state agency Internet sites only.

State: MASSACHUSETTS Restructured: YES

The Massachusetts legislature in late 1997 directed the state Department of Environmental Protection to adopt output-based standards[111] for all power facilities engaged in the retail sale of electricity to end users in the Commonwealth. The standards are for any pollutant of concern to public health. The legislation requires that the state implement the standards for at least one pollutant by May 2003, and it will begin with NOx. If other states in the Northeast implement output-based standards for electricity generation in the meantime, Massachusetts can follow suit. The state DEP has not acted on the generation performance standard to date.[112] The regulatory authority is under Massachusetts General Law c. 111, Sections 142A through 142N.

The state legislature and Department of Environmental Protection believe output-based standards will make it easier to regulate sources that are low-emitting and efficient, while high-emitting and inefficient facilities may need to reduce emissions or purchase allowances from low-emitting sources in order to comply with requirements. The

Department of Environmental Protection's background document on the rule declares that "allocating the available state budget based on electrical output promotes pollution prevention in the electric sector by rewarding energy efficiency, and promotes fair competition in the energy market by leveling the environmental playing field for all generators of electricity."[113]

Chapter 111, Section 142N in Massachusetts General Law states that:

> *Section 142N. For the purpose of preventing, mitigating, or alleviating impacts on the resources of the commonwealth and to the health of its citizens from pollutants emitted by fossil fuel-fired electric generation facilities serving retail customers in the commonwealth, the department of environmental protection shall, in consultation with the office of the attorney general and the department of telecommunications and energy, promulgate rules and regulations to adopt and implement for fossil fuel-fired electric generation facilities uniform generation performance standards of emissions produced per unit of electrical output on a portfolio basis for any pollutant determined by the department of environmental protection to be of concern to public health, and produced in quantity by electric generation facilities. The department of environmental protection shall have said uniform performance standards for at least one pollutant in effect on, but not before, May 1, 2003, unless three or more other northeastern states enact similar standards before that date, in which case the department of environmental protection may adopt such standards prior to May 1, 2003. The department of environmental protection shall issue annually, by March first of each year, an annual report detailing the implementation and compliance of said program, its standards, and its companion rules and regulations.*[114]

As Massachusetts has not developed these standards to date, it is not known whether stipulations for combined heat and power facilities would be included. The state in April 2001 made available a developer's guide to regulations, policies, and programs that affect renewable energy and distributed generation facilities in the Commonwealth. The guidebook references the generation performance standards required in the restructuring legislation.

On another front, in April 2001, Massachusetts took an aggressive step to improve local air quality by targeting reductions at its six dirtiest power plants. Regulation 310 CMR 7.29, "Emissions Standards for Power Plants," requires reductions of NOx, SO2, CO2, and mercury beginning in 2004 (or 2006 depending on reduction choices made by the individual plant). This is accomplished by establishing output-based emission rates for NOx, SO2, and CO2 and establishing an emissions cap on CO2 and Hg emissions from affected facilities. A summary of the standards, compliance paths, and dates are as follows.

MASSACHUSETTS POWER PLANT CLEAN UP STANDARDS[115]

(MA DEP Regulation 310 CMR 7.29)

Pollutant	*Emission Standard*	*Standard Pathway Compliance Dates*	*Repowering Pathway Compliance Dates*
NOx	1.5 lbs/MWh	October 1, 2004	October 1, 2006
SO2	6.0 lbs/MWh	October 1, 2004	October 1, 2006
SO2	3.0 lbs/MWh	October 1, 2006	October 1, 2008
CO2	1800 lbs/MWh annual avg.	October 1, 2006	October 1, 2008

The regulation defines "output-based emission rate" as an emission rate for any pollutant, expressed in terms of actual emissions in pounds over a specified time period per megawatt-hour of net electrical output produced over the same time period. "Output-based emission standard" is defined as the emission standards for each applicable pollutant, expressed in terms of pounds of pollutant emitted per megawatt-hour of net electrical output produced. The regulation is available online at: http://www.state.ma.us/dep/bwp/daqc/files/regs/729final.doc.

The Massachusetts NOx SIP allocates allowances to generation sources on an output basis. To judge emissions on an output rather than input basis, the state must add data on electrical output, which the Ozone Transport Commission points out is widely available.[116] The state's NOx Allowance Trading Program for 2003 includes an output-based allocation for generating units with useful steam output. The Department of Environmental Protection provides a formula for calculating the steam allocation, which is then added to the electrical output allocation, thereby promoting energy efficiency and recognizing two useful energy outputs. Regulation 310 CMR 7.28 applies to any source greater than 25 MW or greater than 250 mmBtu/hr boiler size. If a source is a CHP facility, then the Department of Environmental Protection allows credit for the CHP portion.[117]

The Massachusetts Department of Environmental Protection also has played an integral role in the development of several of the regional model rules to be discussed later in this report. These include the Regulatory Assistance Project's Model Rule for Distributed Generation and the NESCAUM Model Emissions Performance Standard.

State: MICHIGAN — *Restructured:* YES

The state is currently not considering output-based standards in its air quality regulations.

On October 9, 2001, Michigan's legislature proposed Senate Bill 693, a multi-pollutant bill with output-based standards for 25 MW or greater electric power generators, but the legislation did not move.

State: MINNESOTA — *Restructured:* NO

The state is currently not considering output-based standards in its air quality regulations.

State: NEW HAMPSHIRE — *Restructured:* YES

To the extent it can, New Hampshire tries to regulate all air emissions on an output basis and is currently updating many of its regulations to reflect this.[118] New Hampshire has proposed output-based standards targeting four pollutants from the state's highest-polluting power plants. The state in January 2001 released its Clean Power Strategy, which calls for emissions caps based on electricity output for all large electrical generating facilities in the state; put another way, it does not "grandfather" any existing power plant. This action resulted in the Clean Power Act, House Bill 284, which was signed into law in May 2002. The law requires emissions reductions in SO2, NOx, CO2, and mercury.

In New Hampshire's NOx Budget Program[119] that will go into effect in 2005, allocations will be determined on an output-basis. The allocation language is in the New Hampshire Code of Administrative Rules, Part Env-A 3200. The rule extends New Hampshire's NOx Budget Trading Program for the period 2006 and beyond. This cap-and-trade program does not set output-based "standards," but instead establishes output-based allowance allocations.[120] The Department of Environmental Services followed EPA's guidance for output-based allocations, which includes provisions for thermal heat output for cogeneration; however, there currently are no applicable CHP sources in New Hampshire.

New Hampshire believes output-based standards are a way to encourage greater efficiency and pollution prevention. The state also argues that such standards would help create a level playing field and advance competitive markets.

The state also has a new rule regarding smaller electric generating units (EGUs), Env-A 3700, based on legislation passed during the 1999 legislative session. In House Bill 649,[121] the legislature found it necessary to address emissions from the growing number of smaller generators that were not subject to NOx requirements. The bill acknowledged that many businesses have sought to control their high electric costs by using internal combustion engine electricity generators that run on fossil fuels. The legislature recognized that these generators have increased nitrogen oxide (NOx) emissions and that additional units could substantially increase such emissions and increase electric rates for customers purchasing electricity from sources subject to more stringent NOx regulations.

The state views this rule as market-based. Sources emitting NOx > 7 lb/MWh are subject to either paying fees, buying credits, or installing controls. A new provision was added to RSA 125-J, NOx-Emitting Generation Source Requirements, exempting emissions above 7 lb/MWh attributable to cogeneration.

The New Section 125-J:13 reads:

> *I. Each NOx-emitting generation source emitting more than 7 pounds of NOx per megawatt hour generated shall be required to supply to the department NOx emissions information, and the amount of kilowatt hours actually produced during each period listed in subparagraph II(b). Additionally, except as provided either by paragraph I or II of this section, each NOx-emitting generation source shall acquire NOx budget allowances, emissions reduction credits, or other emissions reduction mechanisms on the same basis as a NOx budget source for all of its NOx emissions. However, NOx-emitting generation sources shall not be required to acquire NOx budget allowances, emissions reduction credits, or use emissions reduction mechanisms for the first 7 pounds of NOx emitted for each megawatt-hour of electricity produced and any amounts of NOx above such first 7 pounds that are attributable to the provision of other, non-electric services provided by the generating source, including but not limited to, steam and heat, and any amounts of NOx emitted during any period when the NOx-emitting generation source is operating to provide power during a power shortage at the request of any governmental authority or provider of electrical power to the public generally.*[122]

The New Hampshire Department of Environmental Services has also played an integral role in the development of several of the regional model rules to be discussed later in this report. These include the Ozone Transport Commission NOx Model Rule and the NESCAUM Model Emissions Performance Standard.

State: NEW JERSEY *Restructured:* YES

New Jersey's electricity restructuring legislation, approved in February 1999, addressed the potential need for an emissions performance standard, referred to as an environmental portfolio standard. The law directed the Board of Public Utilities, in consultation with the Department of Environmental Protection, to adopt and implement an emission performance standard if such standards became necessary to meet ambient air quality standards beyond current federal and regional actions. A stipulation in the New Jersey legislation also required the adoption of this emissions performance standard if two other states within the PJM interconnection area, comprising at least 40 percent of retail electricity sales, adopt similar standards.

The legislation allows the state Department of Environmental Protection to take action if existing air quality policies do not go far enough to protect citizens from pollution of power plants within the state and the region. In addition, the state will be required to take action if neighboring states adopt this type of emissions regulation. No state has done so to date, and New Jersey has made no decision to promulgate an emissions performance standard.[123]

The emissions portfolio standard language is found within the "Electric Discount and Energy Competition Act," and is as follows:

> *Public Law 1999. Chapter 23, Section C.48:3-87 Environmental disclosure requirements.*
>
> *38. c. (1) The board [of public utilities] may adopt, in consultation with the Department of Environmental Protection, after notice and opportunity for public comment, an emissions portfolio standard applicable to all electric power suppliers and basic generation service providers, upon a finding that:*
>
> > *(a) The standard is necessary as part of a plan to enable the State to meet federal Clean Air Act or State ambient air quality standards; and*
> >
> > *(b) Actions at the regional or federal level cannot reasonably be expected to achieve the compliance with the federal standards.*
>
> *(2) The board shall adopt an emissions portfolio standard applicable to all electric power suppliers and basic generation service providers, if two other states in the PJM power pool comprising at least 40 percent of the retail electric usage in the PJM Interconnection, L.L.C. independent system operator or its successor adopt such standards.*[124]

The legislation's goal was to prevent large amounts of high-emission generation in the state. As part of New Jersey's restructuring legislation, generation companies also are required to disclose environmental characteristics, such as power plant fuels used and emissions generated. This environmental disclosure should allow consumers to understand what's being emitted to produce their electricity.

Certain states — including Connecticut, Massachusetts, New Hampshire, New York, and New Jersey — allocate the allowances available under the NOx Budget Program in ways that recognize energy efficiency. Their purpose is to reduce emissions from power plants and large stationary sources. The New Jersey NOx Budget Program is located in New Jersey Administrative Code, Title 7, Chapter 27, Subchapter 31 and available online at: www.state.nj.us/dep/aqm/rules.htm. The 2003 allocations will be in part on an output basis: both input-based and output-based emission rates are provided. New Jersey also is committed to adopting output-based standards for distributed generation, based on the Ozone Transport Commission's recommendations.[125]

Finally, New Jersey has reached agreement with power companies to reduce multi-pollutants at power plants in the state. This action does not result from regulation but rather is an enforcement action targeting NSR violations. From the state's greenhouse gas initiative came a settlement with Public Service Electric & Gas to reduce CO2 from New Jersey's fossil-fueled electric generating units by a certain amount of pounds per megawatt-hour (MWh) in 2006.[126]

State: NEW YORK *Restructured:* YES

Governor Pataki set up a Greenhouse Gas Task Force to develop policy recommendations, one of which is a multi-pollutant approach for electric generators. A final report of policy recommendations was to be completed by May 2002.

For distributed generation, the Department of Environmental Conservation is under state order to revise emissions standards, beginning in 2000. Output-based standards are being considered.

Counties within the state have proposed their own actions for limiting carbon dioxide emissions on an output basis. In New York City, the City Council put fourth a CO2 proposal for a declining CO2 emissions performance standard for EGUs greater than 25 MW located in New York City. In Suffolk County, government put forth a CO2 law in June 2001 to have a CO2 emissions rate for all EGUs and steam generating units must be set in lbs/MWh in March 2002. Nassau County also has looked into output-based standards.

State: OHIO *Restructured:* YES

The state is currently not considering output-based standards in its air quality regulations.

State: PENNSYLVANIA *Restructured:* YES

The state does not currently use output-based emissions standards in its air quality regulations. The issue of output-based emissions standards or generation performance standards was raised during the comment period for the state NOx SIP, but action was not taken. The state is in preliminary stage of considering a general permit for distributed generation and is aware of the RAP model rule.

State: RHODE ISLAND *Restructured:* YES

The state is currently not considering output-based standards in its air quality regulations.

State: TEXAS *Restructured:* YES

Effective June 1, 2001, the Texas Commission on Environmental Quality (CEQ)[127] established a standard air-emissions permit for NOx from distributed generation in order to encourage the most energy-efficient configurations, such as combined heat and power. The Air Quality Standard Permit for Electric Generating Units (EGU),[128] Texas

Administrative Code (TAC) Rule 106.511, is a standard permit that was designed to be an expedited method of authorizing clean electric generating units in the state.

The permit, issued under Texas Clean Air Act's Health & Safety Code Sections 382.011, provides a streamlined preconstruction authorization mechanism for electric generating units that are not prohibited by other state or federal permitting statute or regulation. The distributed generation standard is output-based (in lbs/MWh) and establishes pre-certification requirements for a power system.

The standard permit applies to all electric generating units that emit air contaminants, regardless of size, and it reflects BACT (Best Available Control Technology) for electric generating units on an output basis in pounds of NOx per megawatt hour, adjusted to reflect a simple cycle power plant.

For this air quality permit, the state has been divided into two regions — East Texas and West Texas — in order to address ozone nonattainment problem in the East Texas region. In 2005, the permit will require stricter emissions requirements, and the standards for units then will be determined by hours of operation.

The distributed generation permit recognizes that combined heat and power units produce two useful energy outputs, in the form of electricity and heat, and it gives credit for this dual output. The state CEQ produced a guideline, which can be found at: http://www.tnrcc.state.tx.us/permitting/airperm/nsr_permits/files/segu_permitonly.pdf. To meet the emission standards, CHP units may take credit for useful thermal output at the rate of one megawatt-hour for each 3.4 million BTUs of heat recovered. If a CHP unit is not pre-certified by the manufacturer, the owner or operator may submit documentation of the system to receive a CHP credit.

The CHP credit is designed to encourage users to install and use CHP in order to improve the efficiency of generating units where there is a valid need for the recovered heat. In a supplement document, the CEQ offers an example of how this credit works for a 10-megawatt CHP unit.

The Texas CEQ purports that the permit's standards will allow for the cleanest reciprocating engines as well as turbines, microturbines, and fuel cells. This approach should allow the use of more efficient equipment; give an incentive for using CHP without setting standards that would require it; and provide economic incentive for reliable power to be generated at the point of use, as opposed to relying on central plant power with emergency backup.

State: VERMONT — *Restructured:* NO

In the mid-1990s, the state legislature introduced multi-pollutant, output based standards, but nothing progressed. The state is monitoring efforts in other New England states on addressing electric plants greater than 25 MW and monitoring efforts on the RAP Model Rule for distributed generation.

State: WISCONSIN — *Restructured:* NO

The state is currently not considering output-based standards in its air quality regulations.

APPENDIX B. STATE AIR QUALITY BOARD CONTACTS

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CONNECTICUT *Restructured:* YES

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ILLINOIS *Restructured: YES*

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INDIANA *Restructured: NO*

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IOWA *Restructured: NO*

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MAINE *Restructured: YES*

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MARYLAND *Restructured: YES*

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MASSACHUSETTS *Restructured: YES*

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MICHIGAN *Restructured: YES*

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MINNESOTA *Restructured: NO*

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NEW HAMPSHIRE *Restructured: YES*

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NEW JERSEY *Restructured: YES*

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OHIO *Restructured: YES*

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PENNSYLVANIA *Restructured: YES*

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RHODE ISLAND *Restructured: YES*

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TEXAS *Restructured: YES*

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VERMONT *Restructured: NO*

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WISCONSIN *Restructured: NO*

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APPENDIX C.
EUROPEAN COMMISSION PROPOSED CHP DIRECTIVE

ANNEX III OF THE CHP DIRECTIVE COM(2002) 415 FINAL

a) High-efficiency cogeneration

For the purpose of this Directive, high-efficiency cogeneration production shall fulfill the following criteria:

- production from new cogeneration units shall provide primary energy savings of at least 10 percent compared with the references for separate production of heat and power;
- production from existing cogeneration units shall provide primary energy savings of at least 5 percent compared with the references for separate production of heat and power;
- production from cogeneration units using renewable energy sources and from cogeneration installations with an installed capacity below 1 MWe providing primary energy savings in the range 0-5 percent may qualify as high-efficiency cogeneration;
- Member States may introduce principles whereby production from cogeneration units below the thresholds referred to in this Annex may be considered to be partially fulfilling the efficiency criteria. If such principles are applied, appropriate methodologies for determining the reduced efficiency of such production, calculated in proportion to the reduced primary energy savings, shall be developed by the member state and shall be notified to the Commission. In such cases, the reduced efficiency of the cogeneration production shall be clearly displayed on the certificate of origin.

b) Calculation of primary energy savings

The amount of primary energy savings provided by cogeneration production defined in accordance with Annex II to this Directive shall be calculated on the basis of the following formula:

$$\text{PES} = \left[1 - \frac{1}{\frac{\text{CHP H}\eta}{\text{Ref H}\eta} + \frac{\text{CHP E}\eta}{\text{Ref E}\eta}}\right] \times 100\%$$

Where: **PES** is primary energy savings

CHP Hη is the heat efficiency of the cogeneration production

Ref Hη is the heat efficiency of the reference for separate heat production

CHP Eη is the electrical efficiency of the cogeneration production

Ref Eη is the electrical efficiency of the reference for separate electricity production

Subject to prior notification to the Commission, member states may use other formula leading to the same results to calculate the primary energy savings from cogeneration. In the cases where alternative formulas are used, such formula shall be published by the member state.

c) Efficiency reference values for separate production of heat and electricity

The principles for defining the references for separate production of heat and electricity referred to in Article 5(2) and in the formula set out in paragraph b) of this Annex shall establish the operating efficiency of the separate heat and electricity production that cogeneration is assumed to displace.

To define the efficiency reference values, the following principles shall be applied:

1) For new **cogeneration units** as defined in Article 3, the comparison with new separate electricity production shall be based on the principle that similar fuel categories are compared. The following indicative efficiency reference values for new separate electricity production may be used:

INDICATIVE EFFICIENCY REFERENCE VALUES FOR NEW SEPARATE ELECTRICITY PRODUCTION

Fuel category	*Operating efficiency*
Natural gas	55%
Coal	42%
Oil	42%
Renewables and waste	22-35%

In the case of cogeneration units connected at the electricity distribution system, the reference values provided in the above table may be lowered with 5-10% to take account of avoided network losses.

2) For new **cogeneration units** as defined in Article 3, the indicative efficiency reference value of new separate heat production shall be an operating efficiency of 90 percent. In the case of heat production based on oil or coal, the efficiency reference value may be lowered to 85 percent. In the case of heat production based on renewable energy sources or waste, the efficiency reference value may be lowered to 80%. In the case of high temperature steam used for industrial processes, the reference values for separate heat production may be lowered to 80 percent.

3) For **existing cogeneration units** as defined in Article 3, the efficiency reference value for separate electricity production shall be based on the average operating efficiency of the national fossil-fuelled electricity production. Where appropriate, possible cross-border trade in electricity having an impact on the reference values may be taken into account.

4) For **existing cogeneration units** as defined in Article 3 the efficiency reference value for separate heat production shall be based on the average operating efficiency of the national heat production mix.

5) Subject to prior notification to the Commission, member states may include additional aspects in the national criteria for determining the efficiency of cogeneration.

APPENDIX D: CLEAN AIR ACT REGULATIONS & PERMITTING ISSUES

The 1990 **Clean Air Act** is a federal law covering the entire country, but the states do much of the work to carry out the act. For example, a state air pollution agency can hold a hearing on a permit application by a power or chemical plant, and it can fine a company for violating air pollution limits. Under this law, EPA sets limits on how much of a pollutant can be in the air anywhere in the United States. This authority ensures that all Americans have the same basic health and environmental protections. The law allows individual states to have stronger pollution controls, but states are not allowed to have weaker pollution controls than those set for the whole country.

Under CAA, states had to develop **state implementation plans** (SIPs). A SIP is a collection of the regulations a state will use to clean up polluted areas. The Environmental Protection Agency (EPA) must approve each SIP, and if a SIP isn't acceptable, EPA can take over enforcing the Clean Air Act in that state.

Under the CAA, **permits** are issued by states or, when a state fails to carry out the Clean Air Act satisfactorily, by EPA. The permit includes information on which pollutants are being released, how much may be released, and what kinds of steps the source's owner or operator is taking to reduce pollution, including plans to monitor (measure) the pollution.

For most electrical generation sources, the primary air pollution control program of concern is **New Source Review (NSR)**. NSR is a district preconstruction program that governs the construction of major new and modifying stationary sources. NSR is intended to ensure that these sources do not prevent the attainment, or interfere with the maintenance, of the national ambient air quality standards.

Title V of the 1990 Clean Air Act Amendments requires all major sources and some minor sources of air pollution to obtain an operating permit. A Title V permit grants a source permission to operate. The permit includes all air pollution requirements that apply to the source, including emissions limits and monitoring, record keeping, and reporting requirements. It also requires that the source report its compliance status with respect to permit conditions to the permitting authority.

Attainment and Nonattainment areas are designated for a few common air pollutants which can injure health, harm the environment, and cause property damage. EPA calls these pollutants "criteria air pollutants" because the agency has regulated them by first developing health-based criteria (science-based guidelines) as the basis for setting permissible levels. One set of limits (primary standard) protects health; another set (secondary standard) is intended to prevent environmental and property damage. A geographic area that meets or does better than the primary standard is called an attainment area; areas that don't meet the primary standard are called nonattainment areas. EPA has estimated that about 90 million Americans live in nonattainment areas.

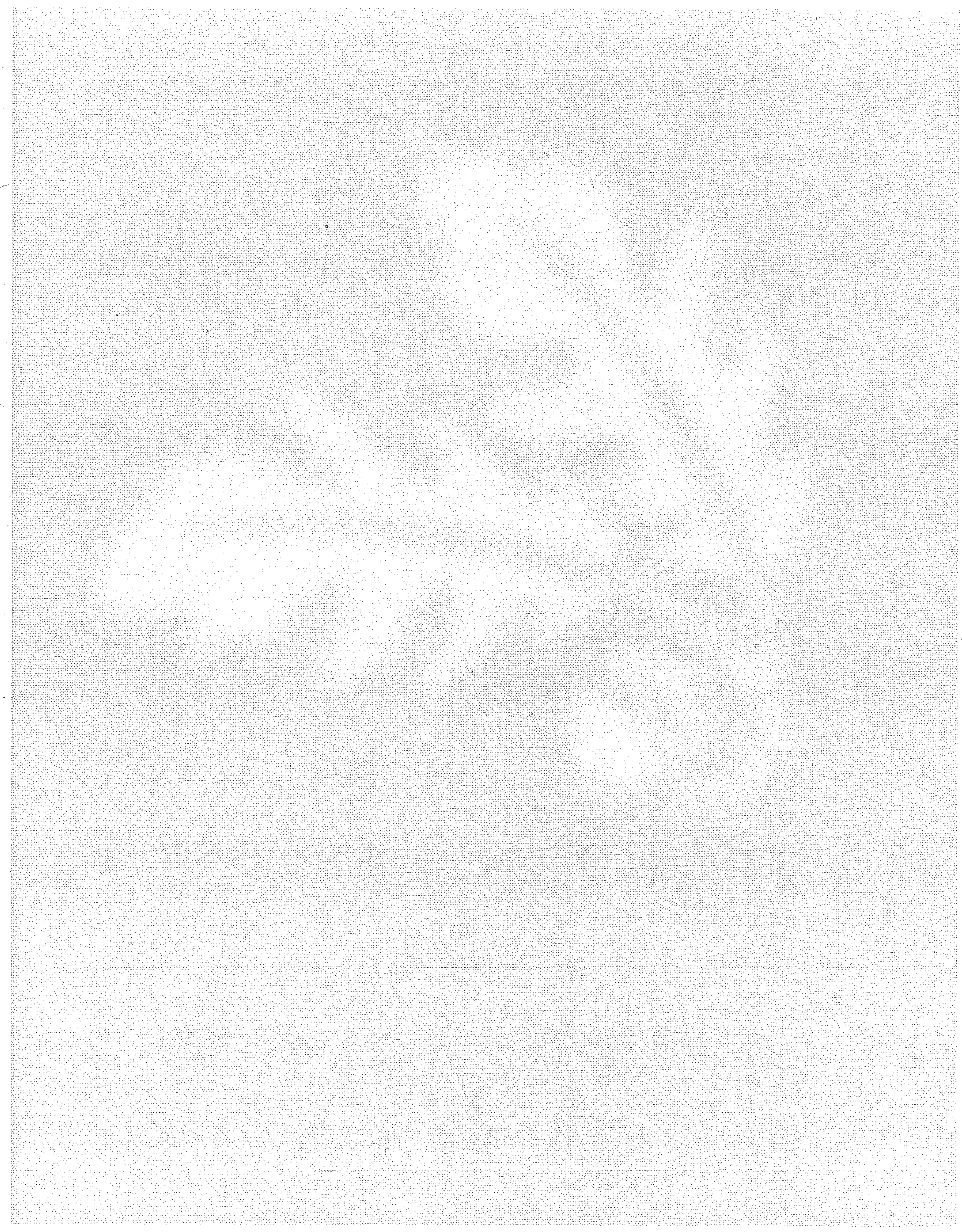

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Exhibit 12

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2001-GT-399

THE W501G TESTING AND VALIDATION IN THE SIEMENS WESTINGHOUSE ADVANCED TURBINE SYSTEMS PROGRAM

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ABSTRACT

The Siemens Westinghouse Advanced Turbine System (ATS) has the ultimate goal of achieving greater than 60% LHV-based net plant thermal efficiency, less than 10 parts per million NOx emissions, a 10% reduction in cost of electricity, and reliability-availability-maintainability (RAM) equivalent to modern advanced power generation systems. The ATS program, which is supported by the U.S. Department of Energy, introduces advanced technologies in three evolutionary steps to minimize risks and to increase the net benefits of the program. The W501G, the first step in the ATS engine introduction, incorporates many ATS technologies such as closed-loop steam cooling, advanced compressor design, and high temperature materials. The lead unit has completed full-load testing at the City of Lakeland McIntosh #5 site in Lakeland, FL and has produced power and revenue for Lakeland Electric since May 2000. Results from the testing are presented and future developments are discussed. Building on the current W501G, advancements will include steam-cooled turbine vanes and leakage enhancements. Continuing this low risk step-wise introduction of new technology, the W501ATS engine adds further advanced designs that achieve the program objectives. Siemens Westinghouse is also infusing ATS technologies into its mature frames in both new units and service upgrades to maximize the benefit of the program.

INTRODUCTION

The Advanced Turbine Systems Program (ATS) funded by the U.S. Department of Energy, Office of Fossil Energy, is an ambitious multi-year effort whose goal is to develop technologies necessary for achieving significant increase in natural gas-fired power generation plant efficiency, a decrease in cost of electricity, and a reduction in harmful emissions, while maintaining the current state-of-the-art reliability, availability, and maintainability (RAM) levels. This thee-phase technology development and demonstration program was started in 1992 and will be completed in 2001 [1–6].

To achieve the ATS Program goals for performance, emissions, electricity cost, and mechanical reliability, significant advancements were required in key technologies applied in gas turbine design. Successful developments were carried out in technologies relating to aerodynamics, combustion, cooling, sealing, materials, and coatings.

The W501ATS engine incorporates new technologies, as well as proven design features developed over the last 50 years and employed successfully in the W501 series of heavy-duty

Presented at the International Gas Turbine & Aeroengine Congress & Exhibition
New Orleans, LA — June 4 – 7, 2001

industrial and utility engines [7]. These proven design features include single-shaft, two-bearing rotor; cold-end generator drive; compressor blade rings; low-alloy-steel rotor discs; curvic-clutched turbine rotor; four-stage turbine; cooled and filtered rotor cooling air; single first-stage turbine vane segments; tangential exhaust struts; and individual combustor baskets. The W501ATS engine is the latest in successful designs evolving from proven predecessors such as the 186 MW W501F and the 253 MW W501G [8, 9].

EVOLUTIONARY APPROACH

Siemens Westinghouse solicits input from an industry advisory panel comprised of members from major U.S. and international utilities and independent power producers. Based on the input from this panel and market analyses, Siemens Westinghouse is pursuing an evolutionary introduction of the ATS, which incorporates ATS-technology in stages culminating in an engine that meets or exceeds all of the program objectives. This approach has two main advantages. First, the evolutionary approach mitigates the risk associated with introducing multiple, advanced technologies simultaneously. Second, the early introduction of ATS technology expands and accelerates the benefit of the program, as compared with limiting the technologies to only the ATS engine.

The evolutionary approach is shown schematically in Figure 1. First, the introduction of the ATS frame begins with the W501G. Many ATS technologies are incorporated in the W501G and are discussed later. Second, from the initial W501G, future enhancement include steam-cooled turbine vanes, leakage improvements, and increased burner temperature. Third, the W501ATS engine evolves from the W501G, which reduces development risks through early demonstration of many critical technologies.

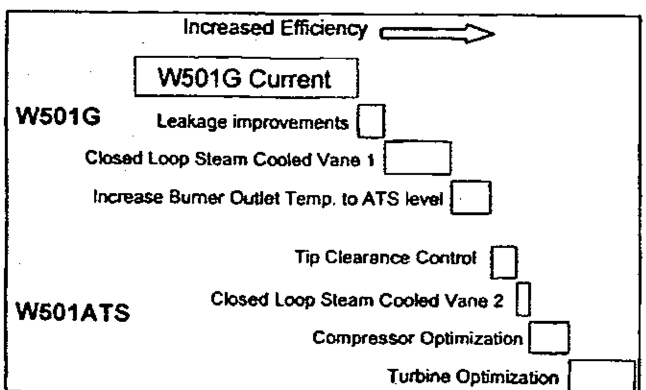


Figure 1 - Evolutionary approach leading to the ATS engine

Siemens Westinghouse is further expanding the benefits of the ATS program by introducing ATS-developed technologies into its mature product lines. For example, the latest W501F incorporates ATS-developed brush seals, coatings, and compressor technology. Furthermore, many of these technologies can be retrofitted into operating units.

Because the F frame accounts for a majority of current new unit sales, this infusion of technology yields significant savings in fuel and emissions. Figure 2 shows the total impact of Siemens Westinghouse ATS technology on CO_2 emissions. Note that much of the net benefit is the result of Siemens Westinghouse's approach of expediting and expanding ATS technology through evolutionary introduction and infusion into mature frames.

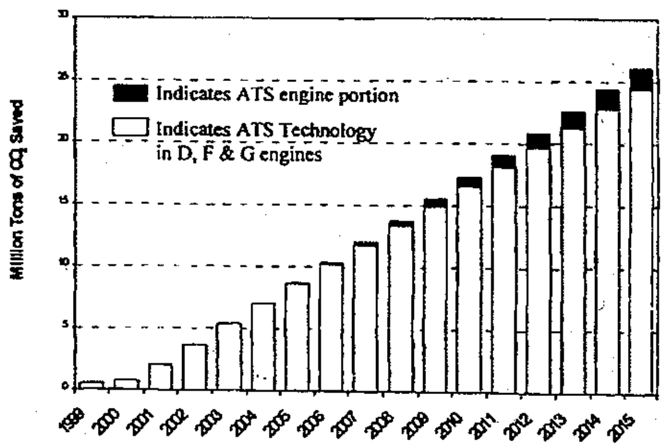


Figure 2 - CO_2 net reductions from ATS Technology

ATS TECHNOLOGY IN OPERATION

The W501G is the first major introduction of the ATS Technology. The W501G incorporates the following ATS engine features:

- ATS advanced 3D compressor
- Advanced brush seals and abradable coatings
- Closed-loop steam cooling
- High temperature thermal barrier coatings
- ATS Row 4 turbine blade.

ATS Advanced 3D Compressor

The W501G incorporates the first sixteen stages of the 27:1 pressure ratio, nineteen-stage, ATS compressor with slight modification of the last three stages, and with vanes 1 and 2 fixed instead of variable. As a result, the W501G operates the ATS mass flow of 558 kg/sec (1230 lbs./sec), but at a pressure ratio of 19:1 – optimized for the G cycle performance.

The design is based on three-dimensional inviscid flow analyses and on custom-designed, controlled-diffusion airfoil shapes. Controlled-diffusion airfoil design technology has been successfully applied in the aircraft industry for many years. The mechanical integrity of each stationary and rotating airfoil was verified by finite element analyses to satisfy steady stress and endurance strength criteria. Each airfoil was tuned to avoid potentially harmful resonant frequencies.

To verify the aerodynamic performance and mechanical integrity of the new high pressure ratio design, the full-scale W501ATS compressor was manufactured and tested in 1997 at a specially-designed facility at the U.S. Navy Base in Philadelphia. To reduce the required power to the 25 MW available at the test facility, the compressor test was carried out at subatmospheric inlet conditions.

The ATS-developed compressor technology has also been retrofitted into the W501F product line. Using the analytical techniques developed and proven in the ATS program, the W501F compressor was upgraded in the latest improvement to this successful frame. This advanced compressor is utilized on new W501F units. In addition, the redesigned compressor can be retrofit to any 42 W501Fs that were built with the original W501F compressor. Applying this ATS technology to the W501F expands the benefit of the ATS program since the W501F compromises more than 70% of future units that are sold or on order at Siemens Westinghouse.

Brush Seals and Abradable Coatings

To minimize air leakage, as well as hot gas ingestion into turbine disc cavities, brush seals were incorporated into the W501ATS engine design at several locations: under the compressor diaphragms, at the turbine disc front, under turbine rims, and at the turbine interstages. Tests were carried out on test rigs for the different brush seal locations to develop effective, rugged, reliable, and long life brush seal systems. At the Philadelphia U.S. Navy Base, full-scale brush seals were tested as part of the ATS Compressor test, which verified the brush seal low leakage and wear characteristics.

To date. ATS-developed brush seals have been successfully incorporated and operated in W501G and later W501F product lines. Pre- and post-upgrade tests have demonstrated performance improvement in retrofit applications.

Considerable performance benefits can be obtained by reducing compressor and turbine blade tip clearances. Abradable coatings permit tip clearances to be minimized without fear of damaging hardware, and they provide more uniform tip clearances circumferentially. Abradable coatings, identified for compressor and turbine applications, were tested to determine abradability, tip-to-seal wear rate, and erosion characteristics. These ATS-developed abradable coatings have been incorporated into the W501F and W501G compressor and front turbine stages (1 and 2). The later turbine stages (3 and 4) employ shrouded blades with honeycomb seals.

Closed-Loop Steam Cooling

Using closed-loop steam cooling on transitions and turbine stationary components has two advantages. First, more compressor delivery air is available for premixing with the fuel gas in the combustor hot end. This allows very lean premixed combustion and makes possible the restriction of NOx emissions to single digits. Second, closed-loop steam cooling significantly improves cycle efficiency by reducing the amount of chargeable air used for cooling and sealing.

The ATS transitions, which duct the hot combustor exit gases to the turbine inlet, are closed-loop steam cooled with air as an alternate coolant at part load. Steam enters the engine through four external connections and is routed to each transition supply manifold through internal piping. The supply manifold feeds the steam to an internal wall cooling circuit. After cooling the transition walls, the steam is collected in an exhaust manifold and ducted out of the engine. The W501G employs the ATS transition.

High-Temperature Thermal Barrier Coatings

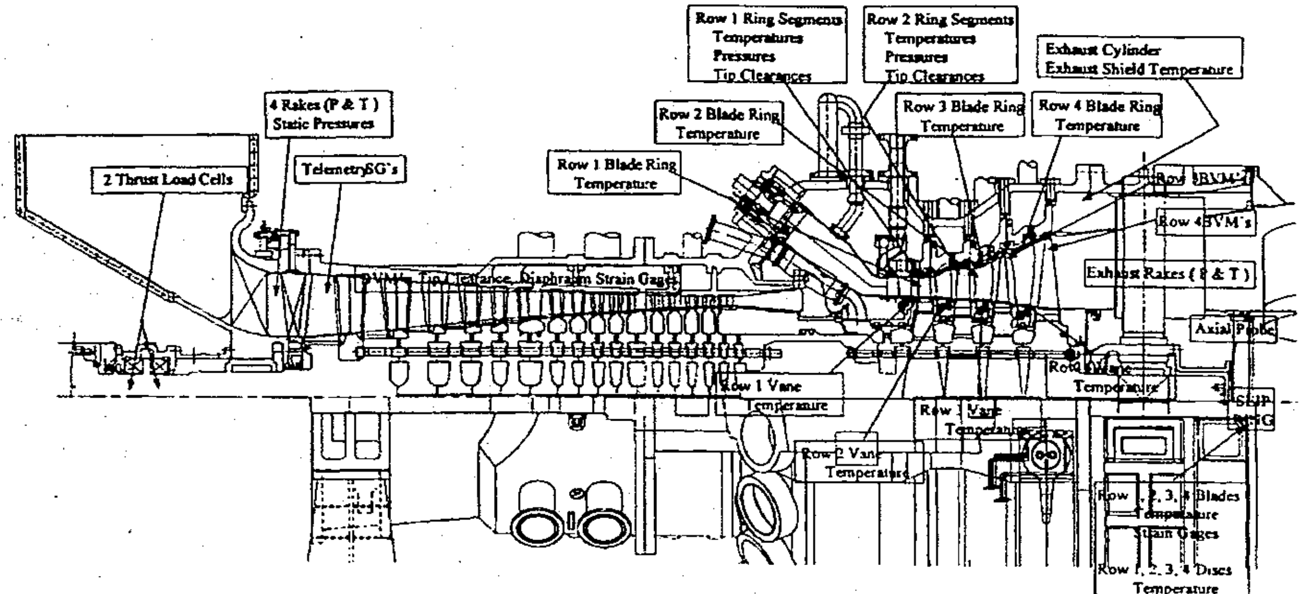
Thermal barrier coatings are an integral part of the W501ATS engine design. A development program is in progress to develop an advanced bond coat/TBC system with a projected service life of more than 24,000 hours. Different bond coats and ceramic materials were evaluated under accelerated oxidation test conditions and down selected. An advanced bond coat/TBC system mechanical integrity and durability was demonstrated in more than 24,000 hours of cyclic testing at 1010°C (1850°F). This advanced bond/coat TBC system has been incorporated on the W501G Row 1 and 2 blades. This coating will improve both the life and durability of these parts, and it can potentially improve future engine performance by reducing the amount of cooling air required.

ATS Row 4 Turbine Blade

The 25% increase in engine mass flow, compared with the baseline F class machines, necessitated an advanced design Row 4 turbine blade to avoid increasing turbine exhaust losses. The ATS Row 4 blade is an uncooled, interlocked, Z-shrouded, cast airfoil. Because the W501G employs the ATS compressor and associated massflow, this blade was first introduced on the W501G. On the first W501G at the City of Lakeland McIntosh #5 site, the blade is instrumented with vibration monitors and strain gauge telemetry. In testing to date the blade has performed as predicted in both aerodynamic performance and mechanical strength.

ENGINE TEST RESULTS

The first W501G was ignited in April 1999, at the City of Lakeland, Macintosh #5 site. The unit has undergone extensive



testing and verification. Since March 2000, the customer has dispatched the unit based on power demands. This lead W501G engine has accumulated over 239 Starts and 850 Fired Hours as of November 2000. Currently, the unit operates in a simple cycle mode with a Once-Through-Steam-Generator for cooling steam production. Construction of the combined cycle plant is underway and will complete in 2002. The W501G Design Plant Performance is shown in Table 1.

Table 1 - W501G Design Plant Performance

Power, Net MW		253
Heat Rate,	kJ/kW-Hr	6,206
	BTU/kW-hr	5,884
Air Flow,	kg/sec	558
	Lbs./sec	1,230
Pressure Ratio		19.5:1

The test program included over 3000 sensors and measured parameters. An engine schematic showing the various sensors is shown in Figure 3. The test program consisted of two phases –emissions/performance mapping and thermal paint testing. For the emissions/performance mapping phase, testing targeted combustion system variables and provided engine performance mapping for different operating conditions such as IGV position and exhaust temperature.

Following the initial testing, turbine flowpath components and combustion components were prepared with thermally reactive paint and installed. The thermally reactive paint changes colors based on exposed temperature. This method is used extensively in aero engine validation since it provides a complete and accurate temperature map of the components at operating conditions. To react the thermal paint, the engine was ramped up to full load, ran for approximately five minutes at full load and then shutdown. The thermal paint test was conducted in two phases. In July 2000, the transitions and row 1 vanes were painted and tested. These components are removable without a major cover lift. In October 2000, a full paint test was conducted which included all turbine blades and vanes and areas of the rotor. Figure 4 shows the scope of the painted components. In addition to the base design, several components were installed with different cooling schemes. The different schemes were tested to evaluate possible cooling flow reductions and component durability enhancements. Both tests were conducted successfully and results are being evaluated.

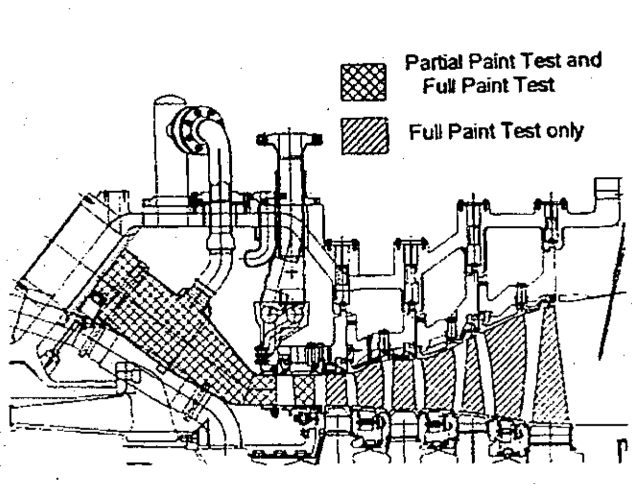


Figure 4 – W501G Paint test

The testing validated the closed-loop steam-cooling in a commercial application. The steam turbine temperatures were measured under both air-cooling at part load before steam quality was achieved and under full-load closed-loop steam cooling. The testing at Lakeland has confirmed the ability to switch between steam and alternate air cooling. As anticipated, actual measured metal temperatures are lower in the new closed-loop steam cooled design than in existing open-loop air-cooled design. The temperatures were measured along the length of the transition and are shown in Figure 5.

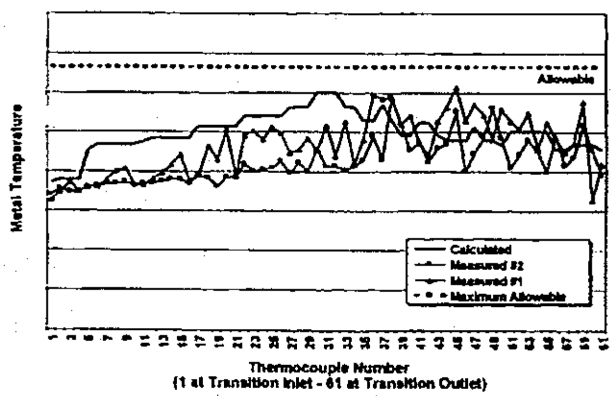


Figure 5 – W501G Transition temperatures

OPERATING EXPERIENCE

During testing and validation, two significant issues were encountered and resolved: vibration on front compressor diaphragms and combustor high frequency dynamics.

Figure 3 – W501G Instrumentation at City of Lakeland McIntosh #5 site in Lakeland, FL

The front compressor diaphragms on stages 1, 2 and 3 exhibited signs of distress after approximately 200 hours of operation. A root cause investigation identified High Cycle Fatigue due to high excitation of airfoils combined with residual stresses and high stress concentration factors. A minor design modification was initially applied and validated in the W501G at the City of Lakeland McIntosh #5 site. Additional dynamic strain gauges were applied for monitoring dynamic stresses. The redesign has operated successfully for a total of over 1000 hours in W501G engines. A full cover lift and NDE inspection at the City of Lakeland McIntosh #5 site was completed and no operating restrictions are in effect.

During testing, high combustion dynamics were observed at approximately 2200 Hz causing distress to combustion system components. A root cause investigation identified insufficient aerodynamic damping as result of closed-loop steam cooling of the transition. To eliminate the dynamics, resonators tuned for 2200 Hz dynamics were added to the transitions. The resonator design was first tested and validated at the Siemens Westinghouse high pressure combustor test facility at Arnold Engineering Development Center in Tullahoma, TN. Subsequently, the modified transitions were validated at the City of Lakeland and successfully dampened the combustor dynamics. As an added precaution, a combustor dynamics monitor has been added as standard supervisory instrumentation as part of digital control system. In the event that combustor dynamics occur, the system will automatically adjust the engine operation to eliminate the dynamics and avoid distress on the components. Validation continues with alternate fuel sources.

DEVELOPMENT ACTIVITIES

Steam-Cooled Vane

Development activities are focused on extending the W501G frame to ATS efficiencies through the introduction of additional technology advancements. The next major step will add a thin-walled, closed-loop, steam-cooled Row 1 turbine vane to the W501G. The steam-cooled vane will extend the benefits of the steam-cooled transition by eliminating most cooling air from the Row 1 vane. The result will be a combination of increased rotor inlet temperature and decreased burner outlet temperature. The benefit will be improved efficiency and reduced NOx. Single-crystal casting trials have been successfully completed at PCC Airfoils, Inc. in Mentor, Ohio.

The ATS steam cooled vane will be first tested in an engine sector rig. The test rig consists of a full-scale combustor basket and transition and a 1/16th-sector vessel, which will operate up to full ATS pressures and temperatures. The rig will be located at Arnold Engineering Development Center at the Arnold Air Force Base in Tennessee. The vane will be instrumented to verify analytical predictions of metal temperatures, heat transfer coefficients, and stress.

After validation in the 1/16th-sector rig, the vane will be retrofit into a W501G. A comprehensive test program will verify vane performance and improved plant performance. Test parameters will include vane metal temperature, stress, and steam temperatures.

Coatings

Thermal barrier coatings (TBC) are an integral part of the W501ATS engine design. A development program is in progress to develop an advanced bond coat/TBC system with a projected service life of more than 24,000 hours. Different bond coats and ceramic materials were evaluated under accelerated oxidation test conditions and down selected. The mechanical integrity and durability of an advanced bond coat/TBC system was demonstrated in more than 24,000 hours of cyclic testing at 1010°C (1850°F).

Under a related program, DOE-Oak Ridge National Laboratory (Contract DE-AC05-95OR22242), new ceramic compositions and TBC concepts were identified which have a sintering resistance and phase stability superior to that of 8YSZ TBC. These compositions and concepts are being further optimized and will be transferred to components for a 8000 hr engine demonstration under a DOE-Chicago contract DE-FC02-00CH11048.

SUMMARY

Technology development efforts have demonstrated that ATS Program goals are obtainable. The results of the technology development programs were incorporated into the W501ATS design. Based on input from a Customer Advisory Board, Siemens Westinghouse is pursuing an evolutionary introduction of ATS technology. The W501G, the first step in this evolution, introduces several ATS technologies such as closed-loop steam cooling, advanced compressor design, and high temperature materials. The first W501G is in operation at the City of Lakeland McIntosh #5 plant in Lakeland, FL. Through 2003, 28 W501G's are committed which will provide a thorough proof of the major ATS technologies. In addition, Siemens Westinghouse is infusing ATS technologies into its entire product line. This approach will result in a lower-risk ATS engine and will significantly increase and accelerate the net benefits of the program.

ACKNOWLEDGMENTS

This program is administered through the U.S. Department of Energy's Federal Energy Technology Center, Morgantown, WV, under the guidance of FETC's Program Manager, Mr. Charles Alsup. Research is sponsored by the U.S. Department of Energy's Federal Energy Technology Center, under Contract DE-FC21-95MC32267.

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Exhibit 13

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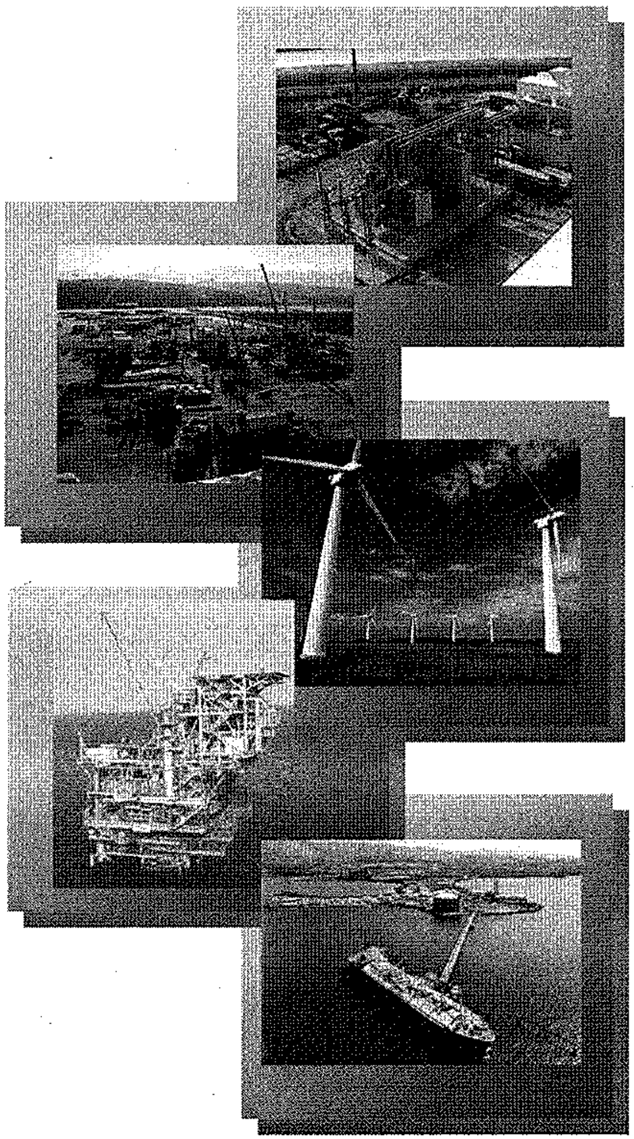

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and
Industrial Facilities**

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Introduction to Universal Energy

Background

- Specializing in power plant support since 1994
- Over 160 different projects in 10 years, 6 continents, 28 countries, 34 states
- In excess of 54,000 MW of electricity brought on line
- Client List include Fortune 100 Power Plant Owners and EPC Companies

Capabilities

- Broad Base of Management Services
- All sectors of the Power, Petrochemical, Offshore and Industrial Markets
- Development, Engineering, Design, Owner's Engineer, Commissioning and Startup, Plant O&M, Training and Plant Procedures, Manpower Services
- Natural Gas, Coal, Wind, Geothermal, Diesel and other Liquid Fuels
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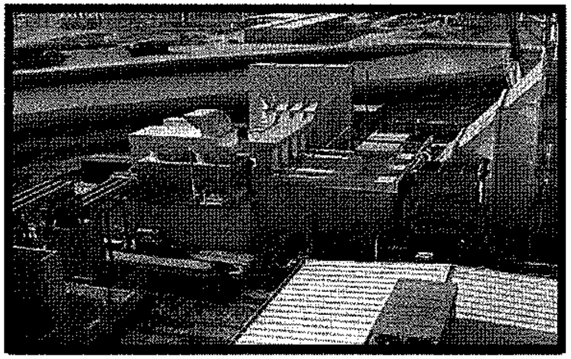
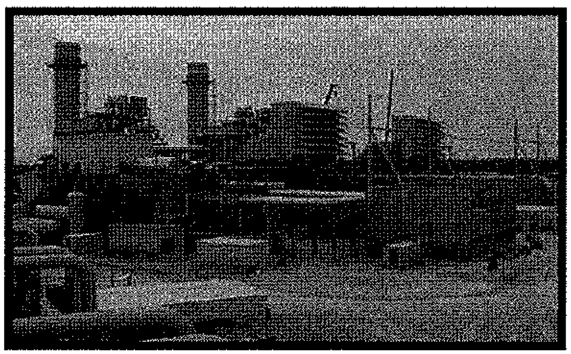


Extensive Experience

Project Management, Construction & Startup Management

- Full Scope Commissioning & Startup package
- Managers and Manpower Support
- Safety Management
- Mechanical, Electrical, and Instrument & Control/DCS Services
- Planning and Scheduling
- QA/QC Documentation



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- Protecting/maintaining the asset
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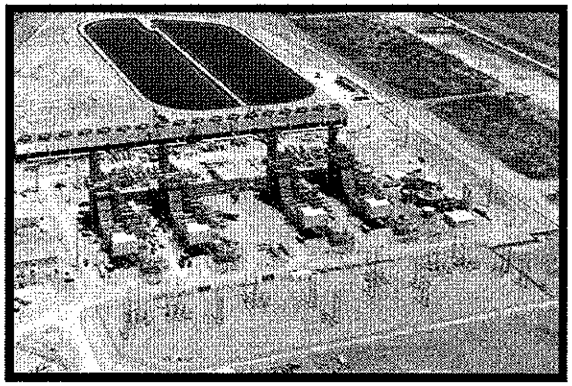
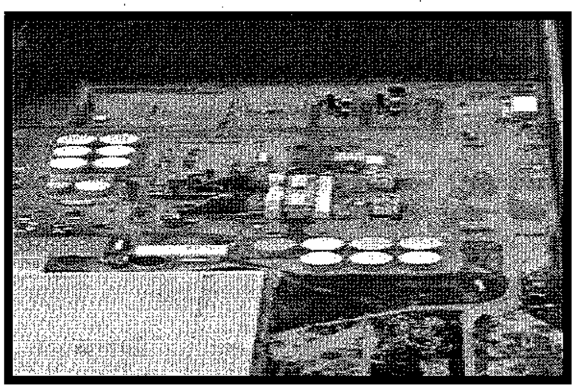


A Unique Team



Unique Solutions

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- Transition & Mobilization Services
- Commercial Management (budget & production control)
- Warranty Management
- Staffing & Training
- LTSA Management & Spare Parts
- Water & Waste Water Management

Owner's Engineer

- Acquisition Audits & Operations Reviews
- Owner's Engineer/Site Representative
- Development Support and Design Review
- Operability, Reliability and Maintainability Reviews
- Plant Performance Review
- Water Usage, Wastewater Reviews, Water Security
- Maintenance Scheduling and Cost Analysis
- Environmental/Safety Compliance Review
- Electrical/Mechanical/Controls Surveys

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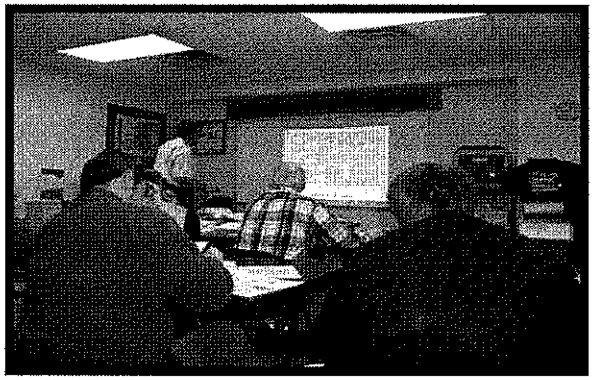
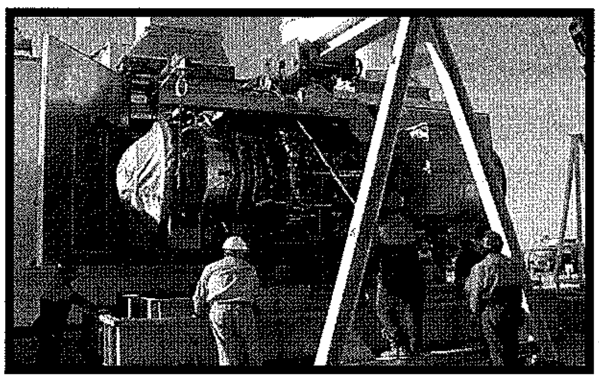


Organizational Development



Technical Skills

Training and Documentation

- Training Audits and Analysis
- Technical Skills Assessment
- Greenfield Operator Training
- Life-Cycle O&M Training Program/OJT
- Operation, Maintenance, Commissioning and Training Procedure Development
- Plant Operating Manuals

Manpower

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- Commissioning & Startup Managers
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- Training & Documentation
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- FULL RANGE OF SERVICES, HARD WORK, QUALITY PEOPLE & COMMITMENT TO THE CLIENT
- Lower costs, competitive rates and service

Project Support

- All inclusive and centrally managed Owner's Engineering Service
- Asset Management and Consulting Services
- O&M at a competitive fee

Project Execution

- Experienced multi-disciplined Project and Startup Management Staff
- Database of experienced and available manpower
- Detailed documentation
- Training and procedures

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Project Highlights

- **Commissioning and Startup:** Over 54,000 MW of thermal power brought online
- **NYPA Emergency Summer Power Program:** Managed Commissioning and Startup of 11xLM6000 units for over 400MW in 6 locations in New York City in the summer of 2001.
- **Peñuelas, Puerto Rico**: Commissioning & Startup and Training – 1MM Bbl LNG Terminal and 500MW Power Plant. Combined LNG terminal, storage, gasification and power facility.
- **Macaé, Brazil**: Commissioning & Startup and Plant Operations –740MW Power Plant. This is the largest multiple-unit simple cycle power plant in the world.
- **Consulting**: Acquisition Due Diligence and Plant Audits – totaling over 19,000MW international and domestic plants. CFB, Waste Coal, Gas and liquid fuels. Combined Cycle, Peaking Plants, Diesels, Geothermal and Biomass Plants.

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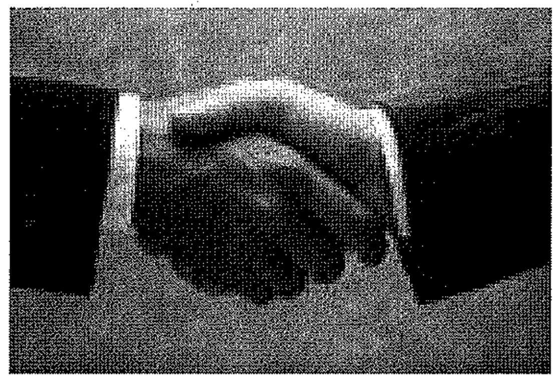

"Work hard,
Do your best,
Keep your word,
Never get too big for your britches,
Trust in God,
Have no fear,
And never forget a friend."
Harry S. Truman

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Exhibit 14

GER-3574G

GE Power Systems

GE Combined-Cycle Product Line and Performance

D.L. Chase
P.T. Kehoe
GE Power Systems
Schenectady, NY

Contents

GE Combined-Cycle Product Line and Performance

Introduction

The development during the past four decades of larger capacity gas turbine designs (50 MW to 380 MW) with increased specific power has led to the parallel development of highly-efficient and economical combined-cycle systems. The GE pre-engineered, combined cycle product line is designated STAG™, which is an acronym for STeam And Gas. Each STAG combined cycle system is an Engineered Equipment Package (EEP) consisting of GE gas turbines, steam turbines, generators, Heat Recovery Steam Generators (HRSGs) and controls. The most efficient of these STAG systems is configured with the GE "H" model gas turbine and is scheduled for commercial operation by the year 2003. The "H" combined cycle will achieve 60 percent (LHV) thermal efficiency.

The STAG EEP is an optimized and matched system of high technology power generation equipment, software, and services configured for convenient integration with the owner's auxiliaries and balance of plant equipment to form an economical power plant. This single source supply of the EEP enables GE to provide guarantees of plant thermal and emission performance as well as warrant system operation.

The product line spans a wide range of capabilities for both 50 and 60 Hz applications. A wide range of configurations is available with standard options that enable the systems to be adapted to suit the economic requirements of each application. The STAG combined-cycle product line includes two major categories:

- Pre-engineered oil- or natural gas-fired systems for electric power generation
- Pre-engineered building blocks for combined-cycle cogeneration systems and coal- or oil-fired integrated gasification combined-cycle (IGCC) power generation systems.

Economical performance of function is the outstanding characteristic of STAG combined-cycle systems. The features that contribute to economical power generation by STAG combined-cycle power generation systems are shown in *Table 1* and those for thermal and power systems are presented in *Table 2.*

- High Thermal Efficiency
- Low Installed Cost
- Fuel Flexibility – Wide Range of Gas and Liquid Fuels
- Low Operation and Maintenance Cost
- Operating Flexibility – Base, Mid-range, Daily Start
- High Reliability
- High Availability
- Short Installation Time
- High Efficiency in Small Capacity Increments

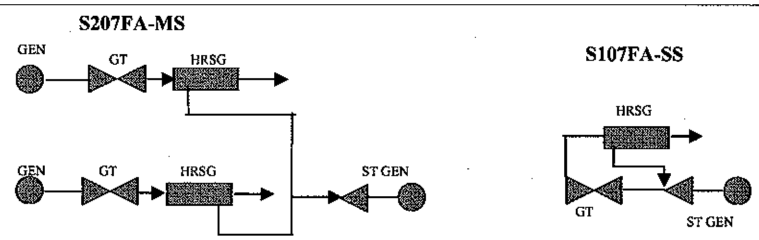
Table 1. STAG combined-cycle power generation system features

- High Thermal Efficiency
- Low Installed Cost
- Low Operation and Mainteance Costs
  - Steam Generation at Process Conditions
  - Extraction/Condensing Steam Turbine
  - Non-Condensing Turbine Exhausting to Process
  - Unfired/Fired HRSGs
  - Gas Turbine DLN/Steam Injection
- High Power to Thermal Energy Ratio
- High Reliability/Availability
- Short Installation Time

Table 2. STAG combined-cycle thermal energy and power system features

STAG Product Line Designations

System designations that identify STAG combined-cycle product line configurations are defined in *Table 3.* This example defines the designation for the single-shaft and multi-shaft combined-cycle configurations.



S	2	0	7FA	-	MS
STAG™	Two GTs		GT Model Series		Multi-Shaft Configuration

S	1	0	7FA	-	SS
STAG™	One GT		GT Model Series		Single-Shaft Configuration

STAG IS A REGISTERED TRADEMARK OF GENERAL ELECTRIC(USA)
AND IS AN ACRONYM FOR STeam And Gas

Table 3. STAG combined-cycle system designations

STAG Product Line Configurations

The product line includes single-shaft and multi-shaft configurations. Simplified block diagrams of these configurations are presented in *Figure 1.* The single-shaft STAG system consists of one gas turbine, one steam turbine, one generator, and one HRSG with the gas turbine and steam turbine coupled to the single generator in a tandem arrangement on a single shaft. Multi-shaft STAG systems have one or more gas turbine generators and HRSGs that supply steam through a common header to a separate, single steam turbine generator.

Single- and multiple-pressure non-reheat steam cycles are applied to STAG systems equipped with GE gas turbines that have rating point exhaust gas temperatures of approximately 1000°F / 538°C or less. Selection of a single- or multiple-pressure steam cycle for a specific application is determined by economic evalua-

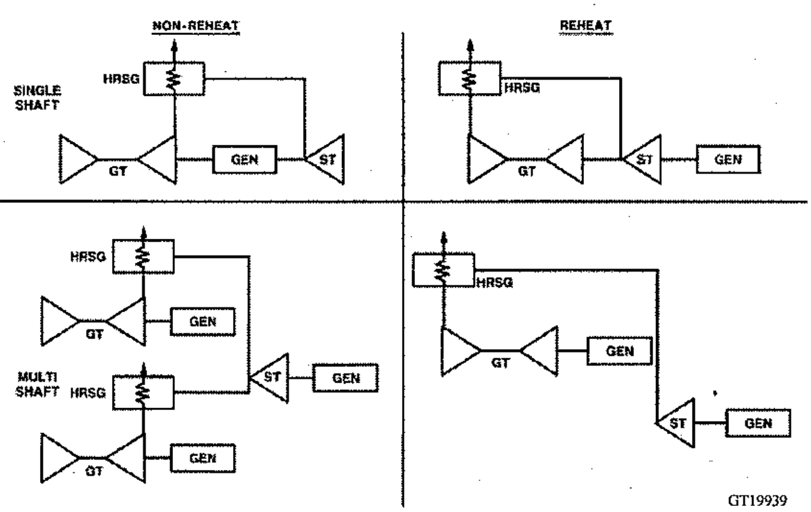


Figure 1. STAG system configurations

tion, which considers plant-installed cost, fuel cost and quality, plant-duty cycle, and operating and maintenance cost.

Multiple-pressure reheat steam cycles are applied to STAG systems with GE gas turbines that have rating point exhaust gas temperatures of approximately 1100°F / 593°C or greater.

A generalized combined-cycle, electric power generation and thermal energy capability map is presented in *Figure 2.* This map is typical of a system supplying process steam at 150 psig/11.4 bars and utilizing a gas turbine with 100 MW rated output.

tomer specific applications in which the need for increased power offsets the corresponding reduction in thermal efficiency.

The most efficient cycles for cogeneration applications are those with fully-fired HRSGs, as indicated by *Figure 2,* at maximum thermal energy output. The fully-fired HRSGs are high in cost because of their water wall construction and need for field erection. Also, fully-fired HRSGs may add to emission considerations as plant siting requirements are evaluated. The primary regions of interest for cogeneration, combined-cycle systems are those with unfired

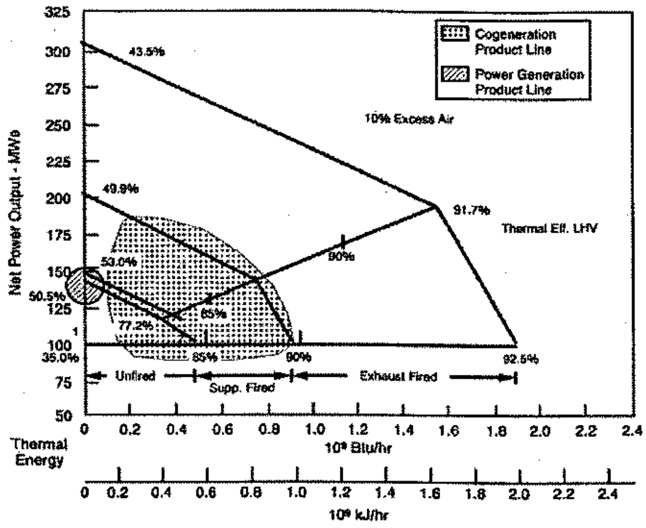


Figure 2. Generalized combined-cycle performance capability

The vertical axis of *Figure 2* with zero thermal energy shows the power and thermal efficiency of combined cycles with unfired, supplementary-fired, and fully-fired steam cycles. The most efficient power generation cycles are those with unfired HRSGs having modular pre-engineered components. These unfired steam cycles are also the lowest in cost and are, therefore, applied in the STAG combined-cycle power generation product line. Supplementary-fired combined-cycle systems are provided for cus-

and supplementary-fired steam cycles. These systems provide a wide range of thermal energy to electric power ratio, 0–12,000 Btu thermal energy per kW (0–12,660 kJ per kW), and represent the range of thermal energy capability and power generation covered by the product line for cogeneration capability.

STAG Power Generation Product Line

The STAG power generation product line includes an array of steam cycle options, which satisfies a wide range of fuels, fuel cost, duty cycle, and other economic considerations. This enables selection of a steam cycle for each application that suits specific economic and operational requirements. Steam cycles utilized in the STAG product line include:

- **Single-Pressure, Non-Reheat Heat Recovery Feedwater Heating.** This steam cycle, shown in *Figure 3*, has an unfired HRSG with finned tube superheater, evaporator, and economizer sections. Energy is recovered from the exhaust gas by convective heat transfer. The HRSG schematic diagram is shown in *Figure 4*. This is the simplest steam cycle that can be applied in a combined cycle and it has been used extensively. It results in a low installed cost. Although it does not produce the highest combined-cycle thermal efficiency, it is a sound economic

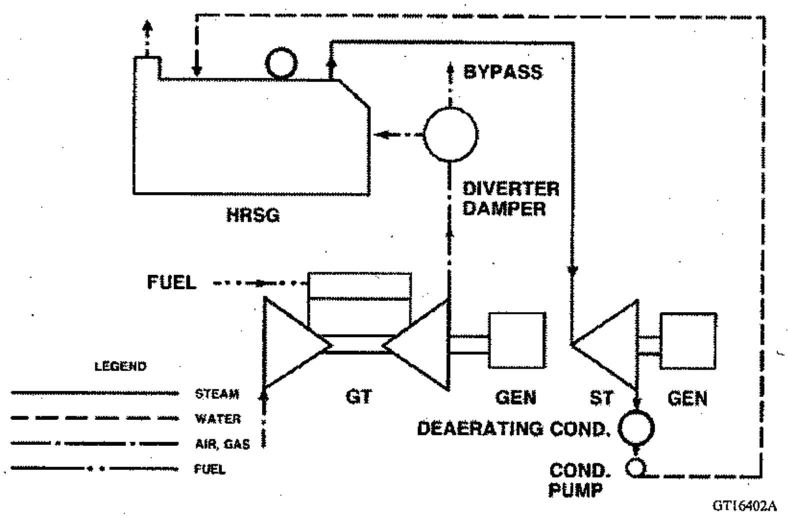


Figure 3. Single-pressure non-reheat cycle diagram

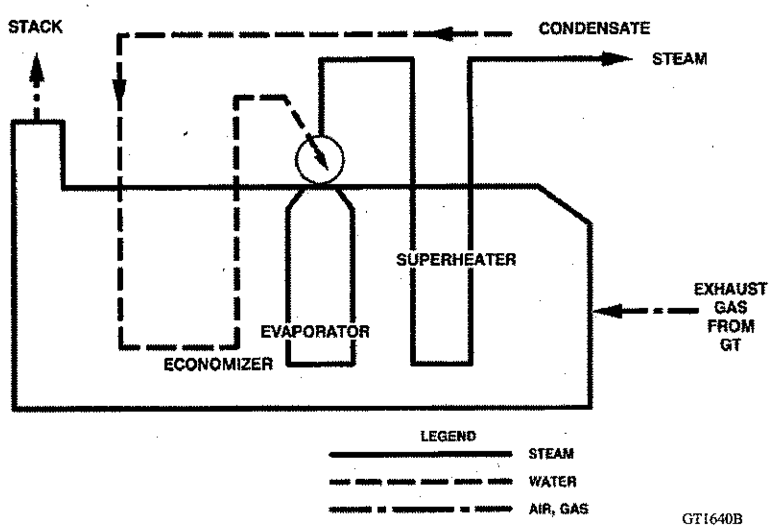


Figure 4. Single-pressure non-reheat HRSG diagram

selection when fuel is inexpensive, when applied in peaking type service, or when burning ash-bearing fuel with high sulfur content. This steam cycle is utilized in the STAG product line primarily with GE gas turbines having a baseload exhaust gas temperature of approximately 1000°F / 538°C or less. The HRSG stack gas temperature with this steam cycle is approximately 340°F / 171°C.

- **Multiple-Pressure, Non-Reheat Heat Recovery / Feedwater Heating.** Multi-pressure steam generation is used to maximize energy recovery from gas turbine exhaust. HRSG gas-side and steam-side temperature profiles for single- and multiple-pressure steam cycles are presented in *Figures 5 and 6.* This illustrates that increasing the number of steam pressure levels reduces the exhaust gas and steam/water energy difference. Two- or three-pressure steam cycles achieve better efficiency than the single-pressure systems, but their installed cost is higher. They are the economic choice when fuel is expensive or if the duty cycle requires a high load factor. The three-pressure steam cycle is shown in *Figure 7* and the HRSG schematic diagram is shown in *Figure 8.* This cycle is similar to the single-pressure cycle with the addition of the low-pressure and intermediate-pressure sections. Improved plant performance with multiple-pressure steam cycles results from additional heat transfer surface installed in the HRSG. The HRSG stack gas temperature is in the range of 200°F / 93°C to 260°F / 127°C.

- **Three-Pressure, Reheat Heat Recovery Feedwater Heating.** The reheat steam cycle matches the characteristics of the "EC," "F," and "H" technology gas turbines. The higher exhaust gas temperature of 1100°F / 593°C or greater provides sufficient high temperature energy to the HRSG to make the reheat steam cycle practical. Fuel gas heating to approximately

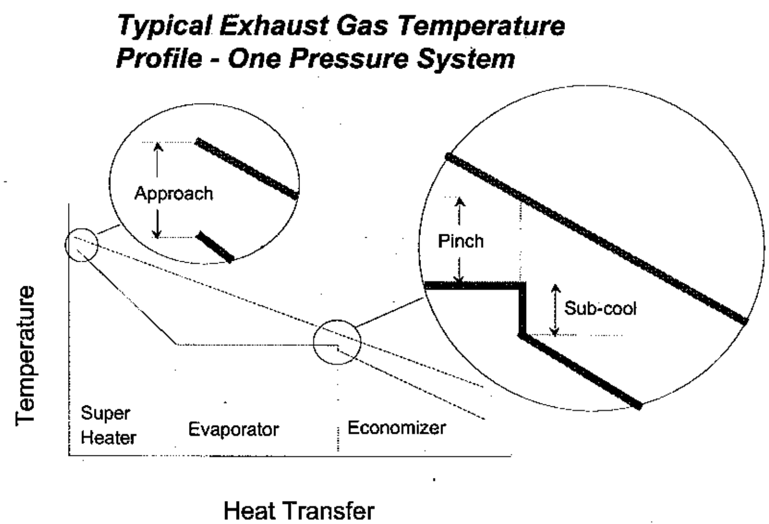


Figure 5. Typical exhaust gas/steam cycle temperature profile for single-pressure system

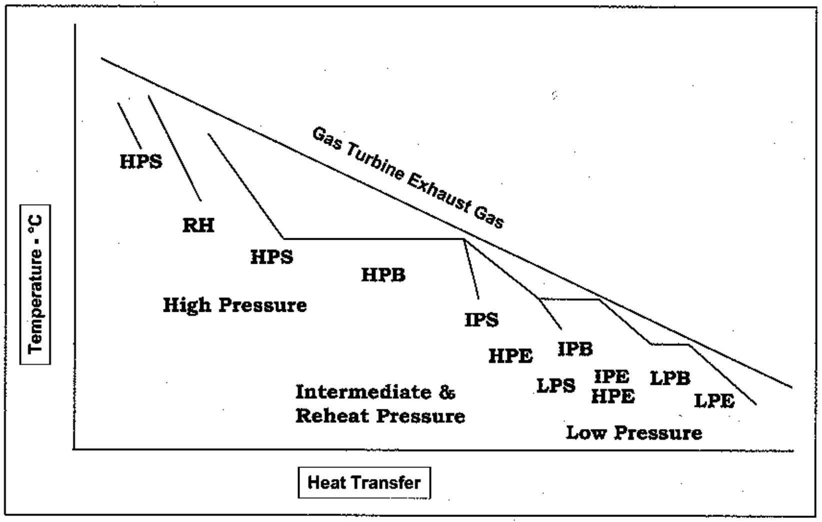


Figure 6. Typical exhaust gas/steam cycle temperature profile for three-pressure system

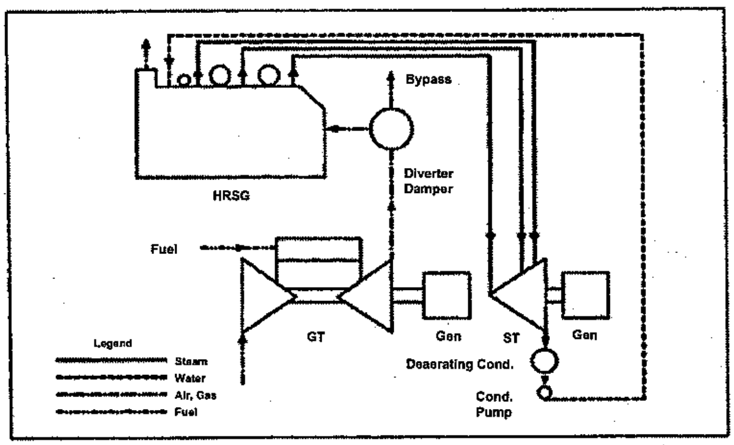


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Figure 7. Three-pressure non-reheat cycle diagram

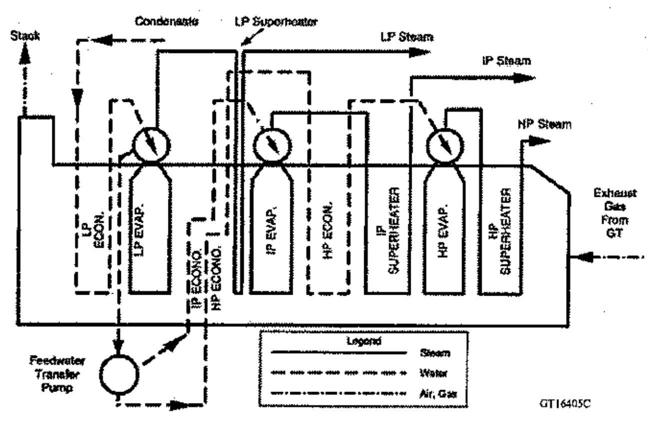


Figure 8. Three-pressure non-reheat HRSG diagram

365°F / 185°C, using water supplied from the HRSG IP economizer discharge, is also included with the "EC" and "F" technology gas turbines. This steam cycle is shown in *Figure 9.* The HRSG schematic is presented in *Figure 10.*

The "H" platform gas turbines, configured with hot gas path components cooled with both a closed-loop, steam-cooling system and an open-loop, air-cooling system design, are designated as MS7001H and MS9001H. The reheat steam cycle utilized with these gas turbines is closely integrated with the gas turbine steam-cooling system. This integration provides additional incentive to select single-shaft STAG configuration for these gas turbines. The steam cycle used with the S107H and S109H is shown in *Figure 11.* The HRSG schematic is shown in *Figure 12.*

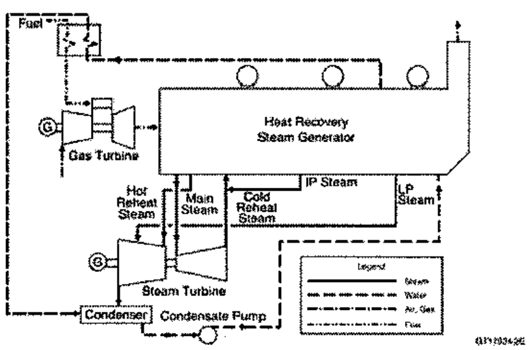


Figure 9. Three-pressure reheat cycle diagram

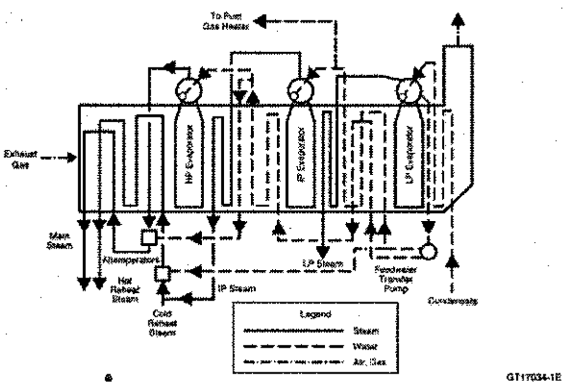


Figure 10. Three-pressure reheat HRSG diagram

These STAG combined-cycle systems are the most efficient power generation systems currently available. The base configuration for the STAG power generation combined-cycle product line is designed for high efficiency when firing natural gas or distillate fuel. A summary of the equipment and system configuration is presented in *Table 4.*

- Unfired, three-pressure steam cycle
  - Non-reheat for rated exhaust gas temperature less than 1000°F/538°C
  - Reheat for rated exhaust gas temperature higher than 1050°F/566°C and fuel heating
  - Heat recovery feedwater heating
  - Feedwater deaeration in condenser
  - Natural circulation HRSG evaporators
- Gas turbine with Dry Low NO_x combustors
- Once-through condenser cooling water system
- Multi-shaft systems
- Single-shaft systems
  - Integrated equipment and control system

Table 4. STAG power generation combined-cycle base configuration

The 60 Hz STAG power generation product line ratings are presented in *Table 5. Table 6* shows the major equipment in each standard STAG system. The 50 Hz product line ratings are presented in *Table 7,* and *Table 8* shows the major equipment in each of these standard STAG systems. These ratings are presented for gas turbine base load operation with natural gas fuel. Nominal throttle and reheat steam conditions for the non-reheat and reheat STAG product lines are defined in *Table 9.*

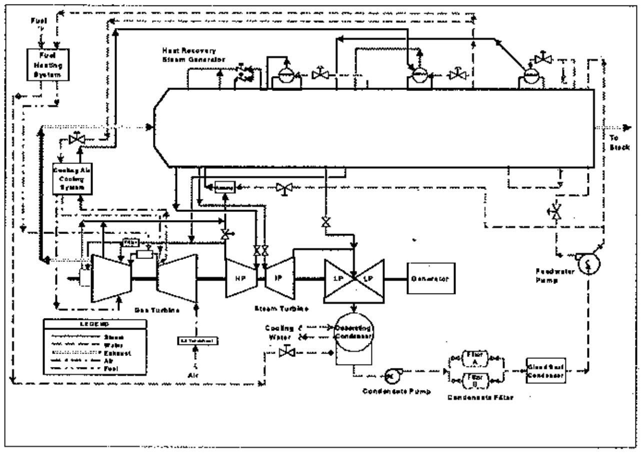


Figure 11. STAG 107H/S109H cycle diagram

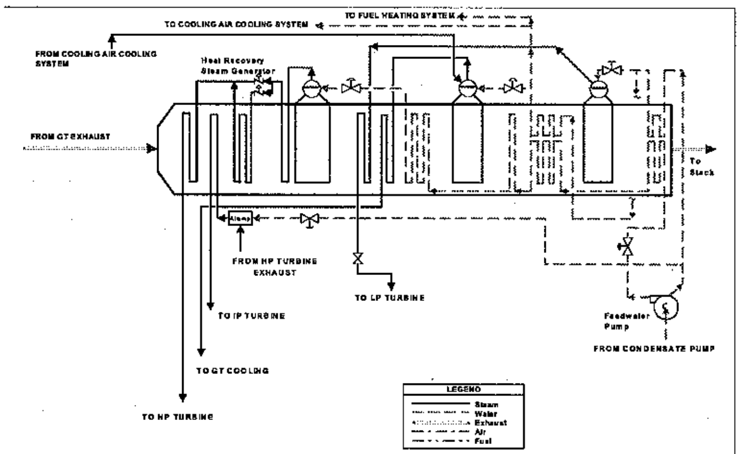


Figure 12. HRSG schematic for S107H/S109H

The STAG product line equipment and plant natural gas fuel ratings defined in *Tables 5 and 7* represent thermodynamic optimum performance that is expected to be the economic optimum configuration for baseload and mid-range dispatch using clean fuels costing about \$2.50 per 10^6 Btu, HHV (\$2.64 per 10^6 Kj, HHV). A wide array of options is available for the STAG power generation product line to suit specific economic criteria as well as the operating and installation preferences of the owner. *Table 10* lists the most commonly-applied options in addition to the base configuration.

Non-reheat steam cycles with one or two pressures and reheat steam cycles with two pressures are also available for the STAG product-line systems. Typical performance variation for these optional steam cycles is presented in *Table 11.* HRSGs with forced circulation evaporators are available to suit specific installation situations and owner preferences. *Figure 13* shows a two-pressure, non-reheat steam cycle with forced circulation HRSG.

Systems can be provided with a deaerator integral to the HRSG that utilizes low-pressure evaporator energy to perform the feedwater deaeration at positive pressure at a small reduction in thermal efficiency. Those systems that include a

Combined cycle Designation		Net Plant Power (MW)	Net Plant Heat Rate(LHV) Btu/kWhr	kJ/kWhr	Thermal Efficiency (%, LHV)
S106B	(4)	64.3	6960	7340	49.0
S206B	(4)	130.7	6850	7230	49.8
S406B	(4)	261.3	6850	7230	49.8
S106FA	(5)	107.1	6440	6795	53.0
S206FA	(5)	217.0	6355	6705	53.7
S107EA	(4)	130.2	6800	7175	50.2
S207EA	(4)	263.6	6700	7070	50.9
S107FA	(5)	262.6	6090	6425	56.0
S207FA	(5)	529.9	6040	6375	56.5
S107FB	(5)	280.3	5950	6280	57.3
S207FB	(5)	562.5	5940	6260	57.5
S107H	(6)	400.0	5690	6000	60.0

Notes: 1. Site conditions =59 F, 14.7 psia, 60% RH (15 C, 1.013 bar)
2. Steam turbine exhaust pressure = 1.2 inches Hg,A (30.48 mm Hg,A)
3. Performance is net plant with allowance for equipment and plant auxiliaries including those associated with a once-through cooling water system
4. Three-pressure, non-reheat, heat-recovery feedwater heating steam cycle
5. Three-pressure, reheat, heat-recovery feedwater heating steam cycle with integrated fuel, gas-heating system
6. Three-pressure, reheat, heat-recovery feedwater heating steam cycle with integrated turbine steam- and air-cooling and fuel-heating systems

Table 5. 60 Hz STAG product line performance

Designation	Gas Turbine No.	Gas Turbine Frame	HRSG No.	HRSG Type	Exhaust No.	Steam Turbine LSB Inches	Steam Turbine LSB mm	Exhaust Config.
• *Heavy Duty GT*								
S106B	1	PG6581 B	1	Non-Reheat, Unfired	1	23	584	Axial
S206B	2	PG6581 B	1	Non-Reheat, Unfired	1	33.5	851	Axial
S406B	4	PG6581 B	2	Non-Reheat, Unfired	2	33.5	851	Down
S106FA	1	PG6101 FA	1	Reheat, Unfired	1	30	762	Axial
S206FA	2	PG6101 FA	1	Reheat, Unfired	2	30	762	Down
S107EA	1	PG7121 EA	1	Non-Reheat, Unfired	1	33.5	851	Axial
S207EA	2	PG7121 EA	2	Non-Reheat, Unfired	2	33.5	851	Down
S107FA	1	PG7241 FA	1	Reheat, Unfired	2	30	762	Down
S207FA	2	PG7241 FA	2	Reheat, Unfired	4	30	762	Down
S107FB	1	PG7251 FB	1	Reheat, Unfired	2	30	762	Down
S207FB	2	PG7251 FB	2	Reheat, Unfired	4	30	762	Down
S107H	1	PG7001 H	1	Reheat, Unfired	2	40	1016	Down

Table 6. 60 Hz STAG product line equipment

low-pressure economizer for high thermal efficiency will require material that resists corrosion because feedwater passing through this section may have a high oxygen concentration, and the external tube surface temperature may be below the exhaust gas dew point temperature. *Figure 14* shows a three-pressure non-reheat HRSG with integral deaerator.

Fuel characteristics affect combined-cycle performance in a variety of ways. High hydrogen content in fuels such as natural gas results in high water content in the combustion products. Water has a higher heat content than air or other combustion products, so fuels with high hydrogen content increase output and efficiency. Ash-bearing fuels foul the gas turbine and HRSG; therefore, equipment and system design considerations that accept fouling reduce plant output and efficiency. Sulfur content in the fuel may require adjustment in the temperature of the stack gas and the water entering the HRSG economizer to prevent condensation of corrosive sul-

Combined cycle Designation		Net Plant Power (MW)	Net Plant Heat Rate (LHV) Btu/kWhr	kJ/kWhr	Thermal Efficiency (%, LHV)
S106B	(4)	64.3	6950	7340	49.0
S206B	(4)	130.7	6850	7230	49.8
S406B	(5)	261.3	6850	7230	49.8
S106FA	(5)	107.4	6420	6775	53.2
S206FA	(4)	218.7	6305	6650	54.1
S109E	(4)	189.2	6570	6935	52.0
S209E	(4)	383.7	6480	6840	52.7
S109EC	(5)	259.3	6315	6660	54.0
S209EC	(5)	522.6	6270	6615	54.4
S109FA	(5)	390.8	6020	6350	56.7
S209FA	(5)	786.9	5980	6305	57.1
S109H	(6)	480.0	5690	6000	60.0

Notes: 1. Site conditions = 59 F, 14.7 psia, 60% RH (15 C), 1.013 bar)
2. Steam turbine exhaust pressure = 1.2 Inches HgA (30.48 mm HgA)
3. Performance is net plant with allowance for equipment and plant auxiliaries including those associated with a once-through cooling water system
4. Three-pressure, non-reheat, heat recovery feedwater heating steam cycle
5. Three-pressure, reheat, heat-recovery feedwater healing steam cycle with integrated fuel gas heating system
6. Three-pressure, reheat, heat-recovery feedwater heating steam cycle with integrated turbine steam and air cooling and fuel heating systems.

Table 7. 50 Hz STAG product line performance

Designation	Gas Turbine No.	Gas Turbine Frame	HRSG No.	HRSG Type	Exhaust No.	Steam Turbine LSB Inches	Steam Turbine LSB mm	Exhaust Config.
• *Heavy Duty GT*								
S106B	1	PG6581 B	1	Non-Reheat, Unfired	1	17	432	Axial
S206B	2	PG6581 B	1	Non-Reheat, Unfired	1	33.5	851	Axial
S406B	4	PG6581 B	2	Non-Reheat, Unfired	2	33.5	851	Down
S106FA	1	PG6101 FA	1	Reheat, Unfired	1	26	660	Axial
S206FA	2	PG6101 FA	2	Reheat, Unfired	1	42	1066	Axial
S109E	1	PG9171 E	1	Non-Reheat, Unfired	1	42	1066	Down
S209E	2	PG9171 E	2	Non-Reheat, Unfired	2	42	1066	Down
S109EC	1	PG9231 EC	1	Reheat, Unfired	1	42	1066	Down
S209EC	2	PG9231 EC	2	Reheat, Unfired	2	42	1066	Down
S109FA	1	PG9351 FA	1	Reheat, Unfired	2	33.5	851	Down
S209FA	2	PG9351 FA	2	Reheat, Unfired	4	33.5	851	Down
S109H	1	PG9001 H	1	Reheat, Unfired	2	42	1066	Down

Table 8. 50 Hz STAG product line equipment

furic acid. The increased stack gas temperature required by higher sulfur content decreases output and efficiency. Performance variation with fuel type (hydrogen, ash and sulfur content typical of each) is presented in *Table 12.*

The STAG product line includes gas turbines with Dry Low NO_x (DLN) combustors that can operate with stack gas NO_x emission concentration as low as 9 ppmvd at 15% oxygen (15.5 g/GJ) without water or steam injection, when operating on natural gas fuel. Water or steam injection may be required to meet NO_x emission requirements when operating on distillate oil fuel. Also, gas turbines are available with conventional, diffusion flame combustors operating with water or steam injection to meet NO_x emission limits. *Table 13* presents stack gas NO_x emissions from gas turbines in typical STAG combined cycle systems for operation with DLN or diffusion flame combustors with natural gas fuel. The effect of water- or steam-injection on NO_x abatement and thermal performance is also presented.

Selective catalytic reduction (SCR) is a stack gas NO_x reduction system that uses ammonia to react with NO_x over a catalyst that reduces NO_x to nitrogen and water. These systems increase the plant installation and operating cost, but

Heat Recovery Feedwater Heater Steam Cycle	Non-Reheat Three-Pressure			Reheat Three-Pressure
Steam Turbine Size (MW)	≤ 40	> 40 <60	≥ 60	> 60
Throttle Pressure (psig) (Kg/cm²,g)	820 (58)	960 (68)	1200 (84)	1400-1800 (98)
Throttle Temperature (°F) (°C)	40 Approach to Gas Turbine (22) Exhaust Gas Temperature			1000-1050 (538-566)
Reheat Pressure (psig) (Kg/cm²,g)	-- --	– –	– –	300-400 (21-28)
Reheat Temperature (°F) (°C)	-- --	– –	-- --	1000-1050 (538-566)
IP Admission Pressure (psig) (Kg/cm²,g)	100 (7)	120 (8)	155 (11)	300-400 (21-28)
IP Admission Temperature (°F) (°C)	20 Approach to Exhaust Gas Temperature (11) Upstream of Superheater			
LP Admission Pressure (psig) (Kg/cm²,g)	25 (1.8)	25 (1.8)	25 (1.8)	40 (2.8)
LP Admission Temperature (°F) (°C)	20 Approach to Exhaust Gas Temperature (11) Upstream of Superheater			

Table 9. STAG product line steam turbine throttle and admission steam conditions

they can reduce NO_x to less than 9 ppmvd at 15% oxygen (15.5 g/GJ) for all combined-cycle systems in the product line. The SCR catalyst typically operates in the 570°F/300°C to 750°F/400°C temperature range, so the catalyst is typically installed within the high-pressure evaporator as shown in *Figure 15.* The ammonia injection grid is installed upstream of the evaporator where the gas temperature is below the temperature at which ammonia oxidizes to form NO_x. This provides intimate mixing of the ammonia and NO_x as the gas passes through the pre-evaporator section.

Carbon monoxide (CO) emissions are low at gas turbine loads above 50%, typically less than

STEAM CYCLE
- Single pressure
- Two pressure
- **Three pressure***
- Reheat
- Non-reheat

DEAERATION
- **Deaerating condenser***
- Deaerator/evaporator integral with HRSG

HRSG DESIGN
- **Natural circulation evaporators***
- Forced circulation evaporators
- **Unfired***
- Supplementary fired

NO_X CONTROL
- Water injection
- Steam injection
- SCR (NO_X and/or CO)
- **Dry Low NOx combustion***

CONDENSER
- **Water cooled (once-through system)***
- Water cooled (evaporative cooling tower)
- Air-cooled condenser

FUEL
- **Natural gas***
- Distillate oil
- Ash bearing oil
- Low BTU coal and oil-derived gas
- Multiple fuel systems

* Base configuration

Table 10. Power generation combined-cycle product line system options

STAG 207EA		
STEAM CYCLE	**NET PLANT OUTPUT (%)**	**NET PLANT THERMAL EFFICIENCY (%)**
THREE PRESSURE, REHEAT	**+0.7**	**+0.7**
THREE PRESSURE, NON-REHEAT	**BASE**	**BASE**
TWO PRESSURE, NON-REHEAT	**-1.0**	**-1.0**
SINGLE PRESSURE, NON-REHEAT	**-4.7**	**-4.7**

STAG 107EA		
STEAM CYCLE	**NET PLANT OUTPUT (%)**	**NET PLANT THERMAL EFFICIENCY (%)**
THREE PRESSURE, REHEAT	**BASE**	**BASE**
TWO PRESSURE, REHEAT	**-1.1**	**-1.1**
THREE PRESSURE, NON-REHEAT	**-1.2**	**-1.2**
TWO PRESSURE, NON-REHEAT	**-2.0**	**-2.0**

Table 11. Performance variation with steam cycle

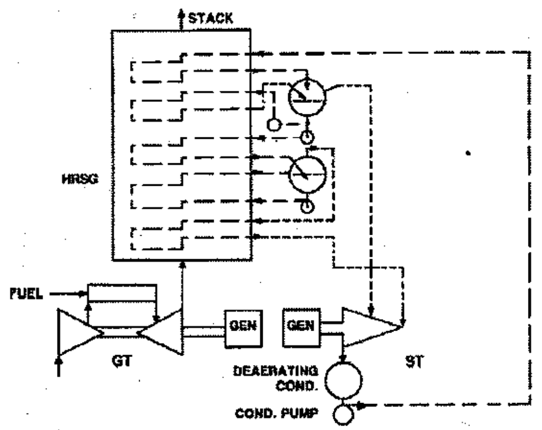


Figure 13. Two-pressure non-reheat steam cycle with forced circulation HRSG

5–25 ppmvd (9-43 g/GJ). Low CO emissions are the result of highly-efficient combustion. Catalytic CO emission abatement systems are also available, if required, for lower emission rates. The CO catalyst is installed in the exhaust gas path, typically upstream of the HRSG superheater.

Options such as compressor inlet cooling, steam or water injection for power augmentation, HRSG supplementary firing and gas turbine peak load capabilities are available for combined-cycle plant power enhancements. They are generally applied primarily for peak period capacity additions.

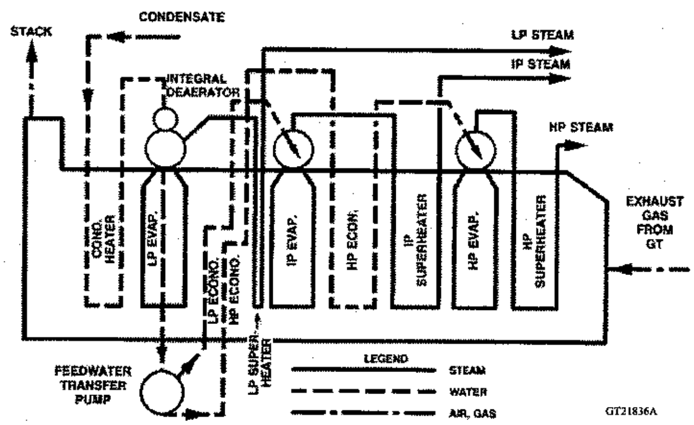


Figure 14. Three-pressure non-reheat HRSG with integral deaerator

	STAG 209E	
FUEL	NET PLANT OUTPUT (%)	NET PLANT THERMAL EFFICIENCY (%)
NATURAL GAS	BASE	BASE
DISTILLATE OIL	-3.0	-2.1
RESIDUAL OIL	-9.3	-7.6

NOTES 1. OPERATING POINT = BASE LOAD
2. TWO PRESSURE, NON-REHEAT RECOVERY FEEDWATER HEATING SYSTEM CYCLE

Table 12. STAG combined-cycle performance variation with fuel characteristics

Gas Turbine	MS7001EA						MS7001FA			
Combustion System	DLN	Diffusion Flame					DLN	Diffusion Flame		
NOx PMVD at 15% O2 (g/GJ)	9 (15.5)	160 (275)	42 (72)		25 (43)		9 (15.5)	212 (365)	42 (72)	
Diluent Injection Water/Fuel by Wt	0	0	0.81	-	1.04	-	0	0	0.89	-
Steam/Fuel by Wt	0	0	-	1.22	-	1.58	0	0	-	1.62
STAG Plant Performance Net Power (Δ%)	Base	Base	+3.5	+1.0	+5.0	+1.1	Base	Base	+5.4	+2.8
Net Heat Rate (Δ%)	Base	Base	+3.6	+2.1	+5.2	+3.4	Base	Base	+3.9	+3.1
Steam Cycle	Non-Reheat, Three Pressure						Reheat, Three Pressure			
Notes:	1.	Site Conditions 59°F, 14.7 psia, 60% RH (15°C, 1.013 bars)								
	2.	Fuel – Natural Gas								

Table 13. Effect of NO_x control on combined-cycle performance

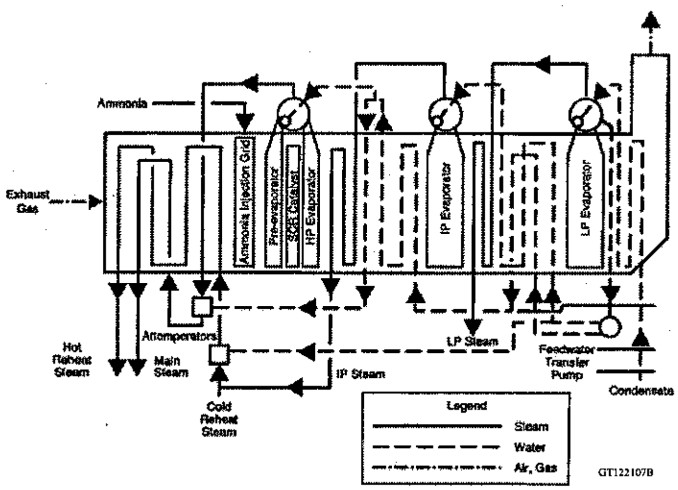


Figure 15. Three-pressure reheat HRSG with SCR

Compressor inlet cooling that uses evaporative cooling is an effective means of adding plant capacity for applications with high ambient air temperature and low relative humidity. An 85% effectiveness evaporative cooler is expected to increase plant output by about 5% during operation at 90°F / 32°C and 30% relative humidity site conditions.

Evaporative and mechanical chiller systems may be used to cool gas turbine inlet air to as low as 45°F / 7°C. These inlet cooling systems can achieve up to 11% capacity increase during operation at site conditions of 90°F / 32°C and 30% relative humidity. Evaporative cooling and chilling systems do not improve combined-cycle plant efficiency; however, they may provide economic peak power addition during warm summer periods.

Supplementary firing of the HRSG can be utilized to increase steam turbine capability by as much as 100%. This will increase plant capacity by about 25%. Cogeneration of power and process energy is usually the incentive for HRSG supplementary firing; however, peaking capacity credits, or leveling fuel consumption over the ambient temperature range to accommodate "take-or-pay" fuel contracts may also justify this option. The incremental efficiency for power produced by supplemental firing is in the 34–36% range based on the lower heating value of the fuel.

While gas turbine water or steam injection can be applied to enhance plant output as well as reduce NO_x emissions, plant efficiency is degraded.

Gas turbine peak load capability is available with many gas turbine configurations and can add 3–10% combined-cycle plant capacity. This may be the most economic approach to small capacity additions for short periods of time because peak load operation significantly impacts gas turbine parts life and maintenance cost. *Table 14* summarizes the performance impact of these combined-cycle power enhancement options.

Combined-cycle systems can be integrated with gasification systems to form efficient coal- or oil-fired power plants with outstanding environmental performance. The standard modules in the STAG combined-cycle product line can be readily adapted to integrated gasification combined cycles (IGCCs).

Figure 16 shows a diagram of an advanced technology "H" platform combined-cycle IGCC system with oxygen-blown gasifier and integration of the air separation unit with the gas turbine. This advanced technology IGCC system promises to be an economical power generation system that can fire coal, petroleum coke, heavy residual oil and other solid or low-grade liquid fuels. The range of ratings for the advanced technology IGCC plants is as follows:

IGCC Unit	Frequency (Hz)	Capacity Range (MW)	Net LHV Thermal Eff. Range (LHV)
STAG 107H	60	400-460	49-51 %
STAG 109H	50	480-550	49-51%

The capacities and efficiencies are shown as ranges because they vary with the type of gasifiers, gas clean-up systems, air and steam cycle integration, coal or other fuel analysis, and fuel moisture content.

Power Enhancement Option	Typical Performance Impact Δ Output	Δ Heat Rate
Base Configuration	Base	Base
Evaporative Cooling GT Inlet Air (85% Effective Cooler)	+5.2%	-
Chill GT Inlet Air to 45°F	+10.7%	+1.6%
GT Peak Load	+5.2%	-1.0%
GT Steam Injection (5% of GT Air Flow)	+3.4%	+4.2%
GT Water Injection (2.9% of GT Air Flow)	+5.9%	+4.8%
HRSG Supplementary Firing	+28%	+9%
Notes: 1. Site Conditions = 90°F, 30% RH 2. Fuel = Natural Gas 3. Three Pressure, Reheat Steam Cycle		

Table 14. STAG system power enhancement options

STAG Combined-Cycle Major Equipment

The major equipment for STAG combined-cycle electric power generation systems includes the line of packaged gas turbine power generation units, unfired HRSGs, steam turbine-generators, and controls. This is a line of proven, reliable equipment with excellent performance characteristics for combined-cycle systems. This equipment includes gas turbine generators and steam turbine generators manufactured by GE as well as HRSGs and controls selected to form a coordinated combined-cycle system for each application. Features of the major equipment that are significant for efficient, reliable combined-cycle systems are presented in the following discussion.

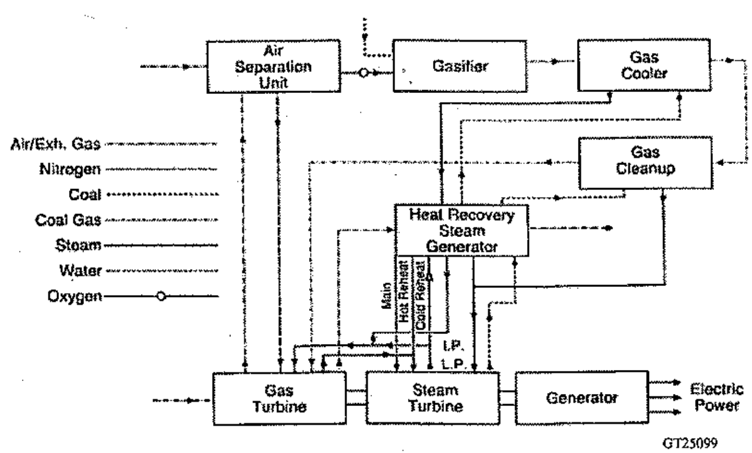


Figure 16. Advanced technology IGCC system

Gas Turbines

The ratings of GE gas turbines applied in the STAG combined-cycle product line are presented in *Table 15*. *Figure 17* shows a cross-section of the PG7121EA gas turbine typical of GE gas turbines with 2035°F / 1113°C firing temperature. The PG9171E gas turbine firing temperature is 2055°F / 1124°C. A cross-section of the PG9351 FA gas turbine is shown in *Figure 18,* which is typical of the GE gas turbines with 2420°F / 1327°C firing temperature, including the PG7241FA.

The next generation "FB" and "H" platform gas turbines are expected to be in commercial service in the first half of this decade. The cross-section of the "H" gas turbine is shown in *Figure 19.* This new machine features closed-loop steam cooling for the first and second stages of its four-stage turbine. In order to optimize performance at the 2600°F / 1426°C firing temperature, a higher-pressure ratio compressor derived from the GE CF680C2 aircraft engine is utilized.

These gas turbines have the following features that uniquely suit them for combined-cycle applications:

- The key performance characteristic of the gas turbine that influences combined-cycle performance is specific power. Specific power is the power produced by the gas turbine per unit of airflow (kW output per lb/sec of compressor airflow). Combined-cycle thermal efficiency

Heavy-Duty	Output (kW)	Frequency (Hz)
PG6581 B	42,100	50 and 60
PG6101 FA	70,140	50 and 60
PG7121 EA	85,400	60
PG7241 FA	171,700	60
PG9171 E	123,400	50
PG9231 EC	169,000	50
PG7251 FB	184,400	60
PG9351 FA	255,600	60
MS7001 H	*	60
MS9001 H	*	50

Notes: 1. Fuel = Natural Gas
2. Site Conditions = ISO Ambient
3. Operating Mode = Base Load, Simple Cycle
*Single-Shaft STAG Combined Cycle Configuration Only

Table 15. GE gas turbines applied to STAG product line

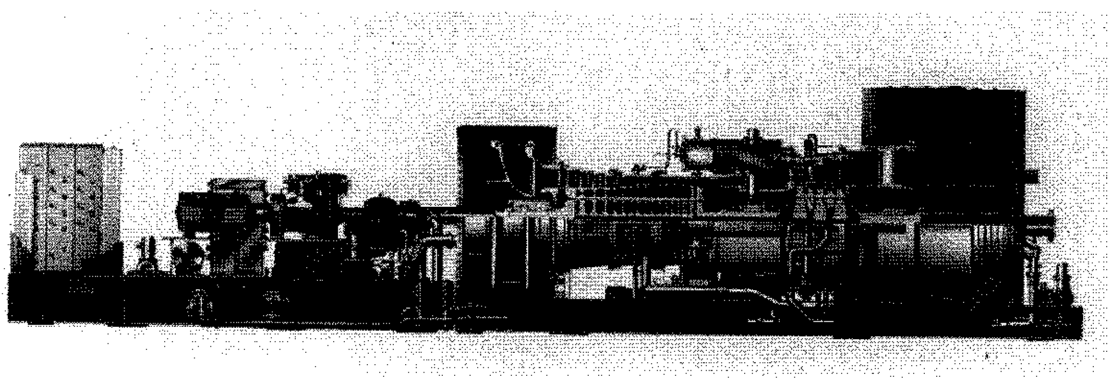


Figure 17. MS7001EA heavy-duty gas turbine

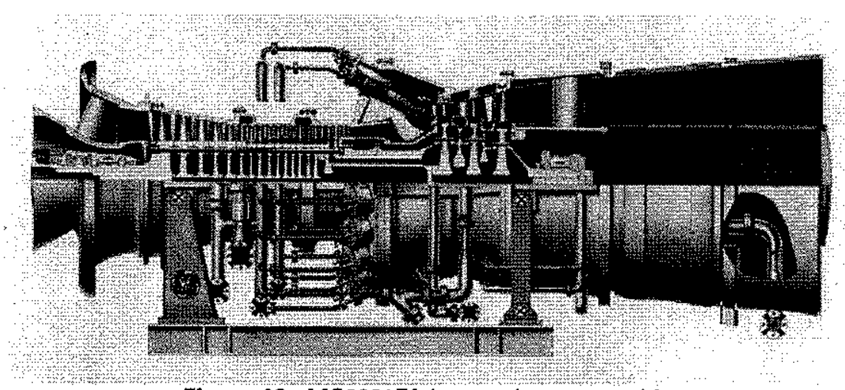
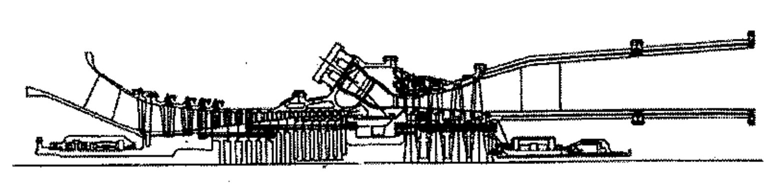


Figure 18. MS9001FA heavy-duty gas turbine

increases as gas turbine specific power increases, as shown in *Figure 20.* This figure shows that gas turbine firing temperature is the primary determinant of specific power. Improvements in combined-cycle thermal efficiency have developed primarily through the increases in gas



Features
- ***Closed Loop Steam Cooling***
- ***4-Stage Turbine***
- ***Compressor Scaled From Proven Design***
- ***Dry Low No_x Combustor***

GT25129

Figure 19. "H" gas turbine cross-section

turbine firing temperature, which have resulted from the development of high-temperature / high strength materials, corrosion-resistant coatings, and improved cooling technology. Commercial development of combined cycles and improvements in combined-cycle efficiency have proceeded in parallel with advances in gas turbine technology.

- STAG systems that utilize the "F" technology gas turbines achieve net thermal efficiencies of 53% (LHV) or greater. STAG systems that utilize "H" technology gas turbines achieve net thermal efficiencies of 58–60% (LHV). These gas turbines have a rated firing temperature of 2420°F / 1327°C and 2600°F / 1426°C, respectively. The "FA" technology turbine has a 15.5 pressure ratio, whereas the "H" technology turbine has a 23.0 pressure ratio. These designs provide the highest gas turbine specific power for this firing temperature. High specific power provides the lowest simple-cycle installed cost in addition to high combined-cycle efficiency.
- The exhaust gas temperature range of 1000–1100°F / 538–566°C is uniquely suited to efficient combined cycles because it enables the transfer of heat from exhaust gas to the steam cycle to take place over a minimal temperature difference. This temperature range results in the maximum in thermodynamic availability while operating with highest temperature and highest efficiency steam cycles.
- Multiple can-annular type combustors with film and impingement cooling meet the environmental requirements for applications throughout the world. They provide reliable operation at high firing temperatures while burning fuels that range from natural gas to residual oil.
- Turbine materials, coatings and cooling systems enable reliable operation at high firing temperatures. This achieves high gas turbine specific power and high efficiency for combined-cycle systems.

- Most GE current product line gas turbines are configured with open-loop cooling of the turbine hot gas path. Hot gas path components are in large part cooled by film cooling that uses air supplied from the compressor. This results in a significant exhaust gas steam temperature drop across the first stage nozzle, and requires significant "chargeable air" to cool the turbine stages. The temperature drop across the first stage nozzle and the chargeable cooling losses increase as turbine inlet temperature increases.
- The advanced "H" platform gas turbine is configured with an integrated closed-loop steam-cooling system. The change in strategy to the closed-loop, steam-cooled system without film cooling allows higher turbine inlet temperatures to be achieved without increasing combustion temperature. This is because the temperature drop across the first stage nozzle is significantly reduced, as shown in *Figure 21.* Gas turbine NO_x emissions can then be maintained at low levels at increased turbine inlet temperature. Another important benefit of the integrated closed-loop, steam-cooling system is the elimination of "chargeable cooling air" for the first- and second-stage rotating and stationary airfoils. This results in two percentage points improvement in combined cycle thermal efficiency.
- Factory packaging and containerized shipment of small parts achieve low installed cost and short installation time.
- Reliable operation results from evolutionary design development that improves parts and components, a high-quality manufacturing program that includes operational factory testing of the gas turbine and accessory systems, follow-up service support by experienced installation and service personnel, and effective spare parts support.
- Low maintenance costs are the result of the combination of the above features and a design to allow convenient access. These include borescope ports to permit inspection of key parts and components without dismantling the equipment.
- The heavy-duty gas turbine product line has fuel flexibility provided by accessory systems, combustion systems, and turbine components, which enable utilization of a wide range of liquid and gaseous fuels. These include 150-400 Btu/scf (6520-16,850 kj/nm^3) gaseous fuels, including those derived from coal, coke, or heavy petroleum products, and liquid fuels including naphtha, light distillates, heavy distillates, crude oil and residual oil.

HRSG

HRSGs in the GE STAG product line are unfired and feature modular construction with finned-tube heat transfer surface and natural or forced-circulation evaporators. *Figure 22* illustrates a natural circulation HRSG with modular construction. An installation showing two of these HRSGs operating with MS7001EA gas turbines is shown in *Figure 23. Figure 24* illustrates the modular-construction, forced-circulation HRSG, and *Figure 25* shows an installation of this type HRSG in a STAG 107EA system.

Each gas turbine exhausts to an individual HRSG. For STAG systems with a MS6001B gas turbine, the standard gas ducting is designed so that two gas turbines exhaust to a single HRSG. These STAG systems are also available with one HRSG per gas turbine. The HRSG and auxiliaries are designed for the specific operating requirements of the STAG combined cycle system. Design features include:

- Exhaust gas bypass system to provide fast startup and shutdown and flexibility of operation for multi-shaft STAG systems. Exhaust gas bypass systems are not used with single-shaft STAG units.
- Flexible tube support system to enable fast startup and load following capability.
- Low gas side pressure drop for optimum gas turbine performance.
- Large, factory-tested modules that can be shipped to provide short

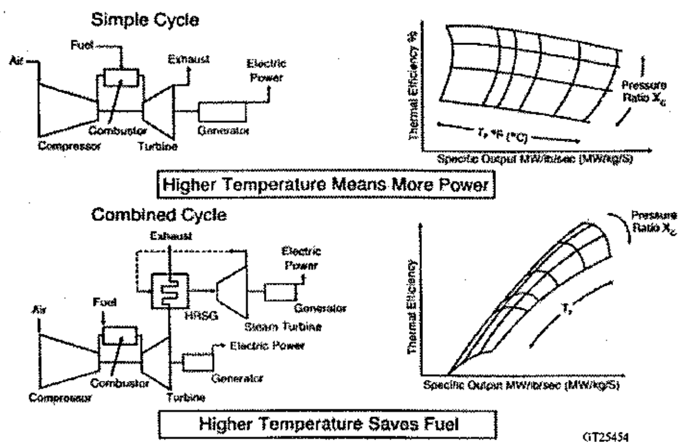


Figure 20. Gas turbine performance thermodynamics

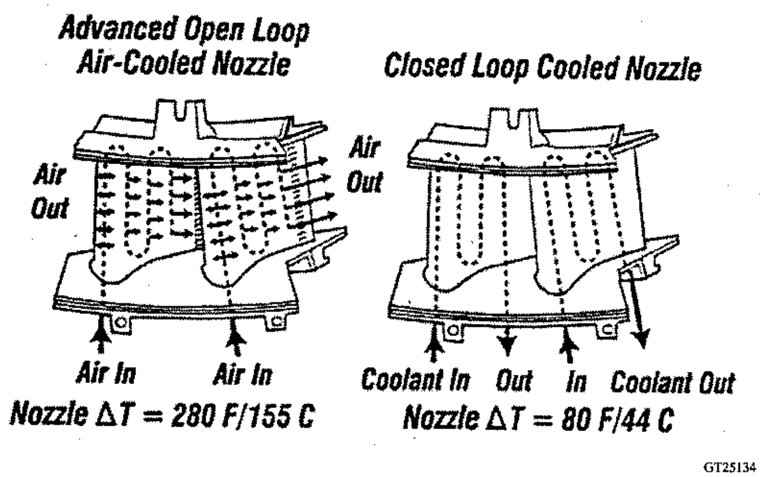


Figure 21. Impact of stage-one nozzle cooling method

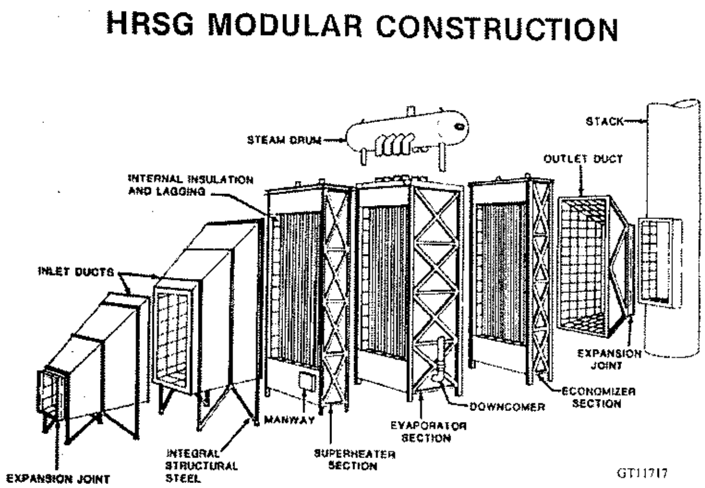


Figure 22. Natural-circulation HRSG modular construction

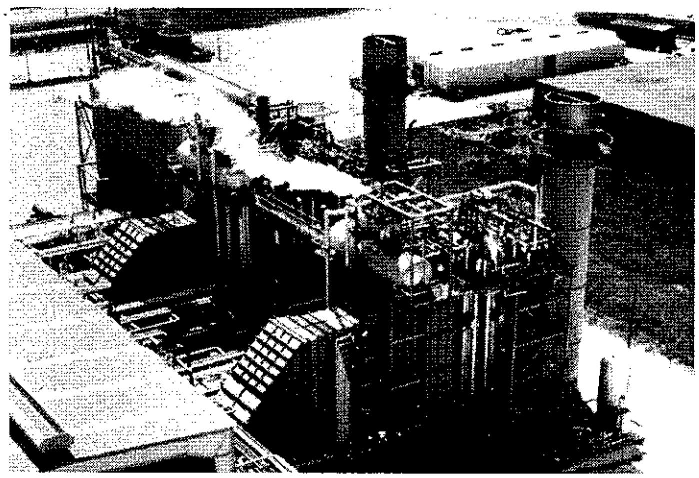


Figure 23. Two natural-circulation HRSGs operating with MS7001EA gas turbines

installation time and low construction cost.

- Fuel flexibility provided by the ability to operate reliably and efficiently, using exhaust gas from gas turbines that burn fuels ranging from natural gas to residual oil.

Steam Turbine

GE offers a complete line of steam turbines for combined-cycle applications. Two or more steam turbine selections are available for each STAG product line offering. Steam turbines with different exhaust annulus areas are available to permit optimization to meet specific condenser cooling conditions. Steam turbines with large exhaust annulus areas are more expensive, but provide increased capability and may be the most economic selection for applications with low steam turbine exhaust pressure. For applications in which steam turbine exhaust pressures are high, small exhaust annulus-area steam turbines provide comparable or higher capability and low cost, and therefore are the economic choice. *Figure 26* illustrates

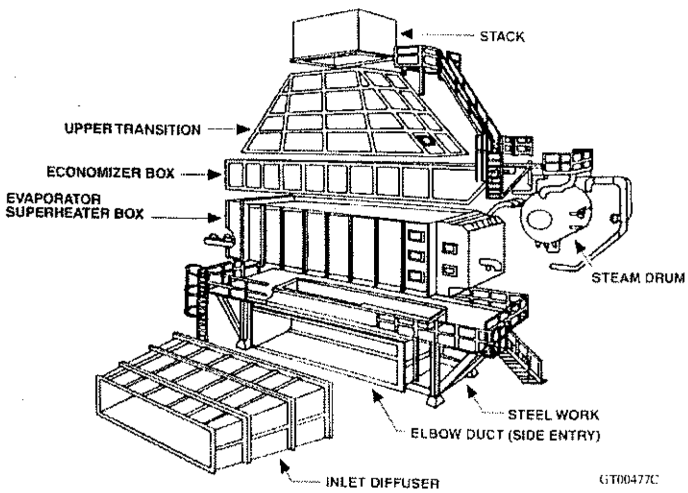


Figure 24. Forced-circulation HRSG modular construction

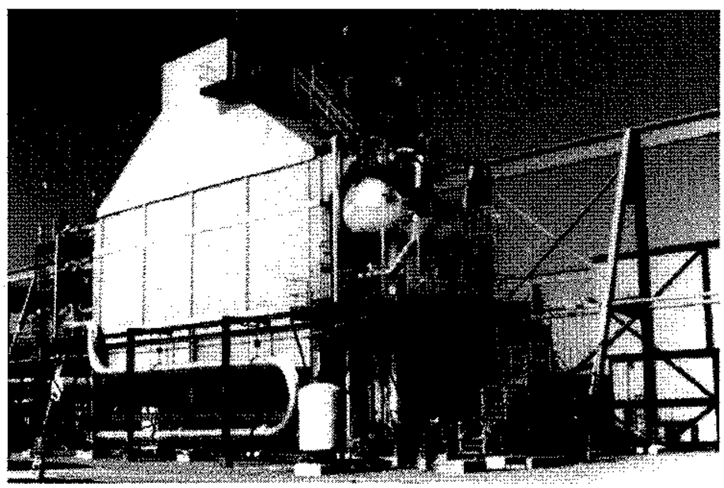


Figure 25. Forced-circulation HRSG with PG7111EA gas turbines

the performance difference for four last-stage buckets that are available for the STAG 107FA combined cycle. Steam turbine last-stage bucket lengths for the STAG product line steam turbines range from 14.3 inches / 363 mm to 42 inches / 1067 mm.

Because there are no extractions for feedwater heating, and steam is generated and admitted to the turbine at three pressures, the flow at the exhaust is approximately 30% greater than the throttle flow. The turbine's last stage generates up to 15% of the steam turbine output, so the efficiency of the turbine's last stage and the sizing of the exhaust annulus area are particularly important for combined-cycle applications.

As with all modern GE steam turbine last-stage buckets, the continuously-coupled design is used for high efficiency and reliability. Continuously-coupled designs permit the use of many relatively slender blades with narrow,

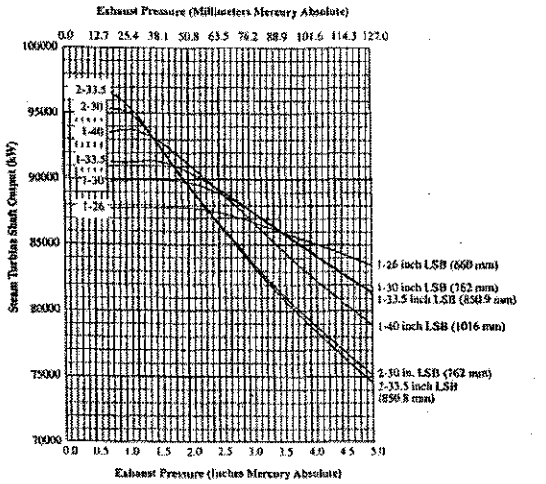


Figure 26. STAG steam turbine last-stage bucket selection

closely-controlled flow passages, particularly in the critical high-velocity tip region. Covers reduce tip leakage losses, provide damping, and help to maintain control of the flow passage.

Steam turbine designs for high exhaust pressure operation typical of those that are needed for air-cooled condenser operation at high ambient temperature are available. These steam turbine designs are capable of reliable and efficient operation at exhaust pressures up to 15 inches Hg,a/381mm Hg,a.

Advanced 3D aero packages incorporate advanced vortex design, contoured inlet section sidewalls, and additional radial tip spill strips for steam turbines larger than 80 MW, which contribute to maximum combined cycle thermodynamic efficiency.

The STAG combined-cycle product line steam turbines include axial exhaust and down exhaust configurations. Axial exhaust is preferred for the single-flow steam turbines, typically applied in the small capacity STAG systems. *Figure 27* shows a single-flow axial exhaust steam turbine.

A line of reheat steam turbines designed specifically for combined-cycle service is available for STAG systems employing the "EC," "F," and "H" technology gas turbines. The single-shaft STAG 107FA, STAG 109FA and STAG 109H are designed as integrated machines with a solid turbine/generator coupling and a single-thrust bearing that includes common lubrication and hydraulic and control systems for both gas turbine and steam turbine. A two-flow reheat steam turbine is shown in *Figure 28.*

Steam turbines specially designed for combined-cycle service have features that include:

- Assembled modules that can be shipped and assembled with a low profile installation that reduces installation time and cost. (Building cost, for indoor installation, also is reduced with the low profile design.)
- Access for borescopic inspection of buckets and nozzles without removal of the turbine upper casing.
- Fast startup and load-following capability provided by minimum shaft diameter in the vicinity of the first stage, large fillets between wheels and rotor, long coupling spans, vertical flexible plate support near the centerline with keys for maintenance of alignment, and off-shell valves with full-arc steam admission.
- All main steam, cold reheat and hot reheat steam pipes connect to the lower half of the shell. This facilitates removal of the upper half shell for maintenance, and eliminates the need for bolted connections in a high temperature piping.
- Sliding pressure operation with the control valves wide open. A control stage at the inlet is, therefore, not

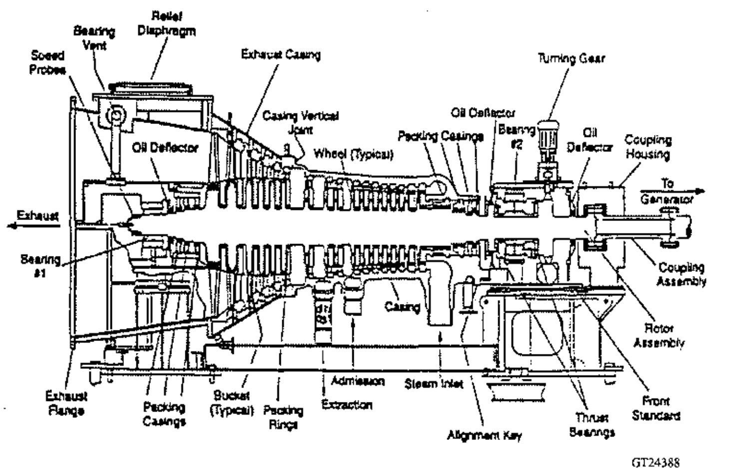


Figure 27. Non-reheat, single casing, axial exhaust steam turbine

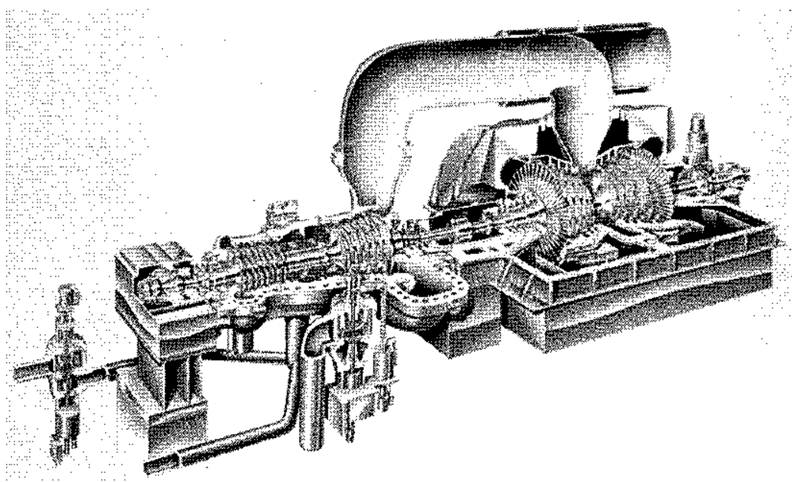


Figure 28. Two-flow, reheat steam turbine

required.

- Applications at 1800 psig/124 bar,g use a single wall construction at the high-pressure stages as well as the reheat inlet. With 2400 psig/165 bar,g applications, a short inner shell encloses the early high-pressure stages. This reduces the load on the horizontal joint bolting and reduces the thickness of the shell flange.

Generators

Generators for the STAG combined-cycle product line gas turbines and steam turbines are factory assembled and tested. Air-cooled generators are standard for the smaller STAG systems using PG6581B, PG6101FA and PG7121EA gas turbines. They may be open-ventilated or totally enclosed water-to-air cooled. If open-ventilated, they are equipped with self-cleaning air filters for desert or other dusty or dirty environments, as shown in *Figure 29.* Hydrogen-cooled generators are standard for the single-shaft and larger multi-shaft STAG systems. The hydrogen-cooled generators can be cooled by plant-cooling water or by ambient air with water-to-air heat exchangers. *Figure 30* shows a typical packaged hydrogen cooled generator for gas turbine application.

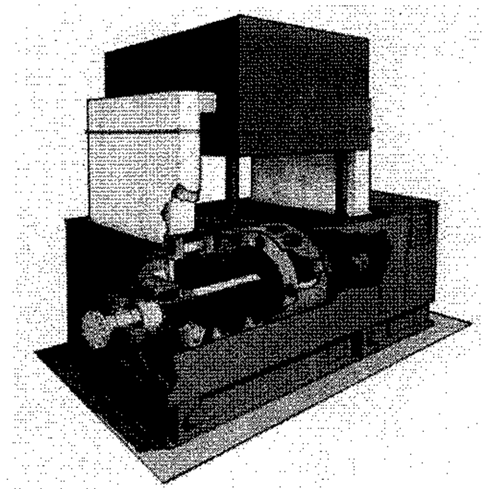


Figure 29. Air-cooled generator with self-cleaning air filter

Controls

The STAG combined-cycle plant has a distributed digital control system with a redundant data highway. The station operator consoles provide interactive color graphic displays of the overall STAG plant, with sufficient detail to enable the operator to conveniently operate the plant.

The control systems for multi-shaft and single-shaft STAG combined-cycle system fundamentally follow the same principle objectives of simplicity, easy starting, automated operation and superior load following ability. All main components of the combined-cycle plant have individual control panels and interfaces that relay information and instructions to and from the plant operator through data highways to the operator console. The operator console will have a detailed graphic display with a high level of detail that enables convenient and informative interaction with the plant as required.

The single-shaft power train is a simple tandem arrangement that does not include an exhaust bypass system and is solidly coupled to one generator with a common overspeed protection device with less auxiliary equipment. *Figures 31 and 32* show block diagrams for multi-shaft and single-shaft arrangements.

The heat recovery combined cycle is a simple system with a minimum of control loops, as shown by the control diagram (*Figure 33*) for a single-pressure, multi-shaft STAG system. The simplicity of this system, coupled with well-established, automated operation of system components, enables effective automation of

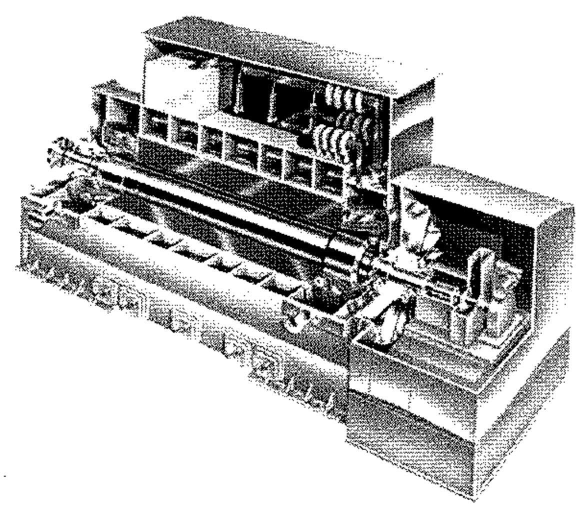


Figure 30. Typical packaged hydrogen-cooled generator

the complete power plant. This minimizes the number of control room operators. Most STAG systems operate with only one control room operator and one roving operator.

The multi-shaft STAG control is configured to enable automated startup and operation after remote manual starting of plant auxiliaries, remote manual operation of each major component, or operation of the gas turbine-generator units from local-control compartments. The control configuration enables maximum availability because the plant can be operated remotely with no additional control room operators. The equipment protection system is provided within the unit controls, so normal protection is maintained during all modes of operation, including local or remote manual operation.

The single-shaft STAG unit control system is a microprocessor-based controller that coordinates the operation of the components in each integrated combined-cycle unit and communicates with the plant control. Because of the simple steam cycle, the tandem coupling of the gas

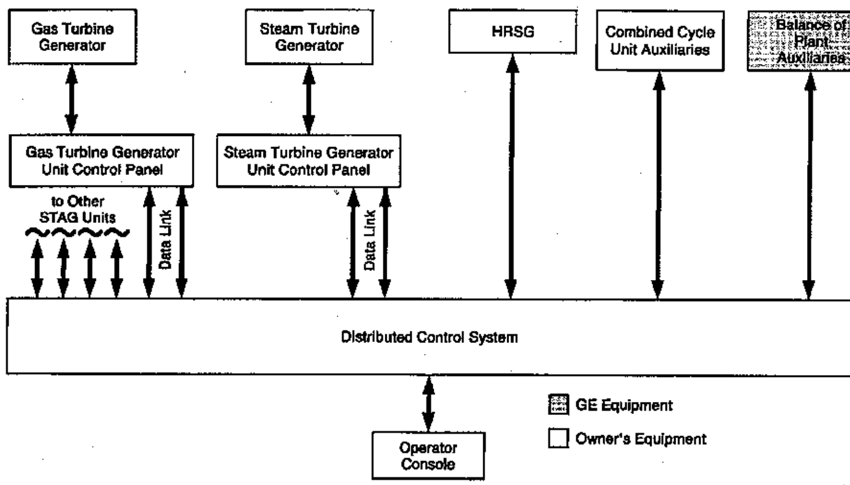


Figure 31. Distributed control system for plant with multi-shaft STAG combined cycle

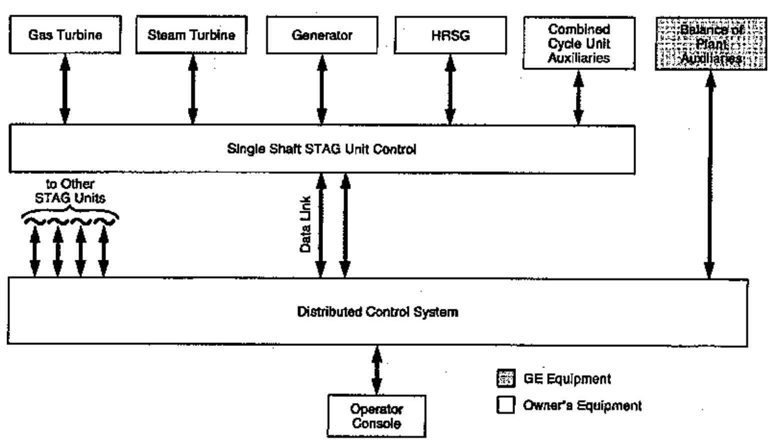


Figure 32. Distributed control system for plant with single-shaft STAG combined cycle

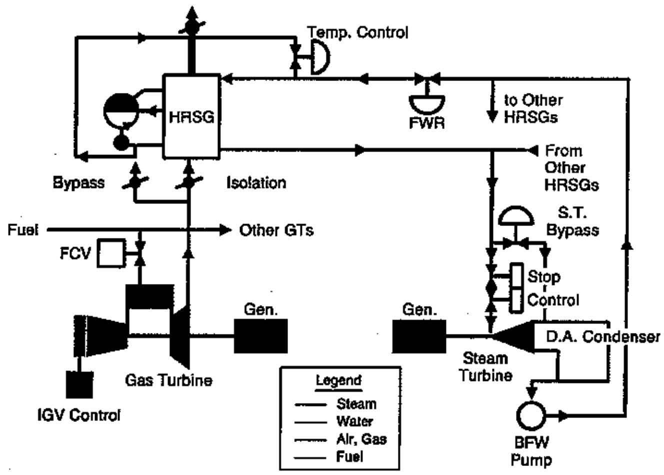


Figure 33. Multi-shaft STAG control diagram

and steam turbines to a single generator, and the elimination of the HRSG exhaust-gas, bypass system, the single-shaft STAG combined-cycle control is very simple. Starting, operation, and shutdown of individual units are automatic. Single-shaft STAG units are controlled by a local unit control system that is coupled to the central control room operator's console by a data highway. One control room operator can operate one or more single-shaft STAG combined-cycle units with this type of control system and the aid of one local operator.

Auxiliaries

The STAG product line ratings are based on plants with once-through systems (seawater or river water) for steam turbine condenser cooling. STAG combined-cycle configurations are also available for operation with a wide range of owner-specified auxiliaries, including evaporative cooling towers and air-cooled condensers. Plant capability and efficiency with these systems is expected to be lower because steam turbine exhaust pressure and cooling system auxiliary power consumption are increased.

Plant Operation

Typical STAG plant performance variation with ambient air temperature is illustrated by the heat rate and power-output capability ambient-temperature effect curves in *Figure 34.* Low heat rate throughout the ambient-air-temperature range is typical of these plants. The low heat rate and increase in output as ambient temperature decreases are achieved by the gas turbine characteristics and optimum equipment matching.

Gas turbine exhaust flow and temperature vary with ambient temperature and barometric pressure. Steam production and steam turbine output vary with the exhaust gas flow and temperature supply to the HRSG. Steam turbines are selected to suit specific application requirements. The steam turbines in the standard systems are sized so that their rated flow matches the steam production.

Excellent part-load heat rate is achieved on multi–shaft systems or multiple single-shaft units by sequentially loading gas turbines to meet system requirements (*Figure 35*). This curve also shows that the plant can operate efficiently following system load with all gas turbines operating. The heat rate increases only 1% at approximately 80% of rating.

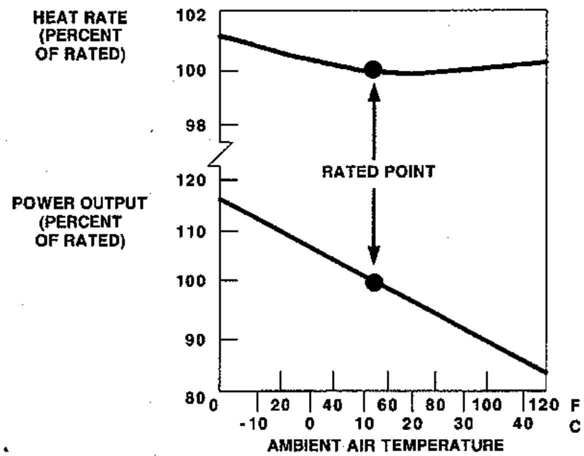


Figure 34. Combined-cycle, ambient air temperature effect curve

The modulated, inlet guide vanes (IGV) on the gas turbine compressor contribute significantly to the excellent part-load performance. The inlet guide vanes are modulated to control air flow in the power plant between the "hash mark" and the point marked "B." Varying the air flow maintains nearly constant gas turbine firing temperature so that the thermodynamic quality of the cycle remains essentially constant. The stack and condenser losses vary almost proportionally with output, so that the heat rate remains almost constant. At loads below the hash mark, the gas turbine operates with constant air flow, and firing temperature is reduced as load is reduced.

Fast starting and loading is characteristic of STAG combined-cycle generation systems. This enables them to operate in mid-range, with daily start peaking service as well as baseload. Typically, STAG systems can achieve full load within one hour during a hot start and within approximately three hours for a cold start. Multi-shaft STAG systems allow the gas turbines to start independently of the steam cycle and provide about 65% of the plant capability within 15–25 minutes, depending on the size of the gas turbine, for hot, warm, and cold starts, as illustrated in *Figure 36.* Single-shaft STAG systems are started and loaded to full capacity in about the same time period as the multi-shaft STAG systems. The startup sequence and load profile for the single-shaft systems differ because the gas and steam turbines are started as a single integrated unit and not as two separate units. Single-shaft STAG startup is illustrated in *Figure 37.*

Plant Arrangements

The STAG combined-cycle equipment can be adapted to installation requirements demanded by varying climactic conditions, system configu-

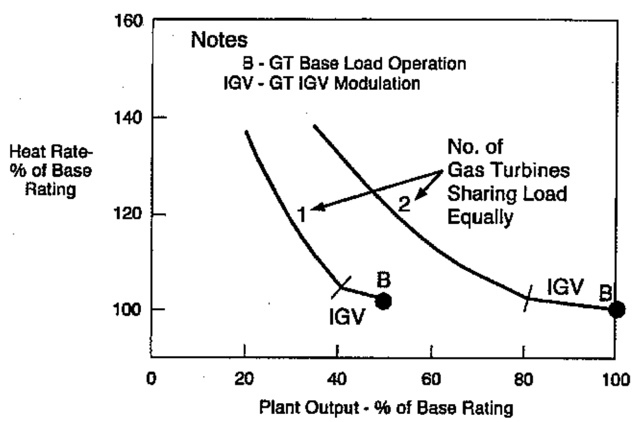


Figure 35. STAG 200 part-load performance

rations and owner/operator preferences. The equipment is suitable for outdoor installations, semi-outdoor installations, or fully-enclosed installations. Plant arrangements have been designed for each STAG system.

Plan views of STAG combined-cycle arrangements are shown in *Figure 38* (multi-shaft, S406B), *Figure 39* (multi-shaft, S207EA), Figure 40 (single-shaft S109E), *Figure 41* (multi-shaft, S207FA), and *Figure 42* (single-shaft, S107FA). An elevation of the single-shaft S107FA is shown in *Figure 43. Figure 44* shows the S107H and S109H plan and elevation views. The S107H provides about 58% increase in combined-cycle power output with only about 10% increase in footprint area.

A 220 MW STAG 207E installation is shown in *Figure 45. Figure 46* presents a STAG 109FA combined cycle installation. *Figure 47* shows a 4000 MW installation with eight STAG 107F and four STAG 207FA systems at one site. These arrangements have indoor turbine-generator equipment and outdoor HRSGs. *Figure 48* shows a plant with two STAG multi-shaft combined-cycle units in an indoor installation. For outdoor installations, the standard gas turbine enclosures are weatherproof, and weatherproof lagging is available for the steam turbines.

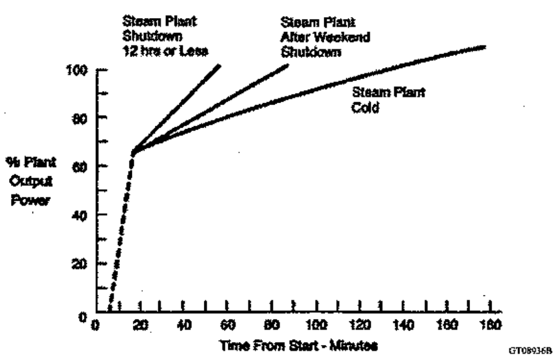


Figure 36. Multi-shaft STAG starting times

Installation

The short installation time and low installation cost of STAG combined-cycle systems are key features contributing to economical power generation. This is due to factory packaging of all major components and containerized shipment of small parts. In addition to low direct construction cost, the short installation time reduces interest payments during construction. The standard factory modules and standardized designs also reduce plant engineering time and cost.

The time from order to commercial operation for pre-engineered, standardized STAG designs is typically 24 months, not including permitting time. The multi-shaft STAG systems can be installed in two phases to reduce the time between order and initial power production. The gas turbines contribute 65% of the plant capacity. Typically, the gas turbine can be installed in less than 18 months to provide power generation while the steam system is being installed. *Figure 49* is a typical two-phase multi-shaft STAG combined-cycle installation schedule.

Utility Load Growth

Power generation economics can be enhanced by the installation of generation capacity in small increments as utility load grows. STAG combined-cycle plants fit this economical pattern because efficient, low-cost plants are available in small blocks of generating capacity.

Flexibility is also available with the pro-generation approach to capacity addition. Initial natural gas/distillate oil-fired, simple-cycle gas turbine installations can be converted to combined cycle later, when power demands require capacity increases. Plot plan area for the steam cycle equipment and transmission line capability are the main considerations during the initial com-

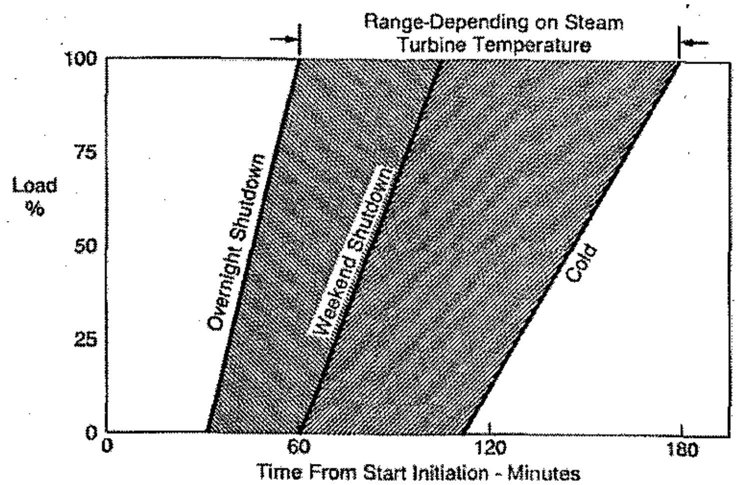


Figure 37. Single-shaft STAG starting times

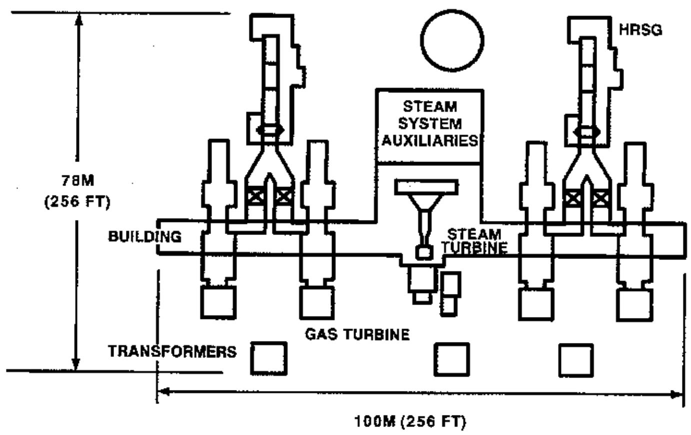


Figure 38. STAG 406B combined-cycle plan

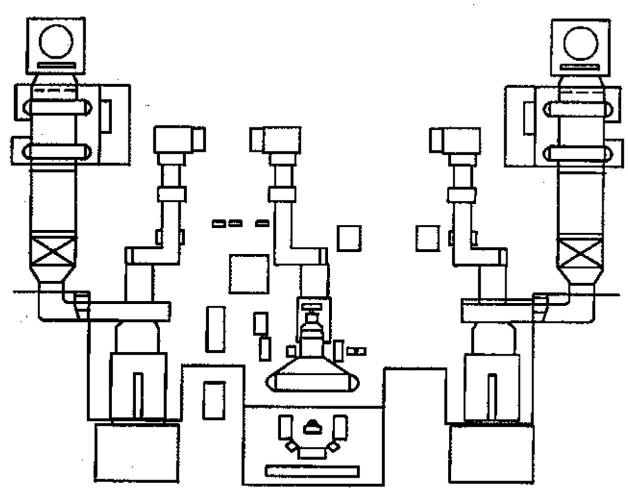


Figure 39. STAG 207EA combined-cycle plan

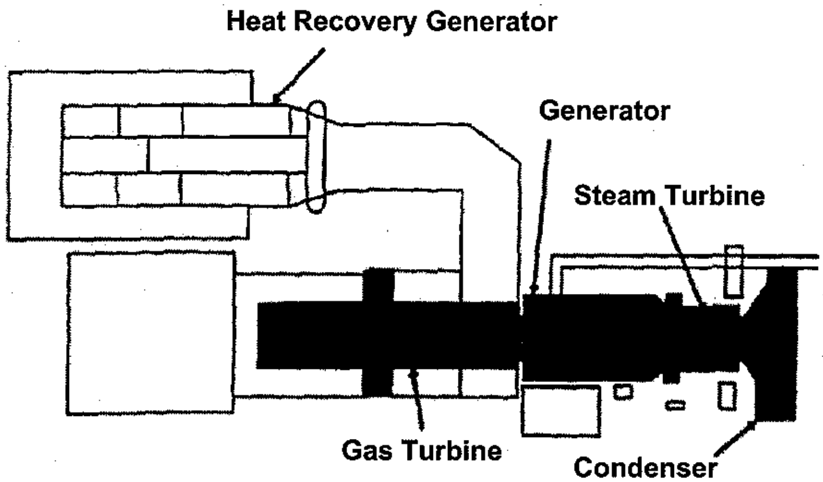


Figure 40. STAG 109E combined-cycle plan

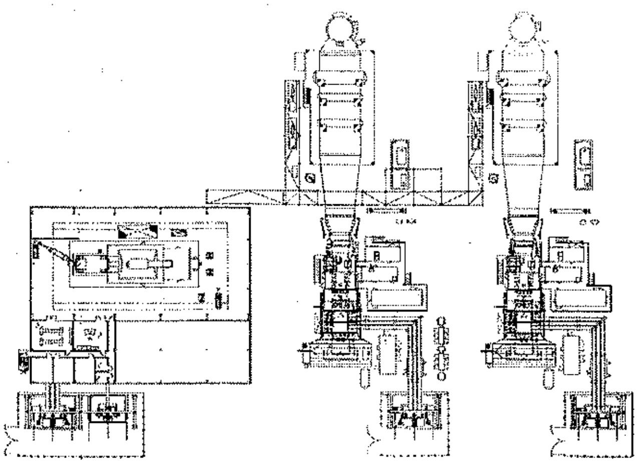


Figure 41. STAG 207FA multi-shaft combined-cycle plan

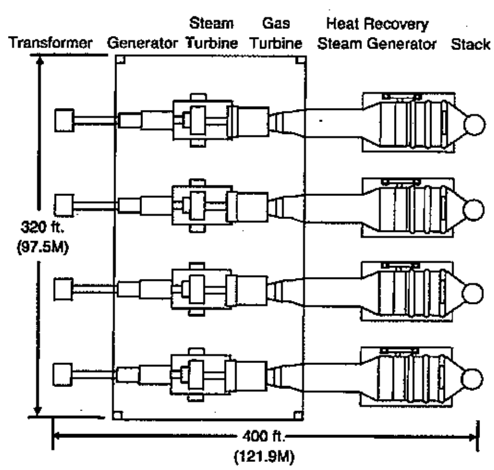


Figure 42. Four-unit STAG 107FA combined-cycle plan

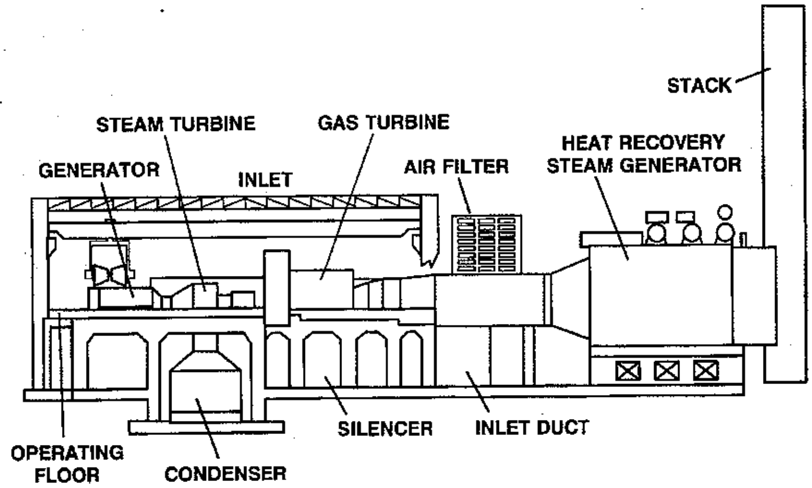
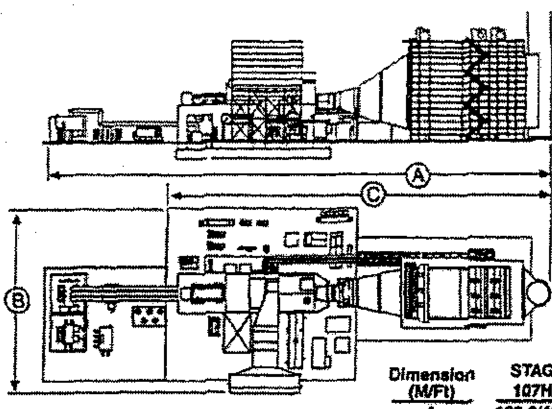


Figure 43. STAG 107FA single-shaft combined-cycle elevation



Dimension (M/Ft)	STAG 107H	STAG 109H
A	129.2/424	135.7/445
B	46.3/152	48.6/159
C	94.2/309	98.9/325

GT25050

Figure 44. Single-shaft S107H and S109H plan and elevation

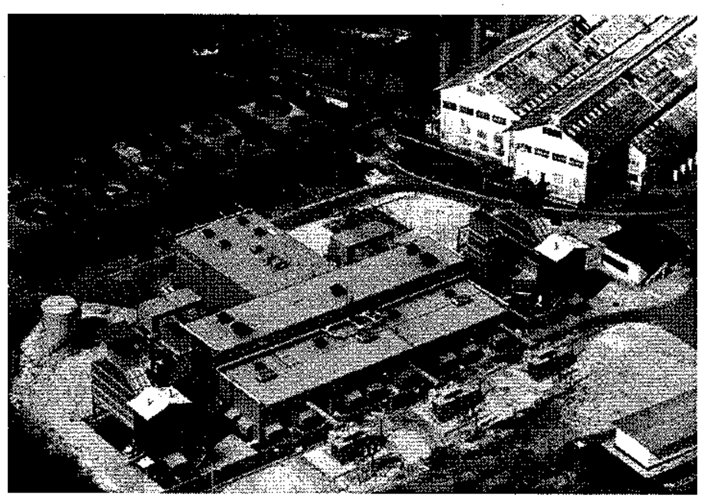


Figure 45. STAG 207E installation

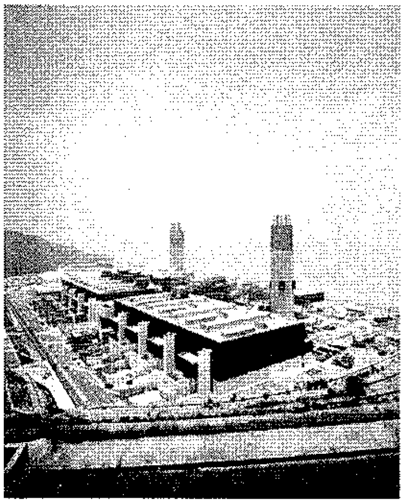


Figure 46. Indoor S109FA installation

mitment for simple-cycle gas turbines. Future conversion to coal-derived fuels also is an option for dealing with the long-range uncertainties of conventional fuel availability and price.

Thermal Energy and Power System Product Line

The product line of thermal energy and power combined-cycle systems (cogeneration and district heating systems) are designed with structured flexibility to provide a wide range of power and thermal energy capacities to suit varied application requirements. The most commonly supplied systems are:

- Steam generation at process conditions with HRSG (no steam turbine)
  - Unfired HRSG
  - Supplemental-fired HRSG
- HRSG and non-condensing steam turbine exhausting to process
  - Unfired, one-pressure HRSG
  - Unfired, two-pressure HRSG
  - Supplemental-fired, one-pressure HRSG
- HRSG with extraction/condensing steam turbine
  - Unfired, one-pressure HRSG
  - Unfired, two-pressure HRSG
  - Supplemental-fired, one-pressure HRSG

The capabilities of the thermal energy and power systems are unique for each gas turbine frame size, as well as each set of process steam conditions for systems with both unfired process HRSGs and unfired HRSGs that have non-condensing steam turbines. The systems

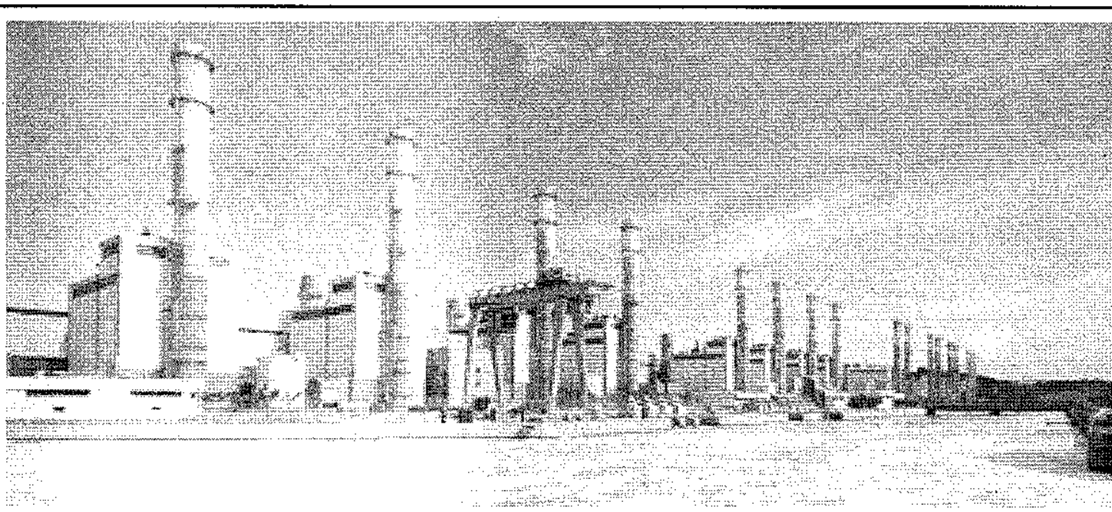


Figure 47. 4000 MW multi-shaft STAG installation

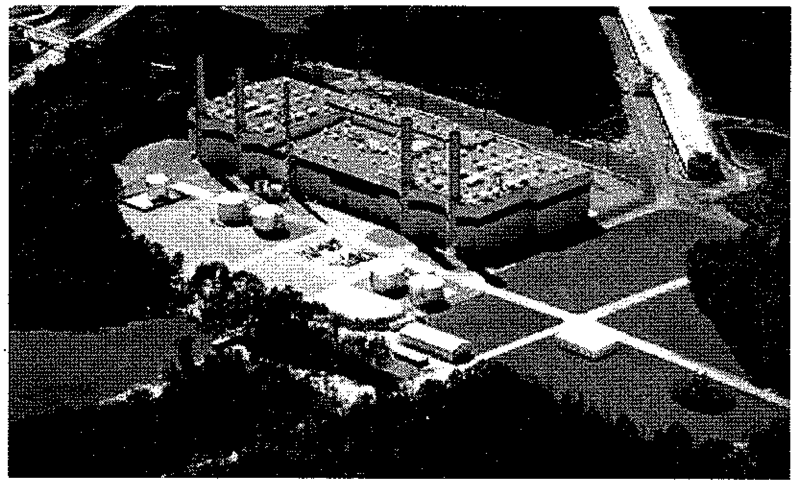


Figure 48. Two 207FA multi-shaft combined-cycle installation

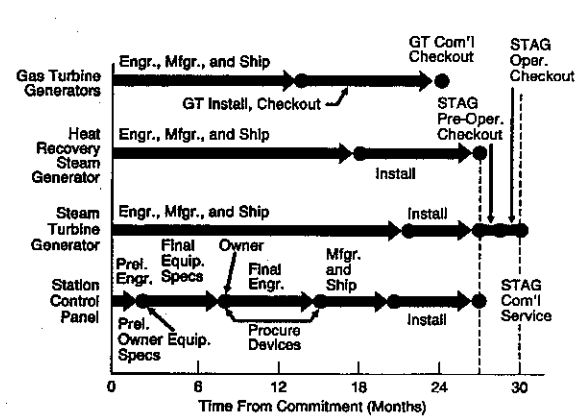


Figure 49. Typical multi-shaft, combined-cycle project schedule

with fired HRSGs and condensing steam turbines provide extraordinary flexibility in both thermal energy and power generation capacity for each gas turbine frame size.

The performance characteristics include the net plant power, LHV heat content in fuel consumed, thermal energy in steam to process, and thermal efficiency and fuel charged to power (FCP). The thermal efficiency for these systems is calculated by the following equation:

$$\eta_{TH} = 100 \times \frac{(Q_p + Q_{TE})}{Q_F}$$

Symbols:

η_{TH} = Thermal efficiency - LHV (%)
Q_F = LHV heat content of fuel consumption (Btu/hr, kJ/hr)
Q_p = Net power output (Btu/hr, kJ/hr)
Q_{TE} = Thermal energy in process steam (Btu/hr, kJ/hr)

The fuel charged to power (FCP) is a useful parameter for comparing an integrated thermal energy and power system with separate systems generating the same power and thermal energy. For this comparison, the LHV heat content of fuel that would be consumed by a conventional fired boiler in producing the same thermal energy is subtracted from the LHV heat consumption of the integrated thermal energy and power system. The resulting FCP can then be compared with the heat rate of a separate power generation facility. This will assess the relative performance of the integrated thermal energy and power system with separate thermal energy and power generation systems. FCP is calculated by the following equation:

$$FCP = 100 \times \frac{(Q_p - [Q_{TE}/\eta_B])}{p}$$

Symbols:

FCP = Fuel charged to power = LHV

(Btu/kWH, kJ/hr)

Q_F = LHV heat content of fuel consumption (Btu/hr, kJ/hr)

Q_{TE} = Thermal energy in process steam (Btu/hr, kJ/hr)

η_B = LHV efficiency of fired boiler producing equivalent thermal energy (%)

P = Net electrical output (kW)

Cycle diagrams for thermal energy and power combined cycle with steam generation at process conditions is presented in *Figure 50.*

These systems include generation of steam at process conditions. *Figure 50* shows combined-cycle cogeneration systems that produce process steam with an unfired or supplementary-fired HRSG. HRSG design for supplementary firing provides the maximum process steam energy supply. *Figure 51* shows combined-cycle cogeneration systems that are equipped with non-condensing steam turbines.

Many variations of these systems can be furnished to satisfy specific process plant energy requirements, including:

- Single automatic-extraction steam turbines to efficiently supply steam at two or three pressures.
- Multi-pressure HRSGs to supply steam at multiple-pressure and temperature conditions. The most flexible thermal energy and power systems are those that include extraction condensing steam turbines. Simplified cycle diagrams for typical systems with single automatic extraction are shown in *Figure 52.* This system has the capability to operate at lower process steam demands while using the excess steam generation to produce power in the condensing section of the steam turbine. These systems can be furnished with double automatic extraction steam turbines and multiple-pressure HRSGs to satisfy specific process steam requirements.

Engineered Equipment Package

The GE Combined-Cycle Engineered Equipment Package (EEP) is a unique combination of equipment and services. It provides the owner with a plant performance guarantee and warranty of operation, and the ability to service the complete power generation system, as well as the capability to customize the plant design, auxiliaries, and structures. This is achieved by including in the GE scope the major combined-

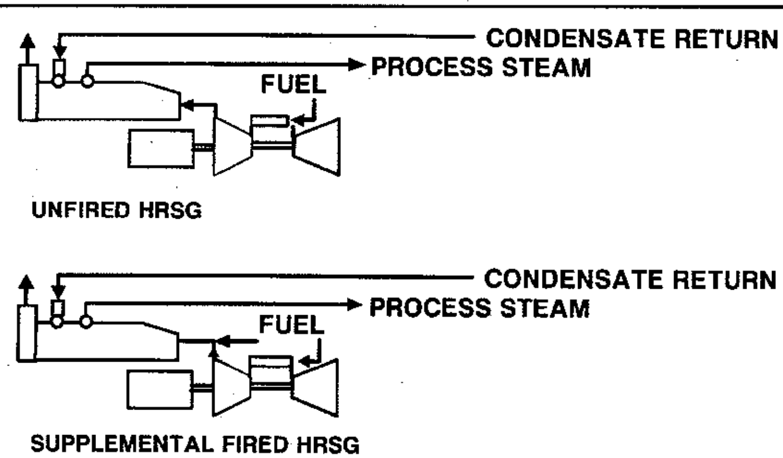


Figure 50. Cycle diagrams – thermal energy and power combined cycle with steam generation at process conditions

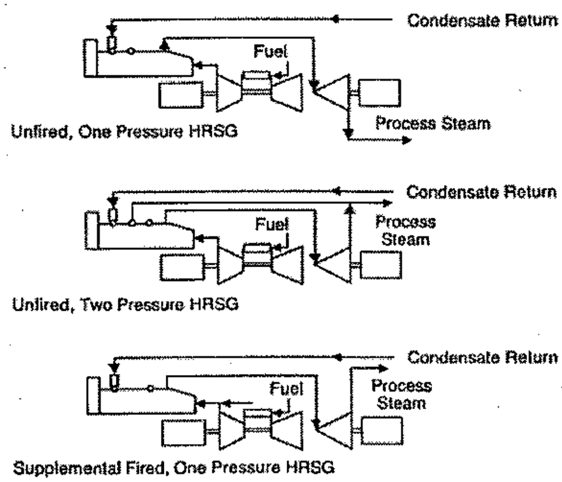


Figure 51. Cycle diagrams – thermal energy and power combined cycle with non-condensing steam turbine

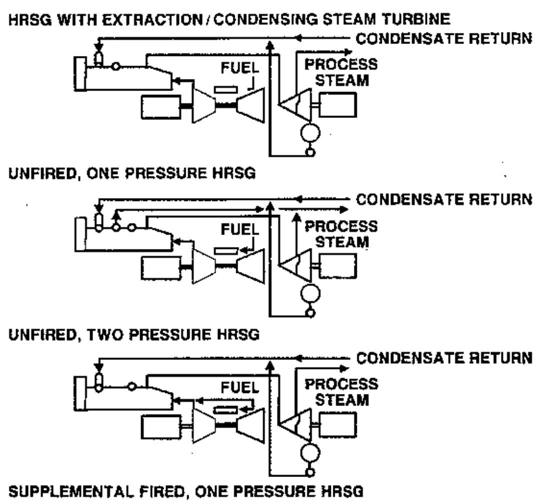


Figure 52. Cycle diagrams – thermal energy and power combined cycle with extraction/condensing steam turbines

cycle equipment that requires close coordination for assurance of meeting the performance and operating objectives. The equipment scope split between GE and the owner is shown in *Table 16.*

The services and software scope split is presented in *Table 17.* Key elements in the GE EEP scope are the combined-cycle system design and the interface definition that enable the owner ,or the owner's architect-engineer or engineer-constructor, to design the plant to meet project specific requirements.

Conclusion

The STAG combined-cycle product line, including power generation systems and thermal energy and power systems ranging from 60 MW to 750 MW, are efficient, low-cost systems that meet the environmental requirements of all countries. The GE combined cycle EEP provides assurance of satisfying performance and operating objectives while allowing a customized plant that incorporates the owner's practices and preferences. The attractive economics, reliability, and operating flexibility of these systems recommend their consideration for all power generation applications.

GENERAL ELECTRIC
- GAS TURBINE(S)
- STEAM TURBINE(S)
- GENERATOR(S)
- HEAT RECOVERY STEAM GENERATOR(S)
- PLANT CONTROLS

OWNER
- MECHANICAL AUXILIARIES
- ELECTRICAL AUXILIARIES
- MAIN ELECTRICAL CONNECTIONS
- BALANCE OF PLANT
  - FOUNDATIONS AND STRUCTURES
  - SWITCHYARD
  - FUEL HANDLING AND STORAGE
  - PLANT COOLING SYSTEM
  - CONSTRUCTION MATERIALS
  - SITE PREPARATION MATERIALS

Table 16. Equipment scope split with engineered equipment package

General Electric
- Plant performance and environmental guarantee
- Combined cycle system design and warranty
- Balance of plant equipment functional specifications
- Equipment interface drawings
- Steady state and dynamic interface definition
- Equipment operation and maintenance
- Operation and maintenance training
- Construction and operation permit support
- Performance and environmental test support

Owner
- Construction and operation permits
- Plant design
- Plant construction
- Plant start-up, commissioning and operation
- Performance and environmental testing
- Site preparation
- Project administration

Table 17. Services and software split with engineered equipment package

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Exhibit 15

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§§1.5.4, 3.4.8, 3.7.2, and 3.10.3; Ex. 67, p. 6.3-3.) Staff testified that for the next few years, natural gas supplies appear to be adequate to supply the IEEC. Beyond this time frame, a new interstate transmission line will likely be needed to supply these markets with inexpensive natural gas. Staff testimony indicated that free market forces will work to ensure that a new interstate natural gas transport system is constructed, or some other means are developed to provide natural gas to the IEEC and San Diego area. (Ex. 67, p. 6.3-3.)

3. Compliance with Energy Standards

No standards apply to the efficiency of IEEC or other non-cogeneration projects. (Ex. 67, p. 6.6-3; *see* Pub. Resources Code, § 25134.)

4. Alternatives to Wasteful or Inefficient Energy Consumption

Applicant provided information on alternative generating technologies, which were reviewed by Staff. (Ex. 1, §3.10; Ex. 67, p. 6.3-6; *See* the **Alternatives** section of this Decision.) Given the project objectives, location, and air pollution control requirements, Staff concluded that only natural gas-burning technologies are feasible. (*Ibid.*) Staff also reviewed alternatives to an F-class gas turbine and concluded that the project configuration and generating equipment appear to be the most efficient feasible combination to satisfy project objectives. (Ex. 67, p. 6.3-7.)

Under expected project conditions, electricity will be generated at a base load efficiency of approximately 56.5 percent LHV without duct firing and 53.2 percent LHV with duct firing.[7] (Ex. 67, pp. 6.3-2 to 6.3-3.)

[7] The average fuel efficiency of a typical utility company base load power plant is approximately 35 percent LHV. (Ex. 67, p. 6.3-3.)

Exhibit 16

Application for Certification

Volume I

CPV Vaca Station

Submitted by

CPV Vacaville, LLC

Submitted to

California Energy Commission

With Technical Assistance by

CH2MHILL

October 2008

ES122007003SAC

without the use of duct firing. Heat balances for additional operating cases are presented in Appendix 2A. The predicted net electrical output of the facility under these conditions is approximately 500 MW at a heat rate of approximately 6,885 British thermal units per kilowatt hour (Btu/kWh) on a higher heating value (HHV) basis. This corresponds with an efficiency of about 55 percent. With HRSG duct firing, the facility will be able to produce a net output of up to 600 MW at an ambient temperature of 75°F with evaporative cooling of the CTG inlet air to 68°F using the GE Energy Frame 7FA. The incremental heat rate of the peaking capacity will range between approximately 9,270 and 9,290 Btu/kWh, corresponding to an efficiency of 38 percent, which is comparable to that of a CTG operating in simple-cycle mode.

Figure 2.1-4b is a similar heat balance assuming the use of Siemens SGT6 5000F CTGs. The predicted net electrical output of the facility under these conditions is approximately 560 MW at a heat rate of approximately 6,875 Btu/kWh on an HHV basis, corresponding to an efficiency of about 55 percent. With HRSG duct firing, the facility will be able to produce a net output of up to 670 MW at an ambient temperature of 75°F with evaporative cooling of the CTG inlet air to 68°F using the Siemens SGT6 5000F CTGs. The incremental heat rate of the peaking capacity will range between approximately 8,890 and 8,910 Btu/kWh, corresponding to an efficiency of 40 percent, which is comparable to that of a CTG operating in simple-cycle mode.

The combustion turbines and associated equipment will include the use of best available control technology (BACT) to limit emissions of criteria pollutants and hazardous air pollutants. NO_x will be controlled to 2.0 parts per million by volume, dry basis (ppmvd), corrected to 15 percent oxygen through the use of dry low-NO_x combustors and SCR. Good combustion practices and a carbon monoxide catalyst also will be utilized to control carbon monoxide emissions to 3.0 ppmvd at 15 percent oxygen. Emissions of volatile organic compounds also will be controlled to 2.0 ppm. BACT for particulate matter with a diameter less than 10 microns (PM_{10}) and sulfur dioxide will be the exclusive use of natural gas. Ammonia slip will be limited to 5 ppmvd to meet the BACT requirements.

2.1.3 Power Plant Cycle

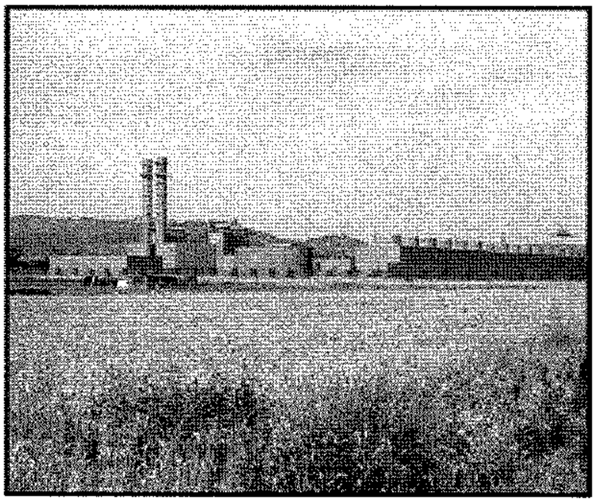
CTG combustion air will flow through the inlet air filters, evaporative coolers, and associated air inlet ductwork, be compressed in the CTG compressor section, and then enter the CTG combustion sections. Natural gas fuel will be injected into the compressed air in the combustion sections and ignited. The hot combustion gases will expand through the power turbine section of the CTGs, causing them to rotate and drive both the electric generators and CTG compressors. The hot combustion gases will exit the turbine sections and enter the HRSGs, where they will heat water (feedwater) that is pumped into the HRSGs. The feedwater will be converted to superheated steam and delivered to the steam turbine at high pressure (HP), intermediate pressure (IP), and low pressure (LP). The use of multiple steam delivery pressures will permit an increase in cycle efficiency and flexibility. High-pressure steam will be delivered to the HP section of the steam turbine, intermediate pressure steam will augment the reheat section of the HRSG and will deliver this steam to the IP section of the STG, low pressure steam will be injected at the beginning of the LP section of the steam turbine, and both flows will be expanded in the LP steam turbine section. Steam leaving the LP section of the steam turbine will enter the deaerating surface condenser and transfer heat to circulating cooling water, which will cause the steam to condense to water.

Exhibit 17

CALIFORNIA
ENERGY
COMMISSION

INLAND EMPIRE ENERGY CENTER

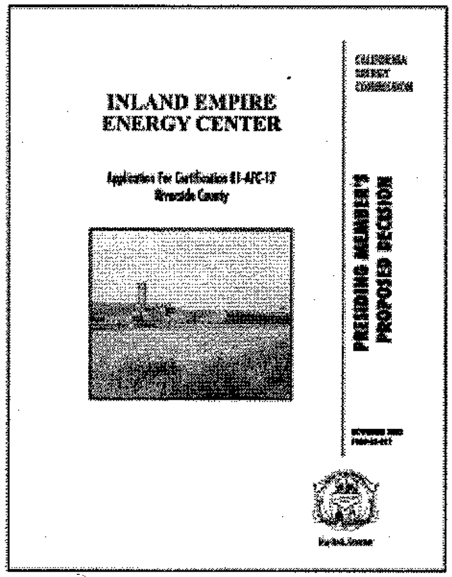
Application For Certification 01-AFC-17
Riverside County



PRESIDING MEMBER'S PROPOSED DECISION

NOVEMBER 2003
P800-03-017

Gray Davis, Governor



INLAND EMPIRE
ENERGY CENTER

Application For Certification 01-AFC-17
Riverside County

CALIFORNIA ENERGY COMMISSION

PRESIDING MEMBER'S
PROPOSED DECISION

CALIFORNIA ENERGY COMMISSION

1516 9th Street
Sacramento, CA 95814
www.energy ca.gov/sitingcases/inlandempire

ROBERT PERNELL
Presiding Committee Member

JAMES D. BOYD
Associate Committee Member

KERRY WILLIS
Hearing Officer

Project fuel efficiency, and therefore its rate of energy consumption, is determined by the configuration of the power producing system and by selection of generating equipment. (Ex. 67, p. 6.3-3.) IEEC is configured as a combined cycle power plant. Electricity will be produced by two gas turbines with a reheat steam turbine that operates on heat energy recuperated from gas turbine exhaust. (Ex. 1, §§ 1.5.2, 3.4.2.) By recovering this heat, which would otherwise be lost up the exhaust stacks, the efficiency of a combined cycle power plant is considerably increased compared with either a gas turbine or a steam turbine operating alone. Staff concluded that the proposed configuration is well suited to the large, steady loads met by a base load plant. (Ex. 67, p. 6.3-4.)

Project efficiency will also be enhanced by inlet air foggers, HRSG duct burners (re-heaters), three-pressure HRSG, a steam turbine unit and circulating water system. (Ex. 1, § 3.4.2, Ex. 67, p. 6.3-4.) Staff's testimony establishes that these features contribute to meaningful efficiency enhancement to the IEEC. The two-train CT/HRSG configuration also allows for high efficiency during unit turndown because one CT can be shut down, leaving one fully loaded, efficiently operating CT. *(Ibid.)*

The IEEC will employ the advanced model turbines instead of the conventional or the next generation models. Applicant plans to use two large advanced model General Electric (GE) Power Systems "F" class combustion turbine generators in a two-on-one combined cycle power train. Staff testified that the F-class gas turbines to be employed in the IEEC represent some of the most modern and efficient machines now available. (Ex. 1, § 3.4.3.1) This configuration is nominally rated at 530 MW and 56.5 percent efficiency LHV at ISO conditions. (Ex. 67, p. 6.3-5.) At base load, the plant will be operating at a heat rate of approximately 6,700 Btu/kwh on a higher heating value basis. The incremental heat rate for peaking capacity will range from 8,100 to 9,000 Btu/kwh (HHV), depending on ambient and operating conditions, (Ex. 1, p. 3-10.)

Exhibit 18

Combined Cycle Ratings

– 2007-08 GTW Handbook –

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
Alstom (50 Hz)										
KA8C2-2	1998	165 000 kW	6783 Btu	50.3%	7156 kJ	45	*****	*****	2 x GT8C2	dual pressure non-reheat HRSG
KA11N2-2	1993	344 800 kW	6647 Btu	51.3%	7013 kJ	45	*****	*****	2 x GT11N2	dual pressure non-reheat HRSG
KA13E2-1	1993	252 800 kW	6458 Btu	52.8%	6813 kJ	45	*****	*****	1 x GT13E2	dual pressure non-reheat HRSG
KA13E2-2	1993	507 400 kW	6435 Btu	53.0%	6789 kJ	45	*****	*****	2 x GT13E2	dual pressure non-reheat HRSG
KA13E2-3	1993	763 200 kW	6417 Btu	53.2%	6770 kJ	45	*****	*****	3 x GT13E2	dual pressure non-reheat HRSG
KA26-1	1996	424 000 kW	5850 Btu	58.3%	6172 kJ	45	*****	*****	1 x GT26	with once through cooler
KA26-2	1996	850 300 kW	5835 Btu	58.5%	6156 kJ	45	*****	*****	2 x GT26	with once through cooler
KA26-2 ICS	2006	857 700 kW	5785 Btu	59.0%	6103 kJ	45	*****	*****	2 x GT26	with once through cooler
Alstom (60Hz)										
KA8C2-2	1998	163 500 kW	6837 Btu	49.9%	7213 kJ	45	*****	*****	2 x GT8C2	dual pressure non-reheat HRSG
KA11N2-2	2001	348 500 kW	6582 Btu	51.8%	6944 kJ	45	*****	*****	2 x GT11N2	dual pressure non-reheat HRSG
KA24-1	1998	278 900 kW	5978 Btu	57.1%	6307 kJ	45	*****	*****	1 x GT24	with once through cooler
KA24-2	1998	560 000 kW	5955 Btu	57.3%	6282 kJ	45	*****	*****	2 x GT24	with once through cooler
Ansaldo Energia (50 Hz)										
COBRA 164.3A	*****	115 400 kW	6301 Btu	54.2%	6648 kJ	*****	75 550 kW	41 800 kW	1 x V64.3A	ISO based performance with
COBRA 264.3A	*****	232 900 kW	6242 Btu	54.7%	6586 kJ	*****	151 100 kW	85 770 kW	2 x V64.3A	4"/12" losses for all models
COBRA 194.2	*****	246 400 kW	6599 Btu	51.7%	6962 kJ	*****	161 300 kW	90 100 kW	1 x V94.2	
COBRA 294.2	*****	499 200 kW	6515 Btu	52.4%	6873 kJ	*****	323 000 kW	186 600 kW	2 x V94.2	
COBRA 394.2	*****	747 100 kW	6529 Btu	52.3%	6889 kJ	*****	483 900 kW	278 200 kW	3 x V94.2	
COBRA 194.3A	*****	411 600 kW	5900 Btu	57.8%	6225 kJ	*****	277 800 kW	140 900 kW	1 x V94.3A	
COBRA 294.3A	*****	820 300 kW	5922 Btu	57.6%	6248 kJ	*****	556 000 kW	278 800 kW	2 x V94.3A	
Bharat Heavy Electricals (50 Hz)										
CC105P	1988	38 500 kW	8180 Btu	41.7%	8630 kJ	*****	25 900 kW	18 200 kW	1 x MS5001	dual pressure
CC205P	1988	77 800 kW	8110 Btu	42.1%	8550 kJ	*****	51 800 kW	27 200 kW	2 x MS5001	dual pressure
CC305P	1988	117 200 kW	8070 Btu	42.3%	8510 kJ	*****	77 700 kW	41 400 kW	3 x MS5001	dual pressure
CC106B	1997	64 300 kW	6960 Btu	49.0%	7340 kJ	*****	41 600 kW	23 800 kW	1 x MS6001B	dual pressure
CC206B	1997	130 700 kW	6850 Btu	49.8%	7320 kJ	*****	83 200 kW	49 400 kW	2 x MS6001B	dual pressure

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
Bharat Heavy Electricals (50 Hz) continued										
CC106C	2004	62 700 kW	6315 Btu	54.1%	6660 kJ	*****	41 700 kW	21 900 kW	1 x MS6001C	dual pressure
CC206C	2004	126 200 kW	6275 Btu	54.4%	6620 kJ	*****	83 400 kW	44 700 kW	2 x MS6001C	dual pressure
CC106FA	2003	117 000 kW	6300 Btu	54.2%	6645 kJ	*****	75 200 kW	43 500 kW	1 x MS6001FA	triple pressure, non reheat
CC206FA	2003	234 800 kW	6280 Btu	54.4%	6625 kJ	*****	150 400 kW	87 800 kW	2 x MS6001FA	triple pressure, reheat
CC109E	2003	190 700 kW	6640 Btu	51.4%	7000 kJ	*****	124 000 kW	70 000 kW	1 x MS9001E	dual pressure
CC209E	2003	384 000 kW	6600 Btu	51.7%	6960 kJ	*****	248 000 kW	142 100 kW	2 x MS9001E	dual pressure
CC309E	2003	577 000 kW	6560 Btu	52.0%	6920 kJ	*****	372 000 kW	214 000 kW	3 x MS9001E	dual pressure
CC1.942	1998	232 500 kW	6630 Btu	51.5%	6990 kJ	*****	152 000 kW	85 500 kW	1 x V94.2	dual pressure
CC2.942	1998	467 500 kW	6600 Btu	51.7%	6960 kJ	*****	304 000 kW	173 000 kW	2 x V94.2	dual pressure
CC3.942	1998	701 000 kW	6600 Btu	51.7%	6960 kJ	*****	456 000 kW	259 000 kW	3 x V94.2	dual pressure
CC109FA	2003	383 600 kW	6164 Btu	55.4%	6502 kJ	*****	251 700 kW	137 000 kW	1 x MS9001FA	triple pressure reheat
CC209FA	2003	772 000 kW	6125 Btu	55.7%	6461 kJ	*****	503 400 kW	279 000 kW	2 x MS9001FA	triple pressure reheat
Ebara (50/60 Hz)										
FT8 PowerPac	1990	32 910 kW	6865 Btu	49.7%	7243 kJ	*****	24 165 kW	8 755 kW	1 x FT8	all with dual pressure HRSGs
FT8 TwinPac	1990	66 745 kW	6770 Btu	50.4%	7143 kJ	*****	48 725 kW	18 020 kW	2 x FT8	and 1.0 psia condenser
FT8-3 PowerPac	1990	36 570 kW	6750 Btu	50.6%	7122 kJ	*****	26 564 kW	10 006 kW	1 x FT8-3	
FT8-3 TwinPac	1990	74 185 kW	6655 Btu	51.3%	7022 kJ	*****	53 688 kW	20 597 kW	2 x FT8-3	
GE Energy Aeroderivative (50Hz)										
LM2000PS	2000	24 123 kW	7 682 Btu	44.4%	8105 kJ	1.0"	18 275 kW	6 417 kW	1 x LM2000PS	
LM2000PJ	2000	24 410 kW	7 231 Btu	47.2%	7629 kJ	1.0"	17 769 kW	7 222 kW	1 x LM2000PJ	
LM2500PE	1981	31 153 kW	6 906 Btu	49.4%	7286 kJ	1.0"	22 239 kW	9 604 kW	1 x LM2500PE	
LM2500PE	1981	31 345 kW	7 385 Btu	46.2%	7791 kJ	1.0"	22 949 kW	9 088 kW	1 x LM2500PE	
LM2500PJ	1995	30 375 kW	6 934 Btu	49.2%	7315 kJ	1.0"	21 713 kW	9 340 kW	1 x LM2500PJ	
LM2500+ RC	2005	46 946 kW	7 106 Btu	48.0%	7497 kJ	1.0"	35 851 kW	12 026 kW	1 x LM2500+ RC	
LM2500+ RD	2005	43 957 kW	6 693 Btu	51.0%	7061 kJ	1.0"	32 723 kW	12 124 kW	1 x LM2500+ RD	
LM6000PC	1997	53 128 kW	6 990 Btu	48.8%	7374 kJ	1.0"	43 131 kW	11 020 kW	1 x LM6000PC	
LM6000PC Sprint	1998	62 546 kW	6 889 Btu	49.5%	7268 kJ	1.0"	50 592 kW	13 119 kW	1 x LM6000PC	
LM6000PD	1997	53 578 kW	6 556 Btu	52.0%	6917 kJ	1.0"	42 527 kW	12 086 kW	1 x LM6000PD	
LM6000PD liquid	2005	51 915 kW	6 589 Btu	51.8%	6951 kJ	1.0"	40 802 kW	12 128 kW	1 x LM6000PD	distillate fuel
LM6000PD Sprint	2000	58 668 kW	6 637 Btu	51.4%	7002 kJ	1.0"	47 277 kW	12 503 kW	1 x LM6000PD	
LM6000PF	2006	53 578 kW	6 556 Btu	52.0%	6917 kJ	1.0"	42 527 kW	12 086 kW	1 x LM6000PF	
LM6000PF Sprint	2006	59 646 kW	6 593 Btu	51.8%	6956 kJ	1.0"	47 809 kW	12 964 kW	1 x LM6000PF	

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
GE Energy Aeroderivative (50Hz) continued										
LMS100PA	2006	117 578 kW	6 811 Btu	50.1%	7186 kJ	1.0"	102 504 kW	16 951 kW	1 x LMS100PA	
LMS100PB	TBD	113 512 kW	6 557 Btu	52.0%	6918 kJ	1.0"	97 967 kW	17 366 kW	1 x LMS100PB	
GE Energy Aeroderivative (60 Hz)										
LM2000PS	2000	23 957 kW	7 589 Btu	45.0%	8006 kJ	1.0"	18 412 kW	6 102 kW	1 x LM2000PS	
LM2000PJ	2000	23 911 kW	7 168 Btu	47.6%	7562 kJ	1.0"	17 657 kW	6 816 kW	1 x LM2000PJ	
LM2500PE	1981	31 931 kW	6 795 Btu	50.2%	7169 kJ	1.0"	23 292 kW	9 332 kW	1 x LM2500PE	
LM2500PE	1981	32 203 kW	7 257 Btu	47.0%	7656 kJ	1.0"	24 049 kW	8 850 kW	1 x LM2500PE	
LM2500PJ	1995	31 125 kW	6 821 Btu	50.0%	7196 kJ	1.0"	22 719 kW	9 087 kW	1 x LM2500PJ	
LM2500+ RC	2005	47 359 kW	7 046 Btu	48.4%	7434 kJ	1.0"	36 333 kW	11 961 kW	1 x LM2500+ RC	
LM2500+ RD	2005	44 327 kW	6 565 Btu	52.0%	6926 kJ	1.0"	33 165 kW	12 055 kW	1 x LM2500+ RD	
LM6000PC	1997	53 954 kW	6 923 Btu	49.3%	7304 kJ	1.0"	43 843 kW	11 147 kW	1 x LM6000PC	
LM6000PC Sprint	1998	62 372 kW	6 852 Btu	49.8%	7229 kJ	1.0"	50 526 kW	13 007 kW	1 x LM6000PC	
LM6000PD	1997	54 180 kW	6 497 Btu	52.5%	6854 kJ	1.0"	43 068 kW	12 153 kW	1 x LM6000PD	
LM6000PD liquid	2005	51 716 kW	6 546 Btu	52.1%	6906 kJ	1.0"	40 712 kW	12 013 kW	1 x LM6000PD	distillate fuel
LM6000PD Sprint	2000	58 678 kW	6 591 Btu	51.8%	6954 kJ	1.0"	47 383 kW	12 401 kW	1 x LM6000PD	
LM6000PF	2006	54 180 kW	6 497 Btu	52.5%	6854 kJ	1.0"	43 068 kW	12 153 kW	1 x LM6000PF	
LM6000PF Sprint	2006	59 684 kW	6 568 Btu	51.9%	6929 kJ	1.0"	48 092 kW	12 719 kW	1 x LM6000PF	
LMS100PA	2006	117 905 kW	6 793 Btu	50.2%	7167 kJ	1.0"	103 045 kW	16 736 kW	1 x LMS100PA	
LMS100PB	TBD	112 806 kW	6 599 Btu	51.7%	6962 kJ	1.0"	98 396 kW	16 204 kW	1 x LMS100PB	
GE Energy Heavy Duty (50 Hz)										
S106B	1987	64 300 kW	6960 Btu	49.0%	7341 kJ	1.2"	41 600 kW	23 800 kW	1 x MS6001B	non-reheat
S206B	1979	130 700 kW	6850 Btu	49.8%	7225 kJ	1.2"	83 200 kW	49 400 kW	2 x MS6001B	non-reheat
S406B	1979	261 300 kW	6850 Btu	49.8%	7225 kJ	1.2"	166 400 kW	99 000 kW	4 x MS6001B	non-reheat
S106C	2002	67 200 kW	6281 Btu	54.3%	6627 kJ	1.2"	44 800 kW	23 100 kW	1 x MS6001C	non-reheat
S206C	2002	136 100 kW	6203 Btu	55.0%	6544 kJ	1.2"	89 600 kW	48 100 kW	2 x MS6001C	non-reheat
S106FA	1991	118 400 kW	6199 Btu	55.0%	6540 kJ	1.2"	76 300 kW	43 900 kW	1 x MS6001FA	reheat
S206FA	1991	239 400 kW	6132 Btu	55.6%	6470 kJ	1.2"	152 600 kW	90 300 kW	2 x MS6001FA	reheat
S109E	1979	193 200 kW	6570 Btu	52.0%	6930 kJ	1.2"	124 300 kW	71 800 kW	1 x MS9001E	non-reheat
S209E	1979	391 400 kW	6480 Btu	52.7%	6835 kJ	1.2"	248 600 kW	148 500 kW	2 x MS9001E	non-reheat
S109FA	1994	390 800 kW	6020 Btu	56.7%	6350 kJ	1.2"	254 100 kW	141 800 kW	1 x MS9001FA	reheat
S209FA	1994	786 900 kW	5980 Btu	57.1%	6308 kJ	1.2"	508 200 kW	289 200 kW	2 x MS9001FA	reheat

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
GE Energy Heavy Duty (50 Hz) continued										
S109FB*	2002	430 000 kW	5890 Btu	57.9%	6214 kJ	1.7"	275 000 kW	163 500 kW	1 x MS9001FB	reheat
S209FB*	2002	859 400 kW	5895 Btu	57.9%	6219 kJ	1.7"	550 000 kW	327 500 kW	2 x MS9001FB	reheat
*Estimated by GTW; contact GE Energy for latest design ratings										
S109H	1997	520 000 kW	5690 Btu	60.0%	6000 kJ	1.2"	****	****	1 x MS9001H	single shaft w/ reheat
Note: All three models above include three-pressure steam cycle and dry low NOx combustion										
GE Energy Heavy Duty (60 Hz)										
S106B	1987	64 300 kW	6960 Btu	49.0%	7341 kJ	1.2"	41 600 kW	23 800 kW	1 x MS6001B	non-reheat
S206B	1979	130 700 kW	6850 Btu	49.8%	7225 kJ	1.2"	83 200 kW	49 400 kW	2 x MS6001B	non-reheat
S406B	1979	261 300 kW	6850 Btu	49.8%	7225 kJ	1.2"	166 400 kW	99 000 kW	4 x MS6001B	non-reheat
S106C	2002	67 200 kW	6281 Btu	54.3%	6667 kJ	1.2"	44 800 kW	23 200 kW	1 x MS6001C	non-reheat
S206C	2002	136 100 kW	6203 Btu	55.0%	6617 kJ	1.2"	89 600 kW	48 100 kW	2 x MS6001C	non-reheat
S106FA	1991	118 750 kW	6208 Btu	55.0%	6550 kJ	1.2"	76 350 kW	44 200 kW	1 x MS6001FA	reheat
S206FA	1991	238 900 kW	6180 Btu	55.2%	6520 kJ	1.2"	152 700 kW	89 700 kW	2 x MS6001FA	reheat
S107EA	1977	130 200 kW	6800 Btu	50.2%	7173 kJ	1.2"	83 500 kW	48 700 kW	1 x MS7001EA	non-reheat
S207EA	1979	263 600 kW	6700 Btu	50.9%	7067 kJ	1.2"	167 000 kW	100 700 kW	2 x MS7001EA	non-reheat
S107FA	1994	262 600 kW	6090 Btu	56.0%	6424 kJ	1.2"	170 850 kW	95 600 kW	1 x MS7001FA	reheat
S207FA	1994	529 900 kW	6040 Btu	56.5%	6371 kJ	1.2"	341 700 kW	195 800 kW	2 x MS7001FA	reheat
S107FB	1999	280 300 kW	5950 Btu	57.3%	6276 kJ	1.7"	183 150 kW	101 030 kW	1 x MS7001FB	reheat
S207FB	1999	562 500 kW	5940 Btu	57.5%	6266 kJ	1.7"	366 300 kW	204 000 kW	2 x MS7001FB	reheat
S107H	1997	400 000 kW	5690 Btu	60.0%	6000 kJ	1.2"	*****	*****	1 x MS7001H	single shaft w/ reheat
Note: All models above include three-pressure steam cycle and dry low NOx combustion										
Hitachi (50/60 Hz)										
2025	1988	81 360 kW	6818 Btu	50.1%	7193 kJ	****	53 860 kW	27 500 kW	2 x H-25	
3025	1988	122 190 kW	6809 Btu	50.1%	7184 kJ	****	80 790 kW	41 400 kW	3 x H-25	
206B	1986	121 000 kW	6960 Btu	49.0%	7350 kJ	****	78 100 kW	42 900 kW	2 x MS6001B	
106FA	1993	106 300 kW	6530 Btu	52.3%	6890 kJ	****	68 900 kW	37 400 kW	1 x MS6001FA	
206FA	1993	215 300 kW	6450 Btu	52.9%	6800 kJ	****	137 800 kW	77 500 kW	2 x MS6001FA	
Hitachi (50 Hz)										
109E	1986	178 700 kW	6950 Btu	49.1%	7335 kJ	****	119 000 kW	59 700 kW	1 x MS9001E	
209E	1986	359 500 kW	6910 Btu	49.4%	7290 kJ	****	238 000 kW	121 500 kW	2 x MS9001E	
109FA	1995	367 400 kW	6170 Btu	55.3%	6510 kJ	****	234 700 kW	132 700 kW	1 x MS9001FA	
Hitachi (60 Hz)										
107EA	1989	128 200 kW	6820 Btu	50.0%	7200 kJ	****	83 500 kW	44 700 kW	1 x MS7001EA	
207EA	1989	258 100 kW	6780 Btu	50.3%	7160 kJ	****	167 000 kW	91 100 kW	2 x MS7001EA	

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
Hitachi (60 Hz) continued										
107FA	1995	253 700 kW	6170 Btu	55.3%	6510 kJ	****	164 000 kW	89 700 kW	1 x MS7001FA	
207FA	1995	509 200 kW	6150 Btu	55.5%	6490 kJ	****	328 000 kW	181 200 kW	2 x MS7001FA	
IHI Power Systems (50/60 Hz)										
LM1600PA	1991	17 420 kW	7280 Btu	46.8%	7691 kJ	****	12 820 kW	4 600 kW	1 x LM1600PA	all ratings on natural gas
LM2500PE	1986	30 350 kW	6763 Btu	50.5%	7136 kJ	****	22 150 kW	8 200 kW	1 x LM2500PE	with inlet & exhaust losses
LM2500PK	1998	35 410 kW	6777 Btu	50.4%	7150 kJ	****	26 020 kW	9 390 kW	1 x LM2500PK	
LM2500RB	2006	40 760 kW	6827 Btu	50.0%	7203 kJ	****	31 740 kW	9 020 kW	1 x LM2500RB	
IHI Power Systems (50 Hz)										
LM6000PC	1997	53 520 kW	6570 Btu	51.9%	6932 kJ	****	42 120 kW	11 400 kW	1 x LM6000PC	
LM6000PC	1997	107 450 kW	6546 Btu	52.1%	6906 kJ	****	84 250 kW	23 200 kW	2 x LM6000PC	
LM6000PD	1997	52 850 kW	6528 Btu	52.3%	6887 kJ	****	41 050 kW	11 800 kW	1 x LM6000PD	
LM6000PD	1997	106 000 kW	6509 Btu	52.4%	6867 kJ	****	82 100 kW	23 900 kW	2 x LM6000PD	
MAN Turbo (50/60 Hz)										
THM 1304-11	1999	32 920 kW	7497 Btu	45.5%	7910 kJ	****	21 520 kW	11 400 kW	2 x THM 1304-11	dual pressure HRSG
FT8 PowerPac	1990	32 910 kW	6865 Btu	49.7%	7243 kJ	****	24 737 kW	8 755 kW	1 x FT8	dual pressure HRSG
FT8 TwinPac	1990	66 745 kW	6770 Btu	50.4%	7143 kJ	****	49 828 kW	18 020 kW	2 x FT8	dual pressure HRSG
Mitsubishi Heavy Industries (50 Hz)										
MPCP1(M701)	1981	212 500 kW	6635 Btu	51.4%	7000 kJ	****	142 100 kW	70 400 kW	1 x M701DA	ratings at electric
MPCP2(M701)	1981	426 600 kW	6610 Btu	51.6%	6974 kJ	****	284 200 kW	142 400 kW	2 x M701DA	generator terminals with
MPCP3(M701)	1981	645 000 kW	6585 Btu	51.8%	6947 kJ	****	426 300 kW	218 700 kW	3 x M701DA	inlet and exhaust losses
MPCP1(M701F)	1992	464 500 kW	5735 Btu	59.5%	6050 kJ	****	307 200 kW	157 300 kW	1 x M701F4	all heat rates LHV natural gas
MPCP2(M701F)	1992	932 100 kW	5716 Btu	59.7%	6030 kJ	****	614 400 kW	317 700 kW	2 x M701F4	
MPCP1(M701G)	1997	498 000 kW	5755 Btu	59.3%	6071 kJ	****	325 700 kW	172 300 kW	1 x M701G2	
MPCP2(M701G)	1997	999 400 kW	5735 Btu	59.5%	6051 kJ	****	651 400 kW	348 000 kW	2 x M701G2	
Mitsubishi Heavy Industries (60 Hz)										
MPCP1(M501)	1981	167 400 kW	6635 Btu	51.4%	7000 kJ	****	112 100 kW	55 300 kW	1 x M501DA	ratings at electric
MPCP2(M501)	1981	336 200 kW	6610 Btu	51.6%	6974 kJ	****	224 200 kW	112 000 kW	2 x M501DA	generator terminals with
MPCP3(M501)	1981	506 200 kW	6585 Btu	51.8%	6947 kJ	****	336 300 kW	169 900 kW	3 x M501DA	inlet and exhaust losses
MPCP1(M501F)	1994	285 100 kW	5976 Btu	57.1%	6305 kJ	****	182 700 kW	102 400 kW	1 x M501F3	all heat rates LHV natural gas
MPCP2(M501F)	1994	572 200 kW	5955 Btu	57.3%	6283 kJ	****	365 400 kW	206 800 kW	2 x M501F3	
MPCP1(M501G)	1995	398 900 kW	5843 Btu	58.4%	6165 kJ	****	264 400 kW	134 500 kW	1 x M501G1	
MPCP2(M501G)	1995	800 500 kW	5823 Btu	58.6%	6144 kJ	****	528 800 kW	271 700 kW	2 x M501G1	
MPCP1(M501H)	2001	403 000 kW	5689 Btu	60.0%	6000 kJ	****	****	****	1 x M501H	steam-cooled rotor

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
Mitsui Engineering & Shipbuilding (50/60 Hz)										
MACS70	1997	8 500 kW	8 385 Btu	40.7%	8 846 kJ	****	6 560 kW	1 940 kW	1 x MSC70	
MACS90	1997	11 730 kW	8 406 Btu	40.6%	8 868 kJ	****	8 910 kW	2 820 kW	1 x MSC90	
MACS100	1997	13 250 kW	8 185 Btu	41.7%	8 635 kJ	****	9 930 kW	3 320 kW	1 x MSC100	
NK - Engines (50/60 Hz)										
NK-37	1993	66 840 kW	7246 Btu	47.1%	7643 kJ	****	47 200 kW	19 640 kW	2 x NK-37	
Pratt & Whitney Power Systems (50/60 Hz)										
FT8 PowerPac	1990	32 910 kW	6865 Btu	49.7%	7243 kJ	****	24 737 kW	8 755 kW	1 x FT8	all with dual pressure HRSGs
FT8 TwinPac	1990	66 745 kW	6770 Btu	50.4%	7143 kJ	****	49 828 kW	18 020 kW	2 x FT8	and 1.0 psia condenser
FT8-3 PowerPac	1990	36 570 kW	6750 Btu	50.6%	7122 kJ	****	27 220 kW	10 006 kW	1 x FT8-3	
FT8-3 TwinPac	1990	74 185 kW	6655 Btu	51.3%	7022 kJ	****	54 840 kW	20 597 kW	2 x FT8-3	
Rolls-Royce (50/60 Hz)										
RB211-G62 DLE	1993	37 725 kW	6801 Btu	50.2%	7175 kJ	****	26 716 kW	12 045 kW	1 x RB211	4/10" losses all models
2 x RB211-G62	1993	75 480 kW	6801 Btu	50.2%	7175 kJ	****	53 432 kW	24 118 kW	2 x RB211	
RB211-GT62 DLE	1999	39 760 kW	6639 Btu	51.4%	7005 kJ	****	28 626 kW	12 205 kW	1 x RB211	
2 x RB211-GT62	1999	79 540 kW	6639 Btu	51.4%	7005 kJ	****	57 252 kW	24 439 kW	2 x RB211	
RB211-GT61 DLE	2000	42 640 kW	6464 Btu	52.8%	6820 kJ	****	31 171 kW	12 593 kW	1 x RB211	
2 x RB211-GT61	2000	85 300 kW	6464 Btu	52.8%	6820 kJ	****	62 342 kW	25 215 kW	2 x RB211	
Rolls-Royce (50 Hz)										
Trent 60 DLE	1996	64 232 kW	6480 Btu	52.7%	6837 kJ	****	50 068 kW	15 261 kW	1 x Trent	4/10" losses, 2P steam
Trent 60 DLE	1996	89 482 kW	6798 Btu	50.2%	7172 kJ	****	50 068 kW	41 348 kW	1 x Trent	duct fired to 1380F
2 x Trent 60 DLE	1996	129 216 kW	6442 Btu	53.0%	6797 kJ	****	100 136 kW	31 277 kW	2 x Trent	4/10" losses, 2P steam
Trent 60 WLE	2001	72 670 kW	6784 Btu	50.3%	7157 kJ	****	58 000 kW	15 893 kW	1 x Trent	NOx water injected
Trent 60 WLE	2001	102 828 kW	7019 Btu	48.6%	7405 kJ	****	58 000 kW	47 043 kW	1 x Trent	duct fired to 1380F
2 x Trent 60 WLE	2001	146 035 kW	6751 Btu	50.5%	7123 kJ	****	116 000 kW	32 495 kW	2 x Trent	4/10" losses, 2P steam
Rolls-Royce (60 Hz)										
Trent 60 DLE	1996	64 601 kW	6497 Btu	52.5%	6855 kJ	****	50 492 kW	15 211 kW	1 x Trent	4/10" losses, 2P steam
Trent 60 DLE	1996	90 326 kW	6816 Btu	50.1%	7191 kJ	****	50 492 kW	41 791 kW	1 x Trent	duct fired to 1380F
2 x Trent 60 DLE	1996	129 899 kW	6462 Btu	52.8%	6818 kJ	****	100 984 kW	31 115 kW	2 x Trent	4/10" losses, 2P steam
Trent 60 WLE	2001	72 898 kW	6743 Btu	50.6%	7114 kJ	****	58 000 kW	16 127 kW	1 x Trent	NOx water injected
Trent 60 WLE	2001	101 719 kW	6989 Btu	48.8%	7374 kJ	****	58 000 kW	45 901 kW	1 x Trent	duct fired to 1380F
2 x Trent 60 WLE	2001	146 441 kW	6712 Btu	50.8%	7082 kJ	****	116 000 kW	32 919 kW	2 x Trent	4/10" losses, 2P steam

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
Siemens Power Generation (50/60 Hz)										
SCC-600 1x1	1981	36 100 kW	6810 Btu	50.1%	7185 kJ	****	24 000 kW	12 550 kW	1 x SGT-600	dual pressure HRSG
SCC-600 2x1	1981	73 150 kW	6730 Btu	50.7%	7100 kJ	****	48 000 kW	26 000 kW	2 x SGT-600	dual pressure HRSG
SCC-700 1x1	1998	41 280 kW	6674 Btu	51.1%	7041 kJ	****	28 400 kW	12 880 kW	1 x SGT-700	dual pressure HRSG
SCC-700 2x1	1998	83 630 kW	6588 Btu	51.8%	6950 kJ	****	56 800 kW	26 830 kW	2 x SGT-700	dual pressure HRSG
SCC-800 1x1	1998	66 500 kW	6353 Btu	53.7%	6703 kJ	****	46 000 kW	21 400 kW	1 x SGT-800	dual pressure HRSG
SCC-800 2x1	1998	135 000 kW	6273 Btu	54.4%	6618 kJ	****	92 000 kW	44 400 kW	2 x SGT-800	dual pressure HRSG
SCC-900 1x1	1982	71 500 kW	7140 Btu	47.8%	7530 kJ	****	48 000 kW	25 000 kW	1 x SGT-900	dual pressure, no reheat
SCC-900 2x1	1982	143 500 kW	7110 Btu	48.0%	7500 kJ	****	96 000 kW	50 500 kW	2 x SGT-900	dual pressure, no reheat
SCC-1000F single shaft	1996	100 800 kW	6487 Btu	52.6%	6844 kJ	****	****	****	1 x SGT-1000F	dual pressure, no reheat
SCC-1000F 2x1	1996	201 200 kW	6501 Btu	52.5%	6858 kJ	****	131 400 kW	74 000 kW	2 x SGT-1000F	dual pressure, no reheat
Siemens Power Generation (50 Hz)										
SCC5-2000E 1x1	1981	251 000 kW	6535 Btu	52.2%	6895 kJ	****	163 800 kW	91 100 kW	1 x SGT5-2000E	dual pressure, no reheat
SCC5-2000E 2x1	1981	505 000 kW	6502 Btu	52.5%	6860 kJ	****	327 600 kW	184 900 kW	2 x SGT5-2000E	dual pressure, no reheat
SCC5-3000E single shaft	1997	290 000 kW	6036 Btu	56.5%	6368 kJ	****	****	****	1 x SGT5-3000E	triple pressure, reheat, 41000 EOH maint Interval
SCC5-3000E 2x1	1997	576 000 kW	6056 Btu	56.3%	6389 kJ	****	370 400 kW	215 300 kW	2 x SGT5-3000E	triple pressure, reheat, 41000 EOH maint Interval
SCC5-4000F single shaft	1995	416 000 kW	5859 Btu	58.2%	6182 kJ	****	****	****	1 x SGT5-4000F	triple pressure, reheat
SCC5-4000F 2x1	1995	832 000 kW	5860 Btu	58.2%	6183 kJ	****	557 400 kW	288 700 kW	2 x SGT5-4000F	triple pressure, reheat
Siemens Power Generation (60 Hz)										
SCC6-3000E 1X1	1993	173 000 kW	6760 Btu	50.5%	7130 kJ	****	117 000 kW	58 500 kW	1 x SGT6-3000E	dual pressure, no reheat
SCC6-3000E 2X1	1993	346 900 kW	6740 Btu	50.6%	7110 kJ	****	234 200 kW	118 000 kW	2 x SGT6-3000E	dual pressure, no reheat
SCC6-5000F 1X1	1989	295 700 kW	5990 Btu	57.0%	6320 kJ	****	196 400 kW	105 300 kW	1 x SGT6-5000F	triple pressure, reheat
SCC6-5000F 2X1	1989	598 000 kW	5950 Btu	57.3%	6280 kJ	****	392 800 kW	217 400 kW	2 x SGT6-5000F	triple pressure, reheat
SCC6-6000G single shaft	1994	397 100 kW	5803 Btu	58.8%	6123 kJ	****	****	****	1 x SGT6-6000G	triple pressure, reheat
SCC6-6000G 2x1	1994	794 300 kW	5803 Btu	58.8%	6123 kJ	****	525 200 kW	281 200 kW	2 x SGT6-6000G	triple pressure, reheat
Solar Turbines (50/60 Hz)										
STAC 60	1993	7 300 kW	8620 Btu	39.6%	9095 kJ	****	5 500 kW	1 800 kW	1 x Taurus 60	single pressure, saturated steam
STAC 70	1994	9 480 kW	8180 Btu	41.7%	8630 kJ	****	7 520 kW	1 960 kW	1 x Taurus 70	ISO rating, STAC system
STAC 100	1994	13 770 kW	8380 Btu	41.0%	8789 kJ	****	10 690 kW	3 080 kW	1 x Mars 100	is designed based on
STAC 130	1998	17 724 kW	8000 Btu	42.7%	8440 kJ	****	14 000 kW	3 724 kW	1 x Titan 130	process steam requirements

Model	Year	Net Plant Output	Heat Rate Btu/kWh	Net Plant Efficiency	Heat Rate kJ/kWh	Condenser Vacuum (Hg)	Gas Turbine Power	Steam Turbine Power	No. & Type Gas Turbine	Comments
Zorya-Mashproekt (50 Hz)										
UGT 10CC1	1998	13 000 kW	7450 Btu	45.8%	7860 kJ	****	9 500 kW	3 500 kW	1 x UGT10000	
UGT 10CC2	1998	26 500 kW	7310 Btu	46.7%	7710 kJ	****	19 000 kW	7 500 kW	2 x UGT10000	
UGT 15CC1	1998	21 200 kW	7690 Btu	44.4%	8110 kJ	****	16 000 kW	5 200 kW	1 x UGT15000	
UGT 15CC2	1988	42 800 kW	7620 Btu	44.8%	8035 kJ	****	32 000 kW	10 800 kW	2 x UGT15000	
UGT 25CC1	1993	33 000 kW	7390 Btu	46.2%	7790 kJ	****	25 000 kW	8 000 kW	1 x UGT25000	
UGT 25CC2	1993	67 200 kW	7260 Btu	47.0%	7660 kJ	****	50 000 kW	17 200 kW	2 x UGT25000	

Simple Cycle Ratings

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Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
Alstom (50 Hz)											
GT8C2	1998	56 300 kW	10 065 Btu	33.9%	17.6	433.0 lb	6219 rpm	946 F	368 166 lb	38 x 17 x 16 ft	gearbox losses included
GT11N2	1993	113 600 kW	10 247 Btu	33.3%	16.0	880.0 lb	3610 rpm	977 F	418 871 lb	31 x 18 x 33 ft	with dry low NOx combustor
GT13E2	1993	179 900 kW	9 247 Btu	36.9%	16.4	1241.0 lb	3000 rpm	950 F	747 354 lb	35 x 21 x 18 ft	with dry low NOx combustor
GT26	1994	288 300 kW	8 956 Btu	38.1%	33.9	1430.0 lb	3000 rpm	1141 F	815 697 lb	40 x 16 x 18 ft	with air quench cooler
GT26	1994	289 139 kW	8 716 Btu	39.1%	33.4	1410.0 lb	3000 rpm	1139 F	815 697 lb	40 x 16 x 18 ft	with once through cooler
Alstom (60 Hz)											
GT8C2	1998	56 200 kW	10 098 Btu	33.8%	17.6	433.0 lb	6204 rpm	946 F	368 166 lb	38 x 17 x 16 ft	gearbox losses included
GT11N2	1993	115 400 kW	10 065 Btu	33.9%	15.5	880.0 lb	3600 rpm	977 F	418 871 lb	31 x 18 x 33 ft	with dry low NOx combustor
GT24	1994	188 200 kW	9 247 Btu	36.9%	32.0	988.0 lb	3600 rpm	1126 F	507 055 lb	35 x 13 x 15 ft	with air quench cooler
GT24	1994	188 782 kW	8 956 Btu	38.1%	32.0	972.0 lb	3600 rpm	1125 F	507 055 lb	35 x 13 x 15 ft	with once through cooler
Ansaldo Energia											
V64.3A	1996	77 000kW	9 487 Btu	36.0%	17.1	470.0 lb	3000/3600	1087 F	242 500 lb	36 x 13 x 16 ft	V64.3A includes gear ox
V94.2	1981	166 000 kW	9 899 Btu	34.5%	11.8	1171.0 lb	3000 rpm	1011 F	650 400 lb	46 x 41 x 28 ft	all weights include auxiliaries
V94.2K	1981	170 000 kW	9 357 Btu	36.5%	12.0	1190.0 lb	3000 rpm	1013 F	650 400 lb	46 x 41 x 28 ft	
V94.3A	1995	285 000 kW	8 624 Btu	39.6%	17.7	1521.0 lb	3000 rpm	1062 F	727 500 lb	43 x 20 x 26 ft	
Aviadvigatel											
GTU-2.5P	1995	2 550 kW	16 175 Btu	21.1%	5.9	56.4 lb	5500/3000	682 F	83 995 lb	43 x 10 x 9 ft	includes gearbox and generator
GTU-4P	1997	4 130 kW	14 220 Btu	24.0%	7.3	65.7 lb	5500/3000	777 F	89 506 lb	43 x 10 x 9 ft	includes gearbox and generator
GTU-6P	2002	6 140 kW	13 077 Btu	26.1%	8.5	71.9 lb	6925/3000	918 F	100 529 lb	43 x 10 x 9 ft	includes gearbox and generator
GTU-12PER	2004	12 400 kW	10 373 Btu	32.9%	16.1	101.2 lb	6500/3000	919 F	198 920 lb	68 x 10 x 9 ft	includes gearbox and generator
GTE-16PA	2005	16 300 kW	9 614 Btu	35.5%	19.9	124.2 lb	3000 rpm	892 F	220 660 lb	68 x 10 x 9 ft	includes generator
GTU-16PER	2004	16 400 kW	9 807 Btu	34.8%	19.5	123.7 lb	5300/3000	923 F	229 784 lb	68 x 10 x 9 ft	includes gearbox and generator
GTU-25PER	2004	22 900 kW	9 249 Btu	36.9%	28.0	166.4 lb	5000/3000	885 F	328 490 lb	82 x 15 x 15 ft	includes gearbox and generator
Bharat Heavy Electricals											
PG5371(PA)	1988	26 300 kW	11 990 Btu	28.5%	10.5	270.0 lb	5100 rpm	909 F	185 220 lb	38 x 11 x 12 ft	all ratings on natural gas
PG6581(B)	2000	42 100 kW	10 642 Btu	32.1%	12.2	315.0 lb	5163 rpm	1011 F	200 665 lb	49 x 11 x 12 ft	
PG6591(C)	2004	42 300 kW	9 400 Btu	36.3%	19.0	258.0 lb	7100 rpm	1065 F	****	****	
PG6111(FA)	2003	75 900 kW	9 755 Btu	35.0%	15.8	447.0 lb	5254 rpm	1119 F	231 525 lb	****	
PG9171(E)	1994	126 100 kW	10 100 Btu	33.8%	12.6	903.0 lb	3000 rpm	1008 F	617 400 lb	66 x 15 x 16 ft	

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
Bharat Heavy Electricals continued											
V94.2	1997	157 000 kW	9 920 Btu	34.4%	11.1	1132.0 lb	3000 rpm	1004 F	650 475 lb	46 x 41 x 28 ft	
PG9351(FA)	1996	255 600 kW	9 250 Btu	36.9%	16.5	1428.0 lb	3000 rpm	1116 F	595 350 lb	74 x 16 x 18 ft	
PG9371(FB)	2004	279 200 kW	9 015 Btu	37.9%	18.5	1404.0 lb.	3000 rpm	1164 F	****	****	
Centrax Gas Turbine											
CX501 KB3	1993	2 691 kW	13 642 Btu	25.1%	8.0	28.3 lb	12857 rpm	1050 F	66 138 lb	30 x 9 x 10 ft	
CX501 KB5	1992	3 947 kW	11 745 Btu	29.1%	10.2	34.7 lb	14571 rpm	1031 F	70 547 lb	30 x 9 x 10 ft	
CX501 KN5	1992	4 495 kW	11 053 Btu	30.9%	10.7	36.2 lb	14571 rpm	1021 F	70 547 lb	30 x 9 x 10 ft	nozzle steam injected
CX501 KH5	1992	6 344 kW	8 551 Btu	39.9%	12.3	40.5 lb	14571 rpm	971 F	77 160 lb	30 x 9 x 10 ft	case steam injected
CX501 KB7	1993	5 333 kW	10 647 Btu	32.1%	13.5	46.4 lb	14571 rpm	930 F	70 547 lb	30 x 9 x 10 ft	
CX501 KN7	1993	5 766 kW	10 194 Btu	33.5%	14.0	47.8 lb	14571 rpm	906 F	70 547 lb	30 x 9 x 10 ft	nozzle steam injected
Dresser-Rand											
KG2-3E	1989	1 895 kW	21 543 Btu	16.7%	4.7	33.0 lb	18800 rpm	1020 F	38 580 lb	22 x 7 x 8 ft	D-R gas turbine
Vectra 30G	2007	22 767 kW	9 421 Btu	36.2%	17.9	151.2 lb	6200 rpm	1017 F	88 200 lb	30 x 14 x 15 ft	LM2500 gas gen, SAC
DR-61G	1981	23 394 kW	9 280 Btu	36.8%	18.2	153.1 lb	3600 rpm	992 F	88 200 lb	30 x 14 x 15 ft	LM2500 gas turb, SAC 60-Hz
Vectra 40G	1998	30 460 kW	8 773 Btu	38.9%	22.4	190.2 lb	6200 rpm	979 F	88 200 lb	30 x 14 x 15 ft	LM2500+ gas gen, SAC
DR-61GP	1996	30 742 kW	8 821 Btu	38.7%	22.5	192.2 lb	3600 rpm	959 F	88 200 lb	30 x 14 x 15 ft	LM2500+ gas turb, SAC 60-Hz
Vectra 40G4	2007	32 905 kW	8 722 Btu	39.1%	23.3	196.4 lb	6200 rpm	1007 F	88 200 lb	30 x 14 x 15 ft	LM2500+G4 gas gen, SAC
DR-61GPP	2005	33 175 kW	8 811 Btu	38.7%	23.0	201.8 lb	3600 rpm	978 F	88 200 lb	30 x 14 x 15 ft	LM2500+G4 gas turb, SAC 60-Hz
DR-63G	1994	42 857 kW	8 192 Btu	41.6%	28.2	278.5 lb	3600 rpm	839 F	83 800 lb	27 x 14 x 19 ft	LM6000, 60-Hz, SAC or DLE
Ebara											
ST6L-795	1986	678 kW	13 826 Btu	24.7%	7.4	7.1 lb	33000 rpm	1092\ F	229 lb	4 x 1 x 2 ft	
ST6L-813	1978	848 kW	13 099 Btu	26.1%	8.5	8.6 lb	33000 rpm	1051 F	300 lb	4 x 2 x 2 ft	
ST18A	1995	1 961 kW	11 237 Btu	30.4%	14.0	17.6 lb	18900 rpm	990 F	772 lb	5 x 2 x 3 ft	
ST40	1999	4 039 kW	10 310 Btu	33.1%	16.9	30.6 lb	14875 rpm	1011 F	1 157 lb	6 x 2 x 3 ft	
SwiftPac 4	****	3 880 kW	10 735 Btu	31.8%	16.9	30.6 lb	14875 rpm	1011 F	****	****	
FT8 PowerPac	1990	25 490 kW	8 950 Btu	38.1%	19.3	187.0 lb	3000/3600	855 F	****	****	
FT8 TwinPac	1990	51 350 kW	8 890 Btu	38.4%	19.3	374.0 lb	3000/3600	855 F	****	****	
SwiftPac 25	****	25 455 kW	8 960 Btu	38.1%	19.5	186.9 lb	3000/3600	856 F	****	****	transportable
SwiftPac 50	****	51 235 kW	8 905 Btu	38.3%	19.5	373.8 lb	3000/3600	856 F	****	****	transportable
FT8-3 PowerPac	1990	27 970 kW	8 900 Btu	38.3%	20.2	193.0 lb	3000/3600	893 F	****	****	
FT8-3 TwinPac	1990	56 340 kW	8 840 Btu	38.6%	20.2	386.0 lb	3000/3600	893 F	****	****	

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
GE Energy Aeroderivative (50 Hz)											
LM2000PS	2000	18 363 kW	10 094 Btu	33.8%	16.0	145.9 lb	3000 rpm	866 F	210 000 lb	57 x 9 x 10 ft	water injected
LM2000PJ	2000	17 855 kW	9 888 Btu	34.5%	16.0	140.2 lb	3000 rpm	925 F	210 000 lb	57 x 9 x 10 ft	DLE
LM2500PE	1981	22 346 kW	9 630 Btu	35.4%	18.0	153.6 lb	3000 rpm	1001 F	250 000 lb	57 x 9 x 10 ft	dry
LM2500PE	1981	23 060 kW	10 041 Btu	34.0%	18.0	157.8 lb	3000 rpm	963 F	250 000 lb	57 x 9 x 10 ft	water injected
LM2500PJ	1995	21 818 kW	9 655 Btu	35.3%	18.0	151.6 lb	3000 rpm	995 F	250 000 lb	57 x 9 x 10 ft	DLE
LM2500PH	1981	26 510 kW	8 679 Btu	39.3%	19.4	167.6 lb	3000 rpm	929 F	250 000 lb	57 x 9 x 10 ft	water injected
LM2500+ RC	2005	36 024 kW	9 263 Btu	36.8%	23.0	213.0 lb	3000 rpm	945 F	250 000 lb	65 x 10 x 23 ft	water injected
LM2500+ RD	2005	32 881 kW	8 949 Btu	38.1%	23.0	201.0 lb	3000 rpm	977 F	250 000 lb	65 x 10 x 23 ft	DLE
LM6000PC	1997	43 339 kW	8 571 Btu	39.8%	30.0	284.7 lb	3000 rpm	803 F	673 370 lb	65 x 14 x 15 ft	water injected
LM6000PC Sprint	1998	50 836 kW	8 478 Btu	40.2%	32.3	300.1 lb	3000 rpm	835 F	673 370 lb	65 x 14 x 15 ft	water injected
LM6000PD	1997	42 732 kW	8 222 Btu	41.5%	30.0	277.1 lb	3000 rpm	844 F	673 370 lb	65 x 14 x 15 ft	DLE
LM6000PD liquid	2005	40 999 kW	8 345 Btu	40.4%	29.5	272.1 lb	3000 rpm	852 F	673 370 lb	65 x 14 x 15 ft	distillate fuel
LM6000PD Sprint	2000	47 505 kW	8 198 Btu	41.6%	32.0	293.1 lb	3000 rpm	835 F	673 370 lb	65 x 14 x 15 ft	DLE
LM6000PF	2006	42 732 kW	8 222 Btu	41.5%	30.0	277.1 lb	3000 rpm	844 F	673 370 lb	65 x 14 x 15 ft	DLE, 15 ppm NOx
LM6000PF Sprint	2006	48 040 kW	8 188 Btu	41.7%	32.1	293.6 b	3000 rpm	840 F	673 370 lb	65 x 14 x 15 ft	DLE
LMS100PA	2006	102 998 kW	7 777 Btu	43.9%	41.0	469.9 lb	3000 rpm	765 F	TBD	130 x 20 x 54 ft	water injected
LMS100PB	TBD	98 440 kW	7 563 Btu	45.1%	40.0	456.0 lb	3000 rpm	783 F	TBD	130 x 20 x 54 ft	DLE
GE Energy Aeroderivative (60 Hz)											
LM2000PS	2000	18 412 kW	9 874 Btu	34.6%	15.6	142.7 lb	3600 rpm	860 F	210 000 lb	57 x 9 x 10 ft	water injected
LM2000PJ	2000	17 657 kW	9 707 Btu	35.2%	15.6	136.1 lb	3600 rpm	918 F	210 000 lb	57 x 9 x 10 ft	DLE
LM2500PE	1981	23 292 kW	9 315 Btu	36.6%	19.1	153.1 lb	3600 rpm	992 F	250 000 lb	57 x 9 x 10 ft	dry
LM2500PE	1981	24 049 kW	9 717 Btu	35.1%	19.1	157.4 lb	3600 rpm	955 F	250 000 lb	57 x 9 x 10 ft	water injected
LM2500PJ	1995	22 719 kW	9 345 Btu	36.5%	19.1	151.0 lb	3600 rpm	987 F	250 000 lb	57 x 9 x 10 ft	DLE
LM2500PH	1981	27 765 kW	8 391 Btu	40.7%	19.4	167.1 lb	3600 rpm	922 F	250 000 lb	57 x 9 x 10 ft	water injected
LM2500+ RC	2005	36 333 kW	9 184 Btu	37.2%	23.0	213.0 lb	3600 rpm	945 F	250 000 lb	65 x 10 x 10 ft	water injected
LM2500+ RD	2005	33 165 kW	8 774 Btu	38.9%	23.0	201.0 lb	3600 rpm	977 F	250 000 lb	65 x 10 x 10 ft	DLE
LM6000PC	1997	43 843 kW	8 519 Btu	40.1%	29.8	283.2 lb	3600 rpm	810 F	532 080 lb	56 x 14 x 15 ft	water injected
LM6000PC Sprint	1998	50 526 kW	8 458 Btu	40.3%	31.9	296.9 lb	3600 rpm	838 F	532 080 lb	56 x 14 x 15 ft	water injected
LM6000PD	1997	43 068 kW	8 173 Btu	41.7%	29.8	274.8 lb	3600 rpm	851 F	532 080 lb	56 x 14 x 15 ft	DLE
LM6000PD liquid	2005	40 712 kW	8 315 Btu	41.0%	29.8	268.2 lb	3600 rpm	856 F	532 080 lb	57 x 15 x 16 ft	distillate fuel
LM6000PD Sprint	2000	47 383 kW	8 162 Btu	41.8%	31.7	290.0 lb	3600 rpm	838 F	532 080 lb	56 x 14 x 15 ft	DLE

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
GE Energy Aeroderivative (60 Hz) continued											
LM6000PF	2006	43 068 kW	8 173 Btu	41.7%	29.8	274.8 lb	3600 rpm	851 F	532 080 lb	56 x 14 x 15 ft	DLE, 15 ppm NOx
LM6000PF Sprint	2006	48 092 kW	8 151 Btu	41.9%	31.9	290.8 lb	3600 rpm	846 F	532 080 lb	56 x 14 x 15 ft	DLE
LMS100PA	2006	103 045 kW	7 773 Btu	43.9%	41.0	469.9 lb	3600 rpm	763 F	TBD	130 x 20 x 54 ft	water injected
LMS100PB	TBD	98 396 kW	7 566 Btu	45.1%	40.0	456.0 lb	3600 rpm	763 F	TBD	130 x 20 x 54 ft	DLE
GE Energy Heavy Duty											
PG6581(B)	1999	42 100 kW	10 642 Btu	32.1%	12.2	311.0 lb	5163 rpm	1018 F	700 000 lb	123 x 24 x 34 ft	all are packaged power plants
PG6591C (50Hz)	2003	45 400 kW	9 315 Btu	36.5%	19.6	269.0 lb	7100 rpm	1078 F	775 000 lb	82 x 28 x 41 ft	50 Hz
PG6591C (60Hz)	2003	45 300 kW	9 340 Btu	36.5%	19.6	270.0 lb	7100 rpm	1078 F	775 000 lb	82 x 28 x 41 ft	60 Hz
PG6111(FA) (50Hz)	2003	77 100 kW	9 760 Btu	35.5%	15.6	467.0 lb	5231 rpm	1117 F	800 000 lb	95 x 66 x 34 ft	50 Hz
PG6111(FA) (60Hz)	2003	77 100 kW	9 795 Btu	35.4%	15.7	467.0 lb	5254 rpm	1118 F	800 000 lb	95 x 66 x 34 ft	60 Hz
PG7121(EA)	1984	85 100 kW	10 430 Btu	32.7%	12.7	648.0 lb	3600 rpm	997 F	1 070 000 lb	132 x 71 x 31 ft	ratings include inlet & exhaust
PG7241(FA)	1994	171 700 kW	9 360 Btu	36.5%	16.0	981.0 lb	3600 rpm	1114 F	1 642 000 lb	180 x 75 x 31 ft	losses & shaft driven auxiliaries
PG7251(FB)*	1999	184 400 kW	9 215 Btu	37.0%	18.4	1000.0 lb	3600 rpm	1155 F	1 642 000 lb	180 x 75 x 31 ft	*for combined cycle use only
PG9171(E)	1992	126 100 kW	10 100 Btu	33.8%	12.6	922.0 lb	3000 rpm	1009 F	1 900 000 lb	115 x 77 x 39 ft	
PG9351(FA)	1996	255 600 kW	9 250 Btu	36.9%	17.0	1413.0 lb	3000 rpm	1116 F	2 400 000 lb	112 x 25 x 50 ft	
PG9371(FB)*	2002	287 400 kW	8 985 Btu	38.0%	18.3	1453.0 lb	3000 rpm	1182 F	2 400 000 lb	112 x 25 x 50 ft	*for combined cycle use only
GE Energy Oil & Gas											
GE10-1	2000	11 250 kW	10 892 Btu	31.4%	15.5	104.7 lb	11000 rpm	900 F	74 970 lb	39 x 8 x 26 ft	DLE, size w/ GT enclosure
PGT16	1989	13 720 kW	9 760 Btu	35.0%	20.2	104.3 lb	7900 rpm	919 F	41 895 lb	27 x 11 x 12 ft	size w/o GT enclosure
PGT20	2002	17 464 kW	9 706 Btu	35.2%	15.7	137.7 lb	6500 rpm	887 F	83 020 lb	30 x 11 x 11 ft	size w/o GT enclosure
PGT25	1981	22 417 kW	9 404 Btu	36.3%	17.9	151.9 lb	6500 rpm	976 F	83 020 lb	30 x 11 x 11 ft	size w/o GT enclosure
PGT25+	1996	30 226 kW	8 612 Btu	39.6%	21.5	185.9 lb	6100 rpm	931 F	67 805 lb	21 x 13 x 13 ft	size w/o GT enclosure
PGT25+G4	2005	32 760 kW	8 594 Btu	39.7%	24.4	196.0 lb	6100 rpm	950 F	68 025 lb	21 x 13 x 13 ft	size w/o GT enclosure
LM6000PD	1994	42 336 kW	8 305 Btu	41.1%	29.3	277.9 lb	3600 rpm	840 F	68 355 lb	31 x 14 x 14 ft	size w/o GT enclosure, DLE
LMS100	2005	98 196 kW	7 582 Btu	45.0%	40.0	456.0 lb	3600 rpm	782 F	TBD	130 x 20 x 54 ft	size w/o GT enclosure, DLE
MS5001	1987	26 830 kW	12 028 Btu	28.4%	10.5	276.1 lb	5094 rpm	901 F	192 785 lb	38 x 10 x 12 ft	size w/o GT enclosure
MS5002E	2003	31 100 kW	9 751 Btu	35.0%	17.0	225.0 lb	5714 rpm	952 F	151 045 lb	56 x 13 x 13 ft	introductory rating
MS6001B	1978	42 100 kW	10 647 Btu	32.1%	12.2	311.0 lb	5163 rpm	1026 F	211 644 lb	51 x 10 x 12 ft	size w/o GT enclosure
MS7001EA	1984	85 400 kW	10 419 Btu	32.7%	12.6	643.0 lb	3600 rpm	998 F	266 759 lb	37 x 11 x 12 ft	size w/o GT enclosure
MS9001E	1976	126 100 kW	10 097 Btu	33.8%	12.6	921.0 lb	3000 rpm	1009 F	479 505 lb	51 x 45 x 16 ft	size w/o GT enclosure

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
Hitachi											
H-15	1990	15 000 kW	10 598 Btu	32.2%	14.7	115.0 lb	9710 rpm	1031 F	429 000 lb	82 x 19 x 36 ft	all ratings on natural gas fuel
H-25	1988	27 500 kW	10 097 Btu	33.8%	14.7	194.0 lb	7280 rpm	1031 F	561 000 lb	115 x 19 x 36 ft	with inlet and exhaust losses
PG5371(PA)	1987	26 300 kW	11 990 Btu	28.5%	10.5	270.0 lb	5100 rpm	909 F	570 000 lb	115 x 19 x 36 ft	& shaft-driven auxiliaries
PG6561(B)	1996	39 620 kW	10 710 Btu	31.9%	12.0	318.0 lb	5123 rpm	989 F	700 000 lb	123 x 24 x 34 ft	
PG6101(FA)	1993	70 140 kW	9 980 Btu	34.2%	15.0	433.0 lb	5247 rpm	1107 F	****	120 x 20 x 34 ft	
PG7121(EA)	1987	85 400 kW	10 420 Btu	32.8%	12.6	658.0 lb	3600 rpm	998 F	1 070 000 lb	132 x 71 x 31 ft	
PG7241(FA)	1994	171 700 kW	9 360 Btu	36.5%	15.5	952.0 lb	3600 rpm	1119 F	1 642 000 lb	180 x 75 x 31 ft	
PG9171(E)	1987	123 400 kW	10 100 Btu	33.8%	12.3	890.0 lb	3000 rpm	1001 F	1 900 000 lb	115 x 77 x 39 ft	
PG9331(FA)	1995	243 000 kW	9 360 Btu	36.5%	14.8	1422.0 lb	3000 rpm	1106 F	2 400 000 lb	112 x 25 x 50 ft	
Hitachi Zosen											
GT10	2006	4 130 kW	11 582 Btu	29.5%	10.4	34.3 lb	14200 rpm	1050 F	1 270 lb	7 x 3 x 3 ft	R-R 501-KB5S, gas fuel nozzle steam injected
GT13	2006	5 600 kW	10 646 Btu	32.1%	14.3	47.0 lb	14600 rpm	940 F	1 691 lb	9 x 4 x 3 ft	R-R 501-KB7S, gas fuel nozzle steam injected
VHP6	2006	6 260 kW	8 847 Btu	38.6%	12.5	40.0 lb	14600 rpm	991 F	1 270 lb	8 x 3 x 3 ft	R-R 501-KH5, gas fuel
IHI Power Systems											
IM270	1996	2 000 kW	13 880 Btu	24.6%	12.2	21.3 lb	20300 rpm	1013 F	4 409 lb	8 x 3 x 3 ft	dry low NOx
IM400	1982	4 100 kW	12 540 Btu	27.2%	10.9	35.1 lb	14580 rpm	1076 F	1 279 lb	7 x 3 x 3 ft	RR 501-KB5S 50/60Hz
IM400	1992	5 460 kW	11 640 Btu	29.3%	13.5	44.8 lb	14580 rpm	951 F	1 691 lb	9 x 4 x 4 ft	RR 501-KB7 50/60Hz
IM400 IHI-FLECS	1996	6 230 kW	9 570 Btu	35.7%	12.4	40.1 lb	14580 rpm	1029 F	1 171 lb	8 x 3 x 3 ft	RR 501-KH5
LM1600PA	1988	13 900 kW	10 130 Btu	33.7%	22.3	103.6 lb	7000 rpm	914 F	6 658 lb	14 x 9 x 7 ft	
LM2500PE	1976	21 900 kW	10 290 Btu	33.2%	20.0	154.3 lb	3000 rpm	986 F	7 815 lb	15 x 6 x 6 ft	50Hz
LM2500PE	1976	22 800 kW	9 960 Btu	34.3%	20.0	154.3 lb	3600 rpm	968 F	7 815 lb	15 x 6 x 6 ft	60Hz
LM2500PK	1998	28 440 kW	9 150 Btu	37.3%	23.0	181.2 lb	3000 rpm	952 F	8 485 lb	16 x 6 x 6 ft	50Hz
LM2500PK	1998	28 500 kW	8 660 Btu	39.4%	23.0	176.1 lb	3600 rpm	937 F	8 485 lb	16 x 6 x 6 ft	60Hz
LM2500RB	2006	31 970 kW	8 720 Btu	39.2%	23.0	193.9 lb	6100 rpm	958 F	31 228 lb	19 x 8 x 9 ft	50Hz
LM6000PC	1997	42 197 kW	8 330 Btu	41.0%	29.4	275.0 lb	3000 rpm	853 F	15 498 lb	16 x 7 x 7 ft	50Hz
LM6000PC	1997	42 623 kW	8 250 Btu	41.4%	29.4	275.0 lb	3600 rpm	853 F	15 498 lb	16 x 7 x 7 ft	60Hz
LM6000PC Sprint	1997	46 070 kW	8 423 Btu	40.5%	30.0	287.9 lb	3000 rpm	833 F	15 498 lb	16 x 7 x 7 ft	50Hz
LM6000PC Sprint	1997	46 370 kW	8 345 Btu	40.9%	30.0	287.0 lb	3600 rpm	835 F	15 498 lb	16 x 7 x 7 ft	60Hz
LM6000PD	1997	41 124 kW	8 390 Btu	40.7%	29.4	273.2 lb	3000 rpm	840 F	19 158 lb	16 x 7 x 7 ft	50Hz, DLE model
LM6000PD	1997	41 540 kW	8 306 Btu	41.1%	29.4	273.2 lb	3600 rpm	840 F	19 158 lb	16 x 7 x 7 ft	60Hz, DLE model
LM6000PD Sprint	1997	45 480 kW	8 424 Btu	40.5%	30.0	288.1 lb	3000 rpm	842 F	19 158 lb	16 x 7 x 7 ft	50Hz
LM6000PD Sprint	1997	45 770 kW	8 345 Btu	40.9%	30.0	286.8 lb	3600 rpm	842 F	19 158 lb	16 x 7 x 7 ft	60Hz

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
IHI Power Systems continued											
STIG-LM1600	1991	16 900 kW	8 607 Btu	39.7%	25.1	116.0 lb	7000 rpm	878 F	****	****	with 20,100 pph steam inj
STIG-LM2500	1986	26 650 kW	8 650 Btu	39.5%	19.7	168.0 lb	3000 rpm	929 F	****	****	with 50,000 pph steam inj - 50Hz
STIG-LM2500	1986	27 990 kW	8 360 Btu	40.8%	20.0	168.0 lb	3600 rpm	922 F	****	****	with 50,000 pph steam inj - 60Hz
Iskra Energetika											
GTES-4	1999	4 100 kW	14 132 Btu	24.2%	7.1	65.0 lb	5500/3000	792 F	352 734 lb	82 x 21 x 25 ft	PMZ GTU-4P
GTES-6	2001	6 200 kW	12 782 Btu	26.7%	8.7	73.9 lb	5500/3000	892 F	352 734 lb	82 x 21 x 25 ft	PMZ GTU-6P
GTES-12	2001	12 000 kW	10 242 Btu	33.3%	15.8	103.8 lb	6500/3000	878 F	573 192 lb	75 x 41 x 34 ft	PMZ GTU-12P
GTES-16	2001	16 000 kW	9 787 Btu	34.9%	19.9	125.9 lb	5500/3000	900 F	573 192 lb	82 x 41 x 34 ft	PMZ GTU-16P
Kawasaki Heavy Industries											
S2A-01	1979	648 kW	17 208 Btu	19.8%	8.5	11.2 lb	1500/1800	885 F	3 263 lb	7 x 4 x 4 ft	weights and dimensions incl. reduction gearbox, fuel/lube
M1A-13X	2001	1 424 kW	14 389 Btu	23.7%	9.6	17.4 lb	1500/1800	977 F	8 697 lb	10 x 4 x 10 ft	oil and starting systems,
M1A-13	1989	1 474 kW	14 086 Btu	24.2%	9.4	17.7 lb	1500/1800	968 F	7 209 lb	8 x 5 x 7 ft	except M7A-01, M7A-01S,
M1A-13D	1995	1 475 kW	14 229 Btu	24.0%	9.5	17.5 lb	1500/1800	986 F	7 518 lb	8 x 4 x 7 ft	and M7A-02.
M1T-13	1989	2 903 kW	14 305 Btu	23.9%	9.4	35.5 lb	1500/1800	968 F	13 668 lb	8 x 7 x 6 ft	all output at electric generator
M1T-13D	1995	2 907 kW	14 439 Btu	23.6%	9.5	35.1 lb	1500/1800	986 F	13 801 lb	8 x 7 x 7 ft	terminals with generator effic. of 95% exc. 98% for M7A-01,
M7A-01	1993	5 512 kW	11 530 Btu	29.6%	12.7	48.0 lb	1500/1800	1013 F	9 921 lb	12 x 5 x 6 ft	M7A-01S, and M7A-02.
M7A-01S	1996	6 545 kW	10 237 Btu	33.3%	12.7	48.9 lb	1500/1800	981 F	10 362 lb	12 x 5 x 6 ft	M1A-13D, M1T-13D, M7A-01D,
M7A-02	1997	6 912 kW	11 190 Btu	30.5%	15.9	59.5 lb	1500/1800	972 F	11 023 lb	12 x 5 x 6 ft	M7A-02D with dry-low NOx comb. M1A-13X with Xonon comb.
M7A-01D	1993	5 381 kW	11 648 Btu	29.3%	12.7	48.0 lb	1500/1800	1008 F	10 362 lb	12 x 5 x 6 ft	
M7A-02D	1997	6 721 kW	11 264 Btu	30.3%	15.9	59.5 lb	1500/1800	955 F	11 464 lb	12 x 5 x 6 ft	
M7A-03D	2006	7 439 kW	10 290 Btu	33.1%	15.9	59.5 lb	1500/1800	948 F	11 658 lb	14 x 5 x 6 ft	
L20A	2001	17 640 kW	9 948 Btu	34.3%	18.0	127.2 lb	3000/3600	1013 F	30 864 lb	22 x 7 x 9 ft	
MAN Turbo											
THM1203A	1979	5 760 kW	15 184 Btu	22.5%	8.0	79.0 lb	7550 rpm	959 F	165 375 lb	49 x 9 x 16 ft	
THM1304-9	1999	8 640 kW	12 341 Btu	27.7%	9.6	99.0 lb	8600 rpm	918 F	169 785 lb	52 x 9 x 17 ft	
THM1304-10	1980	9 320 kW	12 170 Btu	28.0%	10.0	100.0 lb	8600 rpm	932 F	169 785 lb	52 x 9 x 17 ft	
THM1304-11	1999	10 760 kW	11 459 Btu	29.8%	10.8	108.0 lb	8600 rpm	941 F	169 785 lb	52 x 12 x 21 ft	
THM1304-12	2004	11 520 kW	11 165 Btu	30.6%	11.0	108.0 lb	8600 rpm	959 F	169 785 lb	52 x 12 x 21 ft	
THM1304-14	2005	12 680 kW	11 000 Btu	31.0%	11.0	108.0 lb	8600 rpm	1013 F	169 785 lb	52 x 12 x 21 ft	
FT8 PowerPac	1990	25 490 kW	8 950 Btu	38.1%	19.3	187.0 lb	3000/3600	855 F	330 750 lb	66 x 15 x 12 ft	
FT8 TwinPac	1990	51 350 kW	8 890 Btu	38.4%	19.3	374.0 lb	3000/3600	855 F	551 250 lb	115 x 15 x 12 ft	

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
Mitsubishi Heavy Industries											
MF-61	1989	5 925 kW	11 910 Btu	28.7%	15.0	60.0 lb	13800 rpm	925 F	21 605 lb	12 x 8 x 10 ft	all ratings on natural gas
MF-111	1985	14 570 kW	11 020 Btu	31.0%	15.0	121.0 lb	9660 rpm	986 F	48 501 lb	18 x 9 x 8 ft	with inlet and exhaust losses
MFT-8	1994	26 780 kW	8 820 Btu	38.7%	21.0	190.0 lb	5000 rpm	867 F	14 771 lb	23 x 8 x 8 ft	shaft output
MF-221	1994	30 000 kW	10 670 Btu	32.0%	15.0	238.0 lb	7200 rpm	991 F	110 229 lb	25 x 12 x 11 ft	
M501DA	1980	113 950 kW	9 780 Btu	34.9%	14.0	763.0 lb	3600 rpm	1009 F	319 665 lb	38 x 19 x 14 ft	
M501F3	1989	185 400 kW	9 230 Btu	37.0%	16.0	1011.0 lb	3600 rpm	1136 F	429 894 lb	46 x 15 x 15 ft	
M501G1	1997	267 500 kW	8 730 Btu	39.1%	20.0	1320.0 lb	3600 rpm	1113 F	551 146 lb	50 x 15 x 16 ft	
M701DA	1981	144 090 kW	9 810 Btu	34.8%	14.0	972.0 lb	3000 rpm	1008 F	440 917 lb	41 x 17 x 17 ft	
M701F4	1992	312 100 kW	8 683 Btu	39.3%	18.0	1549.0 lb	3000 rpm	1106\ F	922 633 lb	57 x 19 x 19 ft	
M701G2	1997	334 000 kW	8 630 Btu	39.5%	21.0	1625.0 lb	3000 rpm	1089 F	925 926 lb	60 x 20 x 20 ft	
Mitsui Engineering & Shipbuilding											
SB5	1987	1 080 kW	13 390 Btu	25.5%	10.0	11.0 lb	26600 rpm	918 F	2 205 lb	6 x 5 x 3 ft	
SB15	1986	2 720 kW	13 330 Btu	25.6%	10.0	32.0 lb	13070 rpm	916 F	14 109 lb	10 x 5 x 10 ft	
SB30E	1995	7 330 kW	12 200 Btu	28.0%	12.5	72.5 lb	11380 rpm	936 F	41 446 lb	16 x 8 x 12 ft	
SB60-2	1981	12 490kW	11 530Btu	29.6%	12.1	122.0 lb	5680 rpm	853 F	120 591 lb	24 x 11 x 15 ft	two shaft design
SB60-1	1988	13 570kW	11 490Btu	29.7%	13.2	131.0lb	6780 rpm	918 F	114 638 lb	23 x 11 x 15 ft	one shaft design
SB120	1985	23 000kW	11 190Btu	30.5%	11.7	225.0lb	5070 rpm	887 F	198 413 lb	31 x 14 x 20 ft	
MSC40	1970	3 520kW	12 240Btu	27.9%	9.7	41.0lb	1500/1800	819 F	59 524 lb	29 x 8 x 10 ft	Centaur 40
MSC50	1985	4 350kW	11 675Btu	29.2%	10.3	41.9lb	1500/1800	934 F	59 524 lb	29 x 8 x 10 ft	Centaur 50
MSC60	1989	5 000kW	11 250Btu	30.3%	11.7	47.1lb	1500/1800	898 F	59 524 lb	29 x 8 x 10 ft	Taurus 60
MSC70	1994	6 840 kW	10 570 Btu	32.3%	15.0	56.2 lb	1500/1800	894 F	116 843 lb	41 x 9 x 11 ft	Taurus 70
MSC90	1987	9 290 kW	10 765 Btu	31.7%	16.2	86.4 lb	1500/1800	867 F	149 912 lb	48 x 9 x 11 ft	Mars 90
MSC100	1989	10 690 kW	10 505 Btu	32.5%	17.1	91.8 lb	1500/1800	910 F	149 912 lb	48 x 9 x 11 ft	Mars 100
Motor Sich - Progress (50/60 Hz)											
TV3-137	1999	1 100 kW	13 655 Btu	25.0%	7.5	16.1 lb	15000 rpm	790 F	639 lb	7 x 2 x 2 ft	natural gas fuel
AI-20DME	1991	2 500 kW	14 224 Btu	24.0%	9.0	42.7 lb	12300 rpm	968 F	2 646 lb	11 x 3 x 4 ft	dual fuel
GTE-6.3/MS	1997	6 300 kW	11 012 Btu	31.0%	15.3	70.4 lb	8560 rpm	808 F	3 241 lb	13 x 4 x 4 ft	gas fuel
GTE-8/MS	2001	8 000 kW	10 735 Btu	31.8%	17.5	81.1 lb	8560 rpm	846 F	3 241 lb	13 x 4 x 4 ft	gas fuel
MTU Friedrichshafen											
LM1600-PA	1989	13 820 kW	9 577 Btu	35.6%	21.5	103.0 lb	7000/1500	910 F	7 550 lb	15 x 8 x 7 ft	all with 3.5% gearbox and
LM2500 PE	1973	22 460 kW	9 417 Btu	36.2%	18.8	152.0 lb	3600/1500	974 F	10 300 lb	21 x 7 x 7 ft	generator loss
LM2500 PH STIG	1986	27 630 kW	8 450 Btu	40.4%	20.2	167.0 lb	3600/1500	926 F	10 500 lb	21 x 7 x 7 ft	
LM2500+ (PK)	1998	28 070 kW	9 022 Btu	37.8%	22.2	183.0 lb	3600/1500	950 F	11 500 lb	22 x 7 x 7 ft	
NK - Engines											
NK-143	1996	10 000 kW	10 340 Btu	33.0%	11.3	87.5 lb	3000/3600	***	6 835 lb	15 x 5 x 5 ft	
NK-39	1995	16 000 kW	8 981 Btu	38.0%	25.9	120.0 lb	3000/3600	829 F	15 900 lb	19 x 7 x 7 ft	
NK-37	1993	25 000 kW	9 376 Btu	36.4%	23.1	223.0 lb	3000/3600	797 F	21 790 lb	17 x 7 x 7 ft	

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
OPRA Optimal Radial Turbine											
OP16-3A	2004	1 910 kW	12 732 Btu	26.9%	6.7	19.2 lb	26000 rpm	1032 F	3 968 lb	8 x 4 x 5 ft	
OP16-3B (DLE)	2004	1 910 kW	12 732 Btu	26.9%	6.7	19.2 lb	26000 rpm	1032 F	3 968 lb	8 x 4 x 5 ft	
Orenda Aerospace											
OGT2500	1994	2 670 kW	12 780 Btu	26.7%	12.0	33.1 lb	1500/1800	860 F	5 513 lb	10 x 4 x 7 ft	weights, dimensions engine only
GT4000SI	1994	4 050 kW	10 065 Btu	33.9%	12.0	37.5 lb	3000/3600	842 F	5 513 lb	10 x 4 x 7 ft	
GT6000	1994	6 500 kW	11 187 Btu	30.5%	14.0	68.3 lb	3000/3600	788 F	9 923 lb	15 x 6 x 6 ft	weights, dimensions engine only
GT15000	1996	16 300 kW	9 977 Btu	34.2%	19.7	158.7 lb	3000/3600	770 F	28 224 lb	20 x 7 x 8 ft	weights, dimensions engine only
GT16000BF	1991	15 500 kW	11 090 Btu	30.8%	13.0	212.0 lb	3000/3600	662 F	35 280 lb	19 x 9 x 10 ft	diesel, bio oil, heavy oil, ethanol
GT25000	1996	25 500 kW	9 639 Btu	35.4%	21.0	198.2 lb	3000/3600	914 F	35 280 lb	21 x 8 x 9 ft	weights, dimensions engine only
Pratt & Whitney Power Systems											
ST6L-795	1986	678 kW	13 826 Btu	24.7%	7.4	7.1 lb	33000 rpm	1092 F	229 lb	4 x 1 x 2 ft	
ST6L-813	1978	848 kW	13 099 Btu	26.1%	8.5	8.6 lb	33000 rpm	1051 F	300 lb	4 x 2 x 2 ft	
ST18A	1995	1 961 kW	11 237 Btu	30.4%	14.0	17.6 lb	18900 rpm	990 F	772 lb	5 x 2 x 3 ft	
ST40	1999	4 039 kW	10 310 Btu	33.1%	16.9	30.6 lb	14875 rpm	1011 F	1 157 lb	6 x 2 x 3 ft	
SwiftPac 4	2003	3 880 kW	10 735Btu	31.8%	16.9	30.6 lb	14875 rpm	1011 F	****	****	
MobilePac	2005	24 957 kW	9 035Btu	37.8%	19.3	187.0 lb	3000/3600	855 F	****	****	
FT8 PowerPac	1990	25 490 kW	8 950 Btu	38.1%	19.3	187.0 lb	3000/3600	855 F	****	****	
FT8 TwinPac	1990	51 350 kW	8 890 Btu	38.4%	19.3	374.0 lb	3000/3600	855 F	****	****	
SwiftPac 25	2003	25 455 kW	8 960 Btu	38.1%	19.5	186.9 lb	3000/3600	856 F	****	****	transportable
SwiftPac 50	2003	51 235 kW	8 905 Btu	38.3%	19.5	373.8 lb	3000/3600	856 F	****	****	transportable
FT8-3 PowerPac	1990	27 970 kW	8 900 Btu	38.3%	20.2	193.0 lb	3000/3600	893 F	****	****	
FT8-3 TwinPac	1990	56 340 kW	8 840 Btu	38.6%	20.2	386.0 lb	3000/3600	893 F	****	****	
Rolls-Royce											
501-KB5S	1990	3 897 kW	11 747 Btu	29.0%	10.3	33.9 lb	14200 rpm	1040 F	****	****	ratings at sea level, 15 deg C
501-KB7S	1992	5 245 kW	10 848 Btu	31.5%	13.9	46.6 lb	14600 rpm	928 F	****	****	no external pressure losses
501-KH5	1982	6 447 kW	8 509 Btu	40.1%	12.5	40.6 lb	14600 rpm	986 F	****	****	case steam injected 2.73 kg/sec steam injection
RB211-G62 DLE	1993	27 520 kW	9 415 Btu	36.2%	20.8	202.0 lb	4800 rpm	932 F	****	****	
RB211-GT62 DLE	1999	29 500 kW	9 055 Btu	37.7%	21.5	211.0 lb	4800 rpm	920 F	****	****	
RB211-GT61 DLE	2000	32 120 kW	8 680 Btu	39.3%	21.5	208.0 lb	4850 rpm	938 F	****	****	
Trent 60 DLE	1996	51 504 kW	8 104 Btu	42.1%	33.0	334.0 lb	3000 rpm	832 F	****	****	
Trent 60 DLE	1996	51 685 kW	8 138 Btu	41.9%	34.0	341.0 lb	3600 rpm	825 F	****	****	
Trent 60 WLE	2001	58 000 kW	8 346 Btu	40.9%	36.0	365.0 lb	3000 rpm	794 F	****	****	water injected
Trent 60 WLE	2001	58 000 kW	8 336 Btu	40.9%	35.0	358.0 lb	3600 rpm	805 F	****	****	water injected

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
Siemens Power Generation											
SGT-100	1989	4 350 kW	11 370 Btu	30.0%	13.0	39.0 lb	16500 rpm	981 F	78 175 lb	33 x 8 x 11 ft	
SGT-100	1989	4 700 kW	11 309 Btu	30.2%	14.1	42.0 lb	17384 rpm	975 F	78 175 lb	33 x 8 x 11 ft	
SGT-100	1997	5 050 kW	11 294 Btu	30.2%	14.3	43.0 lb	17384 rpm	1015 F	78 175 lb	33 x 8 x 11 ft	
SGT-100	1998	5 250 kW	11 203 Btu	30.5%	14.8	46.0 lb	17384 rpm	986 F	78 175 lb	33 x 8 x 11 ft	
SGT-200	1981	6 750 kW	10 824 Btu	31.5%	12.3	65.0 lb	11053 rpm	871 F	124 000 lb	41 x 8 x 11 ft	
SGT-300	1995	7 900 kW	10 937 Btu	31.2%	13.8	66.0 lb	14010 rpm	999 F	126 000 lb	40 x 8 x 12 ft	
SGT-400	1997	12 900 kW	9 817 Btu	34.8%	16.9	87.0 lb	9500 rpm	1031 F	165 000 lb	61 x 9 x 13 ft	
SGT-500	1968	17 000 kW	10 600 Btu	32.2%	12.0	203.5 lb	3000/3600	707 F	331 000 lb	68 x 16 x 13 ft	50/60 Hz
SGT-600	1981	24 770 kW	9 985 Btu	34.2%	14.0	177.3 lb	7700 rpm	1009F	335 000 lb	68 x 15 x 17 ft	50/60 Hz
SGT-700	1999	29 060 kW	9 480 Btu	36.0%	18.0	201.0 lb	6500 rpm	964F	353 000 lb	68 x 15 x 18 ft	50/60 Hz
SGT-800	1998	45 000 kW	9 224 Btu	37.0%	19.3	287.0 lb	6600 rpm	1001F	379 000 lb	56 x 15 x 13 ft	50/60 Hz
SGT-800	2007	47 000 kW	9 100 Btu	37.5%	20.0	290.0 lb	6600 rpm	1012F	379 000 lb	56 x 15 x 13 ft	50/60 Hz
SGT-900	1982	49 500 kW	10 450 Btu	32.7%	15.3	386.0 lb	5425 rpm	957F	276 000 lb	50 x 12 x 14 ft	50/60 Hz, W251B11/12
SGT-1000F	1996	67 700 kW	9 730 Btu	35.1%	15.8	422.0 lb	5400 rpm	1081 F	242 500 lb	36 x 13 x 16 ft	50/60 Hz, V64.3A
SGT6-3000E	1993	120 500 kW	9 840 Btu	34.7%	14.2	849.0 lb	3600 rpm	986 F	310 000 lb	34 x 12 x 14 ft	W501D5A
SGT5-2000E	1981	168 000 kW	9 825 Btu	34.7%	11.7	1170.0 lb	3000 rpm	998 F	650 360 lb	46 x 41 x 28 ft	V94.2
SGT6-5000F	1989	202 000 kW	8 955 Btu	38.1%	17.4	1120.0 lb	3600 rpm	1073 F	425 000 lb	33 x 13 x 15 ft	W501F
SGT5-3000E	1997	191 000 kW	9 283 Btu	36.8%	13.3	1129.0 lb	3000 rpm	1068 F	727 520 lb	43 x 20 x 26 ft	V94.2A, 41000 EOH Maint Interval
SGT6-6000G	1994	267 500 kW	8 715 Btu	39.2%	19.9	1284.0 lb	3600 rpm	1135 F	600 000 lb	36 x 14 x 15 ft	W501G
SGT5-4000F	1995	286 600 kW	8 638 Btu	39.5%	17.9	1520.0 lb	3000 rpm	1071 F	727 520 lb	43 x 20 x 26 ft	V94.3A
Solar Turbines											
Saturn 20	1985	1 210 kW	14 025 Btu	24.3%	6.8	14.4 lb	22516 rpm	940 F	22 000 lb	18 x 6 x 7 ft	
Centaur 40	1992	3 515 kW	12 240 Btu	27.9%	9.8	41.9 lb	14944 rpm	830 F	52 370 lb	32 x 8 x 9 ft	
Centaur 50	1993	4 600 kW	11 630 Btu	29.3%	10.6	42.1 lb	14944 rpm	950 F	59 700 lb	32 x 8 x 9 ft	
Mercury 50	1997	4 600 kW	8 863 Btu	38.5%	9.9	39.0 lb	14944 rpm	710 F	129 700 lb	37 x 10 x 12 ft	
Taurus 60	1993	5 670 kW	11 225 Btu	31.5%	12.5	48.0 lb	14951 rpm	950 F	66 900 lb	32 x 8 x 9 ft	
Taurus 65	2005	6 300 kW	10 375 Btu	32.9%	15.1	46.5 lb	14951 rpm	1021 F	72 700 lb	32 x 8 x 10 ft	
Taurus 70	1994	7 520 kW	10 100 Btu	33.8%	16.1	59.4 lb	15200 rpm	905 F	125 405 lb	37 x 9 x 9 ft	
Mars 100	1994	10 690 kW	10 520 Btu	32.4%	17.4	91.7 lb	10780 rpm	910 F	160 000 lb	48 x 9 x 12 ft	
Titan 130	1998	15 000 kW	9 695 Btu	38.9%	16.1	109.8 lb	11220 rpm	925 F	162 409 lb	46 x 11 x 11 ft	
Titan 130 Mobile	2005	15 000 kW	9 695 Btu	35.2%	17.0	109.8 lb	11220 rpm	925 F	147 599 lb	46 x 11 x 11 ft	

Model	Year	ISO Base Rating	Heat Rate Btu/kWh	Efficiency	Pressure Ratio	Flow lb/sec	Turbine Speed	Exhaust Temp	Approx Weight	Approx L x W x H	Comments
Turbomach											
TBM-S20	1985	1 204 kW	14 025 Btu	24.3%	6.7	14.4 lb	1500/1800	942 F	44 092 lb	20 x 6 x 9 ft	Saturn 20
TBM-C40	1992	3 515 kW	12 244 Btu	27.8%	9.7	41.9 lb	1500/1800	829 F	88 184 lb	39 x 7 x 11 ft	Centaur 40
TBM-C50	1993	4 600 kW	11 628 Btu	29.3%	10.6	42.1 lb	1500/1800	949 F	97 003 lb	39 x 7 x 11 ft	Centaur 50
TBM-M50	1997	4 600 kW	8 863 Btu	38.5%	9.9	39.3 lb	1500/1800	705 F	110 231 lb	42 x 10 x 11 ft	Mercury 50
TBM-T60	1993	5 670 kW	10 832 Btu	31.5%	12.5	48.0 lb	1500/1800	951 F	99 208 lb	39 x 7 x 11 ft	Taurus 60
TBM-T65	2005	6 300 kW	10 375 Btu	32.9%	15.0	46.5 lb	1500/1800	1021 F	123 459 lb	36 x 7 x 11 ft	Taurus 65
TBM-T70	1994	7 520 kW	10 098 Btu	33.8%	16.0	59.4 lb	1500/1800	906 F	149 914 lb	39 x 10 x 10 ft	Taurus 70
TBM-M100	1994	10 685 kW	10 514 Btu	32.4%	17.4	92.1 lb	1500/1800	908 F	185 188 lb	49 x 10 x 10 ft	Mars 100
TBM-T130	1998	15 000 kW	9 695 Btu	35.2%	16.0	109.8 lb	1500/1800	925 F	196 211 lb	51 x 10 x 10 ft	Titan 130
Vericor											
VPS1	1974	500 kW	16 467 Btu	20.7%	10.5	7.9 lb	1500/1800	908 F	20 000 lb	14 x 9 x 14 ft	
VPS3	1978	3 148 kW	12 553 Btu	28.3%	8.7	28.3 lb	15400 rpm	1108 F	70 000 lb	25 x 9 x 20 ft	
VPS4	1999	3 519 kW	11 907 Btu	30.4%	9.9	30.4 lb	15400 rpm	1076 F	70 000 lb	25 x 9 x 20 ft	
Zorya-Mashproekt											
UGT 2500	1992	2 850 kW	11 975 Btu	28.5%	12.0	36.4 lb	1800/3000	860 F	3 300 lb	10 x 4 x 6 ft	
UGT 6000	1978	6 360 kW	10 835 Btu	31.5%	13.5	67.2 lb	3000 rpm	797 F	7 720 lb	10 x 5 x 6 ft	
UGT 8000	2006	9 000 kW	10 150 Btu	33.6%	17.9	77.2 lb	3000 rpm	896 F	****	****	
UGT 10000	1998	10 300 kW	9 670 Btu	35.3%	19.0	79.4 lb	3000/3600	914 F	9 920 lb	12 x 6 x 6 ft	gearbox losses included
UGT 16000	1980	15 900 kW	10 870 Btu	31.4%	12.5	211.6 lb	3000/3600	662 F	35 270 lb	19 x 9 x 10 ft	
UGT 15000	1988	16 900 kW	9 750 Btu	35.0%	19.5	156.5 lb	3000/3600	788 F	19 840 lb	16 x 9 x 9 ft	
UGT 15000 STIG	1995	25 000 kW	8 130 Btu	42.0%	17.9	160.3 lb	3000/3600	824 F	429 900 lb	82 x 43 x 39 ft	with inlet and exhaust losses
UGT 25000	1993	26 200 kW	9 400 Btu	36.3%	20.5	192.9 lb	3000/3600	905 F	30 860 lb	21 x 8 x 9 ft	

BASF

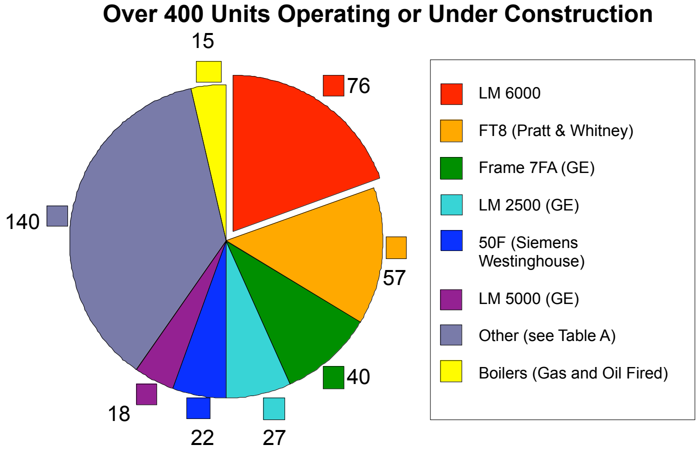
The Chemical Company

Oxidation Catalyst – Power Generation

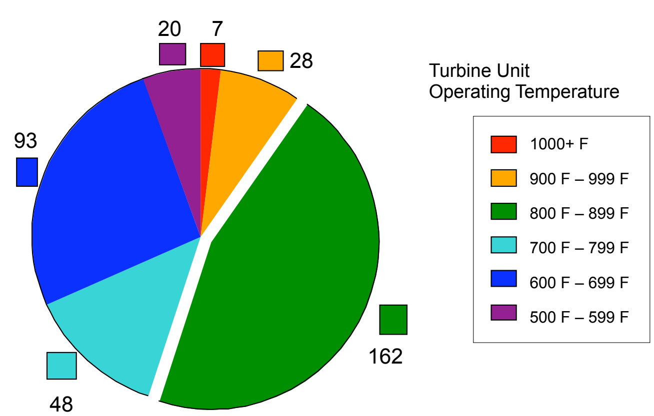
BASF is the #1 oxidation catalyst supplier in the world. We have serviced the Power Generation industry for over 15 years with 400 units operating or under construction (refer to Figure 1 and Table A). Our experience encompasses virtually every make, model, and turbine configuration (see Figure 2).

BASF customers value our experience and do not worry about the performance of their oxidation catalyst. In the power generation industry, the stakes are too high to be shut down – for any reason. Even a short outage can be devastating. Lost revenue can pay for catalyst many times over.

Over 400 Units Operating or Under Construction



Extensive Simple and Combined Cycle Operating Experience



Manufacturer	Model	Units
ABB	GT24	14
Pratt & Whitney	FT8 Twin Pac (2 CT/Unit)	13
GE	10	12
Mitsubishi	501G	9
Westinghouse	501AA	6
GE	LM6000 Sprint	5
Westinghouse	191	4
GE	Frame 7	4
GE	LM2500 (2 CTs/Unit)	4
Westinghouse	251	3
Westinghouse	501G	3
GE	Frame 7E	3
GE	Frame 7EA	3
GE	Frame 7FB	3
ABB	GT10	3
GE	LM1600	3
RR	RB211	3
Solar	Taurus 60	3
Siemens	V84.2	3
Siemens Westinghouse	501G	2
BBC	8	2
Solar	Centaur 50	2
GE	Frame 6	2
GE	Frame 6B	2
Solar	Mars	2
ABB	10B	1
ABB	11N2	1
Westinghouse	251B12	1
Westinghouse	501 D5A	1
Solar	Centaur	1
GE	Frame 7F	1
GE	Frame 9	1
Pratt & Whitney	FT4A9	1
Mannesman	GHH FT8	1
GE	LM1500	1
Solar	Taurus 70	1
Siemens	V84.3A	1
Make/Model Unknown		23

BF-8358, 02/2007

The Chemical Company

BASF is extremely proud of our low cost and technologically superior oxidation catalyst. Our catalysts perform well beyond the warranty period, which makes them an excellent value (refer to Figure 3). Almost all of the Powergen oxidation catalysts that we have supplied are still running. More than 50 units are six to ten years old and 30+ units are over ten years old. No one else in the industry even comes close to this durability.

BASF Catalysts Perform Well Beyond the Warranty

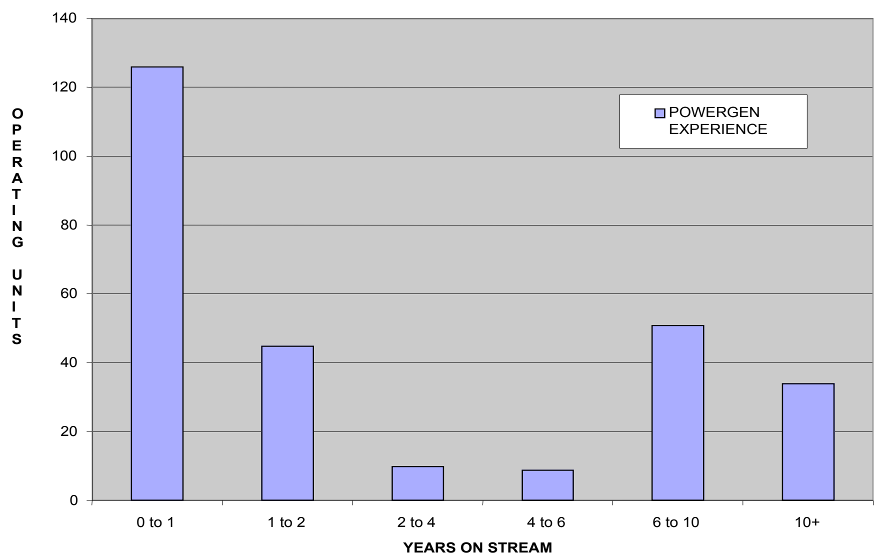


Figure 3 – Catalyst

Other BASF Powergen Experience

- Highest CO removal efficiency – 98%+
- Most VOC experience
- HAPs conversion data
- >99% warranty compliance
- 100% on-time delivery

If you need more detailed information, or have a question about oxidation catalyst, please contact us:

BASF Catalysts LLC
101 Wood Avenue
Iselin, NJ 08830
Telephone: 732-205-5077
Toll-free: 800-631-9505
Fax: 732-205-6146
Web site: www.basf-catalysts.com

Exhibit 20

	StartupDate	SiteLocation	TurbineMfg	Applications	IdenticalUnits	Temperature	Flow	COConv.	VOCConv.	Fuel
1					3	932	59	50.00%		NG/Oil
2	10/1/1986	New Mexico	RR	RB211	3	645	139	90.00%		
3	11/1/1987	Illinois	GE	LM2500	1	519	160	42.00%		
4	12/1/1987	California	GE	Frame 6	2	902	305	90.00%		
5	6/1/1988	California	GE	LM5000	1	750	351	90.00%		
6	6/1/1988	California	Westinghouse	251	1	710	375	82.00%		
7	7/1/1988	California	GE	LM2500	1	936	152	80.00%		
8	7/1/1988	California	GE	LM2500	2	720	154	80.00%		
9	9/1/1988	California	GE	LM2500	1	858	150	83.00%		
10	2/1/1989	California	GE	Frame 7	1	535	695	80.00%		
11	2/1/1989	California	GE	LM2500	6	890	162	82.00%		
12	2/1/1989	California		Boiler	2	533	33	90.00%		
13	3/1/1989	New Jersey	GE	LM2500	1	820	172	80.00%		
14	3/1/1989	California	GE	Frame 7E	1	990	671	85.00%		
15	5/1/1989	California	GE	LM5000	1		300	90.00%		
16	6/1/1989	California	GE	LM2500	1	920	149	84.00%		
17	6/1/1989	California	GE	LM2500	1		148	90.00%		
18	7/1/1989	New York	GE	LM2500	2		148	90.00%		
19	9/1/1989	California	GE	LM5000	1	792	303	80.00%		
20	2/1/1990	California	GE	LM5000	1	760	350	60.00%		
21	6/1/1990	Texas	Westinghouse	191	2	775	267	85.00%		
22	7/1/1990	California	GE	LM2500	1	920	149	84.00%		
23	8/1/1990	Texas	Westinghouse	191	2	775	267	85.00%		
24	12/1/1990	California	GE	LM5000	1	900	333	82.00%		
25	1/1/1991	New Jersey	GE	Frame 7	2	580	750	75.00%		
26	2/1/1991	California	GE	LM5000	1	760	350	80.00%		
27	6/1/1991	California	GE	LM5000	1	760	350	80.00%		
28	7/1/1991	Pennsylvania	GE	LM5000	2	546	286	90.00%		
29	9/1/1991	New York	GE	LM5000	2	550	286	90.00%		
30	9/1/1991	New York	GE	LM5000	1		300	90.00%		
31	10/1/1991	Nevada	GE	LM2500	6	589	148	90.00%		
32	11/1/1991	California	GE	LM5000	1	760	350	80.00%		
33	1/1/1992	California	BBC	8	2	930	410	90.00%		
34	4/1/1992	California	GE	LM5000	1	660	306	80.00%		
35	6/1/1992	California	GE	LM1600	2	959	107	90.00%		
36	8/1/1992	Texas	RR		1	1100	259	95.00%		
37	12/1/1992	New Jersey	Westinghouse	251	2	590	422	90.00%		
38	3/1/1993	Washington	GE	Frame 7	1	625	669	80.00%		
39	5/1/1993	California	GE	LM2500	1	900	157	80.00%		
40	7/1/1993	California	GE	Frame 7E	2	971	687	92.00%		
41	11/1/1993	New Mexico	ABB	10B	1	983	154	87.00%		
42	11/1/1993	New York	GE	Frame 7EA	2	705	663	90.00%		
43	3/1/1994	New Jersey	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	4	678	427	90.00%		
44	4/1/1994	Texas	Solar	Mars	1	980	85	95.00%		
45	7/1/1994	California	GE	LM2500	2		153	90.00%		
46	8/1/1994	California			1	680	91.5	90.00%		
47	8/1/1994	Switzerland	ABB		1	900	60	80.00%		
48	8/1/1994	Massachusetts	ABB	GT10	1	879	184	98.00%		
49	8/1/1994	California	GE	LM6000	1		303	90.00%		
50	8/1/1994	California		Boiler	2	470	12.9	90.00%		
51	4/1/1995	California	GE	LM5000	1	750	342	88.00%		
52	4/1/1995	California	GE	LM5000	1	750	342	88.00%		
53	4/1/1995	California	GE	LM5000	1	880	350	80.00%		
54	6/1/1995	New Jersey		Boiler	2	700	66	90.00%		
55	7/1/1995	New Jersey	Solar	Centaur	1	980	37	91.00%		
56	8/1/1995	New York	GE	LM5000	1		300	90.00%		
57	8/1/1995	California	GE	LM6000	2	560	343	90.00%		
58	8/1/1995	Michigan	GE	Frame 7EA	1	876	673	80.00%		
59	8/1/1995	New Jersey	GE	LM1600	1			90.00%		
60	11/1/1995	California	Pratt & Whitney	FT4A9	1	860	314	80.00%		
61	12/1/1995	New York	Siemens	V84.2	2	1027	750	98.00%		
62	1/1/1996	Colorado	GE	LM6000	1	620	247	80.00%		
63	3/1/1996	California	GE	LM6000	1	938	290	90.00%		
64	4/1/1996	California	GE	LM2500	1	604	162	92.00%		
65	7/1/1996	Minnesota	Westinghouse	501F	1	655	1079	90.00%		
66	8/1/1996	Austria	Mannesman	GHH FT8	1	878	197	70.00%		
67	1/1/1997	Washington	GE	Frame 7F	1	965	1062	82.00%		
68	3/1/1997	Virginia	Westinghouse	251B12	1	700	431	91.00%		
69	3/1/1997	Pennsylvania	Westinghouse	501 D5A	1	1107	931	90.00%		

70	3/1/1997	California	Siemens	V84.2	1	635	782	90.00%		
71	9/1/1998	Massachusetts	ABB	11N2	1	637	888	80.00%		
72	12/1/1998	Scotland	ABB	GT10	1	952	189	95.00%		
73	1/1/1999	Massachusetts	Solar	Centaur 50	1	910	46	80.00%		
74	6/1/1999	Italy	GE	Frame 9	1	660	956	85.00%		
75	10/1/1999	Nevada	Westinghouse	501F	2	600	996	85.00%		
76	10/1/1999	Massachusetts	ABB	GT24	1	633	935	80.00%		
77	10/1/1999	Texas	GE	Frame 6B	2	1019	347	75.00%		
78	12/1/1999	Massachusetts	Westinghouse	501G	1	633	1472	90.00%		
79	3/1/2000	Ohio	Pratt & Whitney	FT8	8	898	214	90.00%		NG
80	6/1/2000	Connecticut	ABB	GT24	3	640	930	80.40%		NG/Distilate Oil
81	7/1/2000	California	Pratt & Whitney	FT8	1	775	73	60.00%		
82	10/1/2000	California	Solar	Centaur 50	1	921	42	88.00%		NG/Propane
83	12/1/2000	Unknown	Pratt & Whitney	FT8	18	898	214	90.00%		NG
84	12/1/2000	Illinois	Pratt & Whitney	FT8	12	898	214	90.00%		NG
85	12/1/2000	West Virginia	Pratt & Whitney	FT8	2	898	214	90.00%		NG
86	3/1/2001	California	Siemens	501F	2	665	1010	89.30%		NG
87	4/1/2001	Texas			1	775	268	85.00%		
88	4/1/2001	Pennsylvania	Westinghouse	501G	2	649	1417	80.00%		NG/Distilate Oil
89	4/1/2001	New Jersey	GE	Frame 7FA	1	759	1073	82.30%		NG/LS-Diesel
90	4/1/2001	West Virginia			6	998	656	50.00%		NG
91	4/1/2001	West Virginia	Pratt & Whitney	FT8	12	898	214	90.00%		NG
92	5/1/2001	California	GE	Frame 7FA	2	1025	1053	62.70%	36.00%	NG
93	6/1/2001	California	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	1	750	390	80.00%		NG
94	6/1/2001	California	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	1	750	390	80.00%		NG
95	6/1/2001	New York	GE	LM6000	11	840	292	93.30%		NG
96	6/1/2001	Washington	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	2	804	471	87.50%		NG
97	6/1/2001	Nevada	Westinghouse	501AA	6	840	814	90.00%		NG
98	6/1/2001	California	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	1	750	390	80.00%		NG
99	6/1/2001	California	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	1	750	390	80.00%		NG
100	6/1/2001	California	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	2	750	390	80.00%		NG
101	6/1/2001	Oregon	Pratt & Whitney	FT8	4	898	214	90.00%		NG
102	6/1/2001	N/A	GE	LM1500	1	850	114			NG/Oil
103	6/1/2001	California	Pratt & Whitney	FT8 Twin Pac (2 CT/Unit	1	750	390	80.00%		NG
104	6/1/2001		Pratt & Whitney	FT8	8	898	214	90.00%		NG
105	6/1/2001	Kansas	Siemens	V84.3A	1	735	1047	51.50%		NG
106	6/1/2001	Idaho	GE	Frame 7FA	1	654	1001	30.00%		NG
107	6/1/2001	Florida	Westinghouse	501F	2	623	1098	90.00%		NG/Oil
108	6/1/2001	California	GE	LM6000	3	858	292	90.00%		NG
109	7/1/2001	California		Boiler	2	730	509	95.00%		NG
110	8/1/2001	California	GE	LM6000	2	750	342	92.00%		NG
111	8/1/2001	Massachusetts	Mitsubishi	501G	4	711	1454	86.60%		NG
112	8/1/2001	Massachusetts	Mitsubishi	501G	2	711	1454	86.60%		NG
113	9/1/2001	Washington	GE	10	4	860	111	80.00%		NG
114	9/1/2001	Arizona	Solar	Taurus 70	1	971	56	60.00%		NG
115	9/1/2001	Connecticut	GE	LM6000 Sprint	5	853	292	90.00%		NG
116	9/1/2001	Massachusetts	ABB	GT24	2	633	910	83.80%		NG
117	9/1/2001	Washington	Solar	Mars	1	860	100	90.00%		NG
118	9/1/2001	Washington	GE	LM2500 (2 CTs/Unit)	4	840	376	90.00%		NG/#2 Oil
119	9/1/2001	California	GE	LM6000	6	840	292	90.00%		NG
120	10/1/2001	Connecticut	ABB	GT24	2	653	938	80.00%		NG/Distilate Oil
121	10/1/2001	California	GE	10	8	850	110	82.60%		NG
122	10/1/2001	California	GE	LM6000	1	750	342	92.00%	30.00%	NG
123	10/1/2001	California	ABB	GT24	4	626	902	90.10%		NG
124	10/1/2001	Utah	GE	LM6000	4	840	278	82.10%		NG
125	11/1/2001	California			1	790	580	80.00%		NG
126	11/1/2001	California	Solar	Taurus 60	1	904	51	92.00%		NG
127	11/1/2001	Texas		Boiler	1	800	64	80.00%		NG
128	11/1/2001	Texas		Boiler	2	672	65	80.00%		NG
129	11/1/2001	New Jersey	GE	Frame 7FA	3	656	1103	73.30%	25.00%	NG
130	11/1/2001	Massachusetts	ABB	GT24	2	626	896	80.30%		NG
131	11/1/2001	California	GE	LM6000	1	750	342	92.00%	30.00%	NG
132	12/1/2001	Colorado	GE	LM6000	2	569	266	75.00%		NG

133	12/1/2001	New Jersey	GE	Frame 7FA	2	664	1072	80.00%		NG
134	12/1/2001	California	Solar	Taurus 60	2	729	50	88.00%		NG
135	12/1/2001	New Jersey		Boiler	4	800	101	90.00%		NG/Refinery Gas
136	1/1/2002	New York			4	856	327	0.00%		NG
137	1/1/2002	Nevada	GE	Frame 7FA	2	665	972	77.30%		NG
138	1/1/2002	Arizona	GE	Frame 7FA	1	654	1003	63.90%		NG
139	1/1/2002	Colorado	GE	Frame 7FA	2	662	1039	76.60%		NG
140	2/1/2002	New Jersey	GE	Frame 7FA	4	674	1078	84.40%		NG
141	2/1/2002	Wisconsin	GE	LM6000	1	739	263	96.00%		NG
142	3/1/2002	California	GE	LM6000	4	885	313	90.00%		NG
143	3/1/2002	Arizona	GE	LM6000	10	842	329	90.00%		NG
144	3/1/2002	New Jersey	GE	LM6000	2	842	329	90.00%		NG/Oil
145	3/1/2002	New Jersey	GE	LM6000	4	842	329	90.00%		NG
146	3/1/2002	New Jersey	GE	LM6000	4	842	329	90.00%		NG
147	3/1/2002	Illinois	GE	LM6000	12	842	329	90.00%		NG
148	3/1/2002	California	GE	LM6000	3	750	342	92.00%		NG
149	4/1/2002		Pratt & Whitney	FT4A9	1	850	266	98.50%		NG
150	4/1/2002		Pratt & Whitney	FT4A9	1	850	531	94.00%		NG
151	4/1/2002	Arizona	Siemens Westinghouse	501F	3	667	1308	76.00%		NG
152	4/1/2002	Washington	GE	Frame 7FA	1	921	1036	71.60%		NG
153	5/1/2002	Arizona	GE	LM6000	1	845	281	80.00%		NG/Oil
154	5/1/2002	California	Solar	Centaur 50	1	725	37	81.20%		NG/Oil
155	5/1/2002	Washington	GE	Frame 7FA	1	644	1013	86.80%		NG
156	5/1/2002	California	GE	LM6000	1	750	342	92.00%		NG
157	5/1/2002	Washington	GE	LM6000	4	858	312	90.00%		NG
158	6/1/2002	Arizona	GE	Frame 7FA	8	670	1060	80.00%		NG
159	6/1/2002	California	GE	Frame 7EA	2	850	824	86.00%		NG
160	6/1/2002	California	GE	LM6000	1	860	291	85.00%		NG
161	6/1/2002		GE	10	4	850	110	70.00%		NG
162	6/1/2002	Arizona	Westinghouse	501F	2	690	1005	85.00%		NG
163	6/1/2002	Arizona	Westinghouse	501F	2	690	1005	85.00%		NG
164	6/1/2002	New York	GE	Frame 7FA	2	661	1050	90.00%		NG
165	6/1/2002	Texas	Siemens Westinghouse	501G	2	682	1468	77.50%		NG
166	7/1/2002	Maryland	ABB	GT10	1	739	189	96.90%		NG/Oil
167	7/1/2002	California	GE	Frame 7FA	2	649	934	80.00%	50.00%	NG
168	8/1/2002	Pennsylvania	Siemens Westinghouse	501F	2	667	1101	65.80%		NG
169	8/1/2002	California			1	1018	297	88.90%		NG
170	9/1/2002	California	GE	LM6000	1	750	342	92.00%		NG
171	9/1/2002				2	1065	984	68.30%		NG
172	9/30/2002		GE	LM6000	12	842	329	90.00%		NG
173	10/1/2002		GE	LM6000	4	829	301	85.70%		NG
174	12/1/2002	Nevada			2	675	1111	84.10%		NG
175	12/1/2002	Washington			2	675	1111	86.50%		NG
176	12/1/2002	Pennsylvania			2	669	1018	67.00%		NG
177	12/1/2002	Pennsylvania			2	669	1018	67.00%		NG
178	1/1/2003	Arizona	Siemens Westinghouse	501F	2	647	1033	90.00%		NG
179	1/1/2003	Michigan	Mitsubishi	501G	3	961	1346	71.20%		NG
180	4/1/2003	New York	GE	Frame 7FA	1	779	914	80.00%		NG
181	5/1/2003	Arizona	GE	Frame 7FA	4	683	1040	81.90%		NG
182	5/1/2003	New Jersey	GE	Frame 7FB	3	637	1061	80.50%		NG
183	6/1/2003				2	698	1188	83.80%		NG
184	10/1/2003	California	GE	Frame 7FA	3	645	1049	48.50%		NG/Oil
185	12/1/2003	Ohio	Siemens Westinghouse	501F	2	696	1004	75.00%		NG
					449					

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Oxidation Catalyst Experience
Power Generation

Application	Startup	# of Units	Temp °F	Flow (#/s)	% CO Conversion	% VOC Conversion	Fuel
RR RB211	Oct-86	3	645	139	90		
GE LM2500	Nov-87	1	519	160	42		
GE Frame 6	Dec-87	2	902	305	90		
Westinghouse 251	Jun-88	1	710	375	82		
GE LM5000	Jun-88	1	750	351	90		
GE LM2500	Jul-88	2	720	154	80		
GE LM2500	Jul-88	1	936	152	80		
GE LM2500	Sep-88	1	858	150	83		
GE LM2500	Feb-89	6	890	162	82		
GE Frame 7	Feb-89	1	535	695	80		
Boiler	Feb-89	2	533	33	90		
GE Frame 7E	Mar-89	1	990	671	85		
GE LM2500	Mar-89	1	820	172	80		
GE LM5000	May-89	1		300	90		
GE LM2500	Jun-89	1		148	90		
GE LM2500	Jun-89	1	920	149	84		
GE LM2500	Jul-89	2		148	90		
GE LM5000	Sep-89	1	792	303	80		
GE LM5000	Feb-90	1	760	350	60		
Westinghouse 191	Jun-90	2	775	267	85		
GE LM2500	Jul-90	1	920	149	84		
Westinghouse 191	Aug-90	2	775	267	85		
GE LM5000	Dec-90	1	900	333	82		
GE Frame 7	Jan-91	2	580	750	75		
GE LM5000	Feb-91	1	760	350	80		
GE LM5000	Jun-91	1	760	350	80		
GE LM5000	Jul-91	2	546	286	90		
GE LM5000	Sep-91	2	550	286	90		
GE LM5000	Sep-91	1		300	90		
GE LM2500	Oct-91	6	589	148	90		
GE LM5000	Nov-91	1	760	350	80		
BBC-8	Jan-92	2	930	410	90		
GE LM5000	Apr-92	1	660	306	80		
GE LM1600	Jun-92	2	959	107	90		
RR	Aug-92	1	1100	259	95		
Westinghouse 251	Dec-92	2	590	422	90		
GE Frame 7	Mar-93	1	625	669	80		
GE LM2500	May-93	1	900	157	80		
GE Frame 7E	Jul-93	2	971	687	92		
ABB 10B	Nov-93	1	983	154	87		
GE Frame 7EA	Nov-93	2	705	663	90		
P&W FT8 Twin Pac (2 CT/Unit)	Mar-94	4	678	427	90		
Solar Mars	Apr-94	1	980	85	95		
GE LM2500	Jul-94	2		153	90		
ABB	Aug-94	1	900	60	80		
Turbine	Aug-94	1	680	91.5	90		
Boiler	Aug-94	2	470	12.9	90		
ABB GT 10	Aug-94	1	879	184	98		
GE LM6000	Aug-94	1		303	90		
GE LM5000	Apr-95	1	880	350	80		
GE LM5000	Apr-95	1	750	342	88		
GE LM5000	Apr-95	1	750	342	88		
Boiler	Jun-95	2	700	66	90		
Solar Centaur	Jul-95	1	980	37	91		

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Oxidation Catalyst Experience
Power Generation

Application	Startup	# of Units	Temp °F	Flow (#/s)	% CO Conversion	% VOC Conversion	Fuel
GE LM6000	Aug-95	2	560	343	90		
GE Frame 7EA	Aug-95	1	876	673	80		
GE LM1600	Aug-95	1			90		
GE LM5000	Aug-95	1		300	90		
P&W FT4A9	Nov-95	1	860	314	80		
Siemens V84.2	Dec-95	2	1027	750	98		
GE LM6000	Jan-96	1	620	247	80		
GE LM6000	Mar-96	1	938	290	90		
GE LM2500	Apr-96	1	604	162	92		
Westinghouse 501F	Jul-96	1	655	1079	90		
MAN GHH FT8	Aug-96	1	878	197	70		
GE Frame 7F	Jan-97	1	965	1062	82		
Westinghouse 501 D5A	Mar-97	1	1107	931	90		
Siemens V84.2	Mar-97	1	635	782	90		
Westinghouse 251B12	Mar-97	1	700	431	91		
ABB 11N2	Sep-98	1	637	888	80		
ABB GT10	Dec-98	1	952	189	95		
Solar CENTAUR 50	Jan-99	1	910	46	80		
GE Frame 9	Jun-99	1	660	956	85		
ABB GT 24	Oct-99	1	633	935	80		
GE Frame 6B	Oct-99	2	1019	347	75		
Westinghouse 501F	Oct-99	2	600	996	85		
Westinghouse 501G	Dec-99	1	633	1472	90		
P&W FT8	Mar-00	8	898	214	90		NG
ABB GT24	Jun-00	3	640	930	80.4		NG/Distilate Oil
P&W FT8	Jul-00	1	775	73	60		
Centaur 50	Oct-00	1	921	42	88		NG/Propane
P&W FT8	Dec-00	12	898	214	90		NG
P&W FT8	Dec-00	2	898	214	90		NG
P&W FT8	Dec-00	18	898	214	90		NG
Siemens 501F	Mar-01	2	665	1010	89.3		NG
GE 7FA	Apr-01	1	759	1073	82.3		NG/LS-Diesel
Westinghouse 501G	Apr-01	2	649	1417	80		NG/Distilate Oil
	Apr-01	6	998	656	50		NG
P&W FT8	Apr-01	12	898	214	90		NG
GE 7FA	May-01	2	1025	1053	62.7	36	NG
GE 7FA	Jun-01	1	654	1001	30		NG
GE LM6000	Jun-01	11	840	292	93.3		NG
Westinghouse 501AA	Jun-01	6	840	814	90		NG
P&W FT8 Twin Pac (2 CT/Unit)	Jun-01	2	804	471	87.5		NG
Westinghouse 501F	Jun-01	2	623	1098	90		NG/Oil
GE LM6000	Jun-01	3	858	292	90		NG
P&W FT8 Twin Pac(2 CTs/Unit)	Jun-01	1	750	390	80		NG
P&W FT8 Twin Pac(2 CTs/Unit)	Jun-01	1	750	390	80		NG
P&W FT8 Twin Pac(2 CTs/Unit)	Jun-01	1	750	390	80		NG
P&W FT8 Twin Pac(2 CTs/Unit)	Jun-01	2	750	390	80		NG
P&W FT8 Twin Pac(2 CTs/Unit)	Jun-01	1	750	390	80		NG
P&W FT8 Twin Pac(2 CTs/Unit)	Jun-01	1	750	390	80		NG
P&W FT8	Jun-01	4	898	214	90		NG
GE LM1500	Jun-01	1	850	114			NG/Oil
Siemens V84.3A	Jun-01	1	735	1047	51.5		NG
Boiler	Jul-01	2	730	509	95		NG
GE LM6000	Aug-01	2	750	342	92		NG
Mitsubishi 501G	Aug-01	4	711	1454	86.6		NG
Mitsubishi 501G	Aug-01	2	711	1454	86.6		NG

Oxidation Catalyst Experience
Power Generation

Application	Startup	# of Units	Temp °F	Flow (#/s)	% CO Conversion	% VOC Conversion	Fuel
ABB GT24	Sep-01	2	633	910	83.8		NG
GE LM6000 Sprint	Sep-01	5	853	292	90		NG
GE LM2500 (2 CTs/Unit)	Sep-01	4	840	376	90		NG/#2 Oil
GE LM6000	Sep-01	6	840	292	90		NG
GE 10	Sep-01	4	860	111	80		NG
Solar Mars	Sep-01	1	860	100	90		NG
Solar Taurus 70	Sep-01	1	971	56	60		NG
ABB GT24	Oct-01	2	653	938	80		NG/Distilate Oil
GE LM6000	Oct-01	4	840	278	82.1		NG
GE LM6000	Oct-01	1	750	342	92	30	NG
ABB GT24	Oct-01	4	626	902	90.1		NG
GE 10	Oct-01	8	850	110	82.6		NG
LP Boiler	Nov-01	2	672	65	80		NG
HP Boiler	Nov-01	1	800	64	80		NG
ABB GT24	Nov-01	2	626	896	80.3		NG
ABB GT10	Nov-01	1	739	189	96.9		NG/Oil
GE 7FA	Nov-01	3	656	1103	73.3	25	NG
GE LM6000	Nov-01	1	750	342	92	30	NG
	Nov-01	1	790	580	80		NG
Solar Taurus 60	Nov-01	1	904	51	92		NG
GE LM6000	Dec-01	4	858	312	90		NG
GE LM6000	Dec-01	1	739	263	96		NG
GE 7FA	Dec-01	2	664	1072	73.9		NG
Boiler	Dec-01	4	800	101	90		NG/Refinery Gas
Solar Taurus 60	Dec-01	2	729	50	80		NG
GE LM6000	Dec-01	2	569	266	75		NG
GE LM6000	Jan-02	3	750	342	92		NG
GE LM6000	Jan-02	1	750	342	92		NG
GE 7FA	Jan-02	1	654	1003	63.9		NG
GE 7FA	Jan-02	2	665	972	77.3		NG
GE 7FA	Jan-02	2	662	1039	76.6		NG
	Jan-02	4	856	327	0		NG
GE LM6000	Feb-02	1	750	342	92		NG
GE 7FA	Feb-02	4	674	1078	84.4		NG
GE LM6000	Mar-02	12	842	329	90		NG/Oil
GE LM6000	Mar-02	8	842	329	90		NG/Oil
GE LM6000	Mar-02	10	842	329	90		NG/Oil
	Mar-02	2	669	1018	65.7		NG
GE LM6000	Mar-02	4	885	313	90		NG
Siemens Westinghouse 501F	Apr-02	3	667	1308	76		NG
GE 7FA	Apr-02	1	921	1036	71.6		NG
	Apr-02	2	669	1018	65.7		NG
GE 7FA	May-02	1	644	1013	86.8		NG
GE 7FA	Jun-02	8	670	1060	80		NG
GE 7FA	Jun-02	2	661	1050	90		NG
Siemens Westinghouse 501G	Jun-02	2	682	1468	77.5		NG
Westinghouse 501F	Jun-02	2	690	1005	85		NG
Westinghouse 501F	Jun-02	2	690	1005	85		NG
GE 7FA	Jul-02	2	649	934	80	50	NG
	Jul-02	2	675	1111	86.1		NG
Siemens Westinghouse 501F	Aug-02	2	667	1101	65.8		NG
	Aug-02	1	1018	297	88.9		NG
	Aug-02	2	675	1111	84.1		NG
Mitsubishi 501G	Jan-03	3	961	1346	71.2		NG
Siemens Westinghouse 501F	Jan-03	2	647	1033	90		NG

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Oxidation Catalyst Experience
Power Generation

Application	Startup	# of Units	Temp ^{o}F	Flow (#/s)	% CO Conversion	% VOC Conversion	Fuel
GE 7FA	Apr-03	1	779	914	80		NG
GE 7FA	May-03	4	683	1040	81.9		NG
GE 7FB	May-03	3	637	1061	80.5		NG
GE 7FA	Oct-03	3	645	1049	48.5		NG/Oil
Siemens Westinghouse 501F	Dec-03	2	696	1004	75		NG
	Total Units	**404**					

Exhibit 21

The Use of Oxidation Catalysts for Controlling Emissions from Gas Turbines: A Historical Perspective with a View Towards the Future

Engelhard Corporation

Mike Durilla, Fred Booth, Ken Burns, William Hizny

POWER-GEN International 2001

December 12, 2001

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Change the nature of things.

PRESENTATION OUTLINE

- Overview
- The Technology
- The Market
- Future Projections
- Summary

OVERVIEW

- An oxidation catalyst is used to reduce CO (carbon monoxide) emissions from gas turbines
  - Catalyst converts CO to harmless CO_2 (carbon dioxide)
- Since 1986, there are over 277 operating installations of oxidation catalyst on gas turbines
- All installations have met emissions warranties
- Virtually maintenance free
  - Catalyst service and/or replacement has not been required.
- Limited catalyst issues
  - Plugging from insulation
  - Phosphorous from gas pipeline on one installation
- Oxidation catalyst effectively reduces aldehyde (formaldehyde) emissions, which may be a future issue

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THE TECHNOLOGY

- Virtually all carbon in the fuel is combusted to CO_2
- Incomplete combustion results with some carbon going to CO
- The oxidation catalyst oxidizes the CO to CO_2

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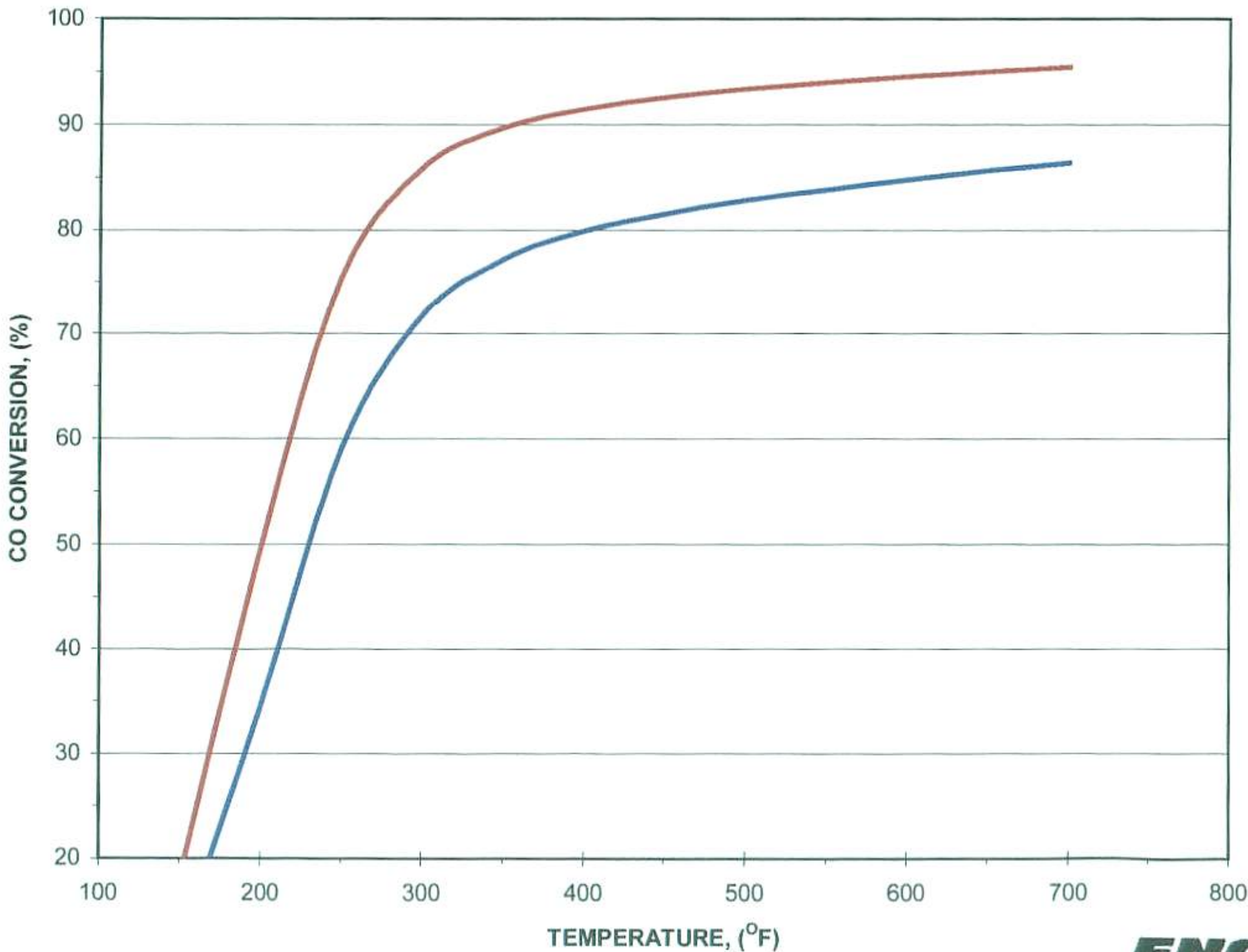
CO CONVERSION CURVE

CARBON MONOXIDE (CO) CONVERSION VS. TEMPERATURE



NOTE:

CO CONVERSION REPRESENTED AT TYPICAL GAS TURBINE CONDITIONS FOR TWO DIFFERENT OXIDATION CATALYST BED DESIGNS

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FACTORS AFFECTING CATALYST LIFE

- Thermal stability of the catalyst
  - Not an issue. Catalyst can operate at 1300°F continuously
  - Thermal degradation of catalyst has not been observed on any field installation
- Contamination or fouling of the catalyst
  - Insulation from duct liners
  - Phosphorous contamination (Corrosion inhibitor from natural gas pipeline)

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DURABILITY CONCERNS WHEN THE PRODUCT WAS FIRST INTRODUCED IN THE 1980'S

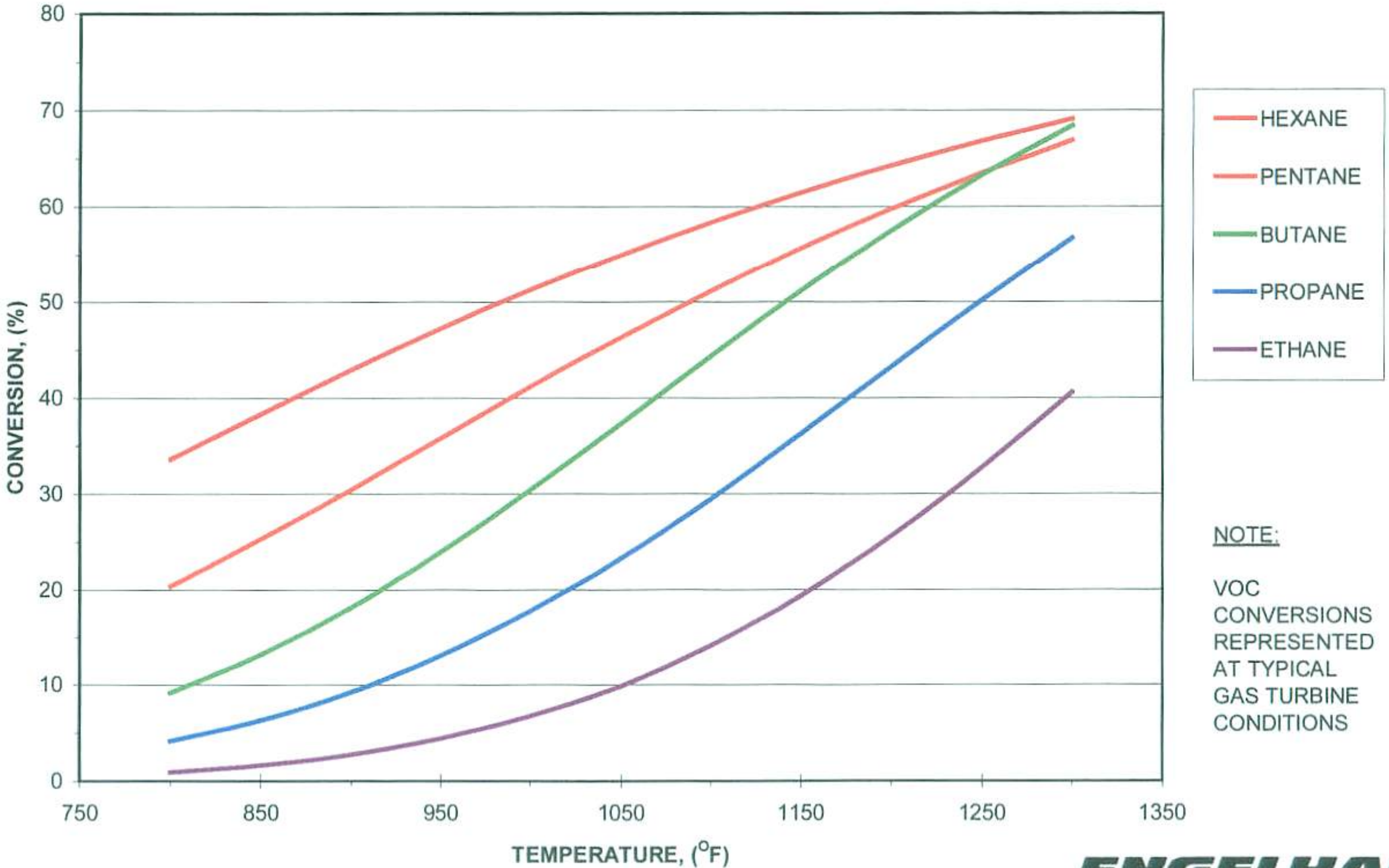
- Contamination from lubricating oils
  - Specifically phosphorous
  - Proven not to be an issue
- Gas turbine steam / water injection
  - Contamination from water solids and additives
  - Proven not to be an issue
- Steam / water leaks from HRSG tubes
  - Additives in steam
  - Proven not to be an issue
- Ambient air contamination
  - Salt air (chlorine is a catalyst poison)
  - Dust particulates
  - Proven not to be an issue

UNBURNED HYDROCARBONS (UHC'S)

- Also referred to as Volatile Organic Compounds (VOC's) or Reactive Organic Compounds (ROG's)
- Many species; each with unique conversion curve
- Lighter (low carbon number) and saturated compounds are the most difficult to convert
  - Methane is the most difficult
  - Aldehydes (formaldehyde) convert as easily as CO

HYDROCARBON CONVERSION CURVE

RELATIVE PERFORMANCE OF OXIDATION CATALYST
FOR CONVERSION OF VARIOUS VOCs



NOTE:

VOC CONVERSIONS REPRESENTED AT TYPICAL GAS TURBINE CONDITIONS

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EVOLUTION OF OXIDATION CATALYST DESIGNS FOR THE GAS TURBINE MARKET

- Initially, catalyst supports were either metal or ceramic honeycombs - metal supports are used by all suppliers
- Initial designs were based almost exclusively on parallel straight channels; technology improvements have led to non-parallel channel patterns
- Catalyst formulations have been predominately precious metal, but formulations have been varied depending on:
  - Oxidation performance requirements and constraints
  - Operating temperature window

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OXIDATION CATALYST SUBSTRATES: "METAL" VS "CERAMIC"

- Metal substrate
  - Lower pressure drop
  - Higher surface area
  - More variable CPSI
  - Greater substrate flexibility:
    - Straight
    - Skew
    - Herringbone
  - Greater design flexibility

- Ceramic substrate
  - Automotive catalyst derivative
  - Broad history of washing

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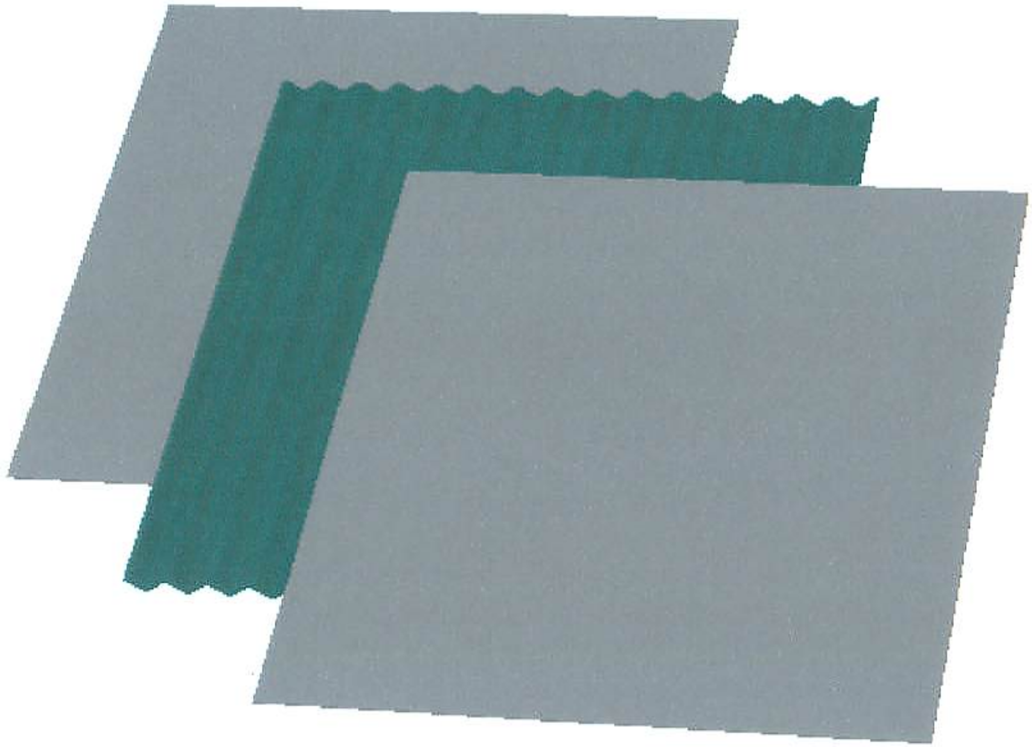
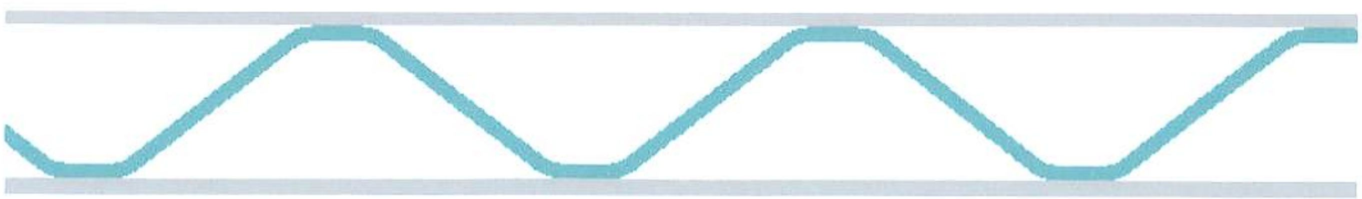
STRAIGHT METAL FOIL SUBSTRATE





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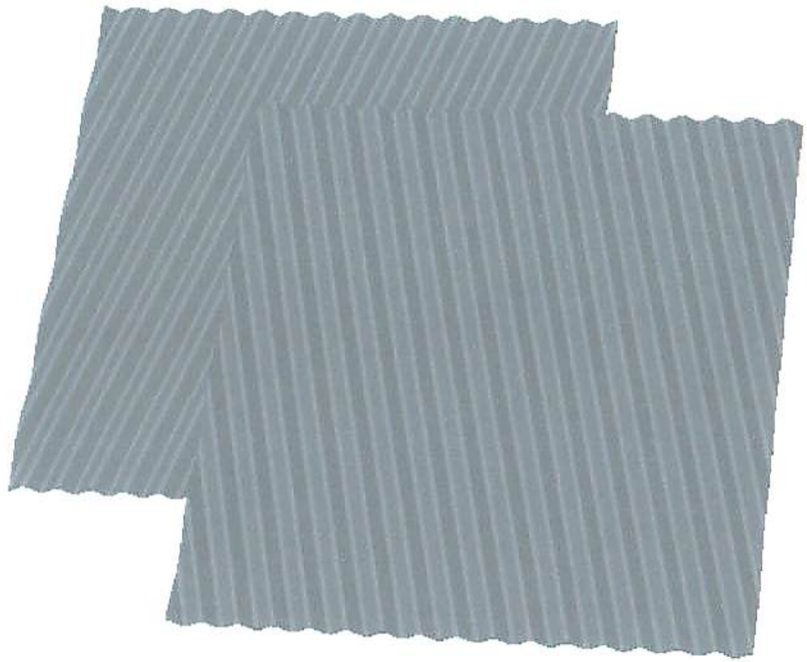
SKEW METAL FOIL SUBSTRATE



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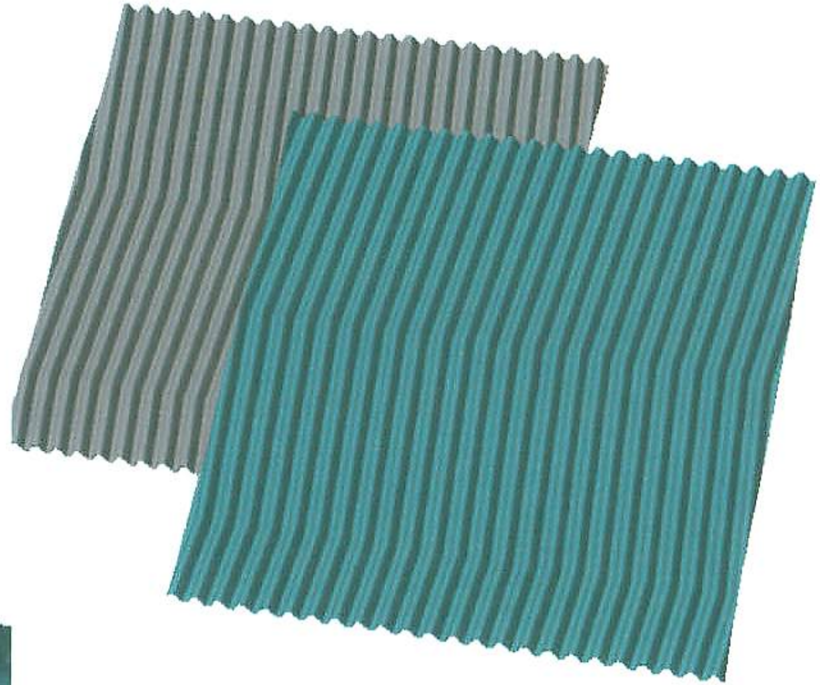
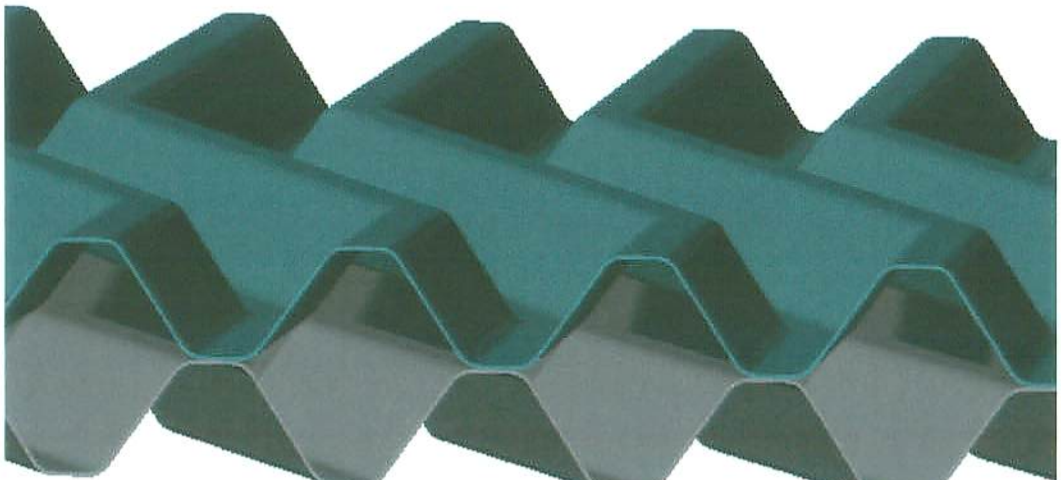
HERRINGBONE METAL FOIL SUBSTRATE





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"A SUPPLIER'S PERSPECTIVE OF THE MARKET"

- 1978 Public Utilities Regulatory Act spurred the use of gas turbine cogeneration power plant installations
- California initially was the strongest market, other areas of the country have followed
- The market has expanded with increasing requirements for CO catalyst
- Applications on all size turbines (> 1 MW)
- Conversion requirements at 80% and 90%, with as high as 98%

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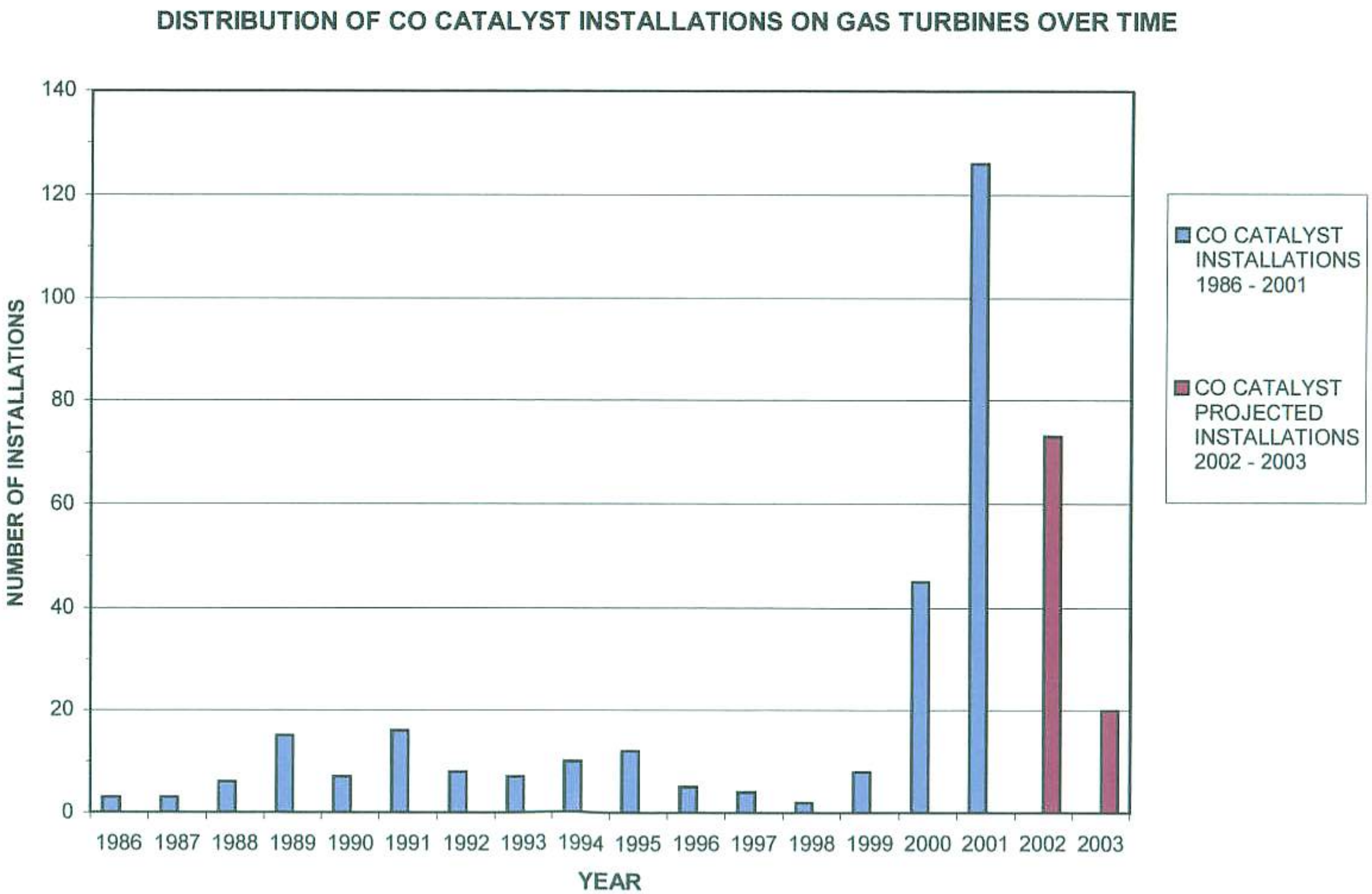
TOTAL MARKET GROWTH:
OXIDATION CATALYST FOR THE GAS TURBINE MARKET



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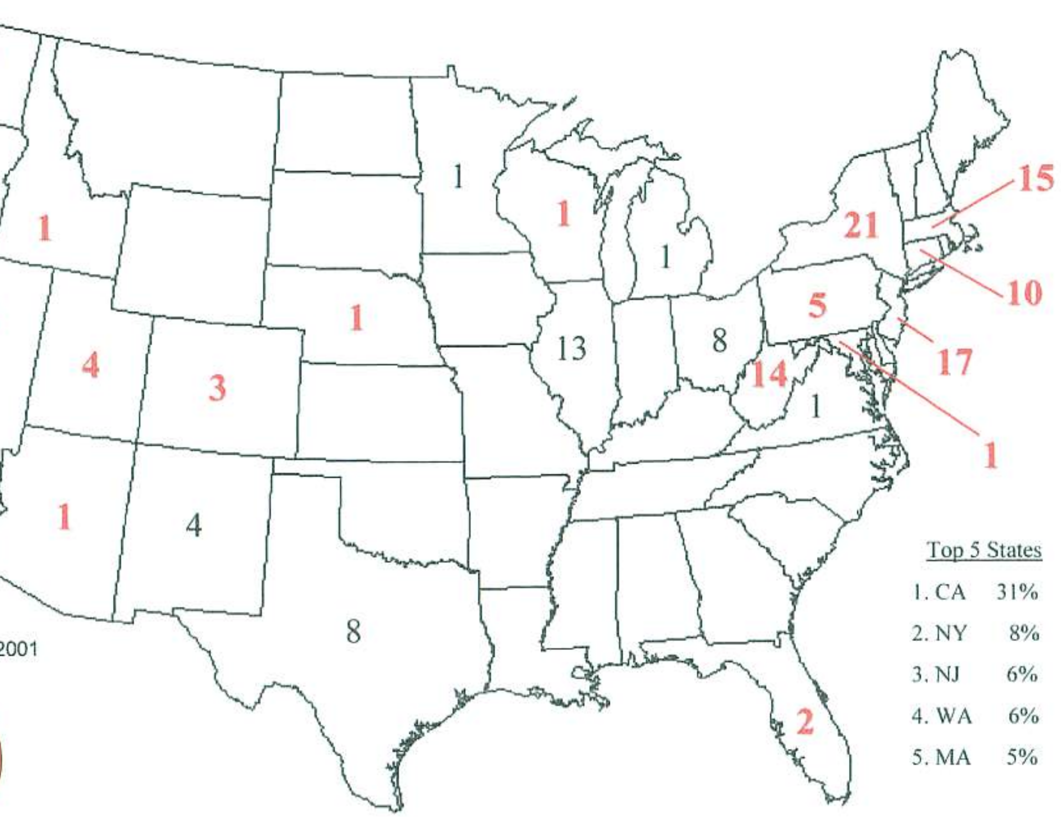
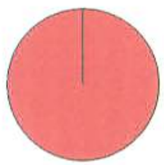
EVOLUTION OF THE U.S. MARKET: 1986 - 2001
OXIDATION CATALYST FOR THE GAS TURBINE MARKET



Top 5 States

1. CA 31%
2. NY 8%
3. NJ 6%
4. WA 6%
5. MA 5%

Installations: 1986 - 2001



1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003

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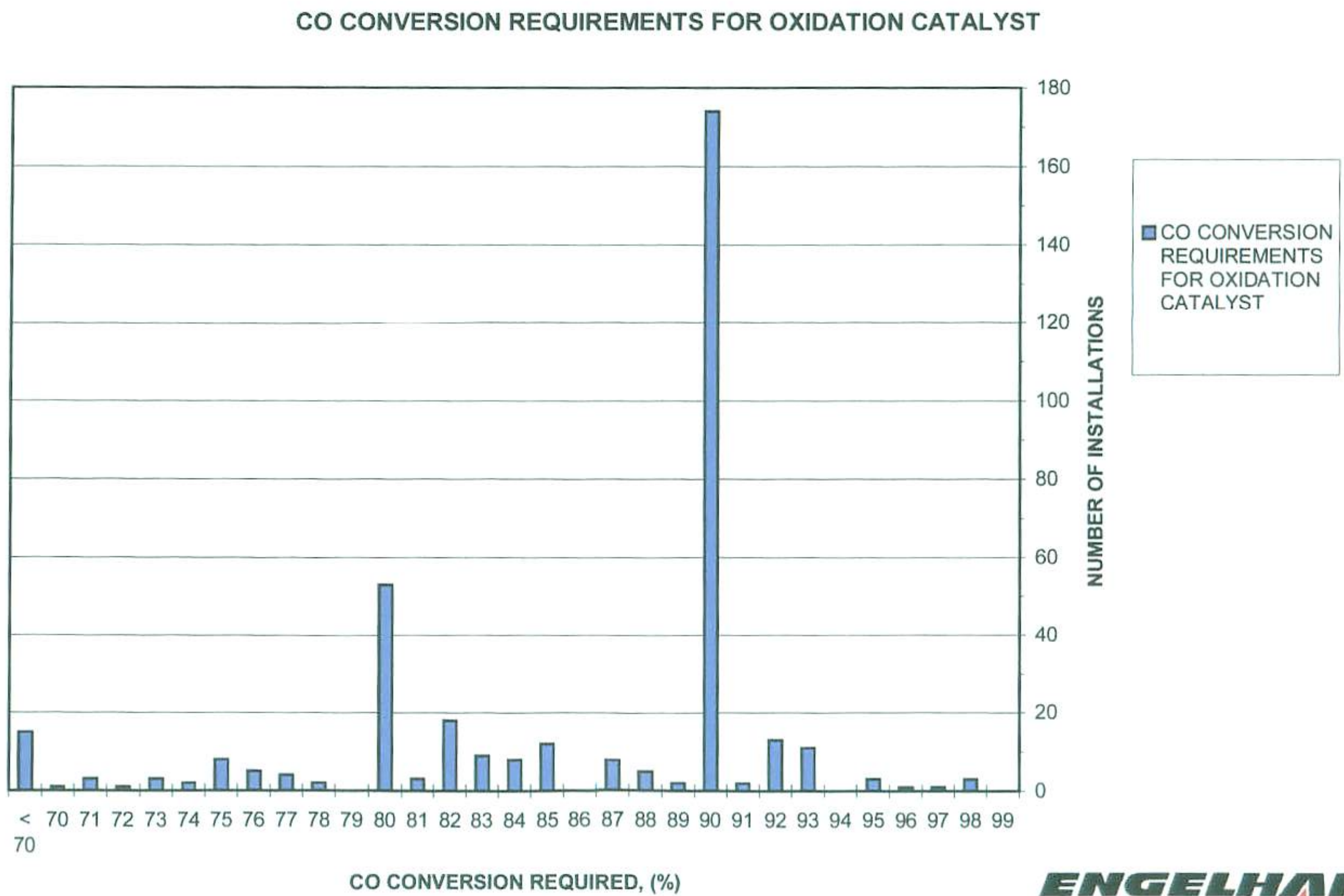
CO CONVERSION DISTRIBUTION AMONG GAS TURBINE MARKET



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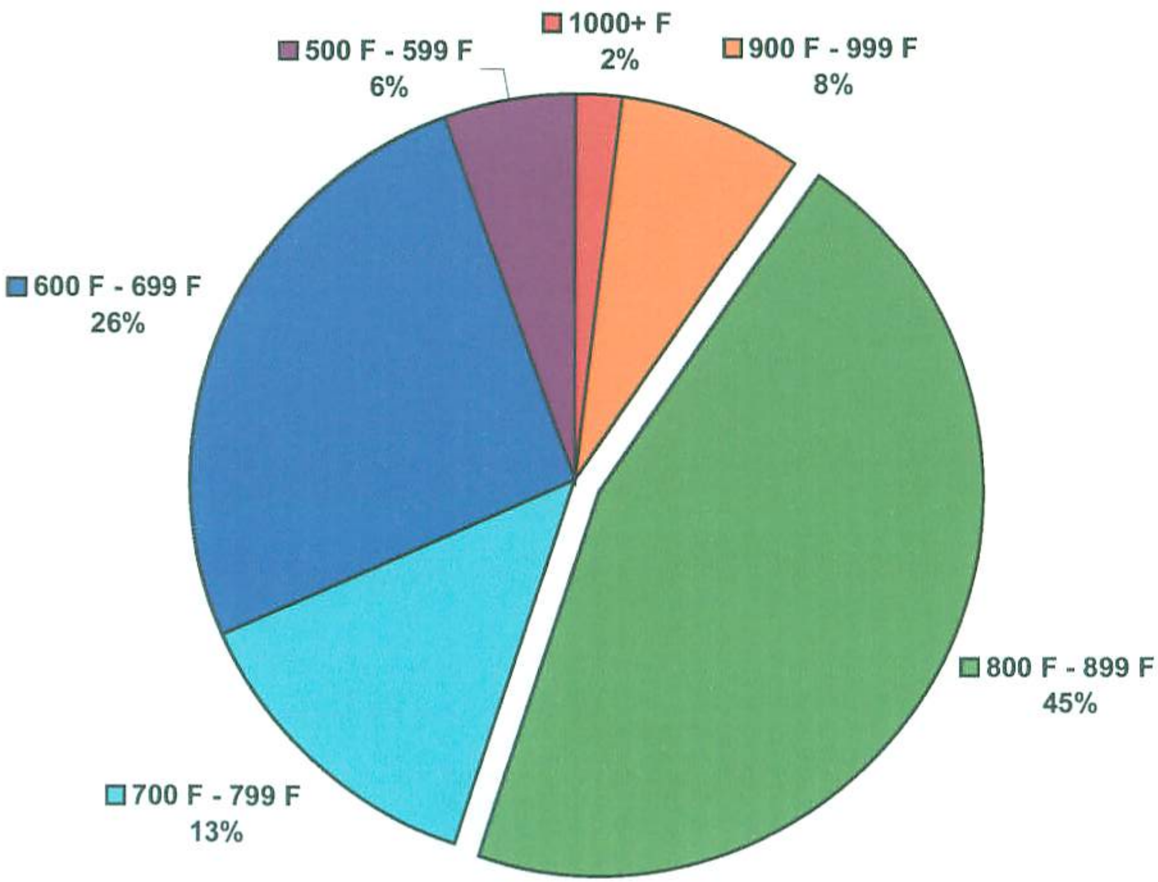
TEMPERATURE DISTRIBUTION AMONG GAS TURBINE MARKET

DISTRIBUTION OF CO CATALYST INSTALLATIONS AMONG GAS TURBINE EXHAUST TEMPERATURES



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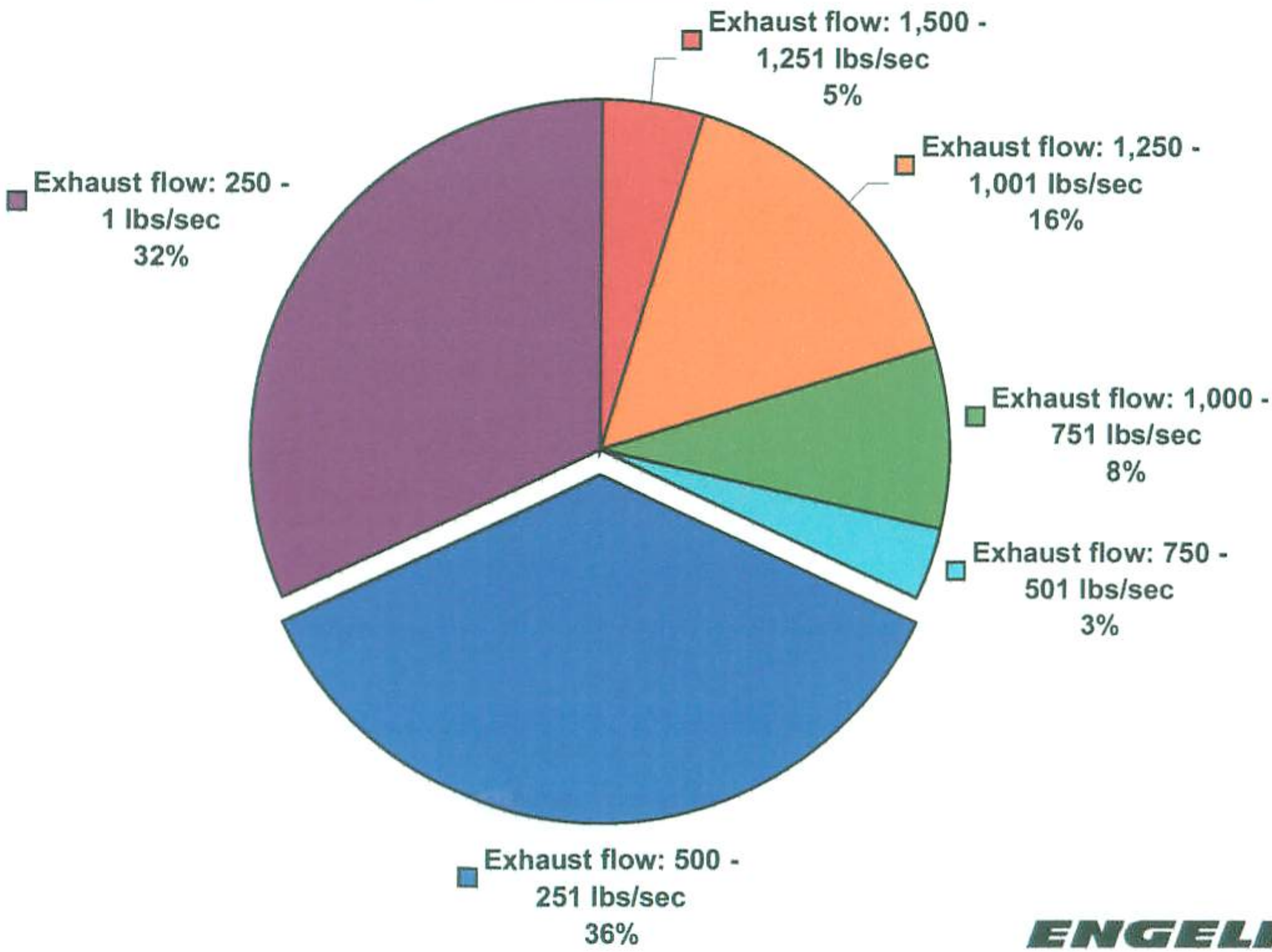
EXHAUST FLOW DISTRIBUTION AMONG GAS TURBINE MARKET

DISTRIBUTION OF CO CATALYST INSTALLATIONS AMONG GAS TURBINE EXHAUST FLOWS



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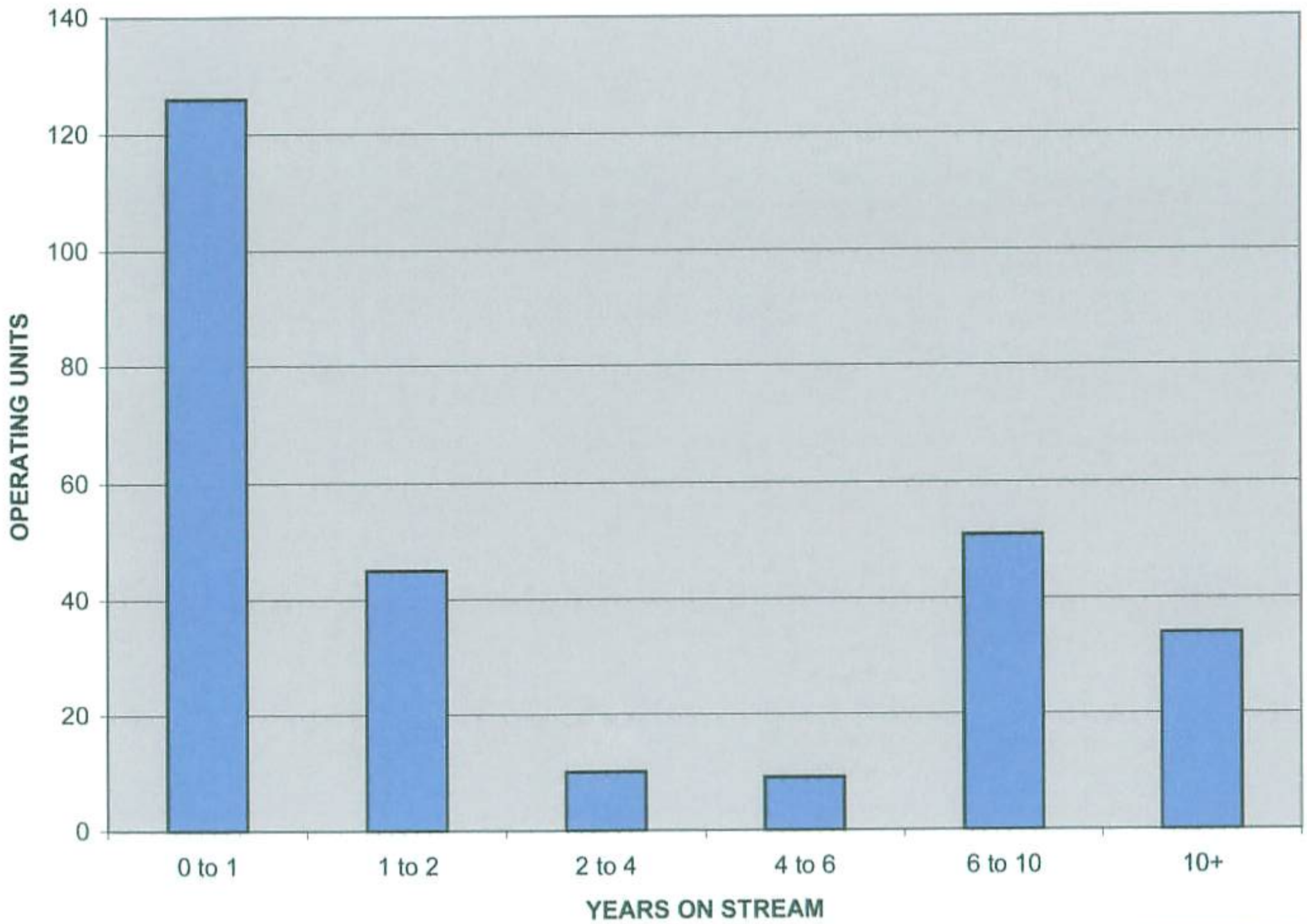
TIME ON STREAM DISTRIBUTION AMONG GAS TURBINE MARKET

Engelhard Catalysts Perform Well Beyond the Warranty



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FUTURE PROJECTIONS

- Further developments in catalyst design
  - More conversion per catalyst volume
  - More conversion per pressure drop
  - Greater conversion at lower temperatures
  - Lower cost

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FUTURE PROJECTIONS, continued

- Increasing percent of turbines being installed will use CO catalyst
- Potential requirements for control of aldehyde (formaldehyde) emissions
- Use of oxidation catalyst to control ammonia slip emissions from SCR catalyst systems on HRSG applications.
- Use of oxidation catalysts in conjunction with SCR catalysts to reach lower emission limits of NOx and ammonia
  - May be more cost effective than simply enlarging the SCR

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SUMMARY

- CO oxidation catalysts for gas turbines:
  - An extensively proven technology
  - Minimal field service issues (virtually maintenance free)
  - Very long catalyst life
  - Increasing market penetration
  - Potential to control aldehyde and ammonia emissions

ADDITIONAL SLIDES

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SAMPLE SCR - OXIDATION CATALYST INSTALLATION

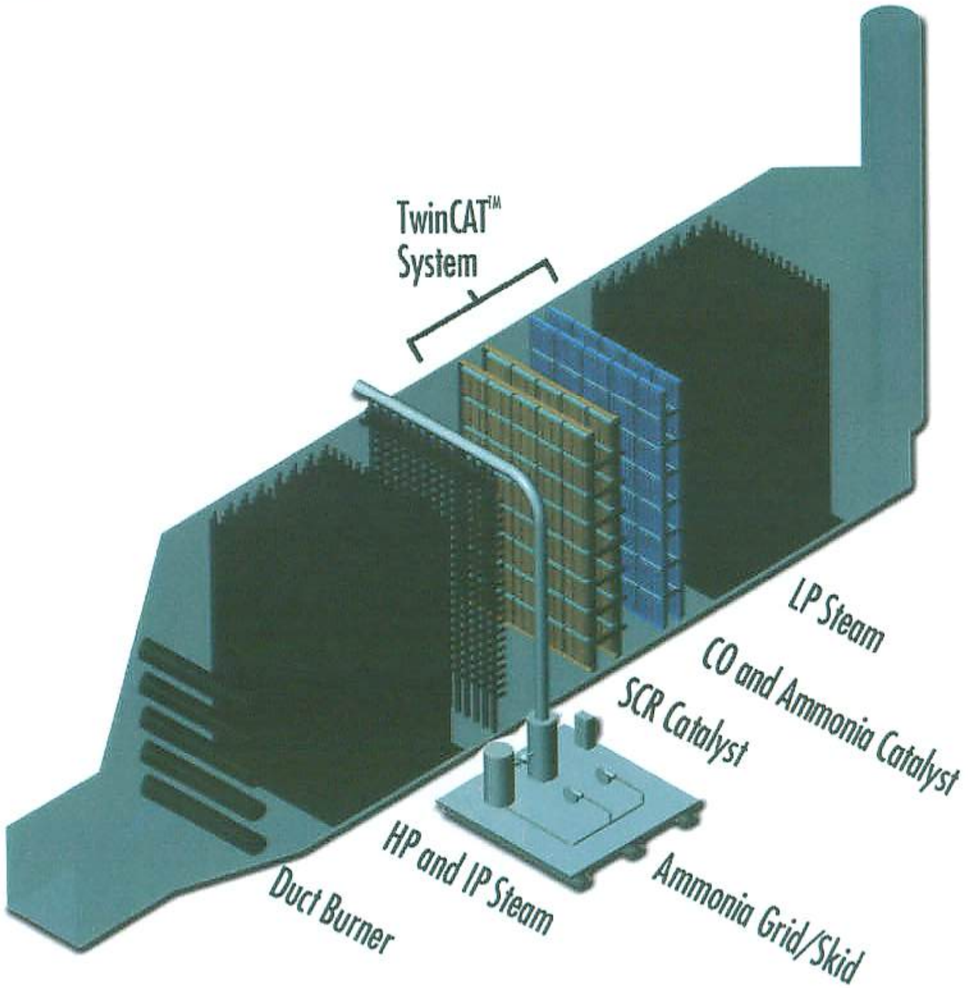

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Exhibit 22

CALIFORNIA ENERGY COMMISSION - ENERGY FACILITY STATUS

Power Plant Projects Filed Since 1996, Updated: 1/9/2009

(Note: Does not include projects filed but were withdrawn before they were approved.)

Color Key

Operational Status	Expected and disclosed
Approved	Expected but undisclosed
In Review	On hold, suspended. According to developers, the new on-line date will be determined when the markets are favorable and/or financing available.
On-line date is expected to be delayed beyond the date shown	
Not Approved/Denied	Cancelled, withdrawn, not built, license expired.

	Projects On Line (Arranged By Online Date)	**Docket Number**	**Status**	**Capacity (MW)**	**Const. Completed (%)**	**Location**	**Date Approved**	**Const. Start Date**	**Original OnLine Date**	**Current / Actual Online Date**
	Sunrise Simple Cycle - Texaco & Edison Mission E.	1998-AFC-04	Operational	320	100	Kern	12/06/2000	12/07/2000	07/01	06/27/2001
	Sutter - Calpine	1997-AFC-02	Operational	540	100	Sutter	04/14/1999	07/01/1999	07/01	07/02/2001
	Los Medanos - Calpine	1998-AFC-01	Operational	555	100	Contra Costa	08/17/1999	09/17/1999	07/01	07/09/2001
	Wildflower Larkspur - Intergen	*2001-EP-01*	*Operational*	*90*	*100*	*San Diego*	*04/04/2001*	*04/05/2001*	*07/01*	*07/16/2001*
	Wildflower Indigo - Intergen	*2001-EP-02*	*Operational*	*135*	*100*	*Riverside*	*04/04/2001*	*04/05/2001*	*07/01*	*09/10/2001*
	Drews - Alliance	*2001-EP-05*	*Operational*	*40*	*100*	*San Bernardino*	*04/25/2001*	*04/26/2001*	*09/01*	*08/15/2001*
	Hanford - GWF	*2001-EP-07*	*Operational*	*95*	*100*	*Kings*	*05/10/2001*	*05/11/2001*	*09/01*	*09/01/2001*
	Century - Alliance	*2001-EP-04*	*Operational*	*40*	*100*	*San Bernardino*	*04/25/2001*	*04/26/2001*	*09/01*	*09/15/2001*
	Escondido - Calpeak	*2001-EP-10*	*Operational*	*50*	*100*	*San Diego*	*06/06/2001*	*06/07/2001*	*09/01*	*09/30/2001*
	Border - Calpeak	*2001-EP-14*	*Operational*	*50*	*100*	*San Diego*	*07/11/2001*	*07/12/2001*	*09/01*	*10/26/2001*
			Subtotal On Line 2001	*1,914*						
	King City - Calpine	*2001-EP-06*	*Operational*	*50*	*100*	*Monterey*	*05/02/2001*	*05/03/2001*	*09/01*	*01/14/2002*
	Gilroy I - Calpine	*2001-EP-08*	*Operational*	*135*	*100*	*Santa Clara*	*05/21/2001*	*05/22/2001*	*09/01*	*02/20/2002*
	Delta - Calpine	1998-AFC-03	Operational	887	100	Contra Costa	02/09/2000	04/01/2000	07/02	05/10/2002
	Henrietta Peaker - GWF	2001-AFC-18	Operational	96	100	Kings	03/05/2002	03/08/2002	06/02	07/01/2002
	Moss Landing - L.S. Power	1999-AFC-04	Operational	1,060	100	Monterey	10/25/2000	11/28/2000	06/02	07/11/2002
1a	Huntington Beach Unit 3 - AES	2000-AFC-13	Operational	225	100	Orange	05/10/2001	05/31/2001	11/01	07/31/2002
2a	Valero Cogen - Valero	2001-AFC-05	Operational	51	100	Solano	10/31/2001	11/05/2001	06/02	10/18/2002
			Subtotal On Line 2002	*2,504*						
	La Paloma - Complete Energy Holdings	1998-AFC-02	Operational	1,124	100	Kern	10/06/1999	01/01/2000	03/02	03/07/2003
	Los Esteros Simple Cycle - Calpine	2001-AFC-12	Operational	180	100	Santa Clara	02/07/2002	07/08/2002	05/03	03/07/2003
	Los Esteros Simple Cycle recertification - Calpine	2003-AFC-02	Operational	0	100	Santa Clara	03/16/2005	07/08/2002	05/03	03/07/2003
	High Desert - Constellation	1997-AFC-01	Operational	830	100	San Bernardino	05/03/2000	05/01/2001	07/03	04/22/2003
	Tracy Peaker - GWF	2001-AFC-16	Operational	169	100	San Joaquin	07/17/2002	07/22/2002	04/03	06/01/2003
	Sunrise Comb. Cycle Amendment - Texaco & Edison Mission E.	1998-AFC-04C	Operational	265	100	Kern	11/19/2001	12/21/2001	06/03	06/01/2003
	Woodland II - Modesto Irrigation District	2001-SPPE-01	Operational	80	100	Stanislaus	09/19/2001	02/21/2002	05/03	06/06/2003
	Blythe I - FPL	1999-AFC-08	Operational	520	100	Riverside	03/21/2001	04/27/2001	04/03	07/15/2003
	Elk Hills - Sempra & Oxy	1999-AFC-01	Operational	500	100	Kern	12/06/2000	06/08/2001	12/02	07/24/2003
1b	Huntington Beach Unit 4 - AES	2000-AFC-13	Operational	225	100	Orange	05/10/2001	05/31/2001	11/01	08/07/2003
			Subtotal On Line 2003	*3,893*						
	Donald Von Raesfeld Power Plant (Pico) - Silicon Valley Power	2002-AFC-03	Operational	147	100	Santa Clara	09/09/2003	09/10/2003	12/04	03/24/2005
	Pastoria - Calpine	1999-AFC-07	Operational	750	100	Kern	12/20/2000	10/03/2001	01/03	07/05/2005
	Metcalf - Calpine	1999-AFC-03	Operational	600	100	Santa Clara	09/24/2001	01/15/2002	07/03	05/27/2005
	Kings River - Kings River Cons. Dist.	2003-SPPE-02	Operational	97	100	Fresno	05/19/2004	11/01/2004	05/05	09/19/2005
	Magnolia - So. Ca. Power Producers	2001-AFC-06	Operational	328	100	Los Angeles	03/05/2003	07/21/2003	05/05	09/22/2005
	Malburg - City of Vernon	2001-AFC-25	Operational	134	100	Los Angeles	05/20/2003	09/11/2003	11/05	10/17/2005
3a	Mountainview Unit 3 - SCE	2000-AFC-02	Operational	528	100	San Bernardino	03/21/2001	09/01/2001	06/03	12/09/2005
			Subtotal On Line 2005	*2,584*						
3b	Mountainview Unit 4 - SCE	2000-AFC-02	Operational	528	100	San Bernardino	03/21/2001	09/01/2001	06/03	01/19/2006
	Cosumnes - SMUD	2001-AFC-19	Operational	500	100	Sacramento	09/09/2003	10/31/2003	06/05	02/24/2006
	Walnut - Turlock Irr. Dist.	2002-AFC-04	Operational	250	100	Stanislaus	02/18/2004	03/15/2004	04/06	02/28/2006
	Palomar Escondido - SDG&E	2001-AFC-24	Operational	546	100	San Diego	08/06/2003	06/01/2004	03/06	04/01/2006
	Riverside En. Res. Cntr. Units 1 & 2 - City of Riverside	2004-SPPE-01	Operational	96	100	Riverside	12/15/2004	02/23/2005	11/05	06/01/2006
	Ripon - Modesto Irrigation Dist	2003-SPPE-01	Operational	95	100	San Joaquin	02/04/2004	04/01/2005	04/05	06/21/2006
			Subtotal On Line 2006	*2,015*						
	Bottle Rock Geothermal Restart	1979-AFC-4C	Operational	17	100	Lake	12/13/2006	12/19/2006	06/07	10/01/2007
	Roseville Combined Cycle - Roseville Electric	2003-AFC-01	Operational	160	100	Placer	04/13/2005	08/18/2005	12/07	11/07/2007
			Subtotal On Line 2007	*177*						
	Niland Peaker - IID	2006-SPPE-1	Operational	93	100	Imperial	10/11/2006	6/25/2007	06/08	05/29/2008
			Subtotal On Line 2008	*93*						
			ON-LINE TOTAL	**13,180**						

	Approved / Under Construction (Arranged By Online Date)	**Docket Number**	**Status**	**Capacity (MW)**	**Const. Completed (%)**	**Location**	**Date Approved**	**Const. Start Date**	**Original OnLine Date**	**Current / Actual Online Date**
1	Inland Empire - GE	2001-AFC-17	Under Construction	800	**92** Unit 2 delayed	Riverside	12/17/2003	8/26/2005	12/05	unit 1: **1/09** unit 2: 7/09

CALIFORNIA ENERGY COMMISSION - ENERGY FACILITY STATUS

Power Plant Projects Filed Since 1996, Updated: 1/9/2009

(Note: Does not include projects filed but were withdrawn before they were approved.)

Color Key

Operational Status	Expected and disclosed
Approved	Expected but undisclosed
In Review	On hold, suspended. According to developers, the new on-line date will be determined when the markets are favorable and/or financing available.
On-line date is expected to be delayed beyond the date shown	
Not Approved/Denied	Cancelled, withdrawn, not built, license expired.

2	Gateway - PG&E	2000-AFC-01	Under Construction	530	96	Contra Costa	5/30/2001	8/30/2001 Resumed: 2/2007	08/03	**3/2009**
3	Starwood Midway - Starwood Power	2006-AFC-10	Under Construction	120	**30**	Fresno	1/16/2008	9/23/2008	06/09	05/09
4	EIF Panoche - Energy Investors Fund	2006-AFC-5	Under Construction	400	64	Fresno	12/19/2007	2/15/2008	11/09	08/09
5	Otay Mesa - Calpine	1999-AFC-05	Under Construction	590	74	San Diego	4/18/2001	5/01/2007	07/03	10/09
6	Humboldt Power Plant - PG&E	2006-AFC-7	Under Construction	163	4	Humboldt	9/24/2008	10/11/2008	09/09	04/10
7	Colusa Generation Station - PG&E	2006-AFC-9	Under Construction	660	**10**	Colusa	4/23/2008	7/28/2008	06/10	10/10
		Under Construction Subtotal		***3,263***						

	Approved / Not Under Construction (Arranged By Online Date)	**Docket Number**	**Status**	**Capacity (MW)**	**Const. Completed (%)**	**Location**	**Date Approved**	**Const. Start Date**	**Original OnLine Date**	**Current / Actual Online Date**
	Blythe I Transmission Line - FPL	1999-AFC-8C	**Pre-Construction**	0	0	Riverside	10/11/2006	2/09	06/07	**2010**
	Victorville Hybrid Gas-Solar - City of Victorville	2007-AFC-1	**Pre-Construction**	563	0	San Bernardino	7/16/2008	4/09	8/10	**10/10**
	Russell City - Calpine & GE	2001-AFC-07	On Hold	600	0	Alameda	10/03/2007	9/09	12/04	06/12
	El Centro Unit 3 Repower - IID	2006-SPPE-2	On Hold	85	0	Imperial	01/03/2007	On Hold	05/09	On Hold
	Morro Bay - L.S. Power	2000-AFC-12	On Hold	1,200	0	San Luis Obispo	08/02/2004 Note: Commis-sion decision not finalized pending NPDS permit	On Hold	On Hold	On Hold
	Tesla - FPL	2001-AFC-21	On Hold	1,120	0	Alameda	06/16/2004	On Hold	On Hold	On Hold
	El Segundo Repower - NRG	2000-AFC-14	On Hold	630	0	Los Angeles	02/02/2005	On Hold Pending Dry Coooling Amendment	On Hold	On Hold
	Los Esteros Combined Cycle - Calpine	2003-AFC-02	On Hold	140	0	Santa Clara	10/11/2006	On Holdt	On Hold	On Hold
	Pastoria Simple Cycle Addition - Calpine	2005-AFC-1	On Hold	160		Kern	12/18/2006	On Hold	06/07	On Hold
	Walnut Creek Peaker - Edison Mission E.	2005-AFC-02	On Hold	500	0	Los Angeles	02/27/2008	9/09	On Hold	On Hold
	San Joaquin Valley - Calpine	2001-AFC-22	On Hold	1,087	0	Fresno	01/14/2004	On Hold	01/06	On Hold
	East Altamont - Calpine	2001-AFC-04	On Hold	1,100	0	Alameda	08/20/2003	8/11	07/05	On Hold
	Salton Sea - Cal Energy	2002-AFC-02	On Hold	215	0	Imperial	12/17/2003	On Hold	01/06	On Hold
	SF Reliability Project - CCSF	2004-AFC-01	On Hold	145	0	San Francisco	10/03/2006	On Hold	06/06	On Hold
	Blythe II - Caithness	2002-AFC-01	On Hold	520	0	Riverside	12/14/2005	On Hold	On Hold	On Hold
		Approved and available for construction.		**8,065**						
A	Three Mountain - Covanta	1999-AFC-02	Not Built and License Expired	500	0	Shasta	05/16/2001	On Hold	12/03	Not Built and License Expired
B	Western Midway Sunset - Edison Mission Energy	1999-AFC-09	Not Built and License Expired	500	0	Kern	03/21/2001	On Hold	07/03	Not Built and License Expired
C	United Golden Gate - El Paso	2000-AFC-05	Not Built and License Expired	51	0	San Mateo	03/07/2001	On Hold	07/01	Not Built and License Expired
D	*Pegasus Energy - Delta Power*	*2001-EP-09*	*Cancelled*	*181*	*0*	*San Bernardino*	*06/06/2001*	*Cancelled*	*Cancelled*	*Cancelled*
E	*Chula Vista 2 - Ramco*	*2001-EP-03*	*Cancelled*	*62*	*0*	*San Diego*	*06/13/2001*	*Cancelled*	*Cancelled*	*Cancelled*
F	Hanford Energy Park - GWF	2000-SPPE-01	Cancelled	99	0	Kings	04/11/2001	Cancelled	Cancelled	Cancelled
G	Valero Cogen - Valero	2001-AFC-05	Not Built and License Expired	51	37	Solano	10/31/2001	02/01/2007	12/02	Not Built and License Expired
		Total Cancelled or License Expired		**1,444**						
		Not Under Construction Subtotal		*9,509*						

APPROVED TOTAL 25,952

Projects Not Approved (Arranged By Decision Date)	**Docket Number**	**Process**	**Capacity (MW)**	**Project Type**	**Location**	**Date Filed**	**Decision Date**		

CALIFORNIA ENERGY COMMISSION - ENERGY FACILITY STATUS

Power Plant Projects Filed Since 1996, Updated: 1/9/2009

(Note: Does not include projects filed but were withdrawn before they were approved.)

Color Key

	Operational Status		Expected and disclosed
	Approved		Expected but undisclosed
	In Review		On hold, suspended. According to developers, the new on-line date
	On-line date is expected to be delayed beyond the date shown		will be determined when the markets are favorable and/or financing available.
	Not Approved/Denied		Cancelled, withdrawn, not built, license expired.

Eastshore - Tierra Energy	**2006-AFC-6**	**12-mo AFC**	**116**	**Brownfield**	**Alameda**	**09/22/2006**	**10/08/2008**		

NOT APPROVED TOTAL 116

	Projects In Review (Arranged By Estimated Decision Date)	Docket Number	Process	Capacity (MW)	Project Type	Location	Date Filed	Estimated Decision Date		Estimated On-line Date
1	El Segundo Amendment - NRG	2000-AFC-14C	Dry Cooling Amendment	[See 00-AFC-14]	Replacement	Los Angeles	6/19/2007	1/09		06/10
2	Orange Grove AFC - J Power USA	2008-AFC-4	12-mo AFC	96	Greenfield	San Diego	6/20/2008	1/09		Unknown
3	Riverside En. Res. Cntr. Units 3 & 4 - City of Riverside	2008-SPPE-1	SPPE	96	Expansion	Riverside	3/19/2008	1/09		12/09
4	Sentinel Peaker - CPV	2007-AFC-3	12-mo AFC	850	Greenfield	Riverside	6/26/2007	1/09		05/10
5	MMC Chula Vista Replacement - MMC Energy, Inc.	2007-AFC-4	12-mo AFC	100	Replacement	San Diego	8/10/2007	2/09		12/09
6	Carlsbad - NRG	2007-AFC-6	12-mo AFC	558	Brownfield	San Diego	9/14/2007	3/09		07/10
7	San Gabriel - Reliant	2007-AFC-2	12-mo AFC	656	Expansion	San Bernardino	4/13/2007	3/09		Unknown
8	Highgrove Peaker - AES	2006-AFC-2	12-mo AFC	300	Expansion	San Bernardino	5/25/2006	4/09		Unknown
9	Sun Valley Peaker - Edison Mission	2005-AFC-03	12-mo AFC	500	Greenfield	Riverside	12/01/2005	4/09		Unknown
10	Southeast Region Energy Project formerly Vernon - City of Vernon	2006-AFC-4	12-mo AFC	943	Brownfield	Los Angeles	6/30/2006	4/09		Unknown
11	Community Power Plant - Kings River Conservation Dist.	2007-AFC-7	12-mo AFC	565	Greenfield	Fresno	9/27/2007	4/09		06/11
12	Carrizo Solar Farm - Ausra	2007-AFC-8	12-mo AFC	177	Greenfield	San Luis Obispo	10/25/2007	4/09		05/10
13	Canyon Power Plant - City of Anaheim	2007-AFC-9	12-mo AFC	200	Brownfield	Orange	12/28/2007	4/09		06/10
14	Ivanpah Solar - Brightsource	2007-AFC-5	12-mo AFC	400	Greenfield	San Bernardino	8/30/2007	5/09		02/11
15	Avenal Energy - Avenal Power Center, LLC	2008-AFC-1	12-mo AFC	600	Greenfield	Kings	2/21/2008	5/09		Unknown
16	Beacon Solar Energy Project - Beacon Solar LLC	2008-AFC-2	12-mo AFC	250	Greenfield	Kern	3/14/2008	5/09		10/11
17	SES Solar Two - SES Solar Two LLC/Stirling Energy	2008-AFC-5	12-mo AFC	750	Greenfield	Imperial	6/30/2008	6/09		Unknown
18	Tracy Combined Cycle - GWF	2008-AFC-7	12-mo AFC	169	Expansion	San Joaquin	7/18/2008	9/09		3/11
19	Marsh Landing Generating Station	2008-AFC-3	12-mo AFC	930	Brownfield	Contra Costa	5/30/2008	10/09		Unknown
20	Willow Pass - Mirant	2008-AFC-6	12-mo AFC	550	Brownfield	Contra Costa	6/30/2008	10/09		7/12
21	Hybrid Gas-solar - City of Palmdale	2008-AFC-9	12-mo AFC	617	Greenfield	Los Angeles	8/4/2008	10/09		2013
22	Lodi Energy Center - NCPA	2008-AFC-10	12-mo AFC	255	Brownfield	San Joaquin	9/10/2008	11/09		2012
23	Hanford Combined-Cycle Power Plant (Hanford Energy Peaker Project Expansion) - GWF Energy LLC	01-EP-7C	Major Amendment	55	Expansion Amendment	Kings	10/1/2008	10/09		?
24	CPV Vaca-Station - Competitive Power Ventures Inc.	2008-AFC-11	12-mo AFC	660	Greenfield	Solano	11/18/2008	11/09		?
25	San Joaquin Solar 1 & 2 (solar thermal & biomass hybrid) - San Joaquin Solar	2008-AFC-12	12-mo AFC	106.8	Greenfield	Fresno	11/26/2008	12/09		5/2011
26	SES Solar One - SES Solar One LLC/Stirling Energy	2008-AFC-13	12-mo AFC	850	Greenfield	San Bernardino	12/2/2008	12/09		2014

CALIFORNIA ENERGY COMMISSION - ENERGY FACILITY STATUS

Power Plant Projects Filed Since 1996, Updated: 1/9/2009

(Note: Does not include projects filed but were withdrawn before they were approved.)

Color Key

(green)	Operational Status	(light cyan)	Expected and disclosed
(yellow)	Approved	(purple)	Expected but undisclosed
(light green)	In Review	(pink)	On hold, suspended. According to developers, the new on-line date will be determined when the markets are favorable and/or financing available.
(grey)	On-line date is expected to be delayed beyond the date shown		
(orange)	Not Approved/Denied	(red)	Cancelled, withdrawn, not built, license expired.

Clean Hydrogen Power Project - BP Arco & Edison Mission Energy	2008-AFC-8	12-mo AFC	[390]	Brownfield	Kern	7/31/2008	Suspended During Review		Suspended During Review

UNDER REVIEW TOTAL 11,233.8

Projects Anounced (Aranged by Estimated Filing Date)		**Process**	**Capacity (MW)**	**Project Type**	**Location**	**Estimated Filing Date**			
eSolar 1 - eSolar Inc.		12-mo AFC	84	Greenfield	Los Angeles	1/09			
eSolar 2 - eSolar Inc.		12-mo AFC	66	Greenfield	Los Angeles	1/09			
Mojave - Solel		12-mo AFC	553	Greenfield	San Bernardino	2009			

ANNOUNCED TOTAL 703.0

Projects Planned (Aranged by Estimated Filing Date)		**Process**	**Capacity (MW)**	**Project Type**	**Location**	**Estimated Filing Date**			
Peaker 1		12-mo AFC	700		Unknown	Unknown			
Peaker 2		12-mo AFC	200		Unknown	Unknown			
Combined Cycle		12-mo AFC	575		Unknown	Unknown			
Combined Cycle		12-mo AFC	575		Unknown	Unknown			
Peaker Expansion 4		12-mo AFC	120		Unknown	Unknown			
Solar Thermal 3		12-mo AFC	160		Unknown	Unknown			
Solar Thermal 4		12-mo AFC	230		Unknown	Unknown			
Solar Thermal 5		12-mo AFC	230		Unknown	Unknown			
Solar Thermal 6		12-mo AFC	250		Unknown	Unknown			
Solar Thermal 7		12-mo AFC	250		Unknown	Unknown			
Solar Thermal 8		12-mo AFC	250		Unknown	Unknown			

PLANNED TOTAL 3,540

NOTES:

Bold text in table identifies a change from the previous report.
* Estimated on-line date if construction is not delayed.
** Estimated on-line date if approved & constructed as proposed.
Projects in italics and an "EP" Docket Number are emergency peakers
Megawatts in [ ] are not included in totals.
{1} 1021 MW replaced with 1200 MW for a net increase of 179 MW
{2} Project approved but replaced by Hanford-GWF (01-EP-7).
{3} 30 MW organic rankine cycle amendment approved 5/11/05.
{4} 130 MW amendment approved 6/22/05.

DEFINITIONS:

Greenfield	Undeveloped
Brownfield	Developed site
Expansion	New unit at existing site, no loss of existing generation
Repower	Modification of existing equipment
Replacement	Demolition of old plant and construction of new plant
On Hold	Applicant has suspended work
Suspended	Committee has suspended the proceeding

Exhibit 23

Alphabetical List of Power Plant Projects Filed Since 1996

- Avenal Energy Project - Avenal Power Center, LLC
- Beacon Solar Energy Project
- Blythe - Blythe Energy LLC
- Blythe II Combined Cycle - Blythe Energy LLC
- Blythe Transmission Line - Blythe Energy LLC
- Border - Calpeak (Emergency Peaker)
- Bottle Rock Geothermal - U.S. Renewables Group (Repower)
- Bullard Energy Center (BEC)
- Canyon Power Plant
- Carlsbad Energy Center - NRG
- Carrizo Energy Solar Farm
- Century - Alliance (Emergency Peaker)
- Chevron Richmond Power Plant Replacement Project - Chevron USA, Inc.
- Chula Vista Energy Upgrade Project - MMC Energy, Inc.
- City of Vernon Malburg Generating Station
- Colusa Generating Station (CGS)
- Community Power - Kings River Conservation District
- CPV Vacaville Station
- Delta - Calpine
- Drews - Alliance (Emergency Peaker)
- East Altamont - Calpine
- Eastshore Power Project - Tierra Energy
- El Centro Unit 3 Repower Project - Imperial Irrigation District (IID)
- El Segundo Repower - Dynegy/NRG
- El Segundo - Dry Cooling Amendment Proceeding
- Elk Hills - Sempra & Oxy
- Escondido - Calpeak (Emergency Peaker)
- Gateway Generating Station (formerly Contra Costa) Power Plant Project
- Gilroy I, Units 1,2 & 3 - Calpine (Emergency Peaker)
- Hanford - GWF (Emergency Peaker)
- Hanford Combined Cycle Power Project -
- Magnolia - SoCal Power Authority
- Malburg Generating Station - City of Vernon
- Marsh Landing Generating Station
- Metcalf - Metcalf Energy Center LLC
- Modesto Irrigation District - Ripon, Simple Cycle
- Morro Bay - Duke
- Moss Landing Unit 1 & 2 - Duke
- Mountainview - SCE
- Niland Gas Turbine Plant (SPPE)
- Orange Grove Energy, Simple Cycle
- Otay Mesa - Calpine
- Palmdale Solar-Gas Hybrid - City of Palmdale
- Palomar Escondido - Sempra
- Panoche Energy Center - Energy Investors Fund
- Pastoria - Calpine
- Pastoria Expansion Project (Pastoria 2) - Pastoria Energy LLC
- Riverside Energy Resource Center - City of Riverside Public Utilities
- Riverside Energy Resource Center Units 3 & 4 **(Expansion Project)** - City of Riverside
- Roseville Energy Park - City of Roseville
- Russell City - Calpine
- Russell City **Amendment** - Calpine
- Salton Sea Geothermal
- San Francisco Electric Reliability Project - City of San Francisco
- San Gabriel Generating Station - Reliant Energy
- San Joaquin Solar 1 & 2 - San Joaquin Solar LLC
- San Joaquin Valley Energy Center - Calpine
- Sentinel Energy Project - CPV Sentinel, LLC
- SMUD Combined Cycle Phase 1
- Solar One Power Project - SES Solar One LLC
- Solar Two Power Project - SES Solar

GWF (Major Amendment)
- Henrietta Peaker - GWF
- Henrietta Combined Cycle Power Project - GWF (Major Amendment)
- High Desert - High Desert Power Project LLC
- Highgrove - AES
- Humboldt Bay Generating Station - PG&E
- Huntington Beach Unit 3 & 4 - AES
- Hydrogen Energy California - Hydrogen Energy International LLC
- Inland Empire Combined Cycle - Calpine
- Ivanpah Solar Electric Generating System
- King City - Calpine (Emergency Peaker)
- Kings River Peaker - Kings River Conservation District
- La Paloma - PG&E Natl. Units 1, 2, 3 & 4
- Lodi Energy Center - Northern California Power Authority
- Los Esteros - Calpine
- Los Esteros PHASE 2 - Calpine
- Los Medanos (Pittsburg) - Calpine

Two LLC
- Southeast Regional Energy Center (Formerly City of Vernon)
- South Bay Combined Cycle - L.S. Power
- Starwood Power - Starwood Power-Midway LLC
- Sunrise - Texaco & Edison Mission E.
- Sun Valley Energy Project - Edison Mission Energy
- Sutter - Calpine
- Tesla Combined Cycle - FPL
- Tracy Peaker - GWF
- Tracy Combined-Cycle Power Plant - GWF Energy, LLC (Project Expansion)
- Vaca Station - CPV Vacaville
- Valero Cogeneration Unit 1 & 2
- Vernon Combined Cycle - City of Vernon
- Victorville 2 Solar-Gas Hybrid Power Project - City of Victorville
- Von Raesfeld (Formerly Pico Power) Combined Cycle - Silicon Valley Power
- Walnut Creek Energy Park (City of Industry) - Edison Mission Energy
- Walnut Energy Center - Turlock Irrigation District
- Wildflower Indigo - Intergen (Emergency Peaker)
- Wildflower Larkspur - Intergen (Emergency Peaker)
- Willow Pass Generating Station - Mirant
- Woodland II Combined Cycle - Modesto Irrigation District

- **Withdrawn Projects List**

Last Modified: 12/22/08

Exhibit 24

Final
Determination of Compliance

Metcalf Energy Center

Bay Area Air Quality Management District
Application 27215

August 24, 2000

Dennis Jang, P.E.
Air Quality Engineer

Contents

15. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) shall not exceed 49,908 MM BTU per calendar day. (PSD for PM_{10})

16. The combined cumulative heat input rate for the Gas Turbines (S-1 & S-3) and the HRSGs (S-2 & S-4) shall not exceed 35,274,060 MM BTU per year. (Offsets)

17. The HRSG duct burners (S-2 and S-4) shall not be fired unless its associated Gas Turbine (S-1 and S-3, respectively) is in operation. (BACT for NO_x)

18. S-1 Gas Turbine and S-2 HRSG shall be abated by the properly operated and properly maintained A-1 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-1 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

19. S-3 Gas Turbine and S-4 HRSG shall be abated by the properly operated and properly maintained A-2 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-2 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

20. The Gas Turbines (S-1 & S-3) and HRSGs (S-2 & S-4) shall comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode and steam injection power augmentation mode. Requirements (a) through (h) do not apply during a gas turbine start-up or shutdown. (BACT, PSD, and Toxic Risk Management Policy)

    (a) Nitrogen oxide mass emissions (calculated as NO_2) at P-1 (the combined exhaust point for the S-1 Gas Turbine and the S-2 HRSG after abatement by A-1 SCR System) shall not exceed 19.2 pounds per hour or 0.00904 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-2 (the combined exhaust point for the S-3 Gas Turbine and the S-4 HRSG after abatement by A-3 SCR System) shall not exceed 19.2 pounds per hour or 0.00904 lb/MM BTU (HHV) of natural gas fired. (PSD for NO_x)

    (b) The nitrogen oxide emission concentration at emission points P-1 and P-2 each shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any 1-hour period. (BACT for NO_x)

    (c) Carbon monoxide mass emissions at P-1 and P-2 each shall not exceed 0.0132 lb/MM BTU (HHV) of natural gas fired or 28.07 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

    (d) The carbon monoxide emission concentration at P-1 and P-2 each shall not exceed 6.0 ppmv, on a dry basis, corrected to 15% O_2, when the heat input to the combustion turbine exceeds 1700 MM BTU/hr (HHV), averaged over any rolling 3-hour period. If compliance source test results and continuous emission monitoring data indicate that a lower CO emission concentration level can be achieved on a consistent basis (with a suitable complaince margin) over the entire range of turbine operating conditions, including duct firing and power steam augmentation operations, and over the entire range of ambient conditions, the District will reduce this limit to a level not lower than 4.0 ppmv, on a dry basis, corrected to 15% O_2. If this limit is reduced, the corresponding mass emission rate limit specified in condition 20(c) shall also be modified to reflect this reduction. (BACT for CO)

(e) Ammonia (NH_3) emission concentrations at P-1 and P-2 each shall not exceed 5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-1 and A-2 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-1 and A-2 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1 and P-2 shall be determined in accordance with permit condition 30. (TRMP for NH_3)

(f) Precursor organic compound (POC) mass emissions (as CH_4) at P-1 and P-2 each shall not exceed 2.7 pounds per hour or 0.00126 lb/MM BTU of natural gas fired. (BACT)

(g) Sulfur dioxide (SO_2) mass emissions at P-1 and P-2 each shall not exceed 1.28 pounds per hour or 0.0006 lb/MM BTU of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-1 and P-2 each shall not exceed 9 pounds per hour or 0.00452 lb PM_{10}/MM BTU of natural gas fired when HRSG duct burners are not in operation. Particulate matter (PM_{10}) mass emissions at P-1 and P-2 each shall not exceed 12 pounds per hour or 0.00565 lb PM_{10}/MM BTU of natural gas fired when HRSG duct burners are in operation. (BACT)

21. The regulated air pollutant mass emission rates from each of the Gas Turbines (S-1 and S-3) during a start-up or a shutdown shall not exceed the limits established below. (PSD)

	Start-Up (lb/start-up)	Start-Up (lb/hr)	Shutdown (lb/shutdown)
Oxides of Nitrogen (as NO_2)	240	80	18
Carbon Monoxide (CO)	2,514	902	43.8
Precursor Organic Compounds (as CH_4)	48	16	5

22. The Gas Turbines (S-1 and S-3) shall not be in start-up mode simultaneously. (PSD)

23. The heat recovery steam generators (S-2 & S-4) and associated ducting shall be designed and constructed such that an oxidation catalyst can be readily installed and properly operated if

Exhibit 25

THE METCALF ENERGY CENTER

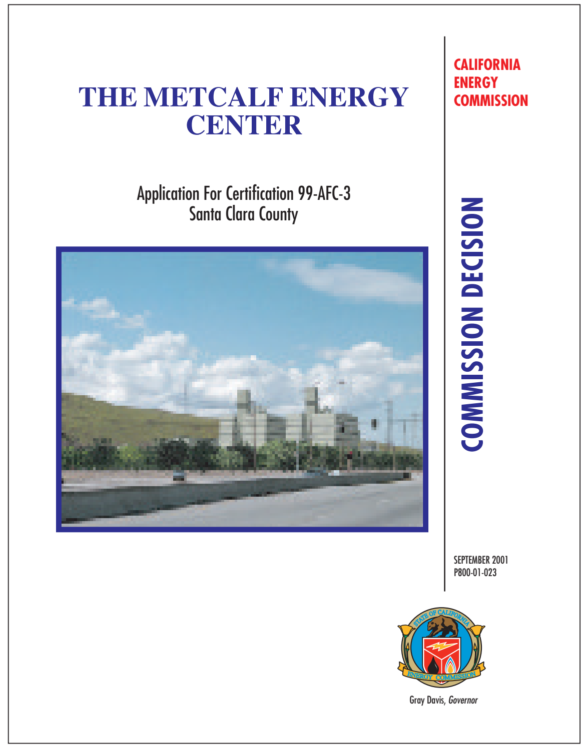
Application For Certification 99-AFC-3
Santa Clara County

CALIFORNIA
ENERGY
COMMISSION

COMMISSION DECISION

SEPTEMBER 2001
P800-01-023

Gray Davis, *Governor*


THE METCALF ENERGY CENTER

Application For Certification 99-AFC-3
Santa Clara County

CALIFORNIA ENERGY COMMISSION

COMMISSION DECISION

SEPTEMBER 2001
P800-01-023

Gray Davis, *Governor*

CALIFORNIA ENERGY COMMISSION

1516 9th Street
Sacramento, CA 98814

www.energy.ca.gov/sitingcases/metcalf

The Metcalf Energy Center Committee

ROBERT A. LAURIE, Commissioner
Presiding Committee Member

WILLIAM J. KEESE, Chairman
Associate Committee Member

Hearing Office

STANLEY VALKOSKY
Chief Hearing Officer

<u>Verification</u>: As part of the monthly Air Quality Reports, the owner/operator shall indicate the date of any violation of this Condition including quantitative information on the severity of the violation.

AQ-55 The project owner shall install an oxidation catalyst to control VOC emissions.

<u>Verification</u>: As part of the final design plans, specifications, and drawings, the project owner shall submit to the District and the CPM for review and approval the final selection and design details of the combustion equipment, including all emission control systems.

Exhibit 26

COMMONWEALTH OF MASSACHUSETTS
EXECUTIVE OFFICE OF ENVIRONMENTAL AFFAIRS
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Metropolitan Boston – Northeast Regional Office

ARGEO PAUL CELLUCCI
Governor

JANE SWIFT
Lieutenant Governor

BOB DURAND
Secretary

LAUREN A. LISS
Commissioner

March 10, 2000

Mr. George Wilson
Sithe Edgar Development, LLC
173 Alford Street
Charlestown, MA 02129

RE: **WEYMOUTH** - Metropolitan
Boston/Northeast Region
PROPOSED CONDITIONAL
MAJOR COMPREHENSIVE PLAN APPROVAL
310 CMR 7.00: APPENDIX A
310 CMR 7.02(2)
Prevention of Significant Deterioration Permit
40 CFR 52.21
Transmittal No. W004896
Application No. MBR-99-COM-018

Dear Mr. Wilson:

The Department of Environmental Protection (the "Department"), Northeast Regional Office (NERO), Bureau of Waste Prevention, has reviewed the Major Comprehensive Plan Application for the proposed 775 megawatt (MW) combined cycle electric generating facility and auxiliary combustion equipment to be located at 1 Bridge Street in Weymouth, Massachusetts. The submittal bears the seal and signature of Dale T. Raczynski, Massachusetts P.E. Number 36207.

The Department is of the opinion that the material submitted is in conformance with the current Massachusetts Air Pollution Control Regulations and hereby **PROPOSES to CONDITIONALLY APPROVE** this facility at the proposed site location, subject to the conditions and provisions stated herein.

This letter combines and includes: the proposed 310 CMR 7.02(2) Comprehensive Plan Approval, the proposed 310 CMR 7.00: APPENDIX A: Emission Offsets and Nonattainment Review Approval, and the proposed Code of Federal Regulations, Title 40, Part 52.21 Prevention of Significant Deterioration (PSD) Permit. These proposed actions are subject to a public comment period and a public hearing as specified in the Code of Federal Regulations, Title 40, Part 51.161 and the Commonwealth's Air Pollution Control Regulations 310 CMR 7.00: Appendix A.

The PROPOSED CONDITIONAL APPROVAL/PSD Permit will allow for commencement of construction of the facility and its operation, and provides information on the project description, emission control systems, facility emission limits, continuous emission monitors, record keeping, reporting and testing requirements.

This facility is also subject to the requirements of the Massachusetts Environmental Policy Act (MEPA) Massachusetts General Laws (M.G.L.) Chapter 30, Sections 61-62H. On September 16, 1999, the Secretary of the Executive Office of Environmental Affairs issued a certificate that the Final Environmental Impact Report (FEIR) (EOEA #11726) adequately complied with the MEPA and its regulations.

On February 11, 1999, the Energy Facility Siting Board issued approval under M.G.L. Chapter 164, §69J of Sithe Edgar Development's Petition to construct and operate the facility. In accordance with that statute, the Department may issue a Plan Approval/Permit for the facility to be constructed.

This PROPOSED CONDITIONAL APPROVAL/PSD Permit is limited to the applicable Air Pollution Control Regulations and does not constitute approval as may be required by other Department regulations or statutes in order for the subject facility to be installed and operated.

A list of submitted information pertinent to the application is delineated in Attachment A.

If you have any questions concerning this matter, please feel free to contact Mr. Marc Altobelli at (978) 661-7642.

Sincerely,

Edward Braczyk
Environmental Engineer
Bureau of Waste Prevention

James E. Belsky
Regional Permit Chief
Bureau of Waste Prevention

Marc Altobelli
Environmental Engineer
Bureau of Waste Prevention

cc: see Attachment List

TABLE OF CONTENTS

I. FACILITY DESCRIPTION

A. Site Description

The Fore River Station site, formerly the Boston Edison Edgar site, consists of approximately 57 acres of land situated on a peninsula along the bank of the Weymouth Fore River in Weymouth, Massachusetts. The existing Edgar Station includes two 12 MW simple cycle combustion turbines (Edgar Units J1 and J2) used for peaking power only. Each combustion turbine fires No. 2 fuel oil with a maximum sulfur content of 0.3 weight percent as the only fuel of use. The Fore River Station site is bounded by the Weymouth Fore River to the west, and south, Bridge Street (Route 3A) to the north, and Monatiquot Street to the east.

The neighboring community consists of a mix of industrial, commercial, and residential properties. The nearest residential area is located approximately 50 feet east of the property fence line.

B. Project Description

Sithe Edgar Development LLC (the "Applicant") proposes to design, construct and operate a new combined-cycle electric generating facility within the boundaries of the existing Fore River Station site in Weymouth, Massachusetts. The Project is referred to as the Fore River Station Project. The Project will be configured as a new main power block generating 775 MW of electric power.

Fore River Station Unit 1(A and B) will include two Mitsubishi Heavy Industries (MHI) Model 501G combustion turbine generators (CTGs) each including a Heat Recovery Steam Generator (HRSG). The new power block will be equipped with one steam turbine generator (STG). Each CTG will have a nominal generating capacity of approximately 250 MW. The hot exhaust gases from each CTG will pass through a HRSG, which will use the heat from these gases to produce steam. These exhaust gases also contain sufficient oxygen to allow the placement of supplemental firing burners in the ducts just upstream of the HRSG equipment. Each HRSG will house an oxidation catalyst for carbon monoxide (CO) control, followed by an ammonia (NH_3) injection grid and selective catalytic reduction (SCR) catalyst for control of nitrogen oxides (NO_X). The steam produced by each HRSG will be fed into a single condensing STG. The STG will have a nominal generating capacity of approximately 275 MW. An air-cooled condenser will be used to condense the steam.

Each MHI 501G turbine will have a maximum energy input at -12ºF ambient of 2,676 Million British Thermal Units per hour (MMBtu/hr), HHV (higher heating value) during natural gas firing. Each supplementary natural gas-fired HRSG will have a maximum energy input of 279 MMBtu/hr (HHV) at -12ºF. Each MHI 501G turbine and supplementary-fired HRSG in combination will have a maximum energy input (at -12ºF ambient) of 2955 MMBtu/hr, HHV during natural gas firing.

During oil firing, each MHI 501G turbine will have a maximum energy input at -12ºF ambient of 2,734 MMBtu/hr, (HHV) at a water to fuel ratio of 0.4 to 1. Each MHI 501G oil-fired turbine and supplementary natural gas-fired HRSG in combination will have a maximum energy input (at -12ºF ambient) of 3,001 MMBtu/hr (HHV).

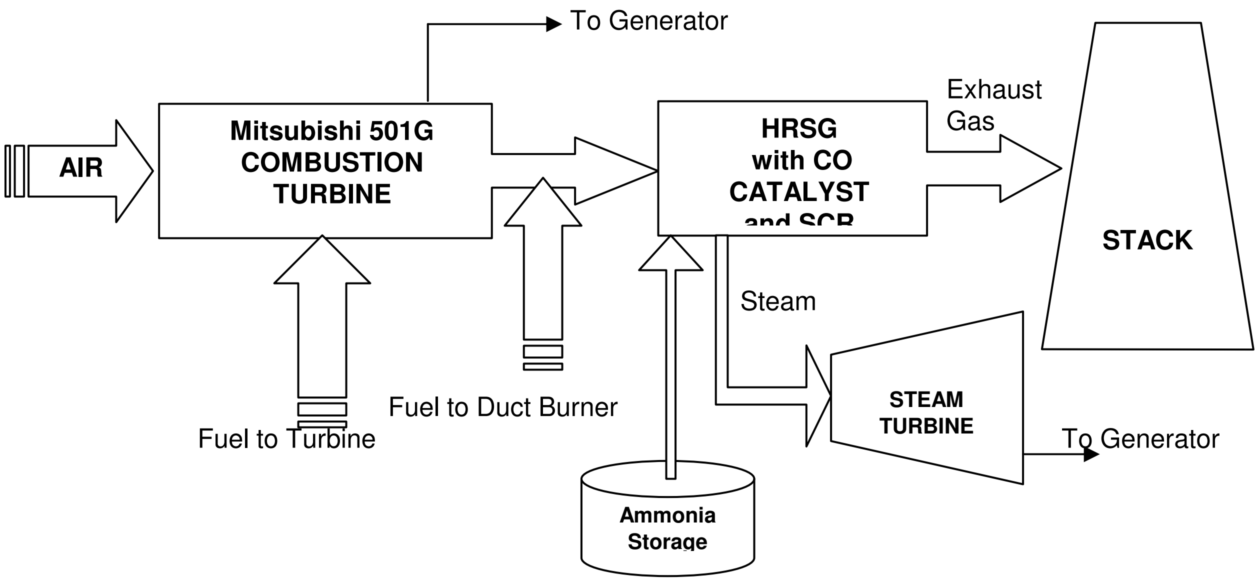
The entire CTG/HRSG facility will use natural gas (with a sulfur content that does not exceed 0.8 grains per 100 cubic feet) as the primary fuel of use. Transportation distillate fuel oil with a sulfur content that does not exceed 0.05 percent by weight will be fired at a maximum annual rate of 29,074,350 gallons per 12-month rolling period when operating at 100% rated capacity and at a temperature of -12^{0}F ambient. The facility will be designed to operate continuously (24 hours per day, 7 days per week), except for equipment downtime to allow for servicing, maintenance, and repair activities.

Other auxiliary equipment includes aqueous ammonia storage tanks, a continuous emissions monitoring system (CEMS), a new auxiliary boiler and a new emergency diesel generator.

The new auxiliary boiler shall be designated as Fore River Unit AB and will provide steam for plant startup when both CTGs are off line. This boiler will fire natural gas (with a sulfur content that does not exceed 0.8 grains per 100 cubic feet) as the primary fuel of use and transportation distillate fuel as a back-up fuel. The auxiliary boiler will have a maximum energy input of 96 MMBtu/hr HHV. This boiler shall be limited to 48,000 MMBtu per 12-month rolling period, corresponding to the equivalent of 500 full load operating hours. This boiler shall be limited to 9,600 MMBtu per month (See Section III (H)).

The new emergency generator, 1,500 kilowatts (kW) or 15.4 MMBtu/hr, HHV, shall be designated as Fore River Unit EDG1 and is required for facility backup power to support shut down operations if no power is available from the utility grid. The emergency diesel generator will fire transportation diesel fuel oil with a sulfur content that does not exceed 0.05 percent by weight and shall be limited to a fuel consumption of 16,500 gallons based on 150 hours of operation per 12-month rolling period.

The exhaust gases from the proposed facility shall be emitted from three new flues located in a common concrete shell, with the stack having a height of 255 feet above ground level. The auxiliary boiler shall utilize one flue and the other two flues shall provide dedicated service for the exhaust of the CTG/HRSG units. Each CTG/HRSG flue will have an inside exit diameter of 20.5 feet, which will provide for a maximum exit velocity of 84.7 feet per second at an exit stack temperature of 311ºF. The auxiliary boiler flue will have an inside exit diameter of 4 feet, which will provide for a maximum exit velocity of 35.0 feet per second at an exit stack temperature of 300ºF. The emergency diesel generator will be equipped with a steel stack with two flues, having a height of 25 feet above ground level. Each stack flue will have an inside exit diameter of 1.0 foot which will provide for a maximum exit velocity of 134 feet per second at an exit stack temperature of 900ºF.



II. EMISSIONS

The operation of the turbine combustors and the auxiliary boiler on natural gas and back-up transportation distillate oil (as well as the emergency diesel generators on transportation distillate oil) will result in emissions to the ambient air of the following criteria air pollutants: Particulate Matter (PM/PM_{10}), Sulfur Dioxide (SO_2), Carbon Monoxide (CO), Nitrogen Oxides (NO_x), and Volatile Organic Compounds (VOC). During firing of the primary fuel, natural gas, the turbine combustors will be a source of emissions of three (3) air toxics: ammonia (NH_3), formaldehyde (CH_2O), and sulfuric acid mist (H_2SO_4). During firing of the back-up fuel, transportation distillate oil, the turbine combustors will also be a source of emissions of several air toxics. Please refer to pages 40 and 41 of this document for a complete listing.

III. EMISSION LIMITS

A. Air pollutant emission rates from the facility shall be kept at the lowest practical level at all times, but shall not exceed the emission limitations as specified in Tables 1 and 2 below.

Table 1: Short Term Emission Limits for Proposed Facility Per Emission Unit				
Pollutant	**Each Combustion Turbine**(1,2)		**Auxiliary Boiler** (4) Natural Gas/Fuel Oil	**Emergency Diesel Generator**(5)
	Natural Gas	**Fuel Oil**		
NO_x	21.8 lbs/hr	65.7 lbs/hr	3.4 / 9.6 lbs/hr	37.44 lbs/hr
CO	13.3 lbs/hr	46.5 lbs/hr	7.7 lbs/hr	3.05 lbs/hr
VOC (unfired)	3.8 lbs/hr	26.0 lbs/hr	0.8/ 0.384 lbs/hr	1.16 lbs/hr
VOC (duct-fired)	6.4 lbs/hr	28.4 lbs/hr	NA	NA
SO_2	6.4 lbs/hr	143.5 lbs/hr	0.3/ 5.01 lbs/hr	0.95 lbs/hr
PM	32.5 lbs/hr	139.6 lbs/hr	0.7/ 7.7 lbs/hr	0.87 lbs/hr
NH_3(3)	8.0 lbs/hr	8.6 lbs/hr	NA	NA
NO_x	0.0074 lbs/MMBtu	0.0233 lbs/MMBtu	0.035/ 0.10 lbs/MMBtu	6.55 gm/bhp-hr
CO	0.0045 lbs/MMBtu	0.0166 lbs/MMBtu	0.08 lbs/MMBtu	0.53 gm/bhp-hr
VOC (unfired)	0.0013 lbs/MMBtu	0.0095 lbs/MMBtu	0.008/ 0.004 lbs/MMBtu	0.20 gm/bhp-hr
VOC (duct-fired)	0.0022 lbs/MMBtu	0.0095 lbs/MMBtu	NA	NA
SO_2	0.0023 lbs/MMBtu	0.0522 lbs/MMBtu	0.0029/ 0.0522 lbs/MMBtu	0.17 gm/bhp-hr
PM	0.011 lbs/MMBtu	0.05 lbs/MMBtu	0.007/ 0.08 lbs/MMBtu	0.15 gm/bhp-hr
NH_3(3)	0.0027 lbs/MMBtu	0.0029 lbs/MMBtu	NA	NA
NO_x	2.0 ppmvd @15% O_2	6.0 ppmvd @15%O_2	NA	NA
CO	2.0 ppmvd @ 15% O_2	7.0 ppmvd @15%O_2	100 ppmvd @ 3% O_2	NA
VOC (unfired)	1.0 ppmvd @ 15% O_2	7.0 ppmvd @15%O_2	NA	NA
VOC (duct-fired)	1.7 ppmvd @ 15% O_2	7.0 ppmvd @15%O_2	NA	NA
SO_2	NA	NA	NA	NA
PM	NA	NA	NA	NA
NH_3	2.0 ppmvd @ 15% O_2(3) (7)	2.0 ppmvd @ 15%O_2(3) (7)	NA	NA
Opacity	<5%, except 5 to < 10% for ≤ 2 minutes during any one hour	< 10%, except 10 to < 15% for ≤ 2 minutes during any one hour		
Smoke	310 CMR 7.06(1)(a)			

Table 2: Long Term Emission Limits For Proposed Facility	
Pollutant	**Proposed Facility(6) (tons per 12-month rolling period)**
NO_x	218
CO	296
VOC	71.5
SO_2	154
PM	352
NH_3(3)	67

Tables 1 & 2 Key:

NO_x	= oxides of nitrogen
CO	= carbon monoxide
VOC	= volatile organic compounds
SO_2	= sulfur dioxide
PM	= particulate matter
NH_3	= ammonia
lbs/hr	= pounds per hour
lb/MMBtu	= pound per million British Thermal Units
gm/bhp-hr	= grams per brake horsepower hour
ppmvd@15%O_2	= parts per million, dry volume basis corrected to 15 percent oxygen
ppmvd@3%O_2	= parts per million, dry volume basis corrected to 3 percent oxygen
NA	= not applicable
%	= percent
<	= less than
$\leq$	= less than or equal to

Tables 1 & 2 Notes:

1. Emission limits are one-hour block averages and do not apply during start-up/shutdown, fuel transfers, and equipment cleaning. Start-ups, shutdowns, and fuel transfers shall not last longer than 3 hours (See Proviso X.2.).

2. Emission rates are for burning natural gas or transportation distillate fuel oil in one combustion turbine and based on 100% load and -12^{o}F ambient while supplemental duct firing. These constitute worst case emissions.

3. Based on maximum ammonia (NH_3) slip (from SCR) of 2.0 ppmvd @15% O_2 (excluding start-up, shutdown, and fuel transfer periods).

4. Emission limits for the auxiliary boiler are one-hour block averages and apply over the normal operating range up to 100% load.

5. Emission limits for the emergency diesel generator are one-hour block averages and apply over the normal operating range up to 100% load.

6. Proposed facility emissions include the two CTG/HRSG pair with supplemental duct firing burners (designated as Fore River Unit 1), the auxiliary boiler (designated as Fore River Unit AB), and an emergency diesel generator (designated as Fore River Unit EDG1). Emissions for the combustion turbines are based upon 8,040 hours of natural gas firing at 100% duct-fired load at an annual average inlet temperature of 51^{o}F ambient, 720 hours of transportation distillate fuel oil with a sulfur content that does not exceed 0.05 percent by weight firing at 100% duct-fired load at an inlet temperature of -12^{o}F ambient and includes combustion turbine start-up emissions (see Application Transmittal No. W004896). Emissions for the auxiliary boiler are based on a 48,000 MMBtu per year restriction and 500 hours of operation. The auxiliary boiler shall be restricted to a total fuel consumption of 48 million cubic feet of natural gas based on a heat input of 1,000 BTU per cubic foot of natural gas or 355,555 gallons of transportation distillate fuel oil with a sulfur content that does not exceed 0.05 percent by weight based on a heat input of 135,000 BTU per gallon of fuel oil, the combined consumption of which shall not exceed the total of 48,000 MMBtu per 12-month rolling period. Emissions for the emergency diesel generator are based on restricted operation of 150 hours or while firing 16,500 gallons per 12-month rolling period of transportation diesel fuel oil having a sulfur content that does not exceed 0.05% by weight. The proposed facility emissions are determined as equal to the total combustion turbine emissions due to the fact that neither the auxiliary boiler nor emergency diesel generator will operate concurrently with combustion turbine operation. Auxiliary boiler operation will only be required for start-up and only in the event that no other combustion turbine is in operation or if steam is not available from some other on-site steam source. The emergency diesel generator will only operate as required to shutdown Unit 1 (A and B) and only in the event that power to achieve shutdown is not available from the electric power grid.

7. For the duration of the optimization program identified in Section X. 3 and XIII.7 the ammonia emission limit shall be State enforceable only. Thereafter, the ammonia emission limit will be federally enforceable.

B. The Applicant shall ensure that the proposed facility shall comply with all emission limits contained in Table 1 above.

C. The Applicant shall ensure that the subject facility does not exceed the annual emissions limits in Table 2 above, based on a 12-month rolling period.

D. The Applicant shall burn natural gas as the primary fuel in the CTGs, the supplemental firing burners (natural gas only firing), and the auxiliary boiler, and shall ensure that the sulfur content of the natural gas to be used at the subject facility does not exceed 0.8 grains per 100 cubic feet.

E. The Applicant shall burn no more than 29,074,350 gallons of transportation distillate fuel oil per twelve-month rolling total in the CTGs (equivalent to no more than 720 hours per year). The sulfur content of the transportation distillate fuel oil to be used at the subject facility shall not exceed 0.05 percent by weight. The Applicant shall not burn transportation distillate fuel oil in the CTGs and the auxiliary boiler during the time period May 1 through September 30 inclusive of any calendar year, except during initial compliance testing, initial plant demonstration and performance testing, periodic readiness testing, in the event of the unavailability of natural gas, or in the case of a variance obtained from the Department to operate during an emergency.

F. The Department and the Applicant have entered into a memorandum of understanding (MOU) concerning the use of zero ammonia technology (ZAT) for the control of nitrogen oxides. A copy of the MOU is included here as Attachment C. For the first five years of operation of the facility, there shall be an interim emission rate for ammonia of 2.0 ppmvd

@ 15% O_2 one-hour block average. Pursuant to the MOU, the emission rate for ammonia after the first five years of operation shall be zero unless the Department extends the interim 2.0 ppm ammonia limit. During the five year period it will be determined whether a ZAT must be installed in the facility. The MOU provides a methodology for making the determination, including a consideration of availability, reliability, comparable costs and the impact on other permits and approvals. A determination of the comparative costs of retrofitting the facility to a ZAT will be made by an independent consultant.

G. The Applicant shall not operate the existing jet turbines when the new facility is operating on transportation distillate fuel oil.

H. The Applicant shall restrict the operation of the subject 96 MMBtu/hr auxiliary boiler to a total BTU cap of no more than 48,000 MMBtu per 12 month rolling period based upon 500 hours of operation while firing natural gas as the primary fuel of use and firing transportation diesel fuel oil having a sulfur content that does not exceed 0.05% by weight as the back-up fuel.

I. The Applicant shall restrict the operation of the 1500 KW (15.4 MMBtu/hr) emergency diesel generator to a total fuel consumption of no more than 16,500 gallons of fuel oil per 12 month rolling period based upon 150 hours of operation per unit while firing transportation diesel fuel oil having a sulfur content that does not exceed 0.05% by weight only, inclusive of periodic readiness testing and emergency use.

IV. ACCIDENTAL RELEASE MODELING OF AQUEOUS AMMONIA

Aqueous ammonia will be used as the reducing agent in the SCR system. A solution of aqueous ammonia (≤ 19.5% by weight solution) will be stored onsite. A 90,000-gallon double walled steel tank will be provided for on-site storage of ammonia. The tank will be equipped with leak detection and an ammonia vapor treatment system. The vapor treatment system will consist of a continuous water quench designed to absorb all ammonia vapor off the tanks. The system will have a ventilation pipe less than 4 inches in diameter. The tanks will be surrounded by concrete berms or fencing to prevent accidental contact with vehicles or other equipment. A catastrophic release from the inner wall of each tank would be contained within its outer wall. The tank vapor treatment system will continue to function even if the aqueous ammonia accumulates within the outer tank wall. Ammonia would be released to the atmosphere through the ventilation pipe only if a rupture of the primary (internal) tank wall were to occur coupled with a loss of power to the ammonia vapor filtration system.

The vaporization and dispersion of the ammonia was modeled to the nearest receptors at the nearest fence line, property boundary line, and public road to the ammonia storage tank. Specific computer dispersion modelling documents that maximum predicted concentrations of ammonia were below the Immediately Dangerous to Life or Health (IDLH) thresholds developed by the National Institute for Occupational Safety and Health (NIOSH) at all receptors.

V. EMISSION OFFSETS AND NONATTAINMENT REVIEW

The entire Commonwealth of Massachusetts is designated "serious" Nonattainment for the pollutant ozone (O_3). Nonattainment review applies to any Applicant with potential emissions of Nitrogen Oxides (NO_x) and/or Volatile Organic Compounds (VOC) from a facility that is at or above the "major source" threshold criterion of 50 tons per year, as well as to "major modifications" at existing "major" facilities, as defined in 310 CMR 7.00: Appendix A. A "major modification" is defined as an increase of 25 or more tpy of nonattainment precursor pollutants at an existing "major" source. NO_x and VOC emissions are precursors to the formation of ozone and "major" NO_x and VOC emitters are regulated pursuant to Appendix A. Applicable requirements for any proposed new major stationary source of nonattainment pollutants require the source to meet Lowest Achievable Emission Rate (LAER) and obtain emission offsets.

Several recent developments have directly impacted the Emission Offsets and Nonattainment review process as required by Appendix A. On May 14, 1999, the D.C. Circuit Court of Appeals remanded the 8-hour ozone standard to the U.S. Environmental Protection Agency (U.S. EPA) to develop an acceptable basis for the standard (American Trucking Associations v. U.S. EPA). However, the standard was not vacated. Then on June 9, 1999, the U.S. EPA determined that the 1-hour ozone standard no longer applies to the eastern portion of the Commonwealth of Massachusetts (including Weymouth). These developments temporarily placed Nonattainment New Source Review (NSR) (310 CMR 7.00: Appendix A) in abeyance.

On October 22, 1999, the Department issued an Emergency Amendment to Appendix A through the emergency promulgation provisions at M.G.L. c.30A Sections 2 and 3. These provisions authorize the Department to immediately adopt, prior to notice and public hearing, regulations which are necessary for the preservation of the public health, safety or general welfare, where the Department finds that observance of the requirements of notice and public comment would be contrary to the public interest. The Regulation adoption reinstates the Appendix A requirements. Regulation 310 CMR 7.00 Appendix A sets offset requirements for major sources, or major modifications thereat, of NOx and VOC at a minimum ratio of 1.2 to 1.

The Applicant has proposed maximum potential NOx and VOC emissions from Fore River Station Unit 1 (A and B), AB and EDG1 of 218 and 70 tons per year, respectively. The Fore River Station Project is thus a "major source" with respect to NOx and VOC emissions.

Since the Project is a major source for NOx and VOC, NOx and VOC offsets are required. 310 CMR 7.00: Appendix B(3) requires that applicants must obtain 5% more ERCs than the number of ERCs needed for offsets. This 5% must be held as a set aside and neither sold nor used. Offsets must be from the same nonattainment area or from another nonattainment area of equal or more severe nonattainment classification if emissions from this other area contribute to ozone nonattainment in the area where the new project will be constructed. At this time, the total number of offsets needed are (218) times (1.26) = 275 tpy of NOx and (71.5) times (1.26) = 90.1 tpy of VOC.

The Applicant has proposed NOx emission limits of 2.0 ppmvd at 15% O_2 for natural gas firing and 6.0 ppmvd at 15% O_2 while combusting transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight), both at one hour block averages. The Applicant has proposed VOC emission limits of 1.0 ppmvd at 15% O_2 for natural gas firing without duct firing, and 1.7 ppmvd at 15% O_2 for natural gas firing with duct firing, both at one hour block averages. The Applicant has proposed a VOC limit of 7.0 ppmvd at 15% O_2 while combusting transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight) at a one hour block average. The Department has verified and concurs with the Applicant's LAER analysis as presented in its Major Comprehensive Plan Application (MBR-99-COM-018, Transmittal W004896) that these proposed NOx and VOC limits constitute NOx and VOC LAER for the project.

The NOx and VOC offset requirements for this facility under Appendix A can be met by withdrawing Massachusetts Department-certified NOx and VOC Emission Reduction Credits (ERCs). Emission reduction credits can come from shutting down an existing source, or curtailing its operation, or by over-controlling an existing source. In all cases, offsets must be real, surplus, permanent, quantifiable, and federally enforceable. The Department will also accept NOx and VOC offsets created by qualifying activities in certain other states provided that the Department has executed a memorandum of understanding or some other mutually acceptable agreement with the other state(s). The offsets created in the other state must be real, surplus, permanent, quantifiable, and federally enforceable.

Sithe Edgar Development, LLC will use NO_X Rate Based ERCs from reduction in NO_X emissions from their Mystic Station. Sithe Edgar Development, LLC has an agreement with BASF to obtain 24.8 tpy of certified VOC offsets for application to the Fore River Project. These VOC offsets are from the total of 154 tpy of Rate Bank VOC ERCs certified by the Department on May 8, 1996 (Approval No. MBR-94-ERC-011) for the VOC reductions at the BASF Bedford, MA facility. Sithe has also acquired 56.6 tpy of certified Rate Bank VOC ERCs from Lightolier Corporation (Approval No. 4P95217), and 8.7 tpy of certified Rate Bank VOC ERCs from Avery Dennison Company (Approval No. MBR-94-ERC-006, MBR-95-ERC-001) for application to the Fore River Station Project.

All NOx and VOC ERCs have been obtained for the proposed Fore River Station Development Project in order to fulfill the requirement for offsets as required by 310 CMR 7.00 Appendices A and B. The appropriate quantity of NOx and VOC ERCs must be surrendered by the Applicant to the Department prior to the commencement of operation of the facility.

VI. NEW SOURCE PERFORMANCE STANDARDS (NSPS)

The subject facility is considered to be an electric utility stationary gas turbine since more than one third of its net electrical output will be sold to a utility. The New Source Performance Standards (NSPS) for gas turbines, 40 CFR 60 Subpart GG of the Code of Federal Regulations, is applicable to this facility. The NSPS restricts NO_x emissions to a nominal value of 75 ppmvd corrected to 15% O_2 (approximately equivalent to 0.3 lb/MMBTU) for an electric utility gas turbine of 100 MMBTU/hr or greater energy input. The Applicant shall ensure that the subject facility complies with this limit through the use of dry low-NO_x combustion technology in conjunction with SCR add-on NO_x control technology to control NO_x emissions to 2.0 ppmvd corrected to 15% O_2 during natural gas firing and 6.0 ppmvd corrected to 15% O_2 during transportation distillate fuel oil firing (with a sulfur content that does not exceed 0.05 percent by weight), well below the NSPS limit.

The NSPS for gas turbines also limits SO_2 emissions to 150 ppmvd corrected to 15% O_2 and restricts fuel sulfur to 0.8 percent by weight. The Project will meet this criteria by combusting natural gas as the primary fuel and transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight) as the back-up fuel, both of which have a fuel sulfur content well below the NSPS limit. The maximum flue gas SO_2 concentration will be 0.0522 lb/MMBtu, well below the NSPS standard.

For the supplemental duct firing HRSG burners, NSPS 40 CFR 60 Subpart Da applies, since the duct burners are rated at more than 250 MMBtu/hr apiece. Subpart Da limits NO_x to 0.2 lb/MMBtu and 1.6 lb/MW-hr gross energy output, limits PM to 0.03 lb/MMBtu, and limits SO_2 to 0.20 lb/MMBtu. The duct burners for the Project, which will operate on natural gas only, are limited herein to emissions of 0.0074 lb/MMBtu and 0.05 lb/MW-hr (after controls) for NO_x, 0.011 lb/MMBtu for PM, and 0.0029 lb/MMBtu for SO_2. The proposed emission limits, contained in Table 1 above, are well below the Subpart Da limits.

The new auxiliary boiler (96 MMBtu/hr) meets the definition of an "affected" facility under the NSPS, 40 CFR 60 Subpart Dc (Small Industrial Commercial Institutional Steam Generating Units). Subpart Dc limits the sulfur content of oil to 0.5 lb/MMBtu or 0.5% by weight and the opacity to 20% with one 6-minute period of no greater than 27% opacity allowed. Fuel sulfur content for the transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight), is well below the NSPS limit.

There are no NSPS requirements for internal combustion engines applicable to the proposed emergency diesel generators.

VII. COMPARATIVE BACT ANALYSIS

The Applicant is required to evaluate Best Available Control Technology (BACT) as it applies to emissions of Nitrogen Oxides (NO_x), Volatile Organic Compounds (VOC) (state BACT only), Particulate Matter (PM), Sulfur Dioxide, and Carbon Monoxide (CO). Nitrogen Oxides and VOC are also subject to Lowest Achievable Emission Rate (LAER) since NO_x and VOC are Ozone precursors. BACT is defined as the optimum level of control applied to pollutant emissions based upon consideration of technical, economic, and environmental factors.

The first step in a BACT analysis is to determine for the emission source, the most stringent control available for a similar or identical source or source category. The proposed facility must utilize BACT to control the emissions of the pollutants listed in Table 3 below. The

Department has verified and concurs with the following Comparative BACT Analysis (as referenced in the Applicant's Major Comprehensive Application and the Supplemental BACT Analysis, dated February 15, 2000).

Table 3: Comparative LAER/BACT Analysis

Control Technology	Emission Rate	LAER/ BACT?	Costs	Reason
NO_x				
SCONOx & Dry Low NOx Combustor with Water Injection during Oil Firing	2.0 ppmvd (natural gas), 6.0+ ppmvd (oil)	Yes for natural gas firing, LAER can be achieved by this method, but it is not the chosen option. It is unknown if LAER can be achieved by this method during oil firing.	$$$$	SCONOx provides additional collateral environmental benefits because it does not use ammonia (NH_3), however, there are collateral environmental and energy costs associated with using SCONOx, such as significant quantities of water are needed and there is additional energy drain. In addition, an economic analysis demonstrates that SCONOx is estimated to be about four times more expensive than SCR. Because there is insufficient information available to quantify all the collateral environmental impacts, then, based upon the economic analysis portion of the top-down BACT process, currently available data, and the tenets and procedures of the BACT process, the Department has concluded that the SCR system is the more cost-effective means to achieve the BACT/LAER emission rates for NOx.
Selective Catalytic Reduction & Dry Low NOx Combustor with Water Injection during Oil Firing	2.0 ppmvd (natural gas), 6.0 ppmvd (oil)	Yes	$$$	method chosen to achieve BACT/LAER (see above)
Dry Low NOx Combustor (DLN) with Water Injection during Oil Firing	50 ppmvd (natural gas), 90 ppmvd (oil)	No	$	more stringent control has been chosen
Water Injection on turbine without DLN	50+ ppmvd (natural gas), 90+ ppmvd (oil)	No	$	more stringent control has been chosen

Table 3: Comparative LAER/BACT Analysis				
Control Technology	**Emission Rate**	**LAER/ BACT?**	**Costs**	**Reason**
SO_2				
Fuel: Natural Gas with 720 hours of oil firing per year	0.0023 lb/MMBtu	Yes	$	Is top BACT case
Low Sulfur Content (0.05% S) Transportation Diesel	0.052 lb/MMBtu	No for primary fuel, Yes for backup fuel	**$**	more stringent control has been chosen for primary fuel, backup fuel limited to 720 hours per year operation.
Oil-Firing (1 – 2% S) with Flue Gas Desulfurization	0.052+ lb/MMBtu	No	$$$	more stringent control has been chosen
PM				
Fuel: Natural Gas with 720 hours of oil firing	0.011 lb/MMBtu	Yes	$	Is top BACT case
Low Sulfur Content (0.05% S) Transportation Diesel	0.05 lb/MMBtu	No, for primary fuel, Yes for backup fuel.	$	more stringent control has been chosen for primary fuel, backup fuel limited to 720 hours per year operation.
Oil-firing (1 – 2% S) with Electrostatic Precipitators	0.05+ lb/MMBtu	no	$$$	more stringent control has been chosen
Oil-firing (1 – 2% S) with Wet Scrubber	0.05+ lb/MMBtu	no	$$$	more stringent control has been chosen
Oil-firing (1 – 2% S) with Fabric Filter Collector	0.05+ lb/MMBtu	no	$$$	more stringent control has been chosen
CO				
CO Oxidation Catalyst (89%+ efficient during natural gas firing, 86% efficient during oil firing)	2 ppmvd (natural gas), 7 ppmvd (oil)	yes	$$$	Is top BACT case
CO Oxidation Catalyst (85% efficient)	2.7 ppmvd (natural gas), 7.5 ppmvd (oil)	no	$$	more stringent control has been chosen
CO Oxidation Catalyst (70% efficient)	5.4 ppmvd (natural gas), 15 ppmvd (oil)	no	$$	more stringent control has been chosen

Table 3: Comparative LAER/BACT Analysis				
Control Technology	**Emission Rate**	**LAER/ BACT?**	**Costs**	**Reason**
Combustion Controls	18 ppmvd (natural gas), 50 ppmvd (oil)	no	$	more stringent control has been chosen
VOC				
Combustion Controls & Oxidation Catalyst	1.0 ppmvd (turbine only-natural gas),1.7 ppmvd (turbine with duct firing-natural gas), 7 ppmvd (oil firing with or without duct firing)	yes	$$$	Is top LAER/BACT case (some VOC control is expected from the CO oxidation catalyst as a secondary benefit)
Combustion Controls	1/1.7/7+ ppmvd	no	$	more stringent control

Table 3 Key:

NO_x	= oxides of nitrogen
CO	= carbon monoxide
VOC	= volatile organic compounds
SO_2	= sulfur dioxide
PM	= particulate matter
NH_3	= ammonia
S	= sulfur
lb/MMBtu	= pound per million British Thermal Units
ppmvd@15%O_2	= parts per million, dry volume basis corrected to 15 percent oxygen
LAER	= lowest achievable emission rate
BACT	= best available control technology
%	= percent
$	= least expensive (relative to control technologies for that specific pollutant)
$$	= moderately expensive (relative to control technologies for that specific pollutant)
$$$	= fairly expensive (relative to control technologies for that specific pollutant)
$$$$	= very expensive (relative to control technologies for that specific pollutant)

VIII. TITLE IV SULFUR DIOXIDE ALLOWANCES AND MONITORING

According to 40 CFR Part 72, the subject facility will be designated as a Phase II Acid Rain

"New Affected Unit" on January 1, 2000 or 90 days after commencement of activities, whichever comes later, but not after the date the facility declares itself commercial. The Phase II application for the subject facility must be submitted to the Department 24 months before the commencement of operation.

The Acid Rain Program effects reductions of sulfur dioxide (SO_2) from existing power plants by allocating SO_2 allowances to existing power plants and by requiring new plants to purchase SO_2 allowances to offset their SO_2 potential to emit. The Applicant shall secure SO_2 allowances for the proposed facility.

The Applicant will be required to have a Designated Representative (DR) and to install a Continuous Emissions Monitoring System (CEMS) to service the subject facility. The DR is the Applicant's facility representative responsible for submitting required permits, compliance plans, emissions monitoring reports, offset plans, and compliance certification, and is responsible for the requirements specified in 40 CFR Part 75 for monitoring and/or reporting SO_2, NO_x and CO_2 emissions as well as opacity and heat input at the proposed facility. As an option, natural gas and oil fired facilities may conduct fuel quality and fuel flow monitoring in place of SO_2 monitoring and flue gas flow monitoring. Natural gas fired units complying with 40 CFR 75.14(c) are exempt from the opacity monitoring requirements. In addition, pursuant to 40 CFR 75.13, CO_2 emissions may be estimated in accordance with 40 CFR Part 75 Appendix G, in lieu of installing a CO_2 CEMS.

The Applicant will also be required to submit a complete, electronic, up-to-date monitoring plan no later than 45 days prior to initial certification test as required by 40 CFR 75.62.

IX. NOISE
(State-Only Requirement)

Daytime and nighttime noise measurements were taken at eight locations around the site. The noise measurements consisted of both A-weighted sound pressure levels and octave band sound pressure levels. A-weighted sound levels emphasize the middle frequency sounds and de-emphasize lower and higher frequency sounds, and are reported in decibels designated as “dBA”. The A-weighted sound pressure levels were recorded for each of the four categories most commonly used to describe ambient noise environments: L_{90}, L_{50}, L_{10}, and L_{eq}. The L_{90} level represents the sound level exceeded 90 percent of the time and is used by the Department for the regulation of noise emissions.

In general, background (L_{90}) levels (in dBA) averaged from 35 to 42 during nighttime hours and from 40 to 55 during daytime hours.

1. The facility shall be designed, constructed, operated and maintained such that at all times:

   a) Other than as approved herein, no sound emissions shall occur that cause a condition of air pollution or exceeds the levels in the Department’s Policy 90-001; and

b) Other than approved herein, sound emissions shall not exceed the levels set forth in Table 3 at the locations as identified in said Table 3.

2. Facility personnel shall identify and evaluate all plant equipment that may cause a noise condition. Sources of noise include, but are not limited to: transformers, the air-cooled condenser, the heat recovery steam generators, the combustion turbines, natural gas compressors, main exhaust stack, and building ventilation systems.

3. The Applicant shall perform the following measures or equivalent alternative measures as noise mitigation and as indicated in (and in addition to) the Applicant's Response, dated February 14, 2000, to the Department's request for additional information with regard to noise mitigation:

a) Enclosure of the following noise-producing components of the Project within an acoustically-designed building: the gas turbines, steam turbines, electric generators, HRSGs, the high pressure and auxiliary boiler feedwater pumps, plant and instrument air compressors, and the auxiliary boiler;

b) Install low noise air-cooled condensers utilizing slower fans, additional blades, and additional surface area over the standard base model;

c) Install enhanced noise suppressants for the combustion turbine air inlets and exhausts;

d) Procure and install quiet-design transformers;

e) Install low noise closed cooling water coolers utilizing slower fans, additional blades, and additional surface area over the standard base model;

f) Install silencers on all vents including those that would or may be activated during start-up and shut down sequences.

g) Install all natural gas compressor equipment within an acoustically designed building.

h) Install lagging or enclosures on all metering equipment, such as valves and associated exposed pipes, to assure the reduction of noise from these sources.

i) Install glycol coolers at the south end of the ACC, at a point furthest away from residential neighborhoods

4. Department Noise Policy 90-0901 limits increases over the existing L_{90} background level to

10 dBA. Additionally, "pure tone" sounds, defined as any octave band level which exceeds the levels in adjacent octave bands by 3 dBA or more, are also prohibited. The Applicant, at a minimum, shall ensure that the subject facility complies with said Policy.

5. The allowable noise levels generated from the operation of the subject facility by the Applicant are summarized in Table 3 of this PROPOSED CONDITIONAL APPROVAL/PSD Permit. Further, based on the noise frequency distribution, no combination of noise sources shall result in a "pure tone condition," as previously defined.

Table 3: Allowable Noise Impacts

LOCATION	AMBIENT (L_{90},dBA)[(1)]	AMBIENT & PLANT (L_{90},dBA)	CHANGE (dBA)[(2)]
R-1 Monatiquot Street	41	47	+6
R-2 Idlewell	35	36	+1
R-3 East Braintree	37	38	+1
R-4 Quincy, W	37	38	+1
R-5 Quincy Point	42	43	+1
R-6 Germantown	39	40	+1
R-7 East Property Fence Line	41	48	+7

Table 3 Notes:

1. The lowest background levels observed during either nighttime or daytime where the noise level is exceeded 90 percent of the time (L_{90}) which is the level regulated by the Massachusetts DEP Noise Policy.

2. The Massachusetts DEP Noise Policy limits new noise increases to no more than 10 dBA over the L_{90} ambient levels. Tonal sounds, defined as any octave band level, which exceeds the levels in adjacent octave bands by 3 dBA or more are not allowed.

6. The Applicant shall conduct a noise survey in accordance with Department procedures/guidelines within 180 days of the facility start-up to verify compliance with the allowable noise impacts specified in Table 3 of this PROPOSED CONDITIONAL APPROVAL/PSD Permit. The Applicant shall provide the Department with a written report describing the results of said noise survey, within 60 days of its completion.

X. SPECIAL CONDITIONS

1. The Applicant shall submit to the Department, in accordance with the provisions of Regulation 310 CMR 7.02(2)(a), plans and specifications for the exhaust stack, combustion turbine generator set, the SCR control system (including the ammonia handling and storage system), the CO catalyst control system, facility plans, the Continuous Emissions Monitor System (CEMS) and the Continuous Opacity Monitoring System (COMS) once the specific information has been determined, but in any case not later than 30 days prior to commencement of construction/installation of each component of the subject facility.

2. The Applicant shall not allow the gas turbines at the subject facility to operate at less than 75% power, excluding start-ups and shutdowns and fuel transfers. Operation below 75% power is limited to no more than 3 hours duration for each start up, shutdown, and fuel transfer or for a duration that may be otherwise practical to achieve start-up from a cold, warm or hot turbine condition.

3. Upon the commencement of facility operation, there will be a 12-month NH3 optimization/minimization program. The program will allow the Applicant to identify and take appropriate measures designed to attain and maintain the ammonia emission limit of 2.0 ppmvd @15% O2 during all operating time (excluding start up, shut down and fuel transfer periods). Appropriate measures include a reasonable additional capital investment and/or increase in operating and maintenance expenditures.

4. The Applicant shall ensure that the SCR control equipment for each subject turbine generator is operational whenever the turbine exhaust temperature attains 558 ^{o}F at the SCR unit during natural gas firing and 608 ^{o}F during fuel oil firing. The above temperature points correspond approximately to 50% combustion turbine power during natural gas and fuel oil firing.

5. The Applicant shall maintain in the proposed facility control room, properly maintained operable, portable ammonia detectors for use during an ammonia spill, or other emergency situation involving ammonia, at the proposed facility.

6. The Applicant shall ensure that the subject ammonia storage tanks shall be equipped with high and low level audible alarm monitors.

7. The Applicant shall maintain an adequate supply of spare parts on-site to maintain the on-line availability and data capture requirements for the subject CEMS and COMS equipment servicing the proposed facility.

8. Within one year of commencement of operation, the Applicant shall file an Operating Permit application with the Department, pursuant to Regulation 310 CMR 7.00: Appendix C for the proposed facility.

9. The Applicant shall ensure that the proposed facility complies with all applicable operational standards contained in 40 CFR Part 72 and 75, 40 CFR 60, 310 CMR 7.27, and 310 CMR 7.28.11 The Applicant shall submit Standard Operating and Maintenance

Procedures (SOMP) for the entire facility to the Department no later than 30 days prior to commencement of operation of the proposed facility. Thereafter, the Applicant shall submit updated versions of the SOMP to the Department no later than 30 days prior to the occurrence of a significant change. The Department must approve of significant changes to the SOMP prior to the SOMP becoming effective. The updated SOMP shall supersede prior versions of the SOMP.

11. The Applicant shall examine and propose, as part of the final emissions test results report, a surrogate methodology or parametric monitoring for PM based on initial compliance test results.

12. The Applicant shall conduct initial compliance tests for "hot start", "warm start", "cold start", shut down, and fuel transfer periods as defined in the Applicant's Major Comprehensive Plan Application (MBR-99-COM-018, Transmittal W004896). Emission data generated from this testing shall be made available for review by the Department prior to determining and approving the maximum allowable emission rate limits (lb/hr, lb/MMBtu, ppmvd), including Opacity limits, for these periods of time. The Department shall incorporate the emission limits into the Final Approval for the facility upon issuance and such limits shall be considered enforceable. The above testing shall be for all pollutants listed in Table 1.

    The Applicant shall submit information for Department review that demonstrates that the emissions generated from the facility during these periods of time do not cause or contribute to an exceedance of applicable National Ambient Air Quality Standards (NAAQS) and Significant Impact Levels (SIL's) for SO_2 , PM_{10}, NO_2, CO or the Threshold Effects Exposure Limits (TELs) for air toxics. This information shall be submitted to the Department as part of the final emissions test results report.

XI. MONITORING AND RECORDING REQUIREMENTS

1. The Applicant shall install, calibrate, test and operate a Data Acquisition and Handling System(s) (DAHS), CEMS, and COMS to measure and record the following emissions from the subject facility:

    a) Oxygen (O_2)
    b) Oxides of Nitrogen (NO_x)
    c) Carbon Monoxide (CO)
    d) Opacity
    e) Ammonia (NH_3)

2. The Applicant shall ensure continuous monitoring and compliance with PM limits utilizing the parametric monitoring methodology developed during the initial compliance test.

3. The Applicant shall ensure that all emission monitors and recording equipment servicing

the proposed facility comply with Department approved performance and location specifications, and conform with the EPA monitoring specifications at 40 CFR Part 60.13 and 40 CFR Part 60 Appendices B and F, and all applicable portions of 40 CFR Parts 72 and 75.

4. The Applicant shall ensure that the proposed facility complies with all the applicable monitoring requirements contained in 40 CFR Parts 72 and 75 (Acid Rain Program), 310 CMR 7.27 (NO_x Allowance Program), and 310 CMR 7.28 (NO_x Allowance Trading Program).

5. The Applicant shall equip the CEMS and COMS with audible and visible alarms to activate whenever emissions from the proposed facility exceed the limits established in Table 1 of this PROPOSED CONDITIONAL APPROVAL/PSD Permit.

6. The Applicant shall operate each CEMS and COMS servicing the proposed facility at all times except for periods of CEMS and COMS calibration checks, zero and span adjustments, preventive maintenance, and periods of unavoidable malfunction.

7. The Applicant shall obtain and record emission data from each CEMS and COMS servicing the proposed facility for at least 75% of the emission unit's operating hours per day, except for periods of CEMS and COMS calibration checks, zero and span adjustments, and maintenance, for at least 75% of the emission unit operating hours per month, and for at least 95% of the emission unit's operating hours per quarter.

8. All periods of excess emissions at the proposed facility, even if attributable to an emergency/malfunction, start up/shutdown or equipment cleaning, shall be quantified and included by the Applicant in the determination of annual emissions and compliance with the annual emission limits as stated in Table 2 of this PROPOSED CONDITIONAL APPROVAL/PSD Permit. (**"Excess Emissions"** are defined as emissions, which are in excess of the short term emissions as stipulated in Table 1.). An exceedance of emission limits in Table 1 due to an emergency or malfunction shall not be deemed a federally permitted release as that term is used in 42 U.S.C. Section 9601(10).

9. The Applicant shall use and maintain its CEMS and COMS servicing the proposed facility as "direct-compliance" monitors to measure NO_x, CO, O_2, NH_3, and Opacity. "Direct-compliance" monitors generate data that legally documents the compliance status of a source.

10. Whenever any gas turbine is operating below 75% load, the VOC emissions shall be considered as occurring at the rate determined in the initial stack test for start up conditions.

11. If either of the proposed gas turbines is operating at 75% load or greater, and if CO emissions are below the CO emission limit at the given gas turbine operating conditions, the VOC emissions shall be considered as meeting the emission limits contained in this PROPOSED CONDITIONAL APPROVAL/PSD Permit subject to correlation as contained

in Proviso X.12 below.

12. If either of the proposed gas turbines is operating at 75% load or greater, and if CO emissions are above the CO emission limit at the given gas turbine operating conditions, the VOC emissions shall be considered as occurring at a rate determined by the equation: $VOC_{actual}=VOC_{LIMIT}$ x (CO_{actual}/CO_{limit}), pending the outcome of the initial compliance testing after which a VOC/CO correlation curve for each turbine will be developed and used for VOC compliance determination purposes.

13. The Applicant shall install and operate a continuous monitoring system to record the transportation diesel fuel oil (with a sulfur content that does not exceed 0.05 percent by weight) consumption and the ratio of water-to-fuel oil being fired in the combustion turbine.

14. The Applicant shall monitor and record the Sulfur and Nitrogen content in natural gas on a daily basis, or pursuant to any alternative fuel monitoring schedule issued for the proposed facility, in accordance with 40 CFR Part 60, Subparts GG 60.334(b)(2), Da, or Dc.

15. The Applicant shall monitor and record the Sulfur and Nitrogen content in the transportation diesel fuel oil (with a sulfur content that does not exceed 0.05 percent by weight) on each occasion that the oil is transferred to the bulk storage tank pursuant to 40CFR Part 60, Subparts GG 60.334(b)(2), Da, Dc, and Part 75, or pursuant to any alternative fuel monitoring schedule issued for the proposed facility, in accordance with 40 CFR Part 60, Subparts GG 60.334(b)(2), Da, or Dc.

16. The Applicant shall install and operate a continuous monitor and alarm system to monitor the temperature at the inlet to the SCR and CO catalysts servicing the proposed facility.

17. A quality control/quality assurance (QA/QC) program must be developed for the long-term operation of the CEMS and COMS servicing the proposed facility which conforms to 40 CFR Part 60, Appendix F, all applicable portions of 40 CFR Parts 72 and 75, 310 CMR 7.27 (NO_x Allowance Program) and 310 CMR 7.28 (NO_x Allowance Trading Program).

    The QA/QC program must be submitted in writing, and reviewed and approved in writing by the Department at least 30 days prior to commencement of facility operation. Any subsequent changes to the program shall be approved by the Department.

18. The Applicant shall monitor and record all required parameters for the proposed auxiliary boiler pursuant to the requirements contained in 310 CMR 7.19(5) (Medium Size Boilers).

XII. RECORD KEEPING REQUIREMENTS

1. A record keeping system for the proposed facility shall be established and maintained on site by the Applicant. All such records shall be maintained up-to-date such that year-to-date

information is readily available for Department examination upon request and shall be kept on-site for a minimum of five (5) years. Record keeping shall, at a minimum, include:

a) Compliance records sufficient to demonstrate that emissions from the proposed facility have not exceeded what is allowed by this PROPOSED CONDITIONAL APPROVAL/PSD Permit. Such records may include, but are not limited to, fuel usage rates, emissions test results, monitoring equipment data and reports.

b) Maintenance: A record of routine maintenance activities performed on the proposed emission units control equipment and monitoring equipment including, at a minimum, the type or a description of the maintenance performed and the date and time the work was completed.

c) Malfunctions: A record of all malfunctions on the proposed emission units control and monitoring equipment including, at a minimum: the date and time the malfunction occurred; a description of the malfunction and the corrective action taken; the date and time corrective actions were initiated; and the date and time corrective actions were completed and the proposed equipment was returned to compliance.

2. The Applicant shall maintain a file for the Certification of Analysis, verified by a qualified laboratory, of the sulfur and nitrogen content of each fuel oil delivery. The Applicant shall maintain records on natural gas consumed by the subject facility to record the sulfur content daily, or at the frequency required pursuant to any alternative fuel monitoring schedule issued for the facility by the Department, in accordance with 40 CFR Part 60, Subpart GG 60.334(b)(2).

3. The Applicant shall maintain on-site for five (5) years all permanent records of output from all continuous monitors for flue gas emissions, fuel consumption, water-to-fuel ratios, SCR and CO control system inlet temperatures, and turbines inlet and ambient temperatures, and shall make these records available to the Department upon request.

4. The Applicant shall maintain a log to record problems, upsets or failures associated with the subject emission control systems, DAHS, CEMS, COMS, or ammonia handling system.

5. The Applicant shall comply with all applicable record keeping requirements regarding the subject facility contained in 40 CFR Parts 72 and 75, 40 CFR 60, 310 CMR 7.27, and 310 CMR 7.28.

6. The Applicant shall make available to the Department for inspection, upon request, the most recent five years of records as contained in Provisos XI 1., 2., 3., 4., and 5..

XIII. REPORTING REQUIREMENTS

1. All notifications and reporting required by this PROPOSED CONDITIONAL APPROVAL/PSD Permit shall be made to the attention of:

   Department of Environmental Protection/Bureau of Waste Prevention
   205A Lowell Street
   Wilmington, Massachusetts 01887
   ATTN: James Belsky, Permit Chief
   Phone: 978.661.7600
   Fax: 978.661.7615

2. The Applicant must notify the Department by telephone or fax as soon as possible, but in any case no later than three (3) business days after the occurrence of any upsets or malfunctions to the proposed facility equipment, air pollution control equipment, or monitoring equipment which result in an excess emission to the air and/or a condition of air pollution.

3. The Applicant shall notify the Department immediately by telephone or fax and within three (3) working days, in writing, of any upset or malfunction to the ammonia handling or delivery systems at the proposed facility. The Applicant also must comply with all notification procedures required under M.G.L. c. 21 E for any release or threat of release of ammonia.

4. The Applicant shall submit a quarterly report to the Department. The report shall be submitted by the 30th of the following month after the end of each quarter and shall contain at least the following information:

   a) The facility CEMS and COMS excess emission data, in a format acceptable to the Department.

   b) For each period of all excess emissions or excursions from allowable operating conditions for the proposed facility, the Applicant shall list the duration, cause, the response taken, and the amount of excess emissions. Periods of excess emissions shall include periods of start-up, shutdown, fuel transfer, malfunction, emergency, equipment cleaning, and upsets or failures associated with the emission control system or CEMS or COMS. (**"Malfunction"** means any sudden and unavoidable failure of air pollution control equipment or process equipment or of a process to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions. **"Emergency"** means any situation arising from sudden and reasonably unforeseeable events beyond the control of this source, including acts of God, which situation would require immediate corrective action to restore normal operation, and that causes the source to exceed a technology based limitation under the Approval, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operations, operator error or decision to keep operating despite knowledge of these things.)

c) Each period during which there was any firing of transportation diesel fuel oil (with a sulfur content that does not exceed 0.05 percent by weight). The period shall include the date of oil firing, the amount of oil fired, and the reasons for and duration of firing. This report shall summarize year-to-date the number of hours of transportation diesel fuel oil use and the total amount of transportation diesel fuel oil burned.

d) A tabulation of periods of operation (dispatch) of the proposed facility.

5. The Applicant shall ensure that the subject facility complies with all applicable reporting requirements contained in 40 CFR Parts 72 and 75, 40 CFR 60, 310 CMR 7.27, and 310 CMR 7.28.

6. In accordance with 310 CMR 7.12(7), the Applicant shall ensure that the proposed facility registers on a form obtained from the Department such information as the Department may specify including:

a) The nature and amounts of emissions from the facility.

b) Information which may be needed to determine the nature and amounts of emissions from the facility.

c) Any other information pertaining to the facility which the Department requires.

d) Information required by 310 CMR 7.12(1)(a) shall be submitted annually.

7. The Applicant shall submit to the Department no later than 13 months after the commencement of operation of the subject facility an ammonia optimization/minimization program report prepared by a qualified independent third-party that shall contain:

a) a summary of the record of deviations from the ammonia emission limit;

b) an evaluation of the reasons for deviations from the ammonia limit;

c) recommendations on all appropriate measures designed to eliminate or mitigate NH_3 deviations and to meet the 2.0 ppmvd@15% O_2 NH_3 emission limit on a 1-hour basis, including a description of all capital investments which have been or will be made to modify or substitute for existing control equipment or changes to operation and maintenance procedures (with a description of the cost, timeline and emission reduction to be achieved by each option);

d) recommendations on any modifications to this CONDITIONAL APPROVAL/PSD Permit that are necessary to implement the identified appropriate measures.

XIV. TESTING REQUIREMENTS

1. The Applicant shall ensure that the proposed facility shall be constructed to accommodate the emissions (compliance) testing requirements contained herein. All emissions testing shall be conducted in accordance with the Department's "Guidelines for Source Emissions Testing" and in accordance with the Environmental Protection Agency reference test methods as specified in 40 CFR Part 60, Appendix A, 40 CFR Part 60 Subpart GG, 40 CFR Parts 72 and 75, or by another method which has been correlated to the above method to the satisfaction of the Department.

2. The Applicant shall conduct initial compliance tests must be conducted within 180 days after initial start up of the proposed facility.

3. The Applicant must obtain written Department approval of an emissions test protocol. The protocol shall include detailed description of sampling port locations, sampling equipment, sampling and analytical procedures, and operating conditions for any such emissions testing. It must be submitted to the Department at least 90 days prior to commencement of testing of the facility.

4. The Applicant shall ensure that a final emissions test results report is submitted to the Department within 60 days of completion of the emissions testing program.

5. The Applicant shall conduct initial compliance tests to demonstrate compliance with the emission limits (lb/hr, lb/MMBtu, ppmvd as applicable, and opacity) of the proposed combustion turbines and the auxiliary boiler as specified in Table 1 for the pollutants listed below. Sulfuric Acid Mist testing shall be included for the combustion turbines when firing of transportation diesel fuel oil (with a sulfur content that does not exceed 0.05 percent by weight). Testing for these pollutants for the combustion turbines will be conducted at four (4) representative steady state loads (but not less than 75% of rated base load), except for PM which will be conducted at 100% of rated base load only. The auxiliary boiler will be tested for NO_x and CO at 100% of rated base load.

Natural Gas Firing	**Transportation Distillate Oil Firing**
Nitrogen Oxides (NO_x)	Nitrogen Oxides (NO_x)

Carbon Monoxide (CO)	Carbon Monoxide (CO)
Volatile Organic Compounds (VOC)	Volatile Organic Compounds (VOC)
Particulate Matter (PM) and Opacity	Particulate Matter (PM) and Opacity
Ammonia (NH_3)	Ammonia (NH_3)
	Sulfuric Acid Mist

6. The Applicant's emissions testing for VOC for the proposed facility shall include VOC testing for the duration of a start up, in order to determine the total mass emissions of VOC during start up conditions. The Applicant shall determine VOC compliance by the VOC/CO correlation curve that will be developed during the same time period as the Project's ammonia optimization/minimization program.

7. In accordance with 310 CMR 7.04(4)(a), the Applicant shall have the proposed units inspected and maintained in accordance with the manufacturer's recommendations and tested for efficient operation at least once in each calendar year. The results of said inspection, maintenance and testing and the date upon which it was performed shall be recorded and posted conspicuously on or near the proposed equipment.

8. In accordance with 310 CMR 7.13 the Department may require additional emission testing of the proposed facility at any time to ascertain compliance with the Department's Regulations or any proviso(s) contained in this PROPOSED CONDITIONAL APPROVAL/PSD Permit.

9. The Applicant shall comply with all applicable testing requirements contained in 40 CFR Parts 72 and 75, 40 CFR 60, 310 CMR 7.27, and 310 CMR 7.28 regarding the proposed facility.

XV. GENERAL REQUIREMENTS

1. The Applicant shall properly train all personnel to operate the proposed facility and control equipment in accordance with vendor specifications. All persons responsible for the operation of the proposed ammonia handling and SCR control systems shall sign a statement affirming that they have read and understand the approved standard operating and standard maintenance procedures. Refresher training shall be given by the Applicant to facility personnel at least once annually.

2. All requirements of this PROPOSED CONDITIONAL APPROVAL/PSD Permit which apply to the Applicant shall apply to all subsequent owners and/or operators of the facility.

3. The Applicant shall maintain the standard operating and maintenance procedures for the subject ammonia handling systems in a convenient location (e.g., control room/technical library) and make them readily available to all employees.

4. The Applicant shall comply with all provisions of 40 CFR Parts 72 and 75, 40 CFR 60, and

310 CMR 6.00-8.00 that are applicable to this facility.

5. The Applicant shall ensure that the proposed facility complies with the requirements of Regulation 310 CMR 7.27(7) and 310 CMR 7.28 in the NO_x Allowance Program and NO_x Allowance Trading Program by the submission of an Emission Control Plan within 6 months of issuance of a CONDITIONAL APPROVAL/PSD Permit. In addition, the facility must submit a monitoring plan, and install, operate and certify the emission monitoring systems required by 310 CMR 7.27(11) within 90 days after the date the unit commences operations.

6. Within 60 days of start up of the proposed facility, the roadways servicing said facility shall be paved and maintained free of deposits that could result in excessive dust emissions.

7. SUSPENSION - This PROPOSED CONDITIONAL APPROVAL/PSD Permit may be suspended, modified, or revoked by the Department if, at any time, the Department determines that the facility is violating any condition or part of the Approval.

8. OTHER REGULATIONS - This PROPOSED CONDITIONAL APPROVAL/PSD Permit does not negate the responsibility of the owner/operator to comply with this or any other applicable federal, state, or local regulations now or in the future. Nor does this PROPOSED CONDITIONAL APPROVAL/PSD Permit imply compliance with any other applicable federal, state or local regulations now or in the future.

9. DUST AND ODOR - The proposed facility shall be operated in a manner to prevent the occurrence of dust or odor conditions which cause or contribute to a condition of air pollution as defined in Regulations 310 CMR 7.01 and 7.09.

10. ASBESTOS - Should asbestos remediation/removal be required as a result of this PROPOSED CONDITIONAL APPROVAL/PSD Permit, such asbestos remediation/removal shall be done in accordance with Regulation 310 CMR 7.15 and 310 CMR 4.00.

11. MODIFICATIONS - Any proposed increase in emissions above the limits contained in this PROPOSED CONDITIONAL APPROVAL/PSD Permit must first be approved in writing by the Department pursuant to 310 CMR 7.02. In addition, any emissions increase may subject the facility to additional regulatory requirements.

12. REMOVAL OF AIR POLLUTION CONTROL EQUIPMENT - No person shall cause, suffer, allow, or permit the removal, alteration or shall otherwise render inoperative any air pollution control equipment or equipment used to monitor emissions which has been installed as a requirement of 310 CMR 7.00, other than for reasonable maintenance periods or unexpected and unavoidable failure of the equipment, provided that the Department has been notified of such failure, or in accordance with specific written approval of the Department.

13. The proposed facility shall be constructed and operated in strict accordance with the APPROVAL/PSD Permit herein. Should there be any differences between the Applicant's Major Comprehensive Plan Application (MBR-99-COM-018, Transmittal W004896) and this APPROVAL/PSD Permit, this APPROVAL/PSD Permit shall govern.

XVI. CONSTRUCTION REQUIREMENTS

During the construction phase of the proposed facility, the Applicant shall ensure that facility personnel take all reasonable precautions (noted below) to minimize air pollution episodes (dust, odor, and noise):

1. Facility personnel shall exercise care in operating any noise generating equipment (including mobile power equipment, power tools, etc.) at all times to minimize noise.

2. Construction vehicles transporting loose aggregate to or from the facility shall be covered and shall use leak tight containers.

3. During construction open storage areas, piles of soil, loose aggregate, etc. shall be covered or watered down as necessary to minimize dust emissions.

4. Any spillage of loose aggregate and dirt deposits on any public roadway, leading to or from the proposed facility shall be removed by the next business day or sooner, if necessary. (A mobile mechanical sweeper equipped with a water spray is an acceptable method to minimize dust emissions).

5. On site unpaved roadways/excavation areas subject to vehicular traffic shall be watered down as necessary or treated with the application of a dust suppressant to minimize the generation of dust.

XVII. DETERMINATION OF PSD APPLICABILITY AND PSD PERMIT

I. Background

The federal government under the jurisdiction of the Environmental Protection Agency (EPA) established National Ambient Air Quality Standards (NAAQS) for six air contaminants, known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are Sulfur Dioxide (SO_2), Particulate Matter having a diameter of 10 microns or less (PM_{10}), Nitrogen Oxides (NO_x), Carbon Monoxide (CO), Ozone (O_3), and Lead (Pb).

The state government under the jurisdiction of the Department of Environmental Protection (the Department) has adopted these ambient air quality standards for the Commonwealth of Massachusetts as stated under 310 CMR 6.00 of the Air Pollution Control Regulations. One of the basic goals of federal and state air regulations is to ensure that ambient air quality, including the impact of existing and new sources, complies with ambient standards.

Towards this end, EPA classified all areas of the country as “attainment”, “nonattainment”, or “unclassified” with respect to the NAAQS.

New major sources of regulated air pollutants or major modifications to existing major sources of regulated air pollutants that are located in areas classified as either “attainment” or “unclassified” are subject to Prevention of Significant Deterioration ("PSD") regulations promulgated under 40 CFR Section 52.21. Pursuant to 40 CFR 52.21(b)(1)(I)(a.) of the PSD Regulations, an attainment pollutant source is considered “major” if it has the potential to emit 100 tons per year (tpy) or more of any pollutant and is listed as one of the 28 designated PSD stationary source categories; or if it is an unlisted source and has the potential to emit 250 tons per year (tpy) or more of any pollutant regulated under the Clean Air Act.

Effective July 1, 1982, the PSD program was implemented by the Department in accordance with the Department's "Procedures for Implementing Federal Prevention of Significant Deterioration Regulations". On July 23, 1999, Sithe Edgar Development LLC (“the Permittee”) submitted to the Department an application for a Prevention of Significant Deterioration (PSD) Permit to construct and operate a new 775 megawatt (MW) combined-cycle combustion turbine electric power generation facility at Fore River Station in Weymouth, Massachusetts. This proposed facility is one of the 28 designated PSD stationary source categories, namely a fossil fuel fired steam electric plant of more than 250 million Btu/hr heat input. Fore River Station is an existing major source of regulated air pollutants.

II. General Information

A. PSD Applicability Determination & Attainment Status

The Permittee is proposing to build a combined-cycle combustion turbine electric power generation facility in Weymouth, Massachusetts. The proposed facility will be located in an area which is in either “attainment” or “unclassified” for Sulfur Dioxide (SO_2), Nitrogen Dioxide (NO_x), Carbon Monoxide (CO), Lead (Pb), and total Particulate Matter (PM), which includes PM that does not exceed 10 microns in size (referred to as PM_{10}). Therefore, the proposed facility will be located in a PSD area for these pollutants. The proposed facility would be categorized as a major modification to an existing major source if emissions were to increase by greater than the following significant PSD pollutant emission rates: 40 tpy of SO_2, 40 tpy of NO_x, 100 tpy of CO, 0.6 tpy of Pb, 25 tpy of PM, 15 tpy of PM_{10}, 7 tpy of Sulfuric Acid (H_2SO_4), or varied emission rates of miscellaneous PSD pollutants.

The proposed facility will have a net increase in emissions above PSD significance levels for SO_2, NO_x, CO, PM, $PM_{10,}$ and $H_2SO_{4.}$ Therefore, PSD review will be required for these pollutants (see 40 CFR 52.51 (b)(23)). The estimated emissions of lead (Pb) as well as other miscellaneous PSD pollutants are not expected to rise above PSD significance levels, therefore, PSD review will not be required for these pollutants.

For information and regulatory requirements concerning Nonattainment New Source Review (NSR), please see Section V of this document.

Table 1 shows the potential maximum annual emissions from the proposed facility, the potential maximum annual emissions from the existing facility and the net emission increases with respect to PSD significance levels for the various pollutants.

Table 1: Fore River Station PSD Pollutant Applicability Evaluation

Pollutant	Potential Maximum Annual Emissions from New Equipment (tpy)(1)(2)	Potential Maximum Annual Emissions from Existing Equipment (tpy)	Net Emission Increase (tpy)	PSD Significant Emission Rate (tpy)	PSD Review Required?
NO_X	218	644	+218	40	Yes
SO_2	154	554	154	40	Yes
CO	296	387	+296	100	Yes
PM	352	196	+352	25	Yes
PM_{10}	352	196	+352	15	Yes
Sulfuric Acid Mist	99	8.3	+99	7	Yes
Lead	0.25	0.0007	+0.25	0.6	No
Other PSD Pollutants(3)	None Expected	None Expected	None Expected	Varies	No

Table 1 Notes:

(1) Based on 8040 hours of natural gas operation at 51^0F , 720 hours of oil operation at -12^0F

(2) The auxiliary boiler (NO_x emissions less than 3 tpy as shown in Appendix B of the submitted application) will not operate concurrently with the turbines except during startup and will not affect potential emissions. The emergency generator will operate only to shut down the facility if no power is available from the utility grid. The auxiliary boiler and emergency generator emissions, estimated in Appendix B of the submitted application, will not impact the project's potential emissions.

(3) Other PSD include vinyl chloride, asbestos, fluorides, hydrogen sulfide, and reduced sulfur compounds.

NO_x = oxides of nitrogen
CO = carbon monoxide
PM = particulate matter
SO_2 = sulfur dioxide
PM_{10} = particulate matter less than 10 microns in aerodynamic diameter
tpy = tons per twelve month rolling calendar period

B. Site Information

The proposed facility will be constructed on the existing 57 acre Fore River Station site located in Weymouth, Massachusetts. The City of Weymouth is located in Norfolk County in the southeast area of the Commonwealth of Massachusetts. The Fore River Station site is located approximately 10 miles southeast of downtown Boston. The site is now principally occupied by two 12 MW simple cycle combustion turbines. These two combustion turbines are used for peaking power only and utilize No. 2 distillate oil (with a sulfur content that does not exceed 0.3 percent by weight) as the only fuel of use. The site will provide convenient access to both the interstate natural gas pipeline system and to the New England electric power transmission grid.

The site area consists of a mix of industrial, commercial, and residential properties. The nearest residential area is located approximately 50 feet east from the fence line. The site is bordered by Monatiquot Street to the east, the Weymouth Fore River to the west and south, and Bridge Street (Route 3A) to the north.

The topography within 2 to 3 miles surrounding the Project site is relatively flat except for several isolated hills. The closest hills include King Oak Hill to the southeast, Baker Hill to the east, Weymouth Great Hill to the east-northeast, Quincy Great Hill to the north-northeast, Forbes Hill to the west-northwest, and Penns Hill to the west-southwest. The topography in the more distant region to the west and south of the Project site is generally hilly. The proposed facility will be located at an elevation of 21 feet above mean sea level. The closest elevation above the stack top of the proposed facility is Rattlesnake Hill on the northeastern edge of the Blue Hill Reservation, approximately 3.7 miles to the west-southwest to the site.

C. Operation Information

The Permittee is proposing to develop, construct and operate a new natural gas-fired, with back up No. 2 transportation distillate oil (with a sulfur content that does not exceed 0.05 percent by weight), combined-cycle electric power generation facility at Fore River Station. The proposed facility will be designed to provide a total nominal electric power output rating of 775 MW to Massachusetts utility companies. The proposed facility will include major equipment comprised of two combustion turbines, two respective heat recovery steam generators (HRSGs) with supplemental duct firing, and one steam turbine. The proposed facility will be configured as one main power block, which will contain two combustion turbine units, each generating 250 MW of electric power. The power block will be arranged in a two-on-one configuration: two combustion turbines, two supplementary-fired HRSGs, and a single steam turbine with a nominal generating capacity of approximately 275 MW. In addition, the Permittee is proposing to install a natural gas-fired with back-up No. 2 transportation distillate oil auxiliary boiler and a diesel oil-fired generator to support emergency conditions.

The existing Fore River Station includes two 12 MW simple cycle combustion turbines used for peaking power only. Each combustion turbine fires No. 2 fuel oil with a maximum sulfur content of 0.3 weight percent as the only fuel of use. The existing Fore River Station peaking units comprised of Edgar Units J1 and J2 will continue to operate as peaking units. These peaking units shall not operate when the proposed facility is operating on back-up oil.

III. Additional Regulatory Air Pollution Requirements

A. Federal

The electric generating facility is subject to the Federal New Source Performance Standards (NSPS), 40 CFR Part 60 Subpart GG, Standards of Performance for Stationary Gas Turbines, which sets SO_2 and NO_x emission limitations and specifies certain monitoring and reporting requirements. The facility will have emission rates, which are significantly less than the NSPS rate. The Department has the responsibility to enforce the NSPS regulations that affect stationary gas turbines.

B. State

The Commonwealth of Massachusetts, Department of Environmental Protection has a number of emission limitations and other air pollution control requirements as set forth in the DEP Air Pollution Control Regulations (310 CMR 7.00) that apply to the combined cycle electric generating facility. The requirements are summarized below.

1) Section 7.01 - General Regulations to Prevent Air Pollution: General Prohibition of Causing a Condition of Air Pollution

2) Section 7.02(2) - Plan Approval and Emission Limitations: requires pre-construction review of plans, specifications, standard operating procedures and standard maintenance procedures, a BACT determination and Department approval in writing.

3) Section 7.04 - Fuel Utilization Facilities ("FUF"): requires pre-construction review of certain sized fuel utilization facilities.

4) Section 7.06 - Visible Emissions: The emissions of smoke from a stationary source must be controlled by the application of modern technology, but in no case shall exceed opacity and smoke as specified in the regulation.

5) Section 7.09 - Dust and Odor, Construction and Demolition: The generation of dust or odor may not cause or contribute to a condition of air pollution.

6) Section 7.10 - Noise: The generator of noise may not cause or contribute to a condition of

air pollution.

7) Section 7.13 - Stack Testing: Requires stack testing if the Department has determined that such testing is necessary.

8) Section 7.14 - Monitoring Devices and Reports: Allows the Department to require sources to install, maintain and use monitoring devices of a design and installation approved by the Department and requires periodic reports on emissions.

9) Section 7.27 and Section 7.28 - NO_x Allowance Program and NO_x Allowance Trading Program: Requires a monitoring plan and certification of the CEMS and establishes the requirements and guidelines for NO_x allowances and trading.

10) Air Toxics Policy - The Department has established ambient guidelines for over 100 air toxic pollutants. The Permittee's compliance with these guidelines is addressed in Section V. Ambient Air Quality Impact Analysis, F. Air Toxics Analysis.

11) Operating Permit - Within one year of commencement of operation, the facility must file an application for an operating permit pursuant to Regulation 310 CMR 7.00, Appendix C.

12) 310 CMR 7.00, Appendix A, Emission Offset & Nonattainment Review - which requires certain size facilities to comply with offsetting of emissions and use of lowest achievable emission rate technology.

C. Nonattainment Issues

The Weymouth area has been designated Nonattainment for Ozone only. For information and regulatory requirements concerning Nonattainment NSR, please see Section V of this document.

IV. Control Technology Review

The proposed combined-cycle electric generating facility is required to evaluate Best Available Control Technology (BACT) as it applies to emissions of Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_x), Carbon Monoxide (CO), Particulate Matter (PM/PM_{10}), and Sulfuric Acid Mist (H_2SO_4) (Nitrogen Oxides are also subject to Lowest Achievable Emission Rate (LAER) since NO_x is an Ozone precursor – See pages 11 and 12 of this PROPOSED CONDITIONAL APPROVAL/PSD Permit). BACT is defined as the optimum level of control applied to pollutant emissions based upon consideration of technical, economic, and environmental factors.

The first step in a BACT analysis is to determine for the emission source, the most stringent control available for a similar or identical source or source category. The Department has verified and concurs with the Permittee's BACT analysis as presented in its Major

Comprehensive Plan Application (MBR-99-COM-018, Transmittal W004896). The proposed combined-cycle electric generating facility must utilize BACT to control the emissions of the following pollutants.

A. Sulfur Dioxide (SO_2)

The control technologies for SO_2 emissions include flue gas desulfurization and fuel type. The Permittee has proposed an emission rate for SO_2 of 0.0023 pounds per million British thermal units (lbs/MMBtu) input when firing natural gas and 0.0522 lbs/MMBtu input when firing transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight). The Department has concluded that use of natural gas, which contains negligible sulfur, as the primary fuel and transportation distillate fuel oil as the back-up fuel is regarded as BACT for SO_2 and additional SO_2 emission controls are not required

B. Nitrogen Oxides (NO_x)

In order to reduce the NO_x emissions, the Permittee proposes to utilize the NO_x control techniques dry low NO_x combustion, water injection for NO_x control on oil and Selective Catalytic Reduction (SCR) in the heat recovery steam generator (HRSG) to achieve a NO_x emission rate of 2.0 ppmvd at 15% O_2 when firing natural gas and 6.0 ppmvd at 15% O_2 when firing transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight). These NO_x emission rates are more stringent than the 75 ppm NO_x emission rate for combustion turbines contained in Subpart GG of the New Source Performance Standards. The Department has concluded that these emission rates are BACT (as well as LAER) for NO_x and that additional NO_x emission controls are not required.

C. Particulate Matter (PM/PM_{10})

The control technologies for PM/PM_{10} emissions include fabric filter collector, electrostatic precipitators, and wet scrubbers and fuel type. The Permittee has proposed an emission rate for PM/PM_{10} of 0.011 lbs/MMBtu input when firing natural gas and 0.050 lbs/MMBtu input when firing transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight). The Department has concluded that use of natural gas, essentially ash free, as the primary fuel and transportation distillate fuel oil as the back-up fuel is regarded as BACT for PM/PM_{10} and that additional PM/PM_{10} emission controls are not required.

D. Carbon Monoxide (CO)

CO emissions are formed due to incomplete combustion of the fuel in the combustion process. Control methods that reduce CO are combustion controls (less stringent) and catalytic oxidation (most stringent). The Permittee proposes the use of an 89% efficient oxidation catalyst as BACT to limit CO emissions to 2.0 ppmvd at 15% O_2 when firing natural gas. The Permittee proposes the oxidation catalyst as BACT to limit CO emissions to 7.0 ppmvd at 15% O_2 when firing transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight). The Department has concluded that these emission rates are BACT for CO and that additional CO emission controls are not required. The use of higher CO removal efficiency catalyst would lead to higher emissions of sulfuric acid mist and PM_{10} due to higher conversion of SO_2 and downstream reaction of SO_3 with ammonia slip from the NO_x SCR system.

E. Sulfuric Acid Mist (H_2SO_4)

H_2SO_4 emissions are formed due to sulfur in the fuel that oxidizes to SO_3 and then combines with H_2O to form H_2SO_4. The Permittee has proposed an emission limitation for H_2SO_4 of 0.0016 lb/MMBtu input when firing natural gas and 0.032 lbs/MMBtu input when firing transportation distillate fuel oil (with a sulfur content that does not exceed 0.05 percent by weight). The Department has concluded that the use of natural gas, which contains negligible sulfur, as the primary fuel and transportation distillate fuel oil as the back-up fuel is regarded as BACT for H_2SO_4 and that additional H_2SO_4 emission controls are not required.

V. Air Impact Analysis

A. General Conditions

An air quality impact analysis was performed to assess Project air quality concentrations against applicable State and Federal standards. This modeling was based on EPA's SCREEN3, Industrial Source Complex Short Term (ISCST3), and CTSCREEN models using terrain data from USGS topographic maps. In addition, the Offshore and Coastal Dispersion Model (OCD) was used to assess potential coastal fumigation effects on plume dispersion. Results for the load conditions that produced the highest predicted concentrations were then compared to significant impact levels (SILs) or ambient air quality standards/PSD increments.

The modeling included the use of EPA recommended ISCST3 (Industrial Source Complex Short Term Version 3) model in the refined mode with hourly meteorological data. The meteorological data that was used consisted of five years of surface observations (1991-1995) collected by the National Weather Service at Logan Airport and one year of Clean Harbor's meteorological data (11/1/88-10/31/89). Modeling was performed for a single stack containing two flues, which is 255 feet tall. The SCREEN3 model was used as an initial analysis for simple and intermediate/complex terrain receptors. The refined modeling techniques included the use of ISCST3 model for simple terrain and CTSCREEN for intermediate and complex terrain. The predicted concentrations are based on the combustion turbine operating under maximum operating conditions. Table 2 presents the maximum predicted concentrations for the new combined cycle units at Fore River Station. Details of the modeling analysis are presented in the PSD/NSR application and the Major Comprehensive Plan Application. The proposed combined cycle units are predicted to have maximum predicted concentrations below SILs for all pollutants and averaging periods. The OCD model also predicted concentrations below the SILs. The maximum concentrations in Table 2 below are based on 8040 hours of operation burning natural gas at 100% load @ -12^{0}F and 720 hours burning fuel oil at 100% load @ -12^{0}F.

Table 2: Maximum Predicted Concentrations for New Combined Cycle Units Criteria

Pollutants					
Pollutant	**Averaging Time**	**Significant Impact Level (ug/m^3)**	**Class II PSD Increment (ug/m^3)**	**NAAQS (ug/m^3)**	**Maximum Concentrations (ug/m^3)**
SO_2	3-HOUR 24-HOUR ANNUAL	25 5 1	512 91 20	1,300 365 80	15.07(2) 3.23(2) 0.20(1)
PM_{10}	24-HOUR ANNUAL	5 1	30 17	150 50	3.14(2) 0.50(1)
NO_2	ANNUAL	1	25	100	0.31(1)
CO	1-HOUR 8-HOUR	2,000 500	No PSD increment established	40,000 10,000	4.31(1) 3.02(1)

Table 2 Notes:

1 = SCREEN3
2 = CTSCREEN
NO_2 = nitrogen dioxide
CO = carbon monoxide
SO_2 = sulfur dioxide
PM_{10} = particulate matter less than 10 microns in aerodynamic diameter
ug/m^3 = micrograms per cubic meter

B. Class I Area Impact Analysis

The nearest Class I area is the Lye Brook National Wilderness area in southern Vermont. This area is to the northwest at a distance of approximately 188 kilometers. Predicted concentrations for each pollutant are well below significant impact levels in this area. The maximum significance levels were not exceeded and the facility will not significantly impact the nearest Class I area.

C. Visibility Impairment Analysis

The Fore River Station Project is located about 188 kilometers to the southeast of the PSD Class I Lye Brook Wilderness Area in southern Vermont and 206 kilometers to the south of the PSD Class I Presidential Range areas in New Hampshire. A visibility impairment analysis, using the VISCREEN model, was performed in order to determine the affect of pollutants on altering the color of the sky or contrast of terrain features with the horizon. Under worst case operations, the visibility impacts were well below screening level thresholds at all these Class I areas.

D. Growth Analysis

The Permittee will provide electricity to the utility grid to satisfy general electric demand. There is not expected to be any appreciable industrial, commercial, or residential growth that would occur as a direct result of this Project due to the self sufficient nature of the proposed facility and the modest number of permanent employees required in plant operations. Therefore, there will be negligible growth-related air pollution impacts from the proposed Project.

E. Cumulative Impacts with the Major Sources in the vicinity of the Proposed Plant

A formal source interaction analysis for the proposed combined cycle units is not required since the maximum predicted concentrations are less than the SILs in all cases. However, based on comments received in the MEPA process, a cumulative impact assessment was performed to demonstrate that combined impacts of the new combined cycle units plus impacts from the existing Edgar Station units, plus the impacts of potential major sources in the vicinity (a 10 mile radii of the proposed Fore River Station) of the plant, plus background, do not exceed applicable air quality standards. This cumulative impact analysis was performed with the ISCST3 model with both 1991-1995 Boston meteorological data and one year of Clean Harbors data.

The results of the cumulative impact analysis show maximum cumulative impacts are below the applicable ambient air quality standards for all air pollutants and averaging periods.

F. Air Toxics Analysis

The Permittee also conducted dispersion modeling for pollutant emissions from the new combined cycle units for non-criteria air pollutants (i.e. applicable metals, metal oxides, ammonia, phosphoric acid, sulfuric acid, and formaldehyde). This analysis was also performed with the ISCST3 model for simple terrain with 1991-1995 meteorological data, and the CTSCREEN model for intermediate /complex terrain. The 24-hour average concentrations were computed for both oil firing and natural gas firing scenarios. The annual average concentrations were computed assuming 8040 hours of operation on natural gas and 720 hours of operation on oil.

A summary of maximum predicted concentrations and the Department's guideline levels is provided in Table 3. The 24-hour concentrations presented represent the maximum of the oil firing or gas firing scenario. All the 24-hour average concentrations presented in Table 3 are based on oil firing, except for formaldehyde.

Table 3: Maximum Predicted Concentrations for New Combined Cycle Units Air Toxics

Pollutant	Averaging Time	Department Guideline Level (ug/m^3)	Maximum Concentrations (ug/m^3)[1]

Table 3: Maximum Predicted Concentrations for New Combined Cycle Units Air Toxics			
Pollutant	**Averaging Time**	**Department Guideline Level (ug/m^3)**	**Maximum Concentrations (ug/m^3)[1]**
Ammonia	24-HOUR ANNUAL	100 100	0.19 0.05
Sulfuric Acid	24-HOUR ANNUAL	2.72 2.72	1.98 0.06
Formaldehyde	24-HOUR ANNUAL	0.33 0.08	0.02 0.01
Antimony	24-HOUR ANNUAL	2.0 1.0	1.48E-03 2.42E-05
Arsenic	24-HOUR ANNUAL	5.00E-04 2.00E-04	1.65E-04 3.58E-06
Beryllium	24-HOUR ANNUAL	1.00E-03 4.00E-04	2.23E-05 3.63E-07
Cadmium	24-HOUR ANNUAL	3.00E-03 1.00E-03	2.63E-04 1.96E-05
Chromium	24-HOUR ANNUAL	1.36 0.68	3.51E-04 5.72E-06
Hexavalent Chromium	24-HOUR ANNUAL	3.00E-03 1.00E-04	6.30E-05 2.48E-05
Copper	24-HOUR ANNUAL	0.54 0.54	8.77E-02 1.43E-03
Lead	24-HOUR ANNUAL	0.14 0.07	3.66E-03 3.52E-04
Mercury	24-HOUR ANNUAL	0.14 0.07	5.85E-05 8.97E-06
Nickel	24-HOUR ANNUAL	0.27 0.18	3.49E-04 5.68E-06
Nickel Oxide	24-HOUR ANNUAL	0.27 0.01	4.45E-04 7.26E-06
Phosphoric Acid	24-HOUR ANNUAL	0.27 0.27	6.48E-02 1.06E-03

Table 3: Maximum Predicted Concentrations for New Combined Cycle Units Air Toxics			
Pollutant	**Averaging Time**	**Department Guideline Level (ug/m^3)**	**Maximum Concentrations (ug/m^3)[1]**
Selenium	24-HOUR ANNUAL	0.54 0.54	3.58E-03 5.83E-05
Vanadium	24-HOUR ANNUAL	0.27 0.27	2.97E-04 4.84E-06
Vanadium Pentoxide	24-HOUR ANNUAL	0.14 0.03	1.06E-03 1.73E-05

Table 3 Notes:

1- ISCST3 was used for the 24-hour natural gas concentrations; CTSCREEN was used for the 24-hour and annual oil concentrations.
2- Annual average assumes 8040 hours of operation burning natural gas at 100% load @ -12^{0}F and 720 hours burning fuel oil at 100% load @ -12^{0}F.
3- All toxic emission rates are based on AP-42 5/95, except that arsenic, chromium, hexavalent chromium, nickel and nickel oxide are based on lab analysis of the fuel, and formaldehyde is based on AP-42, 5/98 emission factor.
ug/m^3 = micrograms per cubic meter

VI. Vegetation And Soils

1. PSD regulations require analysis of air quality impacts on sensitive vegetation types, with significant commercial or recreational value, or sensitive types of soil.

2. Most of the designated vegetation screening levels are equivalent to or exceed NAAQS and/or PSD increments, so that satisfaction of NAAQS and PSD increments assures compliance with sensitive vegetation screening levels.

3. For SO_2, 3-hour and annual sensitive vegetation screening levels are more stringent than comparable NAAQS standards, and there is a 1-hour screening level for SO_2 for which there is no NAAQS equivalent. Maximum 1-hour, 3-hour, and annual SO_2 concentrations from the new units were added to background levels and compared to the vegetation sensitivity concentrations. The 1-hour, 3-hour, and annual vegetation sensitivity threshold values are 917 ug/m^3, 786 ug/m^3, and 18 ug/m^3, respectively. The maximum 1-hour, 3-hour, and annual average concentrations from the proposed new combined cycle units are 13.22 ug/m^3, 15.10 ug/m^3, and 0.20 ug/m^3, respectively which are well below the sensitive vegetation screening level thresholds.

When cumulative impacts with background and the existing Fore River Station are considered, an exceedance is predicted to occur for the annual averaging period. This exceedance is largely due to the existing background ambient concentration. The background level of 23.6 ug/m^3, which is already above the annual sensitivity threshold, was conservatively obtained from the Kenmore Square monitoring location in Boston. This monitoring location is an urban location where higher levels of SO_2 are expected, than at the more suburban/rural coastal environment of Weymouth. The project contribution to the annual SO_2 concentration is less than 0.1%. The usage of natural gas as the primary fuel and transportation distillate fuel oil as the back-up fuel is the best available control for SO_2 emissions from the new combined cycle units at Fore River Station.

XVIII. SECTION 61 FINDINGS

The Applicant's Environmental Impact Report (EIR) has been carefully considered prior to action on their plan application approval request. The Department, in issuing this PROPOSED CONDITIONAL APPROVAL/PSD Permit, requires the Applicant to use all feasible means and measures to avoid or minimize adverse environmental impacts. Measures the Department deems necessary to mitigate or prevent harm to the environment are included in the conditions of this PROPOSED CONDITIONAL APPROVAL/PSD Permit. The Department has made its decision under applicable law based on a balancing, where appropriate, of environmental and socioeconomic objectives, as mandated by 301 CMR 11.01(4).

Pursuant to M.G.L. Chapter 30 Section 61 of the Massachusetts Environmental Policy Act, (MEPA), 301 CMR 11.12 of the MEPA Regulations, and the Secretary's Certificate of finding on the Final EIR, dated September 16, 1999 (EOEA #11726) the Department's Section 61 Findings on the Fore River Development Project determining that all feasible measures have been taken to avoid or minimize impacts to the environment are presented here as follows.

Introduction

This Section 61 Finding has been prepared in compliance with the requirements of Massachusetts General Laws Chapter 30, Section 61. Chapter 30 Section 61 requires state agencies and authorities to review, evaluate and determine impacts on the natural environment of all projects or activities conducted or permitted by them, and to undertake all feasible means and measures to minimize and prevent damage to the environment. In making a determination, agencies are required to issue a "Section 61 Finding" describing project impacts, and certifying that all feasible mitigation measures have been taken.

The Section 61 Finding is associated with the construction of the Fore River Station, a 775 MW natural gas fired combined cycle power plant to be developed and operated by Sithe Edgar Development, LLC (Sithe). The project is proposed to be located on the site of the former Edgar Station, a 57-acre property on the Weymouth Fore River on the Weymouth/Quincy town line in Massachusetts.

History of MEPA Review

Sithe submitted an Environmental Notification Form for the Fore River Station Project to the MEPA Unit on July 15, 1998. The project was noticed in the Environmental Monitor on July 22, 1998. The Secretary of Environmental Affairs issued a Certificate on the ENF on August 21, 1998. The Secretary determined that the project required a Draft Environmental Impact Report (DEIR) and provided the scope of the DEIR.

The DEIR was filed with the Secretary on February 15, 1999. It was noticed in the Environmental Monitor on February 23, 1999. The Secretary of Environmental Affairs issued a Certificate on the DEIR on April 8, 1999.

The Final Environmental Impact Report (FEIR) was filed on August 2, 1999. It was noticed in the Environmental Monitor on August 10, 1999. On September 16, 1999, the Secretary of Environmental Affairs issued a Certificate stating that the FEIR adequately and properly complies with the Massachusetts Environmental Policy Act and with its implementing regulations.

A List of State Permits

The Fore River Station project requires a number of state permits that trigger review under the Massachusetts Environmental Policy Act. The issuing authorities must comply with MGL C. 30, Section 61 to ensure that the proponent has described the impacts and proposed mitigation to minimize and prevent damage to the environment. A list of the state permits required by the project was provided in Section 2.4, Table 2-1 of the FEIR.

Project Mitigation Measures

In this Section 61 Finding, individual mitigation measures that will be undertaken by Sithe both during construction and the operational life of the Project are discussed. These measures are anticipated to reduce or eliminate many of the potential environmental impacts of the Project.

Attachment A is a table summarizing the potential environmental impacts associated with the Project, the mitigation measures which will be undertaken to address each, and a statement of assumed financial responsibility for each.

Attachment B is a summary of the implementation schedule for mitigation measures associated with construction activities.

Attachment C is a summary of the implementation schedule for mitigation measures associated with operation of the Project. Note that all of these measures will remain in force through the life of the Project.

Overview of Project Impacts

Potential impacts from the Fore River Station project are defined as either construction or post-construction and grouped by issue areas. The issue areas are:

- Air Quality
- Noise
- Visual
- Wetlands / Dredging
- Water Use
- Wastewater Discharge
- Stormwater
- Cultural
- Traffic
- Hazardous Materials
- Construction

Project impacts are summarized by issue area below. The potential environmental effects of each impact are described, followed by the proposed mitigation measures that will offset potential impacts

Air Quality

Air impacts are primarily limited to the operation of the Fore River Station during post-construction. Dust control during construction is discussed under Construction Impacts, below.
The Fore River Station will generate air emissions during fuel combustion to produce energy. Nitrogen Oxides (NO_x) are formed in the turbine combustion chamber primarily as a result of the reaction between nitrogen and oxygen (O_2) (oxidation). During oil firing, NO_x is also formed by oxidation of fuel-bound nitrogen (fuel NO_x). Volatile Organic Compounds (VOC) emitted from combustion turbines are products of incomplete combustion of the fuel. Sulfur dioxide (SO_2) is formed by the reaction of sulfur found in fuel with oxygen from the combustion air. Emissions of particulate matter (PM and PM_{10}) result from trace quantities of non-combustibles in the fuel or combustion air or from formation of ammonium sulfates post combustion. Carbon Monoxide (CO) emitted from combustion turbines is a product of incomplete combustion of the fuel.

The Massachusetts Department of Environmental Protection (DEP) and the U.S. Environmental Protection Agency (EPA) have promulgated air quality regulations that establish ambient air quality standards and emission limits. These regulations include: (1) Non-Attainment New Source Review (NSR), (2) Prevention of Significant Deterioration (PSD), (3) National Ambient Air Quality Standards (NAAQS) and (4) New Source Performance Standards (NSPS) for criteria pollutants.

Application of these regulatory requirements is through the DEP Air Plan Approval process.

Mitigation

Natural gas and low-sulfur distillate oil

Through the use of clean-burning natural gas, low sulfur distillate oil as a secondary fuel and advanced combustion and pollution control technologies, including a dry low-NO_x combustor, water injection, a Selective Catalytic Reduction System (SCR) and a CO oxidation catalyst, emissions will be controlled to extremely low levels. In addition, the project will acquire emissions offsets as required for Non-Attainment NSR.

Use of LAER and BACT

Dry low-NO_x combustion limits NO_x formation by lowering flame temperatures through fuel/air optimization. The facility will control NO_x emissions during natural gas firing with dry low-NO_x combustion in combination with SCR. Water injection and SCR will control NO_x emissions during oil firing. Water injection acts as a heat sink in the turbine combustor, further limiting peak flame temperatures and resultant NO_x formation. The use of a dry low-NO_x combustor, with water injection during operation on oil, in combination with SCR technology, achieves LAER for NO_x emissions.

Due to the nature of the state-of-the-art dry low-NO_x combustion system (minimal excess air at flame), the combustion turbine generates VOC at a higher rate than a combustion turbine that utilizes water or steam injection for NO_x control. However, levels of VOC emissions will be maintained at very low levels with substantial savings in water consumption with the control process utilized on this project. Combustion controls and the primary use of clean burning natural gas are the measures taken to minimize VOC emissions. Use of a CO catalyst achieves BACT for CO.

Clean burning natural gas has only trace quantities of SO_2. The use of natural gas as the primary fuel and low sulfur distillate oil as the secondary fuel achieves BACT for SO_2. Particulate matter (PM_{10}) emissions are also minimized by use of clean burning natural gas as the primary fuel and low sulfur oil as a secondary fuel.

In order to comply with the requirements of Non-Attainment NSR for NO_x and VOC, the Fore River Station Project will be required to acquire NO_x and VOC offsets at a minimum ratio of 1.26 to 1.0.

The amount of NO_x and VOC offsets required for the facility is 275 and 90.1 tons per year respectively. Sithe is currently formulating plans to obtain the required NO_x and VOC offsets.

The NO_x offsets will be obtained by curtailing use or adding controls to some of Sithe's existing facilities in Massachusetts. NO_x offsets will most likely be obtained from the emission credits generated by the Sithe Mystic Station Air Quality Implementation Plan (AQIP). With respect to VOC, offsets will be obtained in the following manner: 24.8 tpy from BASF (certified in DEP Approval No. MBR-94-ERC-011); 56.6 tpy from Lightolier (Approval No. 4P95217); and 8.7 tpy from Avery Dennison (Approval No. . MBR-94-ERC-006, MBR-95-ERC-001).

Noise

Noise impacts are associated with construction and post-construction. Construction impacts are discussed below. The operation of the Fore River Station will increase noise levels by 6 dBa over ambient conditions at the nearest residential receptor (Monatiquot Street). Sources of noise during operation include combustion turbines, natural gas compressor, natural gas meters, transformers, glycol coolers, and air-cooled condenser (ACC).

Air is drawn into combustion turbine equipment from the outdoors, used in the gas turbine combustion process, expanded through a power turbine and exhausted through the heat recovery steam generators (HRSGs) before being released from the 255-foot high dual flue stack. A compressor is needed to process natural gas to fuel the combustion turbines. The metering equipment includes various meters and valves, which have the potential of high frequency (hissing) sounds at nearby locations. There will be three main transformers, one for each generator, which will produce a small level of noise. The glycol coolers, sometimes called fin/fan coolers, provide cooling for the combustion turbine lubrication system. The primary source of ACC noise is the fans.

<u>Mitigation</u>

The Fore River Station noise mitigation design includes the following or equivalent alternative measures to achieve the allowable noise impacts below.

a) Enclosure of the following noise-producing components of the Project within an acoustically-designed building: the gas turbines, steam turbines, electric generators, HRSGs, the high pressure and auxiliary boiler feedwater pumps, plant and instrument air compressors, and the auxiliary boiler.

b) Install low noise ACC utilizing slower fans, additional blades, and additional surface area over the standard base model.

c) Install enhanced noise suppressants for the combustion turbine air inlets and exhausts.

d) Procure and install quiet-design transformers.

e) Install low noise closed cooling water coolers utilizing slower fans, additional blades, and additional surface area over the standard base model.

f) Install silencers on all vents including those that would or may be activated during start-up and shut down sequences.

g) Install all natural gas compressor equipment within an acoustically designed building.

h) Install lagging or enclosures on all metering equipment, such as valves and associated exposed pipes, to assure the reduction of noise from these sources.

i) Install glycol coolers at the south end of the ACC, at a point furthest away from residential neighborhoods

Fore River Station Allowable Noise Impacts

Receptor Location	**Ambient L_{90}, dBA**	**Ambient & Plant L_{90} dBA**	**Nighttime Increase, dBA**
R-1 Monatiquot Street, E	41	47	+6
R-2 Idlewell	35	36	+1
R-3 East Braintree	37	38	+1
Quincy, W	37	38	+1
Quincy Point	42	43	+1
Germantown	39	40	+1
Property Fence Line, E	41	48	+7

Sithe will conduct a noise survey within 180 days of the facility start-up to verify compliance with the allowable noise impacts specified in the above table. Sithe will provide the Department with a written report describing the results of said noise survey, within 60 days of its completion.

Furthermore, Sithe will assure that the following mitigation measures are incorporated in the project construction and operation:

- Trucks accessing site will comply with federal regulations limiting noise from trucks.

- Construction equipment sound muffling devices will be in good repair.

- Pile driving will occur only during daytime as defined in local codes. When practical, major construction activities will be limited to daytime.

- Project engineering will incorporate best available noise control technology.

In addition to the normal construction activities, steam and air blows will occur in the final phases of construction. These processes use high pressure steam or air to clean plant piping prior to operation. The testing process will utilize "silent blows," which are continuous releases of steam or air that have been treated to reduce noise.

Estimated noise mitigation costs total $15,840,000: $8,039,000 to reduce increases to 10 dBA at the nearest residential receptor (the Department's Noise Policy Guideline), and an additional $7,801,000 to reduce increases yet further, to 6 dBA at the nearest residential receptor.

Visual

The tallest facility structure will be the plant's stack, which will be 255 feet high. Excepting the stack, the tallest structure will be 102 feet high.

<u>Mitigation</u>

In project layout and design, Sithe has sought to minimize the visual impact of the Fore River Station. Every effort has been made to make visual improvements to the site, to please as large a segment of the population as possible. In general, the site will be much cleaner and better maintained than the current site.

Elements of project design

The existing brick building is being removed and will be replaced with a modern facility. The Fore River Station's powerhouse design height will be 102 feet high, compared to 155 feet for the highest part of existing Edgar Station. The exterior will be insulated metal siding. Sithe's preferred color scheme is white with blue trim; Sithe will finalize this choice in discussions with Weymouth officials.

The project will have one multi -flue stack, rather than individual stacks. The height of the single stack will be 255' a.g.l., compared to the five 250' stacks that served Edgar Station.

Landscaping and public areas

Significant improvements will be made to landscape and revegetate areas of the project site. Landscaping along the western shore of the property will be conducted where possible to screen the building and improve the view of the site from the water. Landscaping will also be proposed south of the air-cooled condenser for the same reason, where it will not interfere with air flow to the air-cooled condenser. Sithe will also provide landscaping along the eastern (Monatiquot Street) edge of the site. Landscaping elements will include a combination of low vegetation (above the MWRA sewer easement) with higher vegetation, berm, fencing and/or trees to the west, shielding the neighborhood from the Fore River Station. Additional landscaping will be provided to the north and east of the powerhouse, and north of Route 3A along a proposed Kings Cove public access area.

Wetlands / Dredging

The Fore River Station will require direct alteration through dredging of approximately 2 acres of nearshore land under the ocean, in the Designated Port Area (DPA) immediately west of the Edgar Station, to accommodate a fuel oil barge pier. Piles will be driven into the seabed to secure barges that dock at the pier. Piles will also be installed in an area north of the Fore River Bridge within the footprint of the existing northern pier to handle the construction barge that will deliver large components of the plant to the project site during construction. Pile driving will result in only temporary impacts that will be mitigated as discussed below. There will also be limited filling of an area landward of the existing bulkhead south of the Edgar Station that currently floods at high tide. An area of Land Subject to Coastal Storm Flowage will be filled to accommodate the ACC, a detention pond, and ancillary facilities. Some stabilization and repair of the existing bulkhead will also take place to provide security to the shoreline. Finally, the existing discharge flume, a remnant structure of the Edgar Station's cooling system, will be filled to improve structural stability, worker safety, and landscaping aesthetics of the site. Because the bottom of the discharge flume is below extreme low water, it comprises a manmade feature of land under the ocean encompassing approximately 15,000 s.f.

Most of the project site within 200 feet of the Weymouth Fore River is formerly-filled tidelands, licensed by DEP under Chapter 91. Three small portions of the site within 200 feet of the Weymouth Fore River were upland, and thus may comprise Riverfront Area (within a DPA). Two of these three areas are previously developed (Edgar Station and pier).

<u>Mitigation</u>

The Fore River Station project will avoid, minimize, and mitigate impacts to the wetland resource areas identified within the project site that are presumed significant to the protection of the interests of the Massachusetts Wetlands Protection Act (MWPA). The Fore River Station will also comply with the State's Stormwater Policy as implemented and regulated through the MWPA and its regulations, and will meet performance standards for Riverfront Area. Since the Fore River Station is located within a DPA, Land Under the Ocean is the only resource identified within the site that is presumed significant to the any of the interests of the MWPA.

Elimination of once-through cooling

A major change from former Edgar Station has been the elimination of once-through cooling, in favor of an ACC. This has reduced potential direct wetland impacts considerably, reducing filling of coastal beach and land subject to coastal storm flowage. Dredging also has been greatly reduced, from 56,150 cy to 28,000 cy.

Work within Bank and 100-foot buffer

To assure that construction-related impacts to the Weymouth Fore River are minimized, all work performed within the bank area and its 100-foot buffer zone will be performed according to the Order of Conditions issued by the Weymouth Conservation Commission.

Potential dewatering activities

Any dewatering activities at the Project site will be performed in accordance with good construction practice per approval by the Weymouth Conservation Commission.

Construction and Operational Stormwater Pollution Prevention Plan (SWPPP)

Sithe will develop and implement a construction and operational SWPPP which will include a commitment to conduct construction and operational activities in accordance with appropriate Best Management Practices (BMPs) intended to prevent stormwater contamination.

Chapter 91 Licensure

Sithe will obtain a Chapter 91 waterway license, and will comply with the terms of that license throughout the operational life of the Project.

Shellfish seeding program

To mitigate any potential impacts from dredging the 2.1 acre area of DPA for the fuel oil barge pier, the applicant will fund a one time shellfish seeding program in Weymouth nearshore waters. The program will be implemented by the Weymouth Shellfish Warden and in consultation with MA Division of Marine Fisheries (MA DMF). An area for seeding will be selected from beds currently harvested by master diggers. Potential seeding areas include Kings Cove, Wessagusset, and the Back River. Seed will be purchased by the applicant from a MA DMF approved shellfish hatchery to ensure that disease free seed is used.

Dredging mitigation

Mitigation measures will be employed during dredging operations and work around the bulkheads. All dredging operations will be conducted from the upland or from a floating barge using either a mechanical clamshell bucket dredge or a hydraulic dredge that will minimize turbidity within the water column. The top and most silty sediment will be dredged using a hydraulic dredge to decrease turbidity. A clamshell will be employed to dredge the more sandy sediments. During clamshell dredging, silt curtains will be employed to localize sedimentation. Dredge activities will be scheduled to avoid sensitive life periods of critical fish species. Installation of piles and bulkhead sheeting will be completed from the upland when possible. Otherwise it will be conducted from a floating barge. All pile driving will be conducted with a vibrating hammer to reduce turbidity within the water column. Fill activities will be conducted behind a cofferdam to avoid increased turbidity within the water column. These mitigation measures will prevent impacts to adjacent habitats during dredging, pile driving, and work around the bulkheads.

At the request of MA Division of Marine Fisheries, there will be no dredging between February 1 and September 15.

Riverfront areas

All work in Riverfront Area will meet performance standards, in conformity with an Order of Conditions issued by the Weymouth Conservation Commission.

Nearshore upland areas adjacent to the ocean will be revegetated with native woody species to provide wildlife habitat not currently available. Revegetation will be concentrated at the two public access areas at Lovell's Grove and Kings Cove, and south of the ACC.

Watershed wetlands restoration plan

Although not proposed as direct mitigation for any potential project impacts, it is important to note that the applicant will also implement a Watershed Wetlands Restoration Plan for the entire Weymouth Back River Watershed and for the portions of Weymouth located in the Fore River Watershed. The purpose of the study is to identify wetland and habitat restoration opportunities and produce a prioritized list of for the future implementation of restoration projects.

Water Use

The Fore River Station requires a reliable source of freshwater for process and potable water uses. As stated in the FEIR, Sithe has continued to work to reduce water requirements. Under normal or "base case" conditions, the plant will use an estimated 46,214 gallons per day (gpd) for HRSG make-up, demineralizer regeneration, equipment washdowns and potable uses (drinking water, showers). Under evaporative cooling conditions, use of freshwater increases to an estimated 105,724 gpd, of which 62,831 gpd is evaporated to the atmosphere. Lastly, during oil firing, water injection is required in order to control the combustion temperature thus limiting NO_x formation to acceptable levels. At full load oil firing, limited to 720 hours per year, the plant will use an estimated 482,200 gpd.

Make-up water for the plant process and sanitary water system will be obtained from the City of Quincy pursuant to the MWRA Straddle Policy. The City of Quincy is a member community of the MWRA system. On an average day the MWRA reservoir system provides 9.7 million gallons per day (mgd) of potable water to Quincy for subsequent distribution to the City's businesses, institutions and 84,000 residents. Peak usage is 13.4 mgd (1997 usage). The MWRA can currently supply the City of Quincy with 20 mgd with an expected increase to 32 mgd in 2004. On December 15, 1999, the MWRA Board of Directors voted final approval of Sithe's application under the MWRA Straddle Policy.

<u>Mitigation</u>

Water conservation and recyling

The Fore River Station has been designed with intensive internal levels of water treatment and recycling, to minimize water use as well as wastewater generation. Water conservation measures will be implemented at the Fore River Station to minimize water demand. The measures proposed include:

1. Dry Low NOx combustors are used rather than water injection during natural gas operation.

2. HRSG blowdown is recycled during normal operation.

3. Flash steam from the high pressure and intermediate pressure continuous blowdown tank is routed to the low pressure drum for recovery rather than to the atmosphere.

4. Steam and condensate system samples are recovered and recycled rather than sent to the waste system.

5. During periods of combustion turbine oil firing when demineralized water requirements increase sharply, offsite regenerated demineralizers will normally be used to provide demineralized water to the combustion turbine, minimizing the quantity of water required for regeneration needs.

6. The combustion turbine inlet evaporative cooler blowdown will be recycled. During periods of combustion turbine evaporative inlet cooling, the makeup water to the coolers shall normally be provided by offsite regenerated demineralizers thus allowing the blowdown from the coolers to be recycled to the main cycle demineralizer system without loss of demineralized water quality, and minimize use of water for regeneration of the main cycle dimineralizer system during recycle of the cooler blowdown.

7. ACC enables use of precoat condensate polishers, rather than deep bed polishers (reducing wastewater generation).

Wastewater Discharge

Process wastewater that can no longer be recycled will be pretreated and discharged, together with sanitary wastewater, to the Weymouth sewer system. Wastewater will be conveyed via an existing 10" PVC sewer pipe to the MWRA system at the existing King's Cove siphon, from where it will be conveyed to the new Nut Island headworks, and then to the Deer Island Treatment Plant.
Under the base case, plant wastewater discharge will be 39,983 gpd. Under the evaporative cooling case, wastewater will be 42,858 gpd. Under the oil-fired case, wastewater will be 42,718gpd. These figures include sanitary wastewater of 625 gpd.

<u>Mitigation</u>

Wastewater reduction through water conservation and recycling

Water conservation and recycling measures (described above) have been reflected in reduced discharge rates. Annualized average wastewater discharge will be 40,229 gpd, reduced from 48,174 gpd in the DEIR.

Wastewater pretreatment

All wastewater will be treated to meet MWRA Pretreatment Standards. All wastewater will be quality tested prior to release to assure that it meets the minimum standards established by the MWRA.

Use of Treatment Equipment

Demineralizer regeneration wastewater will be neutralized in a holding tank. Wastewater from the process drains will be routed through an oil-water separation system. Oil collected in the oil-water separator will be hauled off site for management at a licensed facility.

I/I removal

Peak flows are 42,858 gpd. Sithe will fund the removal by Weymouth of infiltration/inflow at a 7:1 ratio, as discussed between the Weymouth Department of Public Works and DEP, Northeast Region.

Stormwater

Stormwater from the Fore River Station is discharged to the Weymouth Fore River.

Mitigation

Compliance with state Stormwater Management Policy

The Fore River Station design includes pre-redevelopment and new post-redevelopment stormwater management systems that meet the requirements for the NPDES General Construction Permit and the state Stormwater Management Policy for redevelopment projects. The stormwater management design will minimize pollutants in stormwater discharge, and will attenuate peak stormwater runoff discharge rates.

Stormwater management during construction

During construction, mitigation will be taken to manage stormwater runoff and erosion and sedimentation within the Fore River Station site. A Stormwater Pollution Prevention Plan will be prepared incorporating best management practices for stormwater management during construction. Silt fences and/or hay bales will be located along the downslope sides of the construction area adjacent to the Weymouth Fore River, around unstabilized fill areas, around excavated materials which are temporarily stockpiled and around any area where erosion may be a problem. Disturbed portions of the site where construction activity will cease temporarily for 21 days or more will be stabilized with temporary seed, mulch or geotextiles. Stockpiles will be located as far away from the Weymouth Fore River as is practical. Runoff water will be intercepted and directed from work areas to appropriate sediment traps or a sediment basin. Sediment traps will be used in situations requiring minimal amounts of dewatering. Inlets to active catch basins will be protected from sedimentation by hay bales.

During construction, all potential contaminants will be stored, handled and disposed of so that accidental releases to the environment are avoided. Spill prevention and control measures will be described in detail in a Spill Prevention, Control and Countermeasure Plan (SPCC) that will be prepared for construction and will include measures to prevent spills, provide emergency response measures and training of all construction personnel. All erosion and sediment control measures will be maintained in effective operating condition. Regular inspections of the controls will be conducted and documented. Additional specific measures will be implemented as required in the Order of Conditions to be issued by the Weymouth Conservation Commission. Permanent site stabilization (e.g. planting and seeding) will be undertaken upon completion of the site clean-up, regrading, backfilling and topsoil replacement. After the entire site is permanently stabilized, to the satisfaction of the Conservation Commission Administrator, temporary erosion and sediment control measures will be removed.

Stormwater management during operation

During the operation of the Fore River Station mitigation measures will be taken to manage stormwater runoff within the Fore River Station site. 80% total suspended solids (TSS) will be removed from all stormwater discharges from impervious surfaces within the Fore River Station site. Stormwater from the impervious areas within the site will be piped to one of two detention ponds for treatment prior to being released to the discharge outfalls. Both detention ponds will be impervious to prevent water from leaching into the subsoil. Deep sump catch basins will be utilized upstream of the detention basins.

An Operation and Maintenance Plan will be prepared for the stormwater management system that will incorporate Best Management Practices (BMPs). BMPs will include such actions as periodic sweeping of all parking and roadway areas, semi-annual inspections and cleaning of catch basins, and designated snow storage areas.

Cultural

Edgar Station is considered a significant building for architectural and historical reasons as discussed in the EIR. In order to construct the Fore River Station, and to comply with state law, Edgar Station and its associated buildings must be demolished.

<u>Mitigation</u>

Mitigation provided per two Memoranda of Agreement

Sithe consulted with the Massachusetts Historical Commission (MHC) regarding alternatives to demolition of the Edgar Station complex. As a result of this consultation, Sithe agreed to undertake measures to mitigate the adverse impact of the demolition of the Edgar Energy Station. Mitigation measures are included in an MOA (Appendix E of the FEIR) which has been reviewed by the MHC, and will be executed by the MHC, acting as State Historic Preservation Officer, and by U.S. Army Corps of Engineers. In addition, further mitigation activities requested by the Weymouth Historical Commission are outlined in a separate MOA (Appendix D to the FEIR) between Sithe, the Weymouth Historical Commission, and the Weymouth Board of Selectmen.

Photographic recordation of the interior and exterior of the turbine building, switch house, gatehouse, and other extant structures according to Historic American Engineering Record (HAER) standards has been conducted. Copies have been submitted to the MHC and the Weymouth Historical Commission.

Ongoing historic mitigation

Sithe will provide on-site public access to a landscaped area that will memorialize Lovell's Grove, a popular 19th century picnic and promenade spot which once existed at the site. This area will include a memorial, which provides a brief history of the grove. Sithe will sponsor the printing of an illustrated brochure which describes the history of the Edgar Station site and of other historically significant sites along the Fore and Back Rivers. Sithe will make the existing gatehouse, which will be retained, available for the use of the Weymouth Historical Commission to display brochures and other historical materials concerning the Edgar Station site. Sithe will consider assisting the Weymouth Historical Commission and the Town in preserving specific open space along Weymouth's historic waterfront for public access. Sithe will assist the Weymouth Historical Commission in printing an illustrated booklet which summarizes the Historic American Engineering Record (HAER) report for the general public. Sithe will also consult with the Weymouth Historical Commission and the Weymouth Board of Selectmen on final designs for the new Sithe facility to ensure compatibility with the surrounding landscape and buildings.

Traffic

Traffic to and from the Fore River Station will increase over existing conditions as a result of the redevelopment of the project site. Construction workers in the peak month will total 685 per day. Power plant operation traffic will increase marginally with the Fore River Station employing up to 25 workers. Concurrent activities at the site include the construction by the Massachusetts Highway Department (MHD) of the temporary Fore River Bridge, and construction by MWRA of Braintree-Weymouth Relief Interceptor facilities.

<u>Mitigation</u>

Construction traffic mitigation

By opening the passageway under the Route 3A viaduct, Sithe will maintain right-in, right-out access from the site. Further, a member of the construction management team will be designated as Transportation Coordinator so coordination of traffic and transit support measures will be specifically part of that person's job description. This job description will include interaction and coordination with other construction projects. The coordinator will also establish liaison with traffic officials in Weymouth and Quincy so that information can be transmitted between them as appropriate.

As reported in the FEIR the following elements will be implemented between Sithe, MHD and MWRA:

Maintenance of continuous traffic access beneath Route 3A viaduct to permit right-off, right-on access to all projects.

Provision of flagman control should construction operations require temporary suspension of traffic flow beneath Route 3A viaduct.

The above activities will be planned and executed through a hierarchy of planning and coordination meetings:

Monthly owners meetings. Review schedules and projected activities. Identify any problems, develop solutions. Identify plan for use of shared land.

Weekly Site Manager meetings. Review day-to-day activities and coordination. Notify neighborhood of anticipated activities or problems. Coordinate with Weymouth and Quincy police, fire, traffic, and public works departments, and with bridge tenders.

Daily Site Manager communication. Routine communication to keep all components of construction coordination program functioning smoothly.
MWRA has concurred in these recommendations, and agreed that MWRA and contractor representatives will attend and participate in the planning and coordination meetings.
The location of the construction barge access to north of the bridge means that bridge openings will not be required during delivery of major equipment components by barge to the site.

Hazardous Materials

Hazardous substances are in the ground on-site as a result of past uses during the operation of the Edgar Station. In addition, the proposed Fore River Station will be using some hazardous substances necessary for the production of energy and long-term maintenance of the facility infrastructure.

<u>Mitigation</u>

The Fore River Station site's long-term use for electric power generation and the nature of the fuels used have resulted in some hazardous substances being present on portions of the property. Over the past ten years several investigations of the site have been conducted and reported. Sithe has engaged in a program to ensure the appropriate remediation of existing conditions at the Fore River Station site.

Asbestos remediation

The Restructuring Act of 1997 required Sithe to remove unused structures from the Fore River site. Removal of these structures necessarily first required removal of asbestos. Under contract to a licensed asbestos abatement and building demolition contractor, and abatement of asbestos in the existing facilities has been completed. Following asbestos abatement, demolition commenced and is now under way, as required by state law.

Compliance with MCP

As a part of the Project, Sithe will assure that contaminated soils at the Project site receive appropriate remediation in accordance with the Massachusetts Contingency Plan (MCP.). Utilizing the services of a Licensed Site Professional Sithe has also investigating past contamination in a number of areas of the site. Where public access is being provided, risk assessments establish that no unacceptable risk to human health exists in light of the Company's redevelopment plan which includes placement of crushed stone, paving and landscaping. Other areas of the site, which are zoned for industrial use, will meet all applicable cleanup standards.

A plan will be prepared to address the potential for construction worker exposure to hazardous substances at the site. Contractor training and construction management oversight will also be implemented to minimize any risks associated with the low levels of contamination present in some areas of the site.

Operational usage of hazardous substances

Sithe will also transport, use and store several hazardous substances for the operation of the Fore River Station facility. These substances will include distillate fuel oil, aqueous ammonia, and additional chemicals for plant operation such as strong acid and caustic base, water treatment chemicals and maintenance materials. These hazardous substances will be properly stored within the project site in above-ground storage facilities that will have appropriate secondary containment. Delivery and unloading of the substances will be conducted by trained personnel using spill prevention equipment. The required training and spill prevention and response plans will be prepared by Sithe and kept on-site.

Sithe will develop a hazardous materials emergency response plan and retain an emergency response contractor to assure that hazardous materials incidents during both construction and the operational life of the Project are addressed in a thorough and appropriate manner.

Construction

Construction of the Fore River Station project will involve site preparation and earthmoving activities, foundation work, waterfront construction, placement of major equipment and structural steel erection, infrastructure construction and testing and start-up.

Mitigation

Air quality during construction

To mitigate fugitive air particles within the site and surrounding area, standard dust control measures will be employed, including water sprays when necessary to reduce the amount of airborne dust whenever construction activities require exposure of bare soil. In addition, site roadways will receive periodic sweeping. Truck traffic will be minimized to the extent practical by utilizing barges. A tire wash will be set up at the exit of the site.

Construction noise mitigation

To minimize noise disturbances to the community, construction hours for noisy activities will be limited. As noted above, silent steam will be utilized for final pre-operational cleaning of plant piping. To ensure that noise associated with construction equipment is minimized, Sithe will ensure that the construction contractor chosen to complete the Project inspects sound muffling devices on construction equipment to make sure they are in good repair. Trucks accessing the site will comply with federal regulations limiting noise from trucks. In order to reduce the amount of construction related noise caused by pile driving activities, pile driving will occur only during daytime hours.

Construction mitigation to wetland resources

To minimize and avoid impacts to aquatic resources, all in water construction will be scheduled to avoid impacts to fisheries during sensitive life periods. Dredging and pile driving activities will be conducted from the upland or a floating barge using a clamshell bucket dredge and vibrating hammer to minimize increased turbidity levels within the water column. Any temporary increases in turbidity within the water column will be limited by using a siltation curtain around all active dredge operations and pile driving activities.

To manage stormwater runoff and erosion and sedimentation within the Fore River Station site, the project will implement mitigation measures as discussed above.

Sithe will develop and implement a construction SWPPP that will include a commitment to conduct construction activities in accordance with appropriate Best Management Practices (BMPs) intended to prevent stormwater contamination.

All construction activities will be coordinated with the MWRA and the MHD.

Funding Responsibility

Sithe has committed to funding all of the mitigation measures discussed in these Section 61 findings.

Implementation Schedule (Construction)

A schedule for implementation of the mitigation measures associated with construction is included with this document as Attachment B.

Implementation Schedule (Operation)

A schedule for implementation of the mitigation measures associated with operation of the facility is included with this document as Attachment C.

SUMMARY SECTION 61 FINDINGS

Based upon the Environmental Impact Reports and the review of the record, the Department finds that the implementation of the requirements of its permits and the measures described above constitute all feasible measures to avoid damage to the environment and will minimize and mitigate damage to the environment to the maximum extent practicable, within the subject of the required permits.

ATTACHMENT A – TABLE OF MITIGATION MEASURES AND RESPONSIBILITY

EIR Category	Impact	Mitigation	Funding Responsibility	Timing
Air Quality	Construction air quality	Reduce construction dust by water sprays, street sweeping.	Sithe	Construction
	Operational air quality	Use of clean-burning natural gas as fuel.	Sithe	Operation
		Use of low sulfur distillate oil as a back-up fuel	Sithe	Operation
		Use of advanced combustion and pollution control technologies including dry low-NO_X combustors, SCR and oxidation catalysts that represent LAER and BACT.	Sithe	Operation
		Acquisition of offsets at 1.26:1 for VOC emissions	Sithe	Construction
Noise	Construction noise	Trucks accessing site must comply with federal regulations limiting noise from trucks.	Sithe	Construction
		Construction equipment sound muffling devices will be in	Sithe	Construction

EIR Category	Impact	Mitigation	Funding Responsibility	Timing
		good repair.		
		Pile driving will occur only during daytime. When practical, major construction activities will be limited to daytime.	Sithe	Construction
		Use of silent steam blows to clean piping.	Sithe	Construction
	Operational noise	Project engineering will incorporate best available noise control technology to ensure that the Project will not cause greater than 6 dBA (L_{90}) increase in noise at nearest residence.	Sithe	Operation
Visual	Visual Impact	The facility will be 102' high, compared with 174' maximum building height of Edgar Station.	Sithe	Operation
		Only one new stack shell rather than two separate new stacks will be constructed. Stack height will be 255 feet (one stack), compared with five (5) 250-foot stacks that served former Edgar Station	Sithe	Design
		Color scheme determined in consultation with Weymouth officials.	Sithe	Operation
Water Use and Quality	Impacts on Water Consumption	Dry low NOx combustors during natural gas operation. Recycle HRSG blowdown during normal operation. Recycle flash steam. Recycle steam and condensate system samples. Normally regenerate demineralizers offsite during oil firing and evaporative cooling	Sithe	Operation

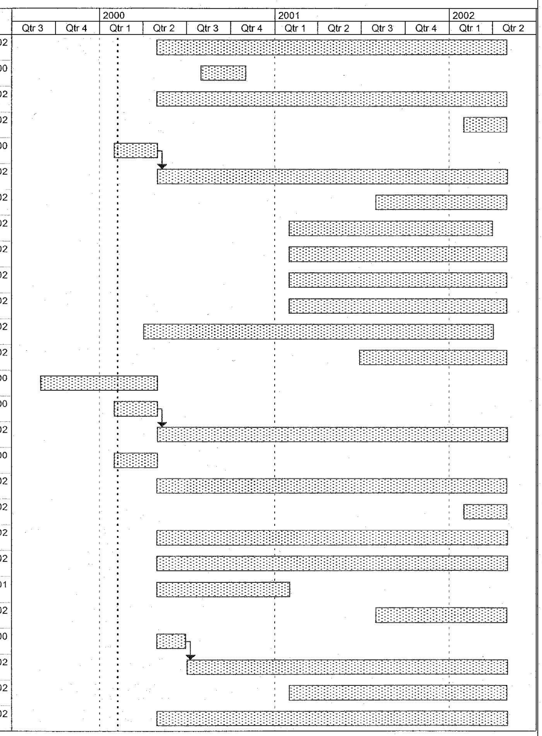
EIR Category	Impact	Mitigation	Funding Responsibility	Timing
		Use precoat condensate polishers. Recycle combustion turbine inlet evaporative cooler blowdown.		
	Wastewater generation	Use water conservation and recycling to minimize wastewater generation.	Sithe	Operation
	Wastewater discharge	Portions of wastewater will be treated and recycled as make-up to the raw water supply. Remaining wastewater will be discharged to municipal sewer system after proper treatment so that streams meet industrial pretreatment standards of the MWRA.	Sithe	Operation
		Fund removal by Weymouth of I/I at 7:1ratio	Sithe	Construction
		Provide secondary containment for all hazardous material storage areas and tanks.	Sithe	Operation
		Test water in containment areas prior to discharge to ensure discharge requirements are met.	Sithe	Operation
		Use treatment equipment to neutralize wastewater from demineralizer regeneration system and to separate oil in process area drains.	Sithe	Operation
Wetlands and Dredging	Potential impacts on wetland resources	Work within bank and 100-foot buffer zone will be performed according to Order of Conditions issued by Weymouth Conservation Commission.	Sithe	Construction
	Thermal impacts on	Utilize Air-cooled condenser	Sithe	Operation

EIR Category	Impact	Mitigation	Funding Responsibility	Timing
	Weymouth Fore River, entrainment and impingingement of fish	rather than once-through cooling		
	Impacts of dredging	Employ silt curtains and clamshell or hydraulic dredging. Fund shellfish seeding program. No dredging between 2/1 and 9/15.	Sithe	Construction
Stormwater	Stormwater runoff	After project completion, stormwater will be treated prior to discharge to the Weymouth Fore River in accordance with DEP Stormwater Management Guidelines.	Sithe	Operation
		Develop and implement SWPPP for construction.	Raytheon	Construction
		Develop and implement SWPPP for operation.	Sithe	Operation
Waterways, Tidelands and Public Access	Potential tidelands impacts	Provide public access areas as provided in Ch. 91 permit.	Sithe	Prior to construction
Hazardous Substances	Impacts of substances during construction	Remediate site contamination in accordance with the MCP.	Sithe	Prior to and during construction
		Prepare plan to address potential for construction worker exposure to hazardous substances at site.	Sithe	Construction
		Provide training and construction management oversight to ensure plan implementation.	Sithe	Construction
	Impacts of substances during operation	Hazardous substance storage vessels and areas will be equipped with secondary	Sithe	Operation

EIR Category	Impact	Mitigation	Funding Responsibility	Timing
		containment to prevent releases from spills.		
		Aqueous ammonia storage tanks will be contained with a double wall design in accordance with API specifications.	Sithe	Operation
		Emergency response procedures and an emergency response contractor will be in place.	Sithe	Operation
Cultural	Demolition of Edgar Station	Photo-recordation program. Lovell's Grove restoration. Gatehouse restoration, and illustrative brochure	Sithe	Construction and operation
Construction Management	Construction Activities	Erosion and sediment control devices and dust reducing measures will be in place to prevent effects on wetlands and waterbodies.	Raytheon	Construction
		Ensure contractor compliance with terms and conditions of environmental permits.	Sithe	Construction
Traffic	Traffic Impacts	Maintain right-in, right-out traffic access	Sithe	Construction
		Coordinate construction period traffic with MWRA and MHD	Sithe, MWRA, MHD	Construction

Attachment B: Implementation Schedule (Construction)

ID	Task Name	Duration	Start	Finish
1	Noise-Control Construction Equipment Noise	523 days	Mon 5/1/00	Wed 5/1/02
2	Noise-Conduct Time Limited Pile Driving	67 days	Tue 8/1/00	Wed 11/1/00
3	Noise-Limit Major Construction Activities To Daytime	523 days	Mon 5/1/00	Wed 5/1/02
4	Silent Steam Blows	64 days	Fri 2/1/02	Wed 5/1/02
5	Stormwater-Develop Construction SWPPP	65 days	Tue 2/1/00	Mon 5/1/00
6	Stormwater-Implement Construction SWPPP	523 days	Tue 5/2/00	Thu 5/2/02
7	Visual-Build Double Flue Stacks	196 days	Wed 8/1/01	Wed 5/1/02
8	Water Supply Conservation-Install Air Cooled Condensers	303 days	Thu 2/1/01	Mon 4/1/02
9	Water Supply Conservation-Install Dry Low Nox Combustors	325 days	Thu 2/1/01	Wed 5/1/02
10	Wastewater- Install Treatment System To Neutralize Wastewater from Demineralizer System	325 days	Thu 2/1/01	Wed 5/1/02
11	Wastewater-Install Oil/Water Separator(s) To Service Process Area Drains	325 days	Thu 2/1/01	Wed 5/1/02
12	Fund removal of I/I at 7:1	523 days	Mon 4/3/00	Wed 4/3/02
13	Soils-Install AST Secondary Containment	220 days	Thu 6/28/01	Wed 5/1/02
14	Soils-Conduct Remediation at Site In Accordance With MCP	174 days	Wed 9/1/99	Mon 5/1/00
15	Hazmat-Develop Hazardous Materials Response Plan	65 days	Tue 2/1/00	Mon 5/1/00
16	Hazmat-Implement Hazardous Materials Response Plan	523 days	Tue 5/2/00	Thu 5/2/02
17	Hazmat-Conduct Hazardous Materials Safety Training For Construction Workers	65 days	Tue 2/1/00	Mon 5/1/00
18	Hazmat-Assure Secondary Containment Of Construction Related Hazardous Materials	523 days	Mon 5/1/00	Wed 5/1/02
19	Hazmat-Install Double Walled Ammonia Tanks	64 days	Fri 2/1/02	Wed 5/1/02
20	Riverfront-Assure Compliance with Weymouth CC OOC	524 days	Mon 5/1/00	Thu 5/2/02
21	Riverfront-Conduct Dewatering in Compliance With Weymouth CC OOC.	524 days	Mon 5/1/00	Thu 5/2/02
22	Riverfront-Install Erosion Control Devices	199 days	Mon 5/1/00	Thu 2/1/01
23	Mitigate impacts of dredging and pier installation	196 days	Wed 8/1/01	Wed 5/1/02
24	Air-Install Dust Control Devices	44 days	Mon 5/1/00	Thu 6/29/00
25	Air-Implement Dust Control Measures (Water Sprays)	479 days	Mon 7/3/00	Thu 5/2/02
26	Cultural - provide historic mitigation	325 days	Thu 2/1/01	Wed 5/1/02
27	Implement Traffic Mitigation and Coordination with MWRA, MHD	524 days	Mon 5/1/00	Thu 5/2/02

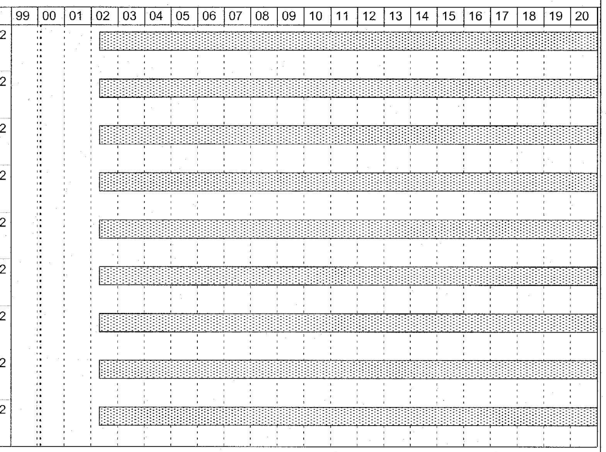


Fore River Station
Contruction Related Mitigation
Implementation Schedule

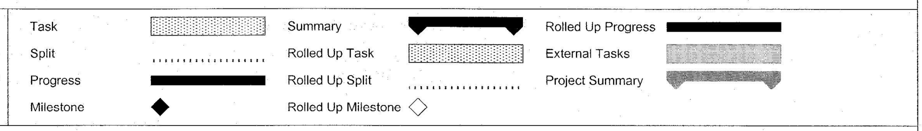
Task | Milestone | Rolled Up Split | External Tasks
Split | Summary | Rolled Up Milestone | Project Summary
Progress | Rolled Up Task | Rolled Up Progress

Attachment C: Implementation Schedule (Operation)

ID	Task Name	Duration	Start
1	Air-Fire ProjectWith Natural Gas, with very low sulfur distillate oil as secondary fuel	5218 days	Wed 5/1/02
2	Air-Operate Project With Dry Low-Nox/SCR/Oxidation Catalyst, with steam injection during oil firing	5218 days	Wed 5/1/02
3	Stormwater-Maintain Effective Stormwater Treatment per Stormwater Management Policy	5218 days	Wed 5/1/02
4	Stormwater-Develop and Comply With Operational SWPPP	5218 days	Wed 5/1/02
5	Wastewater-Reduce Generation Through Water Conservation	5218 days	Wed 5/1/02
6	Wastewater-Maintain Recycling Protocol and Infrastructure (Steam Blowdown)	5218 days	Wed 5/1/02
7	Wastewater-Maintain Monitoring Protocol and Treat as Needed	5218 days	Wed 5/1/02
8	Wastewater-Obtain the Services of a Contractor For Offsite Demineralizer Regeneration	5218 days	Wed 5/1/02
9	Hazmat-Retain Hazardous Materials Emerency Response Contractor	5218 days	Wed 5/1/02



Fore River Station
Operational Remediation
Implementation Schedule



Note: Finish dates noted on this chart are not intended to imply that operational remediation measures will be abandoned after twenty years. All operational remediation will remain in place through the life of the project.

XIX. ZERO AMMONIA TECHNOLOGY MEMORANDUM OF UNDERSTANDING

MEMORANDUM OF UNDERSTANDING BETWEEN THE DEPARTMENT OF ENVIRONMENTAL PROTECTION ("DEP") AND SITHE EDGAR DEVELOPMENT LLC ("SED") FORE RIVER STATION, WEYMOUTH, MASSACHUSETTS REGARDING ACHIEVING A ZERO EMISSION RATE FOR AMMONIA TR#W004896

The parties agree as follows:

1. DEP proposes to issue a draft air permit for the SED Power Plant in Weymouth, MA (the "Facility") that establishes an emission limit of 0 ppm of ammonia.

2. The permit will further provide that the Facility is approved to emit up to 2 ppm of ammonia, subject to optimization testing, for a period of not more than five years from the date of commencement of operations; provided that the 2 ppm ammonia emission standard will remain in effect after that anniversary unless DEP determines, in accordance with the process and criteria set out below, that there is a compatible zero ammonia air pollution control technology (ZAT) available to be installed at the Facility.

3. No later than four years after commencement of operations SED will commence and subsequently submit to the DEP an evaluation of available ZATs to determine if any such technology is compatible to be installed in the Facility. The evaluation should:

(a) review all ZATs that have been demonstrated to meet the Facility's final permit's NOx limit;

(b) provide facts and analysis regarding the extent to which each ZAT qualified under 3(a) meets the criteria set forth at 5 (a)-(d);

(c) incorporate the independent financial analysis set forth at 5(e) for each ZAT that meets the criteria set forth at 5(a)-(d); and

(d) compare the scope and extent of pollution reduction and prevention of each ZAT that meets the criteria set forth at 5 (a)-(e).

4. The parties anticipate that the evaluation should be submitted to DEP within 90 days of its commencement absent unavoidable delay. SED will supplement the evaluation upon DEP's request for reasonably available additional information or analysis. The fourth year anniversary date for commencing the evaluation was established based on the parties' assumption regarding the facility's major maintenance schedule. Upon agreement of the parties the commencement date may be modified.

5. A ZAT will be considered compatible if it meets the following criteria:

(a) The ZAT is commercially available for turbines 100 megawatts or larger.

(b) The ZAT meets all other emission and performance standards established by the permit(s) or such other enforceable emission limits in effect as of the ZAT installation date.

(c) The ZAT is guaranteed to perform with an equivalent or better level of reliability, availability and performance characteristics than was guaranteed for the technology installed at the commencement of operations, Selective Catalytic Reduction (SCR), provided that differences in emission rates will not be considered if the ZAT meets the criteria set forth in 5(b). A copy of the SCR guarantee will be provided to DEP.

(d) The installation, operation and maintenance of the proposed ZAT is consistent with the terms and conditions of the applicable state, town or federal permits or approvals, or other enforceable agreements between SED and a public entity in effect at the time the final permit is issued, that are necessary for the continued operation of the Facility, including but not limited to the City of Quincy's current limits on the Facility's consumption of water and generation of hazardous waste. If a permit, approval or agreement in effect when the evaluation is conducted may require modification to conform with a ZAT's requirements, SED shall use its best efforts to secure such modification unless it is reasonably likely that an appropriate modification could not be obtained. SED may consult with the Department prior to submission of the evaluation on the reasonable likelihood of obtaining a modification and SED's intended course of action.

(e) The installation, operation and maintenance of the ZAT are determined to be comparable to the cost of continued operation and maintenance of the SCR. The costs will be considered comparable if the cost for ZAT is not more than 5% greater than the cost for SCR. An independent third party expert jointly selected by the parties will make the determination of cost comparability in accordance with the general principles and methodology agreed to by the parties and attached hereto. The expert will be retained by SED but will be jointly managed by and be equally independent from both parties. Both parties agree to accept the cost comparability determination of the independent expert.

6. In the event that more than one ZAT meets the criteria set forth in paragraph 5, the technology that achieves the greatest degree of pollution reduction and prevention will be the preferred ZAT selected for installation.

7. The evaluation shall not consider the revision of any final permit emission standards other than ammonia except to the extent that performance of the preferred ZAT reduces other than non-ammonia emissions.

8. The DEP shall determine in accordance with the criteria set forth above whether the evaluation demonstrates that no ZAT is compatible. The written determination will set forth the facts and analysis upon which DEP based the determination. If DEP determines that the

evaluation did not adequately demonstrate that a compatible ZAT is not available, the provisions allowing for a 2 ppm ammonia emission rate will be void and a 0 ammonia emission rate shall become the enforceable permit limit effective on the fifth anniversary of the commencement of Facility's operations date, or within a reasonable period agreed to by the parties and consistent with the Consultant's Analysis, not to exceed 180 days from the final determination, whichever is later. The effective date may be extended by the Department to allow for unanticipated delays in the installation or testing of the selected ZAT.

9. The Department shall prepare a draft compatibility determination, which shall be made available for comment. SED shall have a right to appeal DEP's final compatibility determination pursuant to M.G.L, c. 30A, s. 11. Pending the resolution of an appeal the facility will be permitted to continue to emit 2 ppm of ammonia or such other rate established through optimization testing as provided for in the final permit.

10. Notwithstanding any provision herein, SED may at any time voluntarily install a ZAT in accordance with the provisions of DEP's regulations and the final permit.

11. This Memorandum of Understanding, or applicable provisions thereof, will be incorporated in the Facility's draft and final air permit.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

By: ____
Date:

SITHE EDGAR DEVELOPMENT LLC

By: ____
Date:

PRINCIPLES AND METHODOLOGY FOR DETERMINATION OF COST COMPARABILITY OF NOx REDUCTION TECHNOLOGY

SITHE EDGAR DEVELOPMENT LLC ("SED") and the Massachusetts Department of Environmental Protection ("DEP") have agreed that an independent third party expert jointly selected by SED and DEP and retained by SED will perform an analysis (the "Analysis") of the cost comparability of NOx reduction technologies and will abide by the results of the analysis. DEP will approve the installation of selective catalytic reduction ("SCR") in the SED Weymouth facility (the "Facility") for the commencement of operations. Four years from the commencement of operation of the Facility, a study will be performed to determine whether an available zero ammonia technology ("ZAT") should be installed in the facility as an alternative NOx technology. A portion of that study is a comparison of the costs of continuing to maintain and operate the SCR system to the costs of installing and operating a ZAT system. ZAT shall include SCONOx and any other technology that provides NOx reduction equal to or better than the 2.0 ppm emissions limitation in the plan approval for the facility with no use of ammonia.

1. Consultant. A consultant ("the Consultant") shall be hired to perform an independent financial Analysis comparing the life cycle cost of certain NOx reduction technologies.

2. Time of Performance. The Analysis shall commence four years from the commencement of operation at the Facility and be completed within 90 days, unless extended by SED and DEP. Such extension shall not be unreasonably denied should delays occur that are beyond the control of the Consultant.

3. Technologies to be Analyzed. The Consultant shall analyze SCR which shall be installed and operated in the Facility for the commencement of operations and any ZAT designated by SED and DEP and which SED and DEP agree is available, including, but not limited to SCONOx.

4. Qualifications of the Consultant. The Consultant and its personnel performing the Analysis shall be independent, as defined below, regularly engaged in the business of valuing technology and specifically qualified with respect to:

   (a) demonstrated experience valuing and comparing the relative costs of alternative technologies;
   (b) familiarity with applicable environmental laws and regulations as well as regulatory processes;
   (c) experience with pertinent engineering and construction cost categories; and
   (d) experience with valuing fixed assets for sale or liquidation useful to determining salvage value.

5. Independence of the Consultant. The Consultant shall not be an affiliate of SED or any of its affiliates. Partners, principals and employees of the Consultant who shall work on this engagement shall have no current or contemplated future financial interest in SED. The Consultant's professionals performing the Analysis shall not be working on any DEP project

involving this analysis at the time of engagement. The Consultant shall not earn a contingent fee for performing the scope of work described herein. The Consultant shall not be engaged in the production, sale or installation of the pollution control technologies or have any current or contemplated financial interest in any of the technologies being analyzed.

6. Scope of Work. The Analysis will evaluate and compare the costs of maintaining and operating the SCR equipment installed in the Facility to the costs of installing, maintaining and operating ZATs.

7. Basis of Comparison and Analysis. The Consultant shall prepare the Analysis by comparing the present value of future cash costs directly attributable to the installed SCR and ZATs mutually agreed upon by SEP and DEP. The Consultant shall include all relevant cash costs in its Analysis of the NOx reduction technologies. All costs related to the installation, operation and maintenance of the technologies from the date of the Analysis through the remaining life of the facility will be considered, including but not be limited to: construction planning, design, permitting and execution; process engineering, labor, materials and equipment associated with installation and retrofit activities; plant sequencing, phasing and shut down requirements; lost business and opportunity costs; repair and maintenance; insurance; federal, state and local taxes; performance indemnification; salvage value of SCR; sale of by-products; ammonia delivery, injection, and storage systems; costs of material necessary for operation, including but not limited to ammonia; testing specifically related to the operation of either technology; and disposal cost of by-products. If the Consultant is unable to establish a single cost for a whole or part of the cost analysis and instead provides a cost range, then the cost selected for comparison will be the most likely within the range; provided that if there is no cost that is the most likely cost the mid point of the range will be used as the cost basis. In determining the allocation of costs to either technology, the Consultant shall assume that SED will take all reasonable steps to incur and allocate costs to minimize the cost of ZAT installation.

   The Consultant shall submit a draft list of the specific cost categories and other considerations and assumptions to SED and DEP for comment prior to commencing the Analysis.

   The Analysis shall be carried out over a period of time the Consultant considers appropriate, but not less than fifteen years as the remaining life of the Facility. The Consultant shall estimate a discount rate to evaluate the technologies, after consultation with SED and DEP and obtaining other sources of information it deems appropriate, that consistently reflects the business and financial risks of the Facility. Other considerations or assumptions that may be addressed in the Analyses include, but are not limited to, comparable scale and timing of installation.

   The Analysis shall state the Consultant's conclusion with respect to the relative cost of the SCR system and the ZAT. The report of the Analysis shall make the relevant costs easy to understand and will clearly distinguish factual assumptions from judgment. The Report of the Analysis shall be made available to SED and DEP at the same time.

8. Matters to be Relied upon and Management's Responsibility. The Consultant shall rely upon information provided by SED which SED will represent is accurate to the best of its knowledge and not in conflict with other information known to it. SED shall state this understanding in a representation letter to be dated the last day of the Consultant's work on the Analysis and prior to the issuance of the Consultant's report. Items which the Consultant may rely upon as accurate will include, but may not be limited to: information obtained from interviews with management; plant financials and operating records; technology performance documents or assessments; power purchase agreements; other material contracts; and fixed asset records.

   The Consultant shall require representations, including performance representations from SED or from suppliers of the ZATs being analyzed. Further, once requested by the Consultant, SED shall provide the Consultant the information and documents that the Consultant deems necessary to complete the analysis within a reasonable period of time. The Consultant also retains the right to request and require additional information that it deems appropriate. SED agrees such information shall not be unreasonably withheld.

9. Budget. The consultant's fees will be based on hours spent by staff at their standard hourly rates, subject to a mutually agreed upon not-to-exceed budget, plus out-of-pocket expenses for travel, lodging, subsistence and an allocation of office charges in support of services including computer usage, telephone, facsimile transmission, postage, photo-reproduction and similar expenses.

LIST OF PERTINENT INFORMATION FOR TRANSMITTAL W004896

Name of Facility:	Fore River Station Project
Location:	1 Bridge Street, Weymouth, Massachusetts 02188
Submitted By:	Epsilon Associates, Inc.
Attested To By:	Dale T. Raczynski, P.E. Number 36207
Design Data Sheets:	Air Plan Approval Application Date Received: July 23, 1999 Response to Request for Additional Information Dates Received: July 30, 1999 to February 1999
Plans:	Raytheon Engineers and Constructors Site Plan Drawing No: 42715.081B-SK2000 Elevation Looking North Drawing No: 42715.081B-SK2002 Elevation Looking East Drawing No: 42715.081B-SK2003 SCR Flow and Instrumentation Control Drawing No.: AIG-1 P&ID HRSG Systems Exhaust Gas Drawing No.: MD73041

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John Winkler, DEP/SERO
Craig Goff, DEP/WERO
Thomas Cusson, DEP/CERO
John Kronopolus, DEP/CERO
Bill DiLibero, DEP/CERO (for DEP website)

Exhibit 27

Section II: Non-AQMD LAER/BACT Determinations

Application No.: MBR-99-COM-012

Equipment Category – Gas Turbine

1. GENERAL INFORMATION

DATE: 4/12/2000

A.	MANUFACTURER: Mitsubishi Heavy Industries (MHI)		
B.	TYPE: combustion turbine generators	C.	MODEL: 501G
D.	STYLE:		
E.	APPLICABLE AQMD REGULATION XI RULES:		
F.	COST: $ ( )		SOURCE OF COST DATA:
G.	OPERATING SCHEDULE: 24 HRS/DAY	7 DAYS/WK	52 WKS/YR

2. EQUIPMENT INFORMATION

APP. NO.: MBR-99-COM-012

A. FUNCTION: The new combined cycle electric generating facility will consist of two main power blocks each generating 775 MW of electric power. Each power block consists of two combustion turbine generators (CTG), two heat recovery steam generators (HRSG), and one steam turbine generator (STG). Each CTG will have a nominal generating capacity of 250 MW. Each STG will have a nominal generating capacity of 275 MW

B.	MAXIMUM HEAT INPUT: MHI 501G gas turbine = 2,676 MMbtu/hour at -12 degrees F ambient (each) Supplementary fired HRSG = 279 MMbtu/hour at -12 degrees F ambient (each)	C.	MAXIMUM THROUGHPUT:
D.	BURNER INFORMATION: NO.:		TYPE: dry low-NOx combustors
E.	PRIMARY FUEL: natural gas	F.	OTHER FUEL: NONE
G.	OPERATING CONDITIONS:		

3. COMPANY INFORMATION

APP. NO.: MBR-99-COM-012

A.	NAME: Sithe Mystic Development LLC		
B.	ADDRESS: 39 Rover Street CITY: Everett	STATE: MA	ZIP: 02129
C.	CONTACT PERSON: James McGowan	D.	PHONE NO.:

4. PERMIT INFORMATION

APP. NO.: MBR-99-COM-012

A.	AGENCY: `Massachusetts Department of Environmental Protection'	B.	APPLICATION TYPE: new construction
C.	AGENCY CONTACT PERSON: Cosmo Buttaro	D.	PHONE NO.: (978) 661-7668

4. PERMIT INFORMATION

APP. NO.: MBR-99-COM-012

E. PERMIT TO CONSTRUCT INFORMATION: P/C NO.: MBR-99-COM-012 ISSUANCE DATE: 1/25/2000

☐ CHECK IF NO P/C

F. START-UP DATE: early 2002

G. PERMIT TO OPERATE INFORMATION: P/O NO.: ISSUANCE DATE:

5. EMISSION INFORMATION

APP. NO.: MBR-99-COM-012

A. PERMIT

A1. PERMIT LIMIT:

Short term emission limits for the gas turbines:
NOx =< 21.7 lbs/hr, 0.0074 lbs/MMbtu, 2.0 ppmvd @ 15% O2

CO =< 13.2 lbs/hr, 0.0045 lbs/MMbtu, 2.0 ppmvd @ 15% O2

VOC (unfired) =< 3.8 lbs/hr, 0.0013 lbs/MMbtu, 1.0 ppmvd as methane@ 15% O2

VOC (duct fired) =< 6.4 lbs/hr, 0.0022 lbs/MMbtu, 1.7 ppmvd as methane@ 15% O2

SO2 =< 8.6 lbs/hr, 0.0029 lbs/MMbtu

PM/PM10 =< 32.5 lbs/hr, 0.011 lbs/MMbtu

NH3 =< 8.0 lbs/hr, 0.0027 lbs/MMbtu, 2.0 ppmvd @ 15% O2

Notes:

1. Emission limits are one-hour block averages and do not apply during start-up/shutdown and equipment cleaning. Start-ups shall not last longer than 3 hours.

2. The Massachusetts Department of Environmental Protection and the applicant have entered into a memorandom of understanding (MOU) concerning the use of zero ammonia technology (ZAT) for the control of nitrogen oxides. For the first five years of operation of the facility, there shall be an interim emission rate for ammonia of 2.0 ppmvd @ 15% O2 one-hour block average. Pursuant to the MOU, the emission rate for ammonia after the first five years of operation shall be zero unless the interim 2.0 ppmvd ammonia limit is extended by the Department. During the five year period it will be determined whether a ZAT must be installed at the facility. The determination will be based on the availability, reliability, and comparable costs of the zero ammonia technologies. The MOU provides the methodology for making the determination.

A2. BACT/LAER DETERMINATION: LAER is required for the VOC emissions and BACT is required for the NOx emissions. For this application (for NOx emissions), LAER and BACT requirements are the same. The above permit limits for VOC and NOx comply with LAER and BACT requirements, respectively. The other criteria air pollutants are subject to PSD review.

B. CONTROL TECHNOLOGY

B1. MANUFACTURER/SUPPLIER: To be determined

B2. TYPE: Selective Catalytic Reduction and Oxidation Catalyst

B3. DESCRIPTION:

5. EMISSION INFORMATION

APP. NO.: MBR-99-COM-012

B4.	CONTROL EQUIPMENT PERMIT APPLICATION DATA:	P/C NO.: P/O NO.:	ISSUANCE DATE: ISSUANCE DATE:
B5.	WASTE AIR FLOW TO CONTROL EQUIPMENT: ACTUAL CONTAMINANT LOADING:	FLOW RATE: BLOWER HP: HP	
B6.	WARRANTY:		
B7.	PRIMARY POLLUTANTS: NOx, CO, VOC, PM10, SOx		
B8.	SECONDARY POLLUTANTS: ammonia (particulate precursor)		
B9.	SPACE REQUIREMENT:		
B10.	LIMITATIONS:		
B11.	LOCATION OF PRIOR DEMONSTRATION & AGENCY: FACILITY: Sunlaw Cogeneration Partners I Federal Cold Storage Cogeneration Facility CONTACT PERSON: Ted Guth AGENCY: SCAQMD ADDRESS: 21865 E. Copley Drive CONTACT PERSON: Chris Perri	PHONE NO.: (619) 670-3157 PHONE NO.: (909) 396-2696	
B12.	OPERATING HISTORY:		
B13.	SOURCE TEST/PERFORMANCE DATA ANALYSIS: DATE OF SOURCE TEST: DESTRUCTION EFFICIENCY: PERFORMANCE DATA:	CAPTURE EFFICIENCY: OVERALL EFFICEINCY:	
B14.	SOURCE TEST CONDITIONS/PERFORMANCE DATA: The applicant will conduct initial compliance tests (for NOx, CO, VOC, NH3, and PM10/opacity) within 180 days after initial start up of the proposed facility. Testing will be conducted at four representative steady state loads (but not less than 75% of rated base load), except for PM10 which will be tested at 100% of rated base load only.		

C. COST

C1.	CONTROL EQUIPMENT COST: CAPITAL: $	☐ CHECK IF INSTALLATION COST IS INCLUDED IN CAPITAL COST INSTALLATION: $ (1999)	SOURCE OF COST DATA:
C2.	ANNUAL OPERATIONAL/MAINTENANCE COST:	$ (1999)	SOURCE OF COST DATA:

D. DEMONSTRATION OF COMPLIANCE

D1.	STAFF PERMFORMING FIELD EVALUATION: ENGINEER'S NAME:	INSPECTOR'S NAME:	DATE:
D2.	COMPLIANCE DEMONSTRATION:		
D3.	VARIANCE: CAUSES:	NO. OF VARIANCES:	DATES:
D4.	VIOLATION: CAUSES:	NO. OF VIOLATIONS:	DATES:
D5.	FREQUENCY OF MAINTENANCE:		

6. COMMENTS

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The applicant will install, calibrate, test and operate a data acquisition and handling system, a CEMS, and a COMS to measure and record the opacity and the NOx, CO, NH3, and O2 emissions from the facility. The applicant will ensure continuous monitoring and compliance with PM/PM10 limits using the parametric monitoring methodology developed during the initial compliance test. Detailed record keeping and reporting requirements are included in the permit.

EARTHJUSTICE

BOZEMAN, MONTANA DENVER, COLORADO HONOLULU, HAWAII
INTERNATIONAL JUNEAU, ALASKA NEW YORK, NEW YORK OAKLAND, CALIFORNIA
SEATTLE, WASHINGTON TALLAHASSEE, FLORIDA WASHINGTON, D.C.

January 22, 2009

VIA U.S. AND ELECTRONIC MAIL

Weyman Lee
Senior Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109
weyman@baaqmd.gov

Re: Draft Amended PSD Permit for Russell City Energy Center

Dear Mr. Lee:

This letter is submitted on behalf of Citizens Against Pollution to urge you not to approve the draft prevention of significant deterioration ("PSD") permit as proposed for the Russell City Energy Center. The draft permit fails to meet federal PSD requirements relating to the need for best available control technology ("BACT") and the prevention of air quality impacts that will cause or contribute to violations of the national ambient air quality standards ("NAAQS"). In particular, while we applaud the District and the project applicant for the decision to include for the first time a limit on emissions of carbon dioxide (CO2), the limit selected and the analysis supporting that limit are defective. Because the control of CO2 emissions in a PSD permit is new and precedent-setting, it is all the more important that the standard-setting exercise be done correctly.

Determination of Carbon Monoxide (CO) BACT Limit

The District concludes that "the lowest [CO] emissions that these turbines can reasonably achieve using good combustion practices with an oxidation catalyst is 4.0 [parts per million (ppm)] @ 15% 02 (3-hour average)." Statement of Basis for Draft Amended Federal "Prevention of Significant Deterioration" Permit at 35 (Dec. 8, 2008) (hereinafter "Statement of Basis"). This conclusion, however, is not supported by the evidence provided by the District.

The District identifies numerous facilities that have CO limits of less than 4.0 ppm even with NOx limits of 2.0 ppm. *See* Statement of Basis at 33-34 (Table 11). The relevant sources are reproduced below:

Facility	NOx Limit (ppmvd @ 15% O2)	CO Limit (ppmvd @ 15% O2)	Operational Status
ANP Blackstone, MA-0024	2 (1-hr) No steam 3.5 (1-hr) Steam Inj.	3.0 (1-hr)	In Operation
Goldendale Energy	2 (3-hr)	2 (1-hr)	In Operation
Magnolia, SCAQMD	2 (3-hr)	2 (1-hr)	In Operation
Sierra Pacific Power Co. Tracy Station, NV-0035	2 (3-hr)	3.5 (3-hr)	Unknown
Welton Mohawk, AZ-0047	2 (3-hr)	3 (3-hr)	Unknown
Colusa Generating Station	2 (1-hr)	3 (3-hr)	Not built
Turner Energy Center, OR-0046	2.0 (1-hr)	2.0 (3-hr) > 70% load 3.0 (3-hr) < 70% load	Not built
Wanapa Energy Center, OR-0041	2.0 (3-hr)	2.0 (3-hr)	Not built
Morro Bay – Duke	2.0 (1-hr)	2.0 (3-hr)	Not built
Sumas Energy 2, WA-0315	2 (3-hr)	2 (1-hr)	Not built
IDC Bellingham, MA	1.5 (1-hr)	2 (1-hr)	Not built
CPV Warren, VA-0308	2 (1-hr)	1.2 to 2.5 (3-hr)	Not built

The District's first argument for refusing to set a lower CO limit conforming with the limits set for these other sources is that there is a tradeoff between NOx and CO performance, and the NOx limits set for these other permits are less stringent than the 1-hour average limit of 2.0 ppm proposed for the Russell City Energy Center. Statement of Basis at 34-35. The first problem with the District's claim is that there is no record basis for the asserted need to tradeoff CO stringency for NOx stringency. While we recognize the theoretical relationship between NOx and CO performance, the record shows that there is no unavoidable need to sacrifice CO stringency in exchange for protective NOx controls. To the contrary, the District's table shows that lower and lower CO limits have been imposed without any relaxation in the stringency of the NOx limits.

Second, the District's argument, even if true, does not support the decision to adopt a CO limit of 4.0 ppm. The District claims that meeting the proposed 2.0 ppm 1-hour NOx limit will make achieving a 2 ppm CO limit "much more difficult" but does not claim or offer any analysis to support a claim that such a limit is infeasible or not cost-effective. Nor is there any analysis of limits between 2.0 and 4.0 ppm.

Several sources have limits of 2 ppm for NOx (albeit with 3-hour averages) and 2 ppm for CO (*e.g.*, Goldendale, Magnolia, Wanapa, and Sumas Energy). The District offers no basis for its assertion that if the NOx limits for these identified sources were tightened from 3-hour averages to 1-hour averages, that the CO emission limits would need to be raised from 2 ppm all the way to 4 ppm. In particular, for Goldendale and Magnolia, which are already in operation, the District focuses on the NOx averaging period, but seems to ignore the fact that the CO averaging period is much more stringent than the period proposed for Russell City. Similarly, the ANP Blackstone facility, which is also in operation, must meet a 1-hour NOx limit of 2.0 ppm along with a *1-hour* CO limit of 3.0 ppm. In order to determine what limits are feasible, the District should look at the 3-hour average CO concentrations achieved by these operating sources during periods where 1-hour NOx averages are below 2.0 ppm.

The District's second argument for refusing to set a lower CO limit is that a lower limit cannot be consistently achieved at low loads and under rapidly changing load conditions. Again the District's analysis does not support the selected limit. The data collected by the District show that the less protective limit of 4.0 ppm is only appropriate for periods of low load. During normal, full-load periods, the Metcalf data reported by the District, Statement of Basis at 32-33, as well as notes from the ANP Blackstone permit (attached hereto as Exhibit A), show that limits of 2.0 ppm can be achieved. The solution, therefore, is not to default to the lowest common denominator in setting the BACT limit, but to set separate limits for normal and low-load condition. As shown in the table above, this was the approach taken in ANP Blackstone and Turner Energy Center. For the same reasons that separate limits are established for periods of startup and shutdown, separate limits are appropriate to ensure that BACT is achieved during all operating conditions. The District admits that the proposed limit is set based on emissions expected "under some conditions." Statement of Basis at 35. This is not the proper way to establish a BACT limit. The proposed 4.0 ppm limit for CO does not represent BACT during normal load operations. If the District believes that the limit for normal operations is not appropriate for "some conditions" then the District should analyze what the appropriate limit or averaging time should be for those conditions and set a separate limit accordingly.

We question, however, the District's unsupported assertion that the load changing characteristics of the proposed Russell City project preclude achieving a lower CO limit. The recently proposed Carlsbad Energy Center project is a *retrofit* of a peaking energy power plant (i.e., more dramatic changes in load than a baseload plant). Carlsbad Energy Center will meet a 2.0 ppm (1-hour average) NOx limit while also meeting a 2.0 ppm (1-hour average) CO limit. *See* Preliminary Staff Assessment, Carlsbad Energy Center Project (07-AFC-6) (CEC-700-2008-014-PSA), at 4.1-70 (Dec. 11, 2008). As recommended above, to address the challenges of shifting loads, the proposed Carlsbad permit includes a 3-hour averaging period to meet the 2.0 ppm limit during any transient hour. *See id*.

It is clear that the 4.0 ppm limit proposed for Russell City is outdated and no longer supportable. The District must revise the BACT limit for CO for normal operations to at least 2.0 ppm (1-hour average) to comport with current permitting levels. To the extent a separate limit is needed for other operating conditions, the District must define those conditions and justify the BACT limit selected.

Determination of BACT Limit for Carbon Dioxide (CO2)

At the outset, we want to commend the District and the applicant for acknowledging the need to set a limit for emissions of CO2. Notwithstanding EPA's recent illegal attempt to change its interpretation of existing law,[1] CO2 is a pollutant "subject to regulation" under the Clean Air Act and, as a result, must be controlled using the best available control technology. Unfortunately, the District has failed to conduct a proper BACT analysis for CO2 and has proposed a limit that has no legitimate technical basis. Given the importance of this precedent-setting decision, we urge the District to redo the analysis and give it the proper attention that it deserves.

The first failure in the BACT analysis is the refusal to look at the full range of alternatives to reduce CO2 emissions from the proposed project. These should have included energy production alternatives that do not rely on fossil fuel combustion,[2] hybrid technologies that combine energy sources to improve the overall carbon efficiency of the power plant,[3] requiring co-generation with the project, and changes to the project design that would lower total carbon emissions (e.g., elimination of supplemental duct burners for the heat recovery steam generators, or replacement of those burners with a more efficient microturbine or solar energy collection system[4]). The District's analysis instead focuses primarily on turbine efficiency, but even then seeks to justify a standard that can be met by the old turbines that the applicant has already purchased[5] rather than truly exploring what level of emissions can be achieved using best available technologies.

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[1] We have attached for the record, the petition for reconsideration filed by the Sierra Club, Natural Resources Defense Council and others (Ex. B, hereto) outlining the legal defects with EPA's December 31, 2008 "Interpretation of Regulations That Determine Pollutants Covered by the Federal PSD Permit Program." Should the District decide that a BACT limit for CO2 is not required by the Clean Air Act based on EPA's announcement, we incorporate by reference the legal analysis in the petition for reconsideration explaining why EPA's final action is illegal.

[2] We note that an analysis of non-fossil fuel alternatives is consistent with other State initiatives such as the Air Resources Board's Scoping Plan under the Global Warming Solutions Act (AB32), which calls for the adoption of a 33 percent renewable performance standard (RPS) to be achieved by 2020. *See* http://www.arb.ca.gov/cc/scopingplan/document/psp.pdf. The California Public Utilities Commission has concluded, "if the State is required to generate 33% of its energy from renewable resources by 2020, then all new procurement of new energy resources between now and 2020 must be entirely renewable energy . . . ." CPUC, Renewables Portfolio Standard Quarterly Report, at 10 (Oct. 2008).

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

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

[5] *See* Statement of Basis at 41 n.31 (rejecting use of Fast Start Technology because applicant has already purchased its equipment). *See also* E-mail from Brian Lusher, Air Quality Engineer, BAAQMD, to Weyman Lee, Senior Air Quality Engineer, BAAQMD (Sept. 10, 2008) (noting "the project owner purchased the combustion turbines and steam turbine generator [in 2001]") (attached hereto as Ex. C).

In exploring the efficiency of available turbine technologies, the District relies on the outdated 2002 analysis prepared by the CEC which looked at three turbines and found efficiencies between 55.8 and 56.5 percent. *See* Statement of Basis at 64 n.66. The District notes that the CEC conducted a subsequent project review in 2007 and concluded that the proposed changes to the Russell City plant would not change any of the original conclusion. To the extent the District is trying to suggest that the 2002 review of turbine efficiencies remains valid, that claim is plainly false. The CEC did not review the whether turbine efficiencies had improved over the ensuing 5 years, but instead only looked at whether the amendments to the proposed project would alter the efficiency of the project. *See* Staff Assessment – Part 1 and Part 2 Combined, Amendment No. 1 (01-AFC-7C) at 5.3-1 (June 2007) (CEC-700-2007-005-FSA). Had the District properly conducted a review of current turbine efficiency it would have discovered that efficiencies have significantly improved with newer technology. Of particular note is General Electric's H system turbines, which can reportedly achieve greater than 60 percent efficiency. *See* www.gepower.com/prod_serv/products/gas_turbines_cc/h_system/index.htm. These turbines have been in operation in Balgan Bay, Wales since 2003 and at the Tokyo Electric Power Company's Futtsu Thermal Power Station in Japan since 2007. *See* Ex. D. These turbines have also been proposed for use at the Inland Empire Energy Center here in California. *Id.*[6]

Moreover, even using the outdated efficiency data collected by CEC in 2002, it is clear on the face of the record that the turbines proposed for use at Russell City do not represent the best available control technology. The CEC found that efficiencies of new turbine technologies available in 2002 ranged from 55.8 to 56.5 percent. The turbines that the applicant has already purchased are at the bottom end of this efficiency range but the District makes not attempt to explain why more efficient turbines could not have been required as BACT. *See* Statement of Basis at 64.

The next step in the District's analysis is completely disconnected from the initial review of turbine efficiency. The District says it looked at CO2 emissions levels from existing sources "[t]o determine an appropriate CO2 emissions limitation achievable for this level of energy-efficient technology . . . ." Statement of Basis at 64. The District points to undocumented "information" from the CEC showing 2004 and 2005 emissions from baseload combined-cycle gas turbine plants ranged from 794 to 1058 lb/MW-hr.[7] The District provides no analysis relating this emissions data to the efficiency of the turbines. We presume the upper end of the emissions range reflects the emission rates of older, less efficient turbines and is not relevant for determining the CO2 emission level that should be achievable with modern, efficient turbine technology.

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

[7] These emission data appear to be the same as that described by the California Public Utilities Commission in its SB1368 proceeding. As will be discussed below, the range of reported emissions includes "outlier" sources that do not reflect best available turbine technology and include the effects of unfavorable operating environments such as high altitudes. The blind application of this data is not appropriate for determining CO2 BACT for the Russell City project.

The two specific examples the District actually provides – Delta Energy Center and the Metcalf Energy Center – both use the Siemens-Westinghouse 501F turbines proposed for Russell City. *See* Final Staff Assessment (Part 1 of 2), Delta Energy Center, Application for Certification (98-AFC-3) at 339 (Sept. 10, 1999); Commission Decision, Metcalf Energy Center, Application for Certification (99-AFC-3) at 68 (September 2001) (P800-01-023). The 2006 emissions data for these facilities show that even the older models of these turbines can achieve emissions well below the upper end of the range provided for all turbines (i.e., 855 lb/MW-hr for Delta Energy Center and 912 lb/MW-hr, for Metcalf Energy Center). The District, however, makes no attempt to review which turbines were able to achieve even lower emission levels as reported by the CEC or to explore what emissions levels could be achieved by more efficient available turbines. The District is assuming that the turbine technology for Russell City is fixed because the applicant has already purchased the turbines. This is not the proper way to conduct a BACT analysis.

The analysis of emissions levels should also include a review of permitting decisions for new sources as well. For example, the Carlsbad Energy Project, which is a retrofit of a peaking power plant (i.e., presumably less efficient than a new baseload plant), will emit 891 lb Co2/MW-hr (.405 mt CO2/MW-hr). *See* Preliminary Staff Assessment, Carlsbad Energy Center Project (07-AFC-6) (CEC-700-2008-014-PSA) at 4.1-102 (Dec. 11, 2008). The limited, undifferentiated emissions data that the District uses simply cannot form the basis for identifying *best* performance levels.

After identifying a range of emission levels, the District next asserts without any basis that in order to ensure compliance under all foreseeable operating conditions, "[b]ased on available data the Air District has reviewed for similar sources, and incorporating a reasonable compliance margin," BACT for CO2 is 1100 lb/MW-hr, which conveniently happens to be the maximum level of CO2 emissions allowed for such sources in the State of California. Statement of Basis at 65. This attempt to throw everything into the hat and magically pull out the California emission performance standard as BACT is not a technically defensible BACT determination.

First, as noted above, the available emissions data do not support the conclusion that even the outdated technology proposed for Russell City could emit up to 1100 lb CO2/MW-hr. In fact, a review of the California Public Utilities Commission proceeding on SB1368, where the 1100 lb CO2/MW-hr emission performance standard was developed makes clear that this level of emissions does not reflect the limit of what is achievable by new combined-cycle gas turbines in the State, but instead is what is achievable by most existing units, including "outliers" such as units using dry cooling technologies, or that are sited in less favorable locations such as deserts or at high altitude. *See In re Order Instituting Rulemaking to Implement the Commission's Procurement Incentive Framework for Greenhouse Gas Emissions Standards into Procurement Policies*, Cal. Pub. Util. Comm'n, Interim Opinion on Phase 1 Issues: Greenhouse Gas Emissions Performance Standards, R.06-04-009, Decision 07-01-039, at 64-69 (Jan 25, 2007). This limit represents the *minimum* carbon efficiency of these plants, not the maximum degree of emission reductions achievable.

The District's "reasonable compliance margin" is entirely arbitrary. Not only does the District fail to provide any data to support the need, let alone magnitude of such a margin, it never even explains what the margin is (i.e., what is the baseline emissions level and what is the margin added to it). A "reasonable compliance margin" can only be established in reference to the testing protocols used to measure the similar sources. That is, the District must explain (a) what test methods were used to test the other sources used to establish the limit, (b) what the reliability was for those test methods, and (c) why it is reasonable to assume from the tests that the emissions at those plants in reality vary to the degree claimed. Based on the 2006 data from Delta and Metcalf Energy Centers, the proposed limit suggests that actual CO2 emissions from those facilities may be 30 percent higher than reported levels. This seems highly doubtful and certainly is not a reasonable assumption with no underlying support.

The District attempts to build an argument based on opinions by the Environmental Appeals Board that limits must be set to ensure compliance under all foreseeable operating conditions. Statement of Basis at 65. The District, however, never explains what those foreseeable operating conditions might be and how they will affect CO2 emission levels. Moreover, even if there are such conditions, the appropriate response is to set different limits that assure best controls under all such conditions. Just as a permit could not use startup, shutdown and malfunction conditions to dictate the limit for all operating conditions, so the District cannot claim that the BACT limit must be set at the lowest common denominator of performance.

The arbitrariness of the District's BACT limit is highlighted in the final step of the analysis. The District uses the 1100 lb CO2/MW-hr emissions rate and the carbon content of natural gas to calculate the maximum hourly heat input that would be allowed to ensure the CO2 emissions rate is met. Statement of Basis at 65. The result of this calculation is 2944.3 mmBtu/hr for each turbine/heat recovery steam generator train. *Id.* This number is over 35 percent higher than the baseline maximum heat input of 2168 mmBtu/hr assumed for each power block! *See id.* at 84. Presumably because the District recognized the absurdity of setting a heat input limit higher than the uncontrolled maximum levels assumed for the project (though the District does not explain itself), the District set the actual heat input limit at 2238.6 mmBtu/hr. *Id.* at 65. This limit is still higher than the uncontrolled baseline assumptions on heat input. What this limit means is that the sources can be even less efficient than the already mediocre 55.8 percent level of efficiency reported for these turbines.

This heat input level is not a BACT limit. It has no connection to emission rates achievable by the best performing sources. Moreover, even if the District had used reasonable data to calculate the heat input limit, relying on such a limit alone does not assure BACT at all levels of operation. By only limiting fuel use, the limit may cap hourly emissions of carbon, but it does not ensure the turbines are being maintained to achieve their most efficient operation, which the District identifies at the outset is the basis for determining BACT. It is not enough to assert that sources will always ensure maximum efficiency because of a desire to minimize fuel costs. This simplistic view does not accord with the real world where we are all faced with decisions on when to invest our resources to achieve improvements in efficiency. Power plants are no different than home water heaters, automobiles or any other fuel-burning equipment in that we allow them to degrade, even though it costs us money in fuel, because the cost of maintenance or replacement acts as a barrier. The point of the BACT limit should be to ensure that efficiency is maintained – it is not enough to rely on voluntary decisions to use fuel efficiently. Setting a heat input limit is useful to cap total carbon emissions but is not sufficient to ensure BACT at all times. *See In Re Steel Dynamics, Inc.*, 9 E.A.D. 165, 224 (EAB 2000) (rejecting form of limits that did not ensure compliance on a continual basis at all levels of operation).

The District needs to completely redo the analysis of BACT for CO2 starting with a review of alternatives that do not rely on fossil fuel at all. The District's analysis has been improperly built around trying to justify the use of the turbines that the applicant has already purchased. This is inappropriate in the same way that determining a NOx limit around the prior purchase of aftertreatment technology other than SCR or of burners that are not low-NOx would be inappropriate. Given the extent of the defects in the CO2 BACT analysis in particular, we request that the District revise the draft Statement of Basis with new BACT analyses and recirculate it for another round of public comment.

<u>Analysis of Fine Particulate Matter (PM2.5) Impacts</u>

The District's analysis of PM2.5 air quality impacts is completely deficient. The Bay Area does not meet the national standards for PM2.5, and yet the District proposes to approve this project and allow unmitigated emissions in direct PM2.5 and PM2.5 precursors as if the addition of these emissions can be allowed without jeopardizing public health. The District attempts to hide behind EPA's illegal grandfathering exemption knowing full well that the air quality in the Bay Area is unhealthy and emissions of PM2.5 and its precursors need to be reduced. The District's strategy is misguided and highlights the illegality of EPA's grandfathering provision.

Air quality in the Bay Area violates the 2006 24-hour NAAQS for PM2.5 and the District has known this since at least December 2007. *See* Letter from James Goldstene, Executive Officer, California Air Resources Board, to Wayne Nastri, Regional Administrator, Region 9, U.S. EPA (Dec. 17, 2007) (state recommendations for area designations under the PM2.5 NAAQS based on 2004 through 2006 monitoring data) (Ex. F hereto). The State reevaluated and confirmed its recommendation to designate the Bay Area as nonattainment for PM2.5 based on 2005 through 2007 monitoring data. *See* Letter from James Goldstene, Executive Officer, California Air Resources Board, to Wayne Nastri, Regional Administrator, Region 9, U.S. EPA (Oct. 18, 2008) (Ex. G hereto). EPA signed its final rule designating the Bay Area as nonattainment for PM2.5 on December 22, 2008.

Put simply, the proposed project will violate section 165(a)(3) of the Clean Air Act, which provides:

> No major emitting facility . . . may be constructed in any area to which this part applies unless . . .the owner or operator of such facility demonstrates . . . that emissions will not cause, or contribute to, air pollution in excess of any . . . national ambient air quality standard in any air quality control region.

42 U.S.C. § 7475(a)(3). Air quality in the Bay Area already violates the 24-hour NAAQS for PM2.5. Thus, there is simply no dispute that the added emissions from the Russell City Energy Center will contribute to violations of the PM2.5 NAAQS in the Bay Area. To the extent EPA's

guidance or rules suggest that the District may ignore this statutory requirement, they are flatly illegal. Indeed, EPA has tried to defend its illegal policy by advising that:

> [T]he continued use of the PM10 surrogate policy is not mandatory, and case-by case evaluation of the use of PM10 in individual permits is allowed to determine its adequacy as a surrogate for PM2.5. If, under a particular permitting situation, it is known that a source's emissions would cause or contribute to a violation of the PM2.5 NAAQS, we do not believe that it is acceptable to apply the PM10 surrogate policy in the face of such predicted violation.

See Letter from Stephen L. Johnson, Administrator, EPA, to Paul Cort, Earthjustice, at 3 (Jan. 14, 2009) (Ex. H hereto).

Before this permit is final (especially if there is another challenge of the permit before the Environmental Appeals Board, which seems likely), the PM2.5 nonattainment designation for the Bay Area will become effective. Upon the effective date of the nonattainment designation, permitting of major sources of PM2.5 and its precursors will be subject to nonattainment new source review including the requirement to offset all new emissions and to apply more stringent control technologies. If the District's rules are not written to accommodate such requirements, appendix S of 40 CFR part 51 will apply for all such permitting. *See* 73 Fed. Reg. 28321, 28342 (May 16, 2008). Under federal rules, areas that are nonattainment for PM2.5 after July 15, 2008, will no longer be permitted to implement a nonattainment new source review program for PM10 as a surrogate for PM2.5 nonattainment new source review requirements. *See id.* The District's attempt to push through this permit without acknowledging that these added emissions will worsen the already unhealthy air in the Bay Area is unseemly and short-sighted. Instead, the District should proceed now to require the source to identify offsetting emissions and evaluate the lowest achievable emission rate for PM2.5 and its precursor emissions such as NOx.

<u>Conclusion</u>

The draft permit for the Russell City Energy Center must not be approved. The BACT analysis is built not to identify the "maximum degree of emission reduction . . . achievable," but to justify limits that can be achieved by the old turbines already purchased by the applicant. This is a plain violation of the Clean Air Act, which requires consideration of different production processes and methods, as well as innovative fuel combustion techniques for controlling emissions. *See*

CAA § 169(3). The District should prepare a new analysis and re-notice a revised draft permit for public review. In doing that new analysis, we urge the District to consider more broadly the alternatives available to addressing the energy needs purportedly served by the Russell City project.

Sincerely,

Paul Cort

Paul Cort
Staff Attorney

Cc: Debbie Jordan, EPA w/o enc.
Gerardo Rios, EPA w/o enc.

Enc.: Exhibit A – ANP Blackstone Energy Co. LAER BACT Determinations.

Exhibit B – Amended Petition for Reconsideration, *In re Interpretation of Regulations that Determine Pollutants Covered by the Federal PSD Permit Program* (Jan. 6, 2009).

Exhibit C – E-mail from Brian Lusher to Weyman Lee (Sept. 10, 2008).

Exhibit D – Materials on General Electric H System Combined Cycle Gas Turbine.

Exhibit E – Materials on Westinghouse's Advanced Turbine Systems Program.

Exhibit F – Letter from James N. Goldstene, Executive Officer, CARB, to Wayne Nastri, Regional Administrator, EPA Region 9 (Dec. 17, 2007).

Exhibit G – Letter from James N. Goldstene, Executive Officer, CARB, to Wayne Nastri, Regional Administrator, EPA Region 9 (Oct. 15, 2008).

Exhibit H – Letter from Stephen L. Johnson, Administrator, EPA, to Paul R. Cort, Earthjustice (Jan. 14, 2009).

Attachment A

Section II: Other LAER/BACT Determinations
Application No.: 118969
Equipment Category – Gas Turbine

1. GENERAL INFORMATION	DATE: 4/16/2003
A. MANUFACTURER: Asea Brown-Boveri (ABB)	
B. TYPE: Combined Cycle	C. MODEL: GT-24
D. STYLE:	
E. APPLICABLE AQMD RULES:	
F. COST: $ (NA)	SOURCE OF COST DATA:
G. OPERATING SCHEDULE: 24 HRS/DAY 7 DAYS/WK 52 WKS/YR	

2. EQUIPMENT INFORMATION	APP. NO.: 118969
A. FUNCTION: Power generation: two gas turbines rated at 180 MW each (210 MW w/ steam augmentation), two unfired HRSGs, two steam turbines rated at 95 MW each (85 MW in steam augmentation mode)	
B. MAXIMUM HEAT INPUT: 3630 MMBtu/hr, 4367 MMBtu/hr w/ steam augmentation	C. MAXIMUM THROUGHPUT:
D. BURNER INFORMATION: NO.:	TYPE: Dry Low NOx
E. PRIMARY FUEL: Natural Gas	F. OTHER FUEL: None
G. OPERATING CONDITIONS: Most operation expected to be at or near full capacity w/o steam augmentation. However, due to materials problems, the plant has derated the maximum power output on both power trains to 92% of design capacity.	

3. COMPANY INFORMATION	APP. NO.: 118969
A. NAME: ANP Blackstone Energy Co.	B. SIC CODE:
C. ADDRESS: 204 Elm Street CITY: Blackstone STATE: MA	ZIP: 01504
D. CONTACT PERSON: Robert G. Maggiani	E. PHONE NO.: 508-876-8114

4. PERMIT INFORMATION	APP. NO.: 118969
A. AGENCY: Massachusetts Dept. of Environmental Protection	B. APPLICATION TYPE: new construction
C. AGENCY CONTACT PERSON: Gary Roscoe	D. PHONE NO.: 508-767-2773
E. PERMIT TO CONSTRUCT/OPERATE INFORMATION: ☐ CHECK IF NO P/C — P/C NO.: 118969 ISSUANCE DATE: 4/16/1999; P/O NO.: 118969 ISSUANCE DATE: 3/16/2001	
F. START-UP DATE: March 2001	

5. EMISSION INFORMATION

APP. NO.: 118969

A. PERMIT

A1. PERMIT LIMIT: PPMVD@15%O2 (1-hr block avg.): NOx-2.0, CO-3.0, VOC-1.4 (as CH4), NH3-2.0 except during startups and shutdowns (will be conditioned later on lb-per-event basis). Higher limits (3.5 ppm) are allowed for NOx and VOC in steam-augmentation mode. Higher limits are allowed for CO and VOC at reduced loads: CO-4.0 at 75% load and 20 at 50% load, VOC-2.5 at 50% load. PM limits: 23.9, 19.1 and 14.6 lb/hr at 100%, 75% and 50% load, respectively. Max. sulfur in fuel 0.8 grn/100 cu. ft. Facility-wide TPY limits (12-mo. rolling avg.): NOx-151, CO-437, VOC-49, NH3-47, PM-209, SO2-40, H2SO4-21.

A2. BACT/LAER DETERMINATION: PPMVD@15%O2 (1-hr block avg.): NOx-2.0, CO-3.0, VOC-1.4 (as CH4), NH3-2.0 except during startups and shutdowns. Higher limits allowed for NOx and VOC in steam-augmentation mode and for CO and VOC at reduced loads.

A3. BASIS OF THE BACT/LAER DETERMINATION: Emission limits were negotiated with the applicant.

B. CONTROL TECHNOLOGY

B1. MANUFACTURER/SUPPLIER: Engelhard (oxidation catalyst), Mitsubishi/Cormetech (SCR)

B2. TYPE: Oxidation catalyst and SCR

B3. DESCRIPTION:

B4. CONTROL EQUIPMENT PERMIT APPLICATION DATA: P/C NO.: 118969 ISSUANCE DATE: 4/16/1999
P/O NO.: 118969 ISSUANCE DATE: 3/16/2001

B5. WASTE AIR FLOW TO CONTROL EQUIPMENT: FLOW RATE:
ACTUAL CONTAMINANT LOADING: BLOWER HP:

B6. WARRANTY: The plant is guaranteed to meet the permit limits.

B7. PRIMARY POLLUTANTS: NOx, CO, VOC, PM, SOx

B8. SECONDARY POLLUTANTS: NH3

B9. SPACE REQUIREMENT:

B10. LIMITATIONS: B11. UNUSED

B12. OPERATING HISTORY: Oxidation catalyst and SCR have operated well since startup. As of September 30, 2002, both units had over 5,000 hours operation.

B13. UNUSED B14. UNUSED

C. CONTROL EQUIPMENT COSTS

C1. CAPITAL COST: ☐ CHECK IF INSTALLATION COST IS INCLUDED IN EQUIPMENT COST
EQUIPMENT: $ INSTALLATION: $ (NA) SOURCE OF COST DATA:

C2. ANNUAL OPERATING COST: $ (NA) SOURCE OF COST DATA:

D. DEMONSTRATION OF COMPLIANCE

D1. STAFF PERMFORMING FIELD EVALUATION:
ENGINEER'S NAME: INSPECTOR'S NAME: DATE:

D2. COMPLIANCE DEMONSTRATION:

D3. VARIANCE: NO. OF VARIANCES: DATES:
CAUSES:

5. EMISSION INFORMATION

APP. NO.: 118969

D4. VIOLATION: NO. OF VIOLATIONS: DATES:

CAUSES:

D5. MAINTENANCE REQUIREMENTS:

D6. UNUSED

D7. SOURCE TEST/PERFORMANCE DATA RESULTS AND ANALYSIS:

DATE OF SOURCE TEST: June 5-7, July 5-12 and Dec 5-6, 2001; Feb 11-12 and May 15 2002

CAPTURE EFFICIENCY:

DESTRUCTION EFFICIENCY:

OVERALL EFFICIENCY:

SOURCE TEST/PERFORMANCE DATA: PPMVD@15%O2 (VOC as CH4):

Unit	Date	Load	NOx	CO	VOC	NH3
1	June	75%	1.6	<0.1	0.2	.06
1	June	50%	1.4	0.5	0.2	.08
2	July	75%	1.5	<0.1	0.4	.02
2	July	50%	1.7	0.8	0.4	0.2
2	Dec	87%	1.4	<0.1	<0.1	.05
1	Feb	87%	1.7	0.3	0.1	0.1
1	May	87%	1.6	0.3	0.1	0.1
2	May	87%	1.6	0.0	0.1	0.1

OPERATING CONDITIONS: Steady

TEST METHODS: Test protocol was approved and all tests were formally accepted by Massachusetts DEP. In the July 50%-load test on Unit 2, PM exceeded the limit (19.2 versus 14.6 lb/hr limit). Unit 2 was re-tested at 50% load in December 2001 for PM only, and was well below the limit.

6. COMMENTS

APP. NO.: 118969

A NOx monitor on the turbine exhaust indicates that the ABB GT-24 gas turbine operates with NOx mostly in the 11-15 ppmvd range (corrected to 15%O2). Gas turbines with similar low NOx emissions may not be available in smaller sizes needed by some users, and it may be impractical to control NOx to 2.0 ppm on gas turbines with higher NOx levels. These smaller turbines may rely on water or steam injection for NOx control, and control of CO emissions to 3.0 ppmvd may be difficult on these turbines.

Results of certified CEMS (as posted on USEPA Acid Rain web site) for the first three quarters in 2002 show NOx in compliance with the 2.0 ppm limit with very few exceptions during over 2300 hours operation of Unit 1 and over 3700 hours operation of Unit 2. More exceedances were observed during the first year of operation (2001--1201 hours on Unit 1 and 1463 hours on Unit 2).

This plant has unfired HRSGs. The 3.0 ppmvd (corrected to 15% O2) CO limit at full load may be more difficult to meet on a plant that employs duct burners.

Attachment B

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In the Matter of: EPA Final Action Published at 73 Fed. Reg. 80300 (December 31, 2008), entitled "Clean Air Act Prevention of Significant Deterioration (PSD) Construction Permit Program; Interpretation of Regulations That Determine Pollutants Covered by the Federal PSD Permit Program"

AMENDED PETITION FOR RECONSIDERATION

Pursuant to Section 307(d)(7)(B) of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B), the undersigned organizations petition the Administrator of the Environmental Protection Agency ("the Administrator" or "EPA") to reconsider the final action referenced above. This final action constitutes a *de facto* final rule because it purports to establish binding requirements under the Clean Air Act's Prevention of Significant Deterioration ("PSD") program and create new substantive law regarding the applicability of that program, the obligations of permitting authorities, and the rights of citizens, states, and regulated entities. Because EPA did not conduct a proper rulemaking proceeding prior to implementing this final action, as required by Section 307(d), Petitioners had no opportunity to raise objections to it through public comment. The objections raised in this petition are of central relevance to the outcome of the final action because they demonstrate that the action is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 42 U.S.C. § 7607(d)(9)(A). With respect to each objection, moreover, the regulatory language and EPA interpretations that render the rule arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law appeared for the first time in the final action published on December 31, 2008, 73 Fed. Reg. 80300. The Administrator must therefore "convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed." 42 U.S.C. § 7607(d)(7)(B).

The original Petition for Reconsideration was served on EPA on December 31, 2008. This Amended Petition differs from the original only in that it requests, in Section III, below, that EPA stay the effect of this agency action during the pendency of this

Petition for Reconsideration and during any challenge to this action filed in the U.S. Court of Appeals for the District of Columbia Circuit.

INTRODUCTION

On December 18, 2008, EPA issued a document that purports to establish binding requirements under the Clean Air Act's PSD program and create new substantive law regarding the applicability of that program, the obligations of permitting authorities, and the rights of citizens, states, and regulated entities. Memorandum from Stephen L. Johnson, *EPA's Interpretation of Regulations that Determine Pollutants Covered By Federal Prevention of Significant Deterioration (PSD) Permit Program* (December 18, 2008) (the "Johnson Memo" or "Memo"). EPA published notification of the Johnson Memo in the Federal Register on December 31, 2008. 73 Fed. Reg. 80300.

As discussed below, this final agency action was impermissible as a matter of law, because it was issued in violation of the procedural requirements of the Administrative Procedures Act ("APA"), 5 U.S.C. § 101 et seq., and the Clean Air Act ("CAA"), 42 U.S.C. § 7607, it directly conflicts with prior agency actions and interpretations, and it purports to establish an interpretation of the Act that conflicts with the plain language of the statute. Accordingly, the undersigned organizations request that EPA immediately reconsider and retract the Johnson Memo.

BACKGROUND

In 2007, EPA Region 8 issued a PSD permit for a proposed new 110 MW unit at Deseret Power Electric Cooperative's existing Bonanza coal-fired power plant in Utah. Although Section 165 of the Act requires Best Available Control Technology ("BACT") for "each pollutant subject to regulation under this Act," and although CO_2 is regulated under the Act, the permit contained no BACT limits for CO_2.

In response to comments filed by Sierra Club, EPA contended for the first time in issuing the permit that it was precluded from requiring BACT limits for CO_2 based on a "longstanding interpretation" of the CAA that limited pollutants "subject to regulation" to those subject to actual control of emissions, as opposed to the CO_2 monitoring and reporting regulations in Subchapter C of Title 40 of the CFR. Sierra Club appealed the final permit to EPA's Environmental Appeals Board ("EAB" or "Board").[1]

The EAB rejected EPA's theory, vacated the permit and remanded it to Region 8: "[W]e conclude that the Region's rationale for not imposing a CO_2 BACT limit in the Permit – that it lacked authority to do so because of an historical Agency interpretation of the phrase 'subject to regulation under the Act' as meaning 'subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant' – is not supported by the administrative record." *In re Deseret Power Electric Cooperative*, PSD Appeal 07-03, slip op. at 63 (EAB Nov. 13, 2008), 13 E.A.D. __ *("Bonanza").* To the contrary, the Board found that the **only** relevant interpretation of the applicable statutory and regulatory language was to be found in EPA's 1978 PSD rulemaking. That interpretation directly contradicted EPA's theory, and in fact "augurs in favor of a finding" that "subject to regulation under this Act" encompasses any pollutant covered by a regulation in Subchapter C of Title 40 of the CFR, such as CO_2. *Bonanza* at 41.

In addition, the Board also required an additional public notice and comment process addressing the question of CO_2 BACT limits for the Bonanza facility: "On remand, the Region shall reconsider whether or not to impose a CO_2 BACT limit in the Permit. In doing so, *the Region shall develop an adequate record for its decision, including reopening the record for public comment.*" *Id.* at 64 (emphasis added).

Due to the importance of the issue, the EAB suggested that EPA might want to undertake a proceeding of national scope to deal more broadly with the question of how to address CO_2 in the context of PSD permitting. Regardless of the chosen procedural

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[1] The EAB has exclusive jurisdiction within EPA to review PSD permit decisions. 40 C.F.R. § 124.2(a) ("The Administrator delegates authority to the Environmental Appeals Board to issue final decisions in RCRA, PSD, UIC, or NPDES permit appeals filed under this subpart, including informal appeals of denials of requests for modification, revocation and reissuance, or termination of permits under Section 124.5(b). An appeal directed to the Administrator, rather than to the Environmental Appeals Board, will not be considered.").

mechanism, however, the Board was clear that additional notice and comment proceedings were necessary before EPA could adopt changes to the PSD program.

EPA responded to *Bonanza* by issuing the Johnson Memo, which states, "As of the date of this memorandum, EPA will interpret this definition of 'regulated NSR pollutant' to exclude pollutants for which EPA regulations only require monitoring or reporting but to include each pollutant subject to either a provision of the Clean Air Act or regulation adopted by EPA under the Clean Air Act that requires actual control of emissions of that pollutant." Johnson Memo at 1. EPA published a notice in the Federal Register on December 31, 2008, stating that the Johnson Memo "contains EPA's 'definitive interpretation' of 'regulated NSR pollutant.'" 73 Fed. Reg. 80300.

OBJECTIONS

I. BECAUSE THE JOHNSON MEMO IS NOT AN "INTERPRETIVE RULE," ITS ISSUANCE VIOLATES PROCEDURAL REQUIREMENTS THAT MANDATES AGENCY RECONSIDERATION

The Johnson Memo purports to be "establishing an interpretation clarifying the scope of the EPA regulation that determines the pollutants subject to" the PSD program. Johnson Memo at 1. Whatever else the Johnson Memo is, it is definitely not an "interpretive rule." As the D.C. Circuit has explained:

> Interpretative rules "simply state[ ] what the administrative agency thinks the statute means, and only *remind[ ] affected parties of existing duties.*" *General Motors Corp. v. Ruckelshaus,* 742 F.2d 1561, 1565 (D.C. Cir. 1984) (en banc) (internal quotation marks omitted). Interpretative rules may also construe substantive *regulations. See Syncor Internat'l Corp. v. Shalala,* 127 F.3d 90, 94 (D.C. Cir. 1997).

Assoc. of Amer. RR v. Dept. of Transp., 198 F.3d 944 at 947 (D.C. Cir. 1999) (emphasis added). It is clear that EPA has so characterized it solely to avoid the procedural requirements – most importantly, public notice and comment – that would otherwise be imposed by the Clean Air Act, the Administrative Procedures Act, and the *Bonanza* decision. The Johnson Memo is a substantive rule, and not an interpretive one, because it reverses a formal agency interpretation, overturns an EAB decision, and amends the substance of the PSD program.

A. <u>The Johnson Memo Reverses a Formal Agency Interpretation</u>

In 1978, EPA determined in a Federal Register preamble that the phrase "'subject to regulation under this Act' means any pollutant regulated in Subchapter C of Title 40 of the Code of Federal Regulations for any source type." 43 Fed. Reg. 26,388, 26,397 (June 19, 1978). This earlier interpretation – which has never been withdrawn or modified – directly conflicts with the interpretation the Memo purports to adopt. As discussed more fully below (pp. 8 *et seq.*), because the Subchapter C regulations include, *inter alia*, regulations that require monitoring and reporting of CO_2 emissions, the EAB held that this language offers *no* support for an interpretation applying "BACT only to pollutants that are 'subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant.'" *Bonanza* at 41. The logical implication of the 1978 Preamble is that BACT applies to CO_2 emissions. At a minimum, the 1978 Preamble accords agency permitting offices discretion under the Act and under EPA's regulations (which merely parrot the language of the Act) to require CO_2 BACT limits in PSD permits. Either way, the Johnson Memo impermissibly seeks to change that interpretation so as to *preclude* consideration of CO_2, thereby significantly modifying the nature and scope of the PSD program without notice and comment rulemaking.

The D.C. Circuit has held that when an agency's purported interpretation of a statute or regulation "constitutes a fundamental modification of its previous interpretation," the agency "cannot switch its position" without following appropriate procedures. *Paralyzed Veterans of Am. v. D.C. Arena L.P.*, 117 F.3d 579, 586 (D.C. Cir. 1997). Once an agency provides an interpretation of a statute – as EPA did here, in 1978 – "it can only change that interpretation as it would formally modify the regulation itself: through the process of notice and comment rulemaking." *Id.*

In an effort to bypass the procedures required by *Paralyzed Veterans*, the Memo claims that it is not actually refuting the 1978 Preamble's interpretation. It suggests, first, that because the 1978 Preamble did not itself "amplify the meaning of the term 'regulated in,'" EPA remains free to insert a wholly new definition of that term. Johnson Memo at 19. The Agency may not, however, evade the procedures mandated by *Paralyzed Veterans* by disguising a revision of governing law as an interpretation of its previous interpretation. *Paralyzed Veterans*, 117 F.3d at 586 (refusing to allow revisions or modifications of agency interpretations without notice and comment).

Second, the Memo contends that "the 1978 statement referred to the language in the statute which said 'pollutant subject to regulation under this Act,'" while "the 2002 regulation I am interpreting here uses the phrase 'pollutant that otherwise is subject to regulation under the Act.'" Johnson Memo at 19. The latter phrase, however, is a component of the former, so that the Memo's interpretation of "pollutant[s] . . . otherwise . . . subject to regulation under the Act" necessarily limits its interpretation of "pollutant[s] subject to regulation under this Act." 40 C.F.R. § 52.21(b)(50)(iv).

B. The Johnson Memo Overturns the EAB's *Bonanza* Decision.

While the Johnson Memo states that it "is not intended to supersede the Board's decision," Johnson Memo at 2, that is exactly what it does, even though the Administrator has no jurisdiction to undo a statutory interpretation adopted in an EAB ruling or substitute his judgment for that of the Board. *See* 40 C.F.R. § 124.2(a). The Board held that to adopt a new interpretation of the PSD regulatory program, EPA *must* undertake a new notice and comment process. *Bonanza* at 64 ("On remand, the Region *shall* reconsider whether or not to impose a CO_2 BACT limit in the Permit. In doing so, the Region *shall* develop an adequate record for its decision, including reopening the record for public comment.") (emphasis added).

Thus, the EAB – the final agency decision-maker as to PSD permits – has already addressed whether a notice and comment process is required for EPA to change its position regarding the appropriate scope of analysis in PSD permits, and concluded that it is. Significantly, the Board also ruled that the existing record was inadequate to support the agency's attempted reinterpretation of the Act – directing the agency on remand to "develop an adequate record for its decision." *Id.*[2]

[2] The EAB also specifically *rejected* EPA's argument that its interpretation was supported by "historic practice," finding it insufficient to undo "the authority the Region admit[ed] it would otherwise have under the statute." *Bonanza* at 46. In its attempt to circumvent the Board's conclusion, the Memo appears to introduce new evidence that

While the Board suggested that "[t]he Region should consider whether interested persons, as well as the Agency, would be better served by the Agency addressing the interpretation of the phrase 'subject to regulation under this Act' in the context of an action of nationwide scope, rather than through this specific permitting proceeding," *id.*, the Board clearly anticipated a process involving public notice and comment. EPA simply can not excuse itself from its legal obligation to pursue additional notice and comment before finalizing a change to its PSD regulations merely by seeking to adopt its new interpretation of the Act through an "interpretive rule".

To the extent that the Johnson Memo attempts to rely on public participation in the specific adjudicatory proceeding regarding the Bonanza plant, or public participation in an advanced notice of proposed rulemaking ("ANPRM") (which broadly addressed the implications of any and all potential EPA regulatory actions regarding greenhouse gases, 73 Fed. Reg. 44353 (July 30, 2008)), such reliance is legally insufficient to cure the procedural failures of this illegal rulemaking. Among other things, the *Bonanza* proceeding addressed only a single facility, and the adjudicatory process associated with an individual permit proceeding cannot substitute for notice and comment on a legislative rule of broad national significance. Even the parties to that proceeding did not have the benefit of the agency's fully-developed litigation position until EPA filed its supplemental brief that the Board ordered after oral argument. As the Board's final order requiring notice and comment on remand clearly indicates, that proceeding did not provide sufficient public process to support a decision to omit a CO_2 BACT limit from that particular permit, much less serve as an adequate substitute for notice and comment on a rule of nationwide scope.

Similarly, in the ANPRM, EPA never indicated its intention to take imminent final action establishing new parameters for the PSD regulatory program. To the contrary, the ANPRM by its very nature was probing and exploratory, not a vehicle intended to result in a final and binding agency policy. Indeed, as the Administrator's preface to the ANPRM explained: "None of the views or alternatives raised in this notice represents

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has never been subject to scrutiny of any kind. Johnson Memo at 11 (referring to "the record of permits compiled to support this memorandum").

Agency decisions or policy recommendations. It is premature to do so." 73 Fed. Reg. at 44355. Moreover, neither the adjudicatory proceeding nor the ANPRM provided any notice of EPA's specific intent to reinterpret the agency's policy articulated in the 1978 preamble. Accordingly, these activities cannot serve to dispose of the agency's obligation to undertake notice and comment processes before adopting a final legislative rule amending the CAA's PSD program.

C. <u>The Johnson Memo Substantively Amends the PSD Program</u>

The Johnson Memo seeks to substantively amend EPA regulations to establish new legal rights, restrictions, and/or obligations under the Act's PSD program, without any associated notice and comment process. This 19-page memo also takes a large number of other regulatory steps, including establishing specific exceptions to this rule (*e.g.,* exempting pollutants that are subject to regulation under the Act through state implementation plans ("SIPs") (Johnson Memo at 15));[3] establishing Regional Office responsibilities with regard to future SIP submittals (*Id.* at 3 n.1); determining how pollutants will become subject to PSD permitting in the future on enactment of new congressionally-mandated emission limits (*Id.* at 6 n.5); imposing requirements that address when pollutants for which EPA has made a regulatory endangerment determination must be treated as PSD pollutants (*Id.* at 14); and defining when and how import restrictions will trigger PSD for a pollutant. The sheer breadth of issues addressed, regarding numerous and disparate regulatory programs, defies EPA's claim that this is a mere "interpretive rule."

Thus, EPA's action constitutes an unlawful rulemaking under the APA and the CAA. EPA's action in the Johnson Memo, according to its own terms, treats the conclusions in the Memo as binding on EPA itself, and on states implementing the federal PSD program through delegation agreements with EPA, and leads "private parties or . . . permitting authorities to believe that it will declare permits invalid unless

[3] We note, as EPA points out, that it has adopted a similar approach in at least one other regulatory program, *see* Johnson Memo at 15-16 (regarding the treatment of ammonia as $PM_{2.5}$ precursors), but that it did so – as it should have here – by notice and comment rulemaking. *See* 70 Fed. Reg. 65984; 73 Fed. Reg. 28321.

they comply with [its] terms." *Appalachian Power Co. v. EPA*, 208 F.3d 1015, 1021 (D.C. Cir. 2000). The Johnson Memo states that its newly established substantive parameters governing EPA's regulatory program, which significantly modify the federal PSD program, represent the agency's "settled position." *Id.* at 1022. It "reads like a ukase." *Id.* at 1023. Finally, the Memo certainly creates and/or changes the "rights," "obligations," and scope of authority of various parties, including EPA itself, citizens, regulated entities, and possibly delegated State permitting authorities, and "commands," "requires," "orders," or "dictates" a particular regulatory approach that will affect the rights of parties in currently pending and future permitting actions. *Id.* at 1023; *see also General Elec. Co. v. EPA*, 290 F.3d 377, 380 (D.C. Cir. 2002) (EPA risk assessment document was a legislative rule, "because on its face it purports to bind both applicants and the Agency with the force of law").

In sum, the Johnson Memo is a new regulation that adopts a substantially new interpretation of the Act and seeks to implement that interpretation through uncodified substantive changes to the PSD regulatory program. The D.C. Circuit has made clear that agencies may not avoid the procedural requirements by this sort of subterfuge:

> Although [our] verbal formulations vary somewhat, their underlying principle is the same: ***fidelity to the rulemaking requirements of the APA bars courts from permitting agencies to avoid those requirements by calling a substantive regulatory change an interpretative rule.***

U.S. Telecom Ass'n v. F.C.C., 400 F.3d 29, 35 (D.C. Cir. 2005) (emphasis added and citations omitted). Accordingly, EPA must withdraw the Johnson Memo, and proceed, if at all, through appropriate notice and comment procedures.

II. THE POSITIONS ASSERTED IN THE JOHNSON MEMO ARE IMPERMISSIBLE UNDER THE CLEAN AIR ACT

The Johnson Memo purports to adopt a binding interpretation of a regulation that parrots the Clean Air Act phrase, "pollutant subject to regulation under this Act." That interpretation would "exclude pollutants for which EPA regulations only require monitoring or reporting but . . . include each pollutant subject to either a provision in the Clean Air Act or regulation adopted by EPA under the Clean Air Act that requires actual control of emissions of that pollutant." Johnson Memo at 1. The Memo thus attempts to revive a definition that the EAB found was not supported by any prior EPA interpretation of the statute. The Memo misconstrues the plain language of the Act, adopts impermissible interpretations of existing regulations, and ignores the distinct purpose of the PSD program in a vain attempt to forestall CO_2 emissions limits. In so doing, the Memo runs contrary to the Clean Air Act's clear mandate and flouts the Supreme Court's direction to use the regulatory flexibility that Congress provided to address new threats, such as climate change. *Massachusetts v. EPA,* 127 S. Ct. 1438, 1462 (2007).

A. The Johnson Memo Ignores the Plain Language of the Clean Air Act Requiring BACT for CO_2 Emissions.

EPA must impose emissions limitations on CO_2 in PSD permits for new coal-fired power plants. Section 165(a)(4) of the Clean Air Act requires BACT "for each pollutant subject to regulation under this chapter emitted from . . . such facility." 42 U.S.C. § 7475(a)(4). As even EPA now acknowledges, CO_2 is a pollutant under the Clean Air Act. *Massachusetts* , 127 S. Ct. at 1462. It is emitted abundantly by coal-fired generators and is currently regulated under the Clean Air Act through the Delaware SIP, as well as under monitoring and reporting requirements established by Section 821 of the 1990 Clean Air Act Amendments and the CO_2 monitoring requirements established by Congress' 2008 Appropriations Act.[4]

1. The Delaware SIP

On April 29, 2008, EPA approved a State Implementation Plan revision submitted by the State of Delaware that establishes emissions limits for CO_2, effective May 29, 2008. AR 123.3, 12.3, 73 Fed. Reg. 23101. The SIP revision imposes such CO_2 limits on new and existing distributed generators. Delaware Department of Natural Resources and Environmental Control; Division of Air and Waste Management, Air Quality Management Section, Regulation No. 1144. AR 123.2, Ex. 12.2., § 3.0.

In EPA's proposed and final rulemaking notices, EPA stated that it was approving the SIP revision "under the Clean Air Act," 73 Fed. Reg. 11,845, and "in accordance

[4] To the extent the EAB declined to hold that the PSD provision requires use of BACT for CO_2 emissions, the undersigned disagree with the Board's decision in that case. *American Bar Ass'n v. F.T.C.*, 430 F.3d 457, 468 (D.C. Cir. 2005) (reviewing courts "owe the agency no deference on the existence of ambiguity").

with the Clean Air Act," 73 Fed. Reg. at 23,101. EPA's approval made these CO_2 control requirements part of the "applicable implementation plan" enforceable under the Act, 42 U.S.C. § 7602(q), and numerous provisions authorize EPA to so enforce these SIP requirements, *e.g.*, 42 U.S.C. § 7413 (authorizing EPA compliance orders, administrative penalties and civil actions). In addition, EPA's approval makes these emission standards and limitations enforceable by a citizen suit under Section 304 of the Act. 42 U.S.C. § 7604(a)(1), (f)(3).

The Delaware SIP Revision constitutes regulation of CO_2 under the Clean Air Act because it was adopted and approved under the Act and is part of an "applicable implementation plan" that may be enforced by the state, by EPA, and by citizens under the Clean Air Act. Thus CO_2 is a pollutant "subject to regulation" under the Act for BACT purposes, **even under the definition put forth in the Johnson Memo** because it is "subject to . . . [a] regulation adopted by EPA under the Clean Air Act that requires actual control of emissions." Johnson Memo at 1.

Nevertheless, in an effort to evade the consequences of the Delaware SIP, the Memo purports to create an exception specifically designed to exclude the SIP from its definition of "regulation under the Act." *Id.* at 15. As support for its novel (and incorrect) interpretation, the Memo purports to rely on *Connecticut v. EPA*, 656 F.2d 902 (2d Cir. 1981). It construes that case as holding that the "Congress did not allow individual states to set national regulations that impose those requirements on all other states." Johnson Memo at 15. But *Connecticut* does not support that conclusion; indeed, it has nothing to do with the issue here, namely whether a particular pollutant is "subject to regulation" under the Act. Clean Air Act § 165(a)(4). Rather, *Connecticut* discusses only whether the quantitative limits imposed by one state on a particular pollutant apply to neighboring states under the "good neighbor" provision in § 110. *See Connecticut*, 656 F.2d at 909 (Section "110(a)(2)(E)(i) is quite explicit in limiting interstate protection to federally-mandated pollution standards.") (emphasis added). *Connecticut* provides no support to the Johnson Memo's arbitrary limitation on the scope of what constitutes a regulation under the Act – and demonstrates that the Memo's interpretation is driven not by the language or purpose of the statute, but rather by the agency's intractable refusal to address CO_2 emissions.

Nothing illustrates this better than the Memo's conclusion that "EPA does not interpret section 52.21(b)(50) of the regulations to make CO2 'subject to regulation under the Act' for the nationwide PSD program based solely on the regulation of a pollutant by a single state in a SIP approved by EPA." Johnson Memo at 15. In other words, conceding that the Delaware SIP constitutes "regulation under the Act", the Memo takes the position that such regulation by a single state is not enough. Neither the Act nor its regulations provide a basis for this position – indeed, the Memo makes no attempt to provide a basis.

Thus the Johnson Memo replaces the simple statutory test of whether a pollutant is "subject to regulation under the Act" with a test of whether the pollutant is "subject to regulation under the Clean Air Act in a sufficient number of states or, alternatively, in the state (or Region) where the facility is to be constructed."[5] But that is not what the Act says, nor does the Memo offer any support for the contention that regulation of CO_2 in another part of the country does not count as "regulation." Under the plain language of Section 165(a)(4), if CO_2 emissions are restricted under the Clean Air Act, whether in one state or all 50, they are "subject to regulation under the Act" – even under the Memo's improperly narrow definition of "regulation."

Finally, SIP regulations appear in "Subchapter C of Title 40 of the Code of Federal Regulations." 43 Fed. Reg. at 26,397. *See, e.g.,* 40 C.F.R. § 52.420 (2008) (incorporating by reference provisions of Delaware SIP). They are, accordingly, within the scope of the Agency's governing 1978 interpretation, even if that interpretation meant to say "regulated by requiring actual control of emissions" when it said "regulated." If the EPA wished to exclude SIP-based regulations, it would be required to modify its current interpretation, and provide the public with notice and an opportunity to comment upon that modification. *See Paralyzed Veterans,* 117 F.3d at 586.[6]

[5] The Memo does not disclose how many states Administrator Johnson believes would suffice. Two? Three? Six? Fourteen?

[6] The EAB did not reach the issue of whether CO_2 is regulated under the Clean Air Act because it is regulated in the Delaware SIP, instead directing EPA to consider this issue "along with other potential avenues of regulation of CO_2." *Bonanza* at 55 n.57.

2. Section 821

In addition to being regulated under the Delaware SIP, CO_2 is regulated under Section 821 of the Clean Air Act Amendments of 1990. Section 821 requires EPA to "promulgate regulations" requiring major sources, including coal-fired power plants, to monitor carbon dioxide emissions and report their monitoring data to EPA:

> The Administrator of the Environmental Protection Agency *shall promulgate regulations* within 18 months after the enactment of the Clean Air Act Amendments of 1990 *to require that all affected sources subject to Title [IV] of the Clean Air Act shall also monitor carbon dioxide emissions* according to the same timetable as in Sections [412](b) and (c). *The regulations shall require that such data be reported to the Administrator.* The provisions of Section [412](e) of title [IV] of the Clean Air Act shall apply for purposes of this Section in the same manner and to the same extent as such provision applies to the monitoring and data referred to in Section 412.

42 U.S.C. § 7651k note; Pub. L. 101-549; 104 Stat. 2699 (emphasis added). In 1993, EPA promulgated these regulations, which require sources to monitor CO_2 emissions, 40 C.F.R. §§ 75.1(b), 75.10(a)(3), prepare and maintain monitoring plans, *id.* § 75.33, maintain records, *id.* § 75.57, and report monitoring data to EPA, *id.* § 75.60-64. The regulations prohibit operation in violation of these requirements and provide that a violation of any Part 75 requirement is a violation of the Act. *Id.* § 75.5. Not only do the regulations require that polluting facilities "measure . . . CO_2 emissions for each affected unit," *id.* § 75.10(a), they also prohibit operation of such units "so as to discharge or allow to be discharged, emissions of . . . CO_2 to the atmosphere without accounting for all such emissions . . . . " *Id.* § 75.5(d).

In *Bonanza*, EPA argued that monitoring regulations are not actually regulation and that Section 821 did not actually amend the Clean Air Act. The EAB having rejected EPA's attempt to banish Section 821 from the Act, the Johnson Memo now depends solely on the flawed argument that regulation requiring monitoring and reporting is not regulation. On the contrary, monitoring and reporting requirements clearly constitute regulation. Against the backdrop of Section 165's use of "regulation," Congress explicitly used that exact same word in Section 821 to refer solely to monitoring and reporting requirements. Just like regulations restricting emissions quantities, the regulations EPA promulgated implementing Section 821 have the force of law, and violation results in severe sanctions. 40 C.F.R. § 75.5; 42 U.S.C. § 7413(c)(2) (punishable by imprisonment of up to six months or fine of up to $10,000 for making false statement or representation or providing inaccurate monitoring reports under Clean Air Act).[7] Indeed, as the Region and OAR admitted in the supplemental brief (and exhibits) they filed with the EAB in *Bonanza*, EPA has enforced section 821 in a number of consent decrees that require the installation of CO_2 monitoring equipment.

In support of the interpretation of "regulation" to mean only a restriction on emissions quantity, the Johnson Memo recites the assorted dictionary definitions of "regulation" from the *Bonanza* briefing without any discussion of Section 821 and its use of this exact same word. Nor does the Memo appear to recognize that each of those definitions would include monitoring. Its preferred definition – "the act or process of controlling by rule or restriction" – encompasses regulations to monitor emissions just as easily as regulations that limit emissions quantities. Pursuant to Section 821, CO_2 is "controlled" by a "rule or restriction" because EPA's regulations require that emissions be monitored, which cannot be done if those emissions are freely emitted; by definition, monitoring requires that the flow of emissions be controlled. Indeed, monitoring creates more direct control over emissions of a pollutant than import restrictions, which involve only indirect control over emissions. Moreover, "control" is not synonymous with "cap" or "limit." The Memo clearly recognizes that distinction because it repeatedly supplements the original language of its interpretation ("actual control of emissions") by adding "limitation" ("actual control or limitation of emissions"). *See, e.g.,* Johnson Memo at 8. Finally, *Black's* defines "control" as "the power or authority to manage, direct, or

[7] In addition to the monitoring requirements imposed by Section 821, Congress has specifically required monitoring of all greenhouse gases, including CO_2, economy-wide, in the 2008 Consolidated Appropriations Act. H.R. 2764; Public Law 110-161, at 285 (enacted Dec. 26, 2007). As a result, CO_2 monitoring and reporting is required under the Act separate and apart from Section 821. The Johnson Memo attempts to evade the consequences of the Appropriations Act requirement by, among other things, opining that a pollutant is not "subject to regulation" when Congress specifically tells EPA to regulate it, but only when EPA actually adopts regulations. Johnson Memo at 14. The deadline has passed for EPA to issue the proposed regulations required by the Appropriations Act with no action by EPA.

oversee." *Black's Law Dictionary* (8th ed. 2004). Monitoring and reporting regulations certainly constitute oversight.

The Johnson Memo serves to confuse rather than clarify the definition of regulation. EPA should withdraw it and comply with the plain language of the Act, which requires BACT limits for pollutants subject to monitoring and reporting regulations.

B. The Interpretation in the Johnson Memo is Inconsistent with the Only Relevant Regulatory History.

1. The 1978 Preamble

The Johnson Memo repudiates the only Agency interpretation of the words "subject to regulation under this Act" that the EAB identified as "possess[ing] the hallmarks of an Agency interpretation that courts would find worthy of deference" – the preamble to the Agency's 1978 Federal Register rulemaking, 43 Fed. Reg. 26,388, 26,397 (June 19, 1978). *Bonanza* at 39. In the 1978 Federal Register preamble, the Administrator established that "'subject to regulation under this Act' means any pollutant regulated in Subchapter C of Title 40 of the Code of Federal Regulations for any source type." 43 Fed. Reg. at 26,397. As the Board recognized, that preamble offers *no* support for an interpretation applying "BACT only to pollutants that are 'subject to a statutory or regulatory provision that requires actual control of emissions of that pollutant.'" *Bonanza* at 41. Instead (again, as expressly noted by the Board) it implies that "CO_2 became subject to regulation under the Act in 1993 when the Agency included provisions relating to CO_2 in Subchapter C." *Id.* at 42 n.43.

Under the 1978 preamble definition, CO_2 is "subject to regulation" for BACT purposes because it is regulated under Subchapter C of Title 40 of the Code of Federal Regulations. In its 1993 rulemaking to revise the PSD regulations, EPA did not withdraw its 1978 interpretation of "subject to regulation." *See Bonanza* at 42; *see also* Acid Rain Program: General Provisions and Permits, Allowance System, Continuous Emissions Monitoring, Excess Emissions and Administrative Appeals, 58 Fed. Reg. 3,590, 3,701 (Jan. 11, 1993) (final rule implementing § 821's CO_2 monitoring and reporting regulations). Nor has any subsequent rulemaking, including the 2002 rulemaking on which the Johnson Memo relies, disturbed the 1978 interpretation. *See*

Bonanza at 46. Thus, the only existing EPA interpretation of the phrase "subject to regulation" in Section 165(a)(4), 42 U.S.C. § 7465(a)(4), affirms that BACT is required for CO_2 emissions because it is regulated under the Act's implementing regulations.

The Johnson Memo seeks to change this interpretation. It purports to establish that henceforth, BACT will be required for "only those pollutants for which the Agency has established regulations requiring actual controls on emissions," Johnson Memo at 12 precisely the interpretation to which, according to the Board, "the 1978 Federal Register preamble *does not lend support." Bonanza* at 41 (emphasis added).

EPA seeks to elide its amendment of the 1978 interpretation via two routes. First, it asserts that "the specific categories of regulations identified in the second sentence of the passage quoted above are all regulations that require control of pollutant emissions." Johnson Memo at 12. *Bonanza* directly refutes that claim: "Nothing in the 1978 preamble . . . indicates that the Agency intended to depart from the normal use of 'includes' as introducing an illustrative, and non-exclusive, list of pollutants subject to regulation under the Act." *Bonanza* at 40 (holding that "we must reject" the "conten[tion] that only the pollutants identified in the preamble by general category defined the scope of the Administrator's 1978 interpretation).

Second, the Memo claims that the phrase "regulated in" as it appears in the 1978 Preamble is ambiguous and thus subject to clarification by the Agency, such that the 1978 Preamble may be understood to mean "regulated by actual control of emissions" by use of the term "regulated." Johnson Memo at 12. ("[I]t is still not clear that a monitoring or reporting requirement added to subchapter C would make that pollutant 'regulated in' Subchapter C because of the alternative meanings of the term regulation, regulate, and regulated discussed earlier").

This newly proposed understanding of the words "regulated in" fits so unnaturally with the text of the 1978 Federal Register preamble as to defy credibility. That understanding would, entirely *sub silentio,* impose an enormously substantive and restrictive qualification by use of the words "regulated in," while dismissing the far more prominent reference to "Subchapter C of Title 40 of the Code of Federal Regulations" as irrelevant verbiage. Like Congress, agencies cannot be presumed to hide such "elephants in mouseholes." *Whitman v. American Trucking Ass'n*, 531 U.S. 457, 468 (2001). The words "regulated" and "regulation," appear pervasively throughout the 1978 Federal Register preamble, uniformly meaning (as they always do) *any* act of regulating or regulation. *See, e.g.*, 43 Fed. Reg. 26,389 ("The regulations made final today apply to any source . . ."), 26,398 ("In the regulations adopted today, EPA's assessment of the air quality impacts of new major sources and modifications will be based on" certain EPA guidelines), 26,401 ("Such offsets have always been acceptable under the agency's PSD regulations . . . ."), 26,402 ("Environmental groups pointed out that the proposed regulations did not specifically require Federal Land Managers to protect "affirmatively" air quality related values . . . .").

Those references demonstrate that the Agency in 1978 used "regulation" and "regulate" as they are generally used: to encompass all forms of regulation. In explaining the meaning of the phrase "subject to regulation," the Agency offered no hint that, merely by employing the words "regulated in," it was departing from that standard-English definition – much less that it was adopting the Johnson Memo's "alternative" definition. Under any plausible reading, the 1978 Federal Register preamble used "regulated in" to describe *all* the regulations contained "in Subchapter C of Title 40 of the Code of Federal Regulations." *See Bonanza* at 41-42 & n.43 (noting that "plain and more natural reading of the preamble's interpretative statement suggests a different unifying rule" than a rule that would limit "regulation" to actual control of emissions).[8]

The Johnson Memo's proposed interpretation of the term "subject to regulation" via the "regulated in" subterfuge is not only disingenuous, but absurd. The Memo claims that the Agency can freely substitute its new definition of "regulation" as "regulation requiring actual control of emissions" for the word "regulation" in whatever form the latter appears, apparently in any regulatory document. Johnson Memo at 11.

[8] Indeed, in *Bonanza* EPA assumed that the 1978 Preamble used the word "regulated" in this most natural sense, hence its reliance on the enumerated examples as limiting "the scope" of the reference to the Code of Federal Regulations, and its citation of the preamble to the 1993 rulemaking as reflecting an intent to avoid including CO_2 among the pollutants regulated under the Act. *Bonanza* at 41-42.

Nor, logically, does it stop there: not only "regulation", but also "regulate" and "regulated" are now up for grabs; they now mean anything Administrator Johnson wants them to mean, wherever they might appear in any environmental statute or EPA regulation.

2. The 2002 Regulation

The Johnson Memo attempts to narrow the plain language of the Clean Air Act and EPA's 1978 interpretation of that language by purporting to interpret a 2002 implementing regulation rather than the statute itself. That regulation states:

> *Regulated NSR pollutant,* for purposes of this section, means the following:
>
> (i) Any pollutant for which a national ambient air quality standard has been promulgated and . . . any constituent[s] or precursors for such pollutant[s]. . . . identified by the Administrator [e.g., volatile organic compounds are precursors for ozone];
>
> (ii) Any pollutant that is subject to any standard promulgated under section 111 of the Act;
>
> (iii) Any Class I or II substance subject to a standard promulgated under or established by title VI of the Act; [or]
>
> (iv) **Any pollutant that otherwise is subject to regulation under the Act;** except that any or all hazardous air pollutants either listed in section 112 of the Act or added to the list pursuant to section 112(b)(2) of the Act, which have not be delisted pursuant to section 112(b)(3) of the Act, are not regulated NSR pollutants unless the listed hazardous air pollutant is also regulated as a constituent or precursor of a general pollutant listed under section 108 of the Act.

40 C.F.R. § 52.21(b)(50) (emphasis added). The Memo declares that it is interpreting the phrase "any pollutant that otherwise is subject to regulation under the Act" in this definition when it excludes pollutants subject to monitoring regulations and pollutants regulated "solely . . . by a single state in a SIP approved by EPA." Johnson Memo at 15.

In reality, the Johnson Memo is interpreting the language of the statute. The agency's interpretation of its regulation is not entitled to deference because the regulation simply parrots the language of the statute.

> [T]he existence of a parroting regulation does not change the fact that the question here is . . . the meaning of the statute. An agency does not acquire special authority to interpret its own words when, instead of using its expertise and experience to formulate a regulation, it has elected merely to paraphrase the statutory language.

Gonzales v. Oregon, 546 U.S. 243, 257 (2006). Moreover, because the regulation merely paraphrases statutory language that EPA already interpreted in 1978, that earlier interpretation applies to the language of both the statute and rule absent an indication in the 2002 rulemaking that EPA was abandoning it; as EAB found, that rulemaking contained no such indication. *Bonanza* at 46. EPA cannot now change its prior interpretation in a memo issued with complete disregard for the public notice and comment that the law requires. *See* pp. 4-9, *supra*.

The Johnson Memo rationalizes its narrow interpretation by relying on a canon of statutory construction known as *ejusdem generis*, which provides that "where general words follow the enumeration of particular classes of things, the general words are most naturally construed as applying only to things of the same general class as those enumerated." *Am. Mining Cong. v. EPA*, 824 F.2d 1177, 1189 (D.C. Cir. 1987) (quoted in *Bonanza* at 45). It reasons that EPA can construe "otherwise subject to regulation" in subsection (iv) to apply to the same class of pollutants allegedly covered by subsections (i) – (iii) of the "regulated NSR pollutant" definition—those "pollutants subject to a promulgated regulation requiring actual control of a pollutant." Johnson Memo at 8.

Numerous defects undermine this reasoning. Most importantly, it directly conflicts with the *Bonanza* decision because the EAB explicitly held that it is not appropriate to use *ejusdem generis* to interpret a parroting regulation "[w]ithout a clear and sufficient supporting analysis or statement of intent *in the regulation's preamble*." *Bonanza* at 46 (emphasis added). The Memo attempts to remedy this omission by belatedly supplying "additional analysis and statement of intent regarding the regulation." Johnson Memo at 9. Analysis in a memo, however, is an inadequate substitute for the missing analysis in the rulemaking itself. The EAB held that the analysis should be in the preamble, and the failure to include it deprives the public of proper notice and the opportunity to comment.

Indeed, *ejusdem generis* is entirely inapplicable in this situation. The fundamental dispute here concerns the meaning of a broadly-worded provision of the Clean Air Act, not the nearly identical language of a subsection of the regulation. The Act does not contain a list; it contains a single broad category of pollutants "subject to regulation." The Supreme Court has cautioned against narrowly interpreting the broad language of the Clean Air Act. *Massachusetts*, 127 S.Ct. at 1462. EPA may not restrict that language through the back door by interpreting a parroting regulation with a narrowing canon of construction not suited to the statute itself.

Even looking at only the regulation, applying *ejusdem generis* is inappropriate because "the whole context dictates a different conclusion." *Norfolk & W. Ry. Co. v. Am. Train Dispatchers' Ass'n*, 499 U.S. 117, 129 (1991). The first three subsections of the regulation refer to pollutants subject to a "standard" that has been promulgated, while the fourth covers "[a]ny pollutant that is *otherwise* subject to *regulation* under the Act." 40 C.F.R. 52.21(b)(50) (emphasis added). The use of "otherwise" and "regulation" indicates that it applies to pollutants regulated in some other way than by a standard. Moreover, subsections (i) through (iii) are not so alike, since subsection (i) refers to ambient air quality standards that in and of themselves do not require control of emissions, (ii) refers to standards governing emissions from sources, and (iii) refers to standards that only indirectly control emissions. Tellingly, the "general class" that the Johnson Memo identifies ("pollutants that are subject to a promulgated regulation requiring actual control of a *pollutant*") differs from the other iterations of the interpretation (pollutants subject to a regulation "that requires actual control of *emissions* of that pollutant)," in a way evidently designed to minimize the differences among the three pollutant categories enumerated. Memo at 8, 1 (emphasis added).

C. The Johnson Memo Contravenes the Purpose and Structure of the Clean Air Act By Prohibiting BACT for CO_2 Emissions.

Limiting BACT as described in the Johnson Memo ignores the broad, protective purpose of the PSD program. Congress explicitly stated that the purpose of the PSD program was to "protect public health and welfare from **any** actual or **potential adverse effect** which in the Administrator's judgment may reasonably be anticipate[d] to occur from air pollution . . . notwithstanding attainment and maintenance of all national ambient air quality standards." 42 U.S.C. § 7470(1) (emphasis added). In stark contrast, Congress required EPA to make an endangerment finding before establishing generally applicable standards such as the NAAQS, New Source Performance Standards, or motor vehicle emissions standards. Each of these programs expressly require EPA to find that emissions of a pollutant "cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare" as a prerequisite to regulation. *Id.* § 7408(a)(1)(A); *id.* § 7521(a)(1); *see also id.* § 7411(b)(1).

In the PSD program, Congress used language showing that it clearly intended that BACT apply regardless of whether an endangerment finding had been made for that pollutant. Thus Congress – which was quite familiar with the "endangerment trigger" – deliberately established a much lower threshold for requiring BACT than an "endangerment finding." Thus requiring BACT for "each pollutant subject to regulation under the Act" meshes perfectly with the purpose of the PSD program to guard against any "potential adverse effect" as opposed to "endangerment of public health or welfare." And because the BACT analysis entails a case-by-case inquiry, it is more dynamic in assimilating new information than other statutory standards, such as New Source Performance Standards.

As the Johnson Memo's focus on endangerment demonstrates, *see, e.g.*, Johnson Memo at 18, the interpretation it adopts improperly limits the scope of the PSD program and the BACT requirement. It ignores the broader purpose of the PSD program by limiting the BACT requirement to pollutants already subject to limitations on emissions. *Id.* at 13. Strangely, it attempts to justify this interpretation by stating: "The fact that Congress specified in the Act that BACT could be no less stringent than NSPS and other control requirements under the Act indicates that Congress expected BACT to apply to pollutants controlled under these programs." *Id.* But, quite obviously, the fact that BACT *applies* to pollutants controlled under those programs does not mean that it is *limited* to them. Instead, the congressional directive that BACT be no less stringent than those other control requirements is a further indication that BACT is meant to be ***more*** protective and apply more broadly. The Johnson Memo demonstrates a fundamental misperception of the role of the PSD program and its BACT requirement within the Act.

D. The Need to Study Pollutants Does Not Justify Prohibiting BACT for CO_2.

The Johnson Memo defends the decision to prohibit BACT limits for CO_2 by asserting that it would "frustrate the Agency's ability to gather information using Section 114 and other authority and make informed and reasoned judgments about the need to establish controls or limitations on individual pollutants." *Id.* at 9. This rationale is nothing but a red herring. Throughout the *Bonanza* proceeding, EPA has not identified a single pollutant other than CO_2 that would be affected by an interpretation of "regulation" in Section165 to include monitoring and reporting regulations. EPA is free to gather information about pollutants under Section 114 without adopting regulations. And Congress explicitly singled out CO_2 as a pollutant of special concern in Section 821. Nothing in that provision indicates that Congress intended CO_2 to be considered regulated under the Act for some purposes but not for other purposes. If Congress directs EPA to adopt monitoring regulations under the CAA for particular pollutants, it can choose to expressly exclude those pollutants from BACT requirements, but it did not do so in Section 821.

The Johnson Memo opines that "[t]he current concerns over global climate change should not drive EPA into adopting an unworkable policy of requiring emissions controls under the PSD program any time that EPA promulgates a rule under the Act that requires a source to gather or report emissions data under the Act for any pollutant." *Id.* at 10. But EPA has not demonstrated that anything is unworkable about requiring BACT for pollutants subject to monitoring regulations when Congress has expressly singled out specific pollutants for regulation without excluding them from BACT. And it has not demonstrated that BACT would be required in any other situation. EPA has pointed to nothing in the Act that supports its position that requiring BACT for pollutants subject to monitoring conflicts with Congress' information-gathering objectives under the Act. *See Massachusetts,* 127 S.Ct. at 1460-61 ("And unlike EPA, we have no difficulty reconciling Congress' various efforts to promote . . . research to better understand climate change with the agency's pre-existing mandate to regulate 'any air pollutant' that may endanger the public welfare.") (footnote and citation omitted). As the Supreme Court has held, EPA cannot ignore its duties under the Clean Air Act to address pollutants that cause global climate change, and the statute offers the regulatory flexibility needed to do so. *Id.* at 1462.

The plain language of the Clean Air Act, its structure, and authoritative regulatory history of the phrase, "subject to regulation under this Chapter" all support the conclusion that BACT is required for *each* pollutant subject to any sort of regulation under the Act. The EAB has held that EPA has never established a contrary position in any action entitled to deference, and it may not now do so in an internal agency memorandum.

III. EPA SHOULD STAY THE EFFECT OF THE JOHNSON MEMO

By its own terms, the Johnson Memo purports to go into effect "immediately." Johnson Memo at 2. Because the Memo so clearly violates both the procedural requirements of the Administrative Procedure Act, the Clean Air Act, and the *Bonanza* decision, as well as the substantive requirements of the Clean Air Act, EPA should stay implementation of the Memo during the pendency of this Petition for Reconsideration and during the pendency of any challenge to the Memo in the U.S. Court of Appeals for the District of Columbia Circuit.

CONCLUSION

EPA must reconsider its final action for all of the reasons stated above.

DATED: January 6, 2009

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Attachment C

Weyman Lee

From: Brian Lusher
Sent: Wednesday, September 10, 2008 3:19 PM
To: Weyman Lee
Subject: Fast start up text

The District has been closely following the recent development of new technologies that will allow facilities to reduce their startup times. The District is aware of the software and other operation modifications that have the potential to achieve significant emissions reductions, although it should be noted that at this stage these modifications have only limited operational experience. In addition, some designs utilize an additional source such as an auxiliary boiler which has additional emissions associated with it that would offset the reductions from the shortened startup times. It should be noted that most of the reduced startup time technologies require some new hardware and retrofit packages are not commercially available at this time.

The District has reviewed information about some of the reduced startup time gas turbine/HRSG designs and would note that these designs offer reduced startup times and reduced startup emissions. However, most of these designs are not as efficient as a base load design combined cycle turbine/HRSG plant such as Gateway. The March 2001 Final Staff Assessment for the project has the plant efficiency at 54.1% on a Lower Heating Value basis. The District has reviewed some of the new reduced startup designs that are intermediate peaking designs and these plants have an efficiency just below 50% on a Lower Heating Value basis.

The Gateway project was originally permitted in 2001, however, and at the time such these technologies had not yet been developed. As a result, they were not included in the design and permitting of the project. Moreover, the project owner purchased the combustion turbines and steam turbine generator at that time. Requiring the project to incorporate such technologies at this stage would necessitate a complete redesign of the project and the purchase of new equipment. It would therefore not technologically feasible to implement these reduced start time technologies for the Gateway project at this time.

[redacted]

Attachment D

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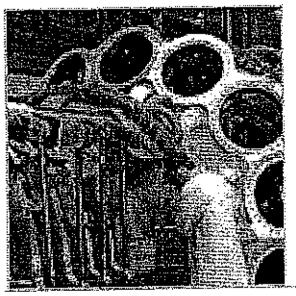
H System™ Combined Cycle Gas Turbine



60 Percent Fuel Efficiency

GE's H System – an advanced combined cycle system capab breaking the 60 percent efficiency barrier – integrates the gas steam turbine and heat recovery steam generator into a seam system, optimizing each component's performance. Undoubte leading technology for both 50 and 60 Hz applications, the H (higher efficiency and output to reduce the cost of electricity of fired power generation system.

Features & Benefits

Closed-Loop Steam Cooling

Open loop air-cooled gas turbines have a significant temperature drop across the first stage nozzles, which reduces firing temperature. The closed-loop steam cooling system allows the turbine to fire at a higher temperature for increased performance, yet without increased combustion temperatures or their resulting increased emissions levels. This closed-loop steam cooling enables the H System to achieve 60 percent fuel efficiency at rated conditions while adhering to the strictest low nitrogen oxide standards and reducing carbon dioxide emissions. Additionally, closed-loop cooling also minimizes parasitic extraction of compressor discharge air, thereby allowing more air to flow to the combustor for fuel premixing.

Single Crystal Materials

The use of these advanced materials on the first stage nozzles and buckets, and thermal barrier coatings on the first and second stage nozzles and buckets, ensures these components stand up to high firing temperatures while meeting maintenance intervals.

Dry Low NOx Combustors

Building on GE's design experience, the H System employs a can-annular lean pre-mix DLN-2.5 Dry Low NOx (DLN) Combustor System. Fourteen combustion chambers are used on the 9H, and 12 combustion chambers are used on the 7H. GE DLN combustion systems have demonstrated the ability to achieve low NOx levels in several million hours of field service around the world. The H System DLN 2.5 combustion system wil have increased fuel flexibility, while maintaining the capability to achieve low NOx between 50 and 100% load.

Small Footprint/High Power Density

The H System offers improved power density per installed megawatt compared to other combined cycle systems, once

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Power Systems for the 2' Century: "H" Gas Turbine Combined Cycles (252KE

MPG Video: H System: W Most Advanced Combine Gas Turbine (19MB ZIP)

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News Archive

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Learn more about the H System launch site, Baglan Bay

Combined Cycle Performance at Rated Conditions	**60 Hz (S107H)**	**50 Hz (S 109H)**
Plant Output	400 MW	520 MW
Heat Rate	5,690 Btu/kWh (6,000 kj/kWh)	5,690 Btu/kWh (6,000 kj/kWh)
Net Plant Efficiency	60 Percent	60 Percent
Gas Turbine Number and Type	1x MS7001H	1x MS9001H

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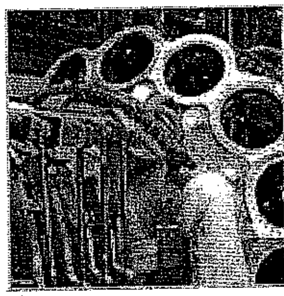
H System™ Combined Cycle Gas Turbine



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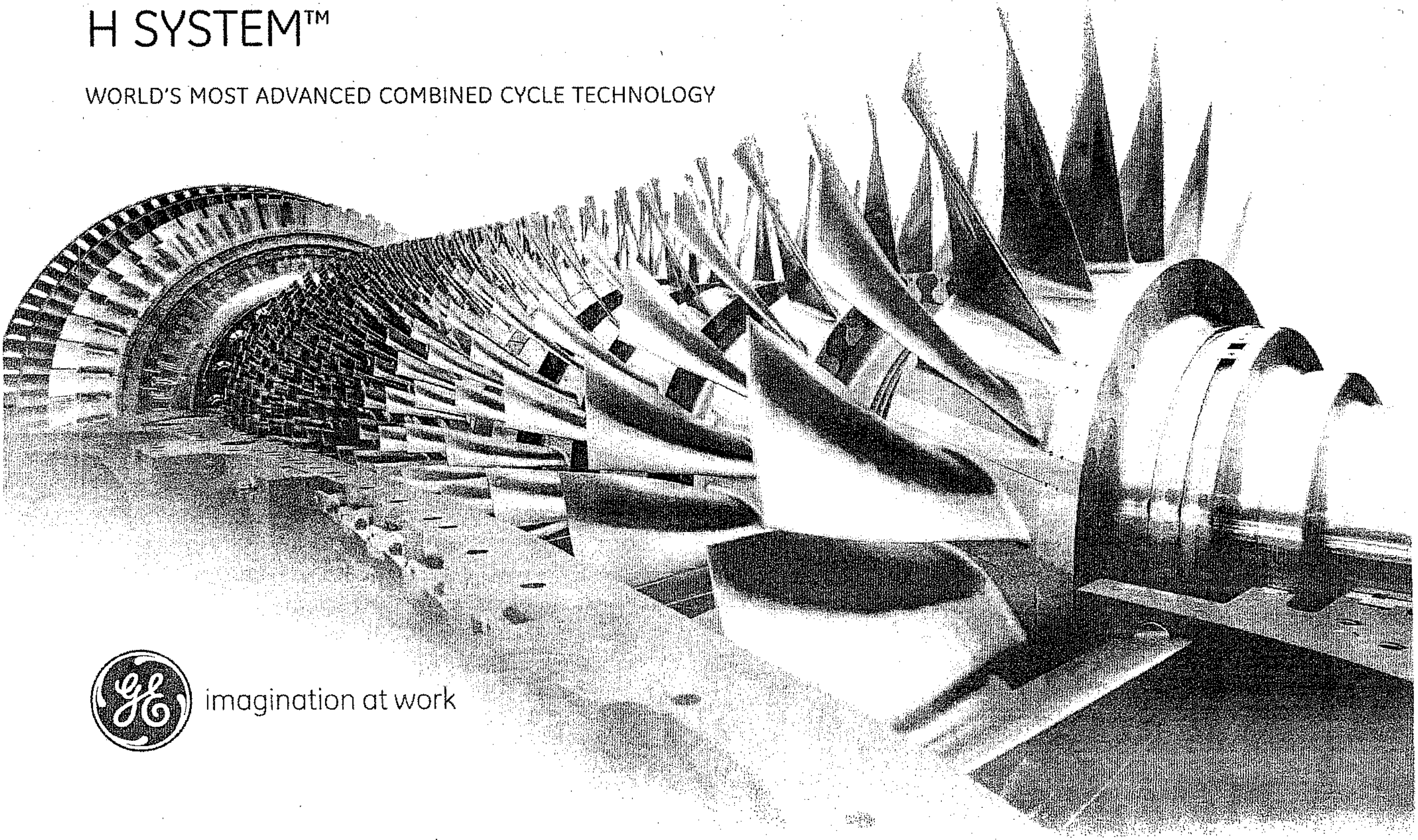
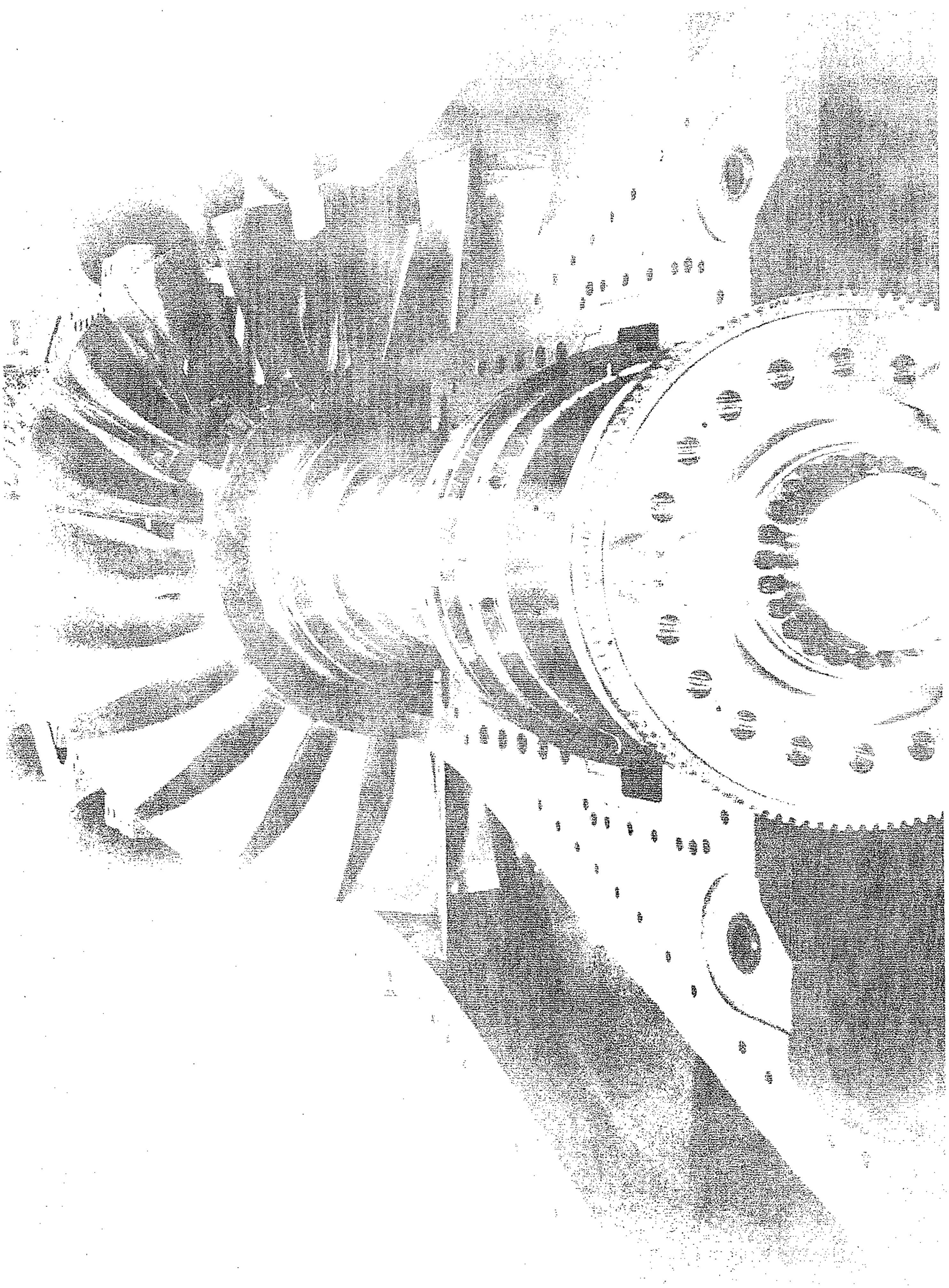
H SYSTEM™

WORLD'S MOST ADVANCED COMBINED CYCLE TECHNOLOGY



imagination at work



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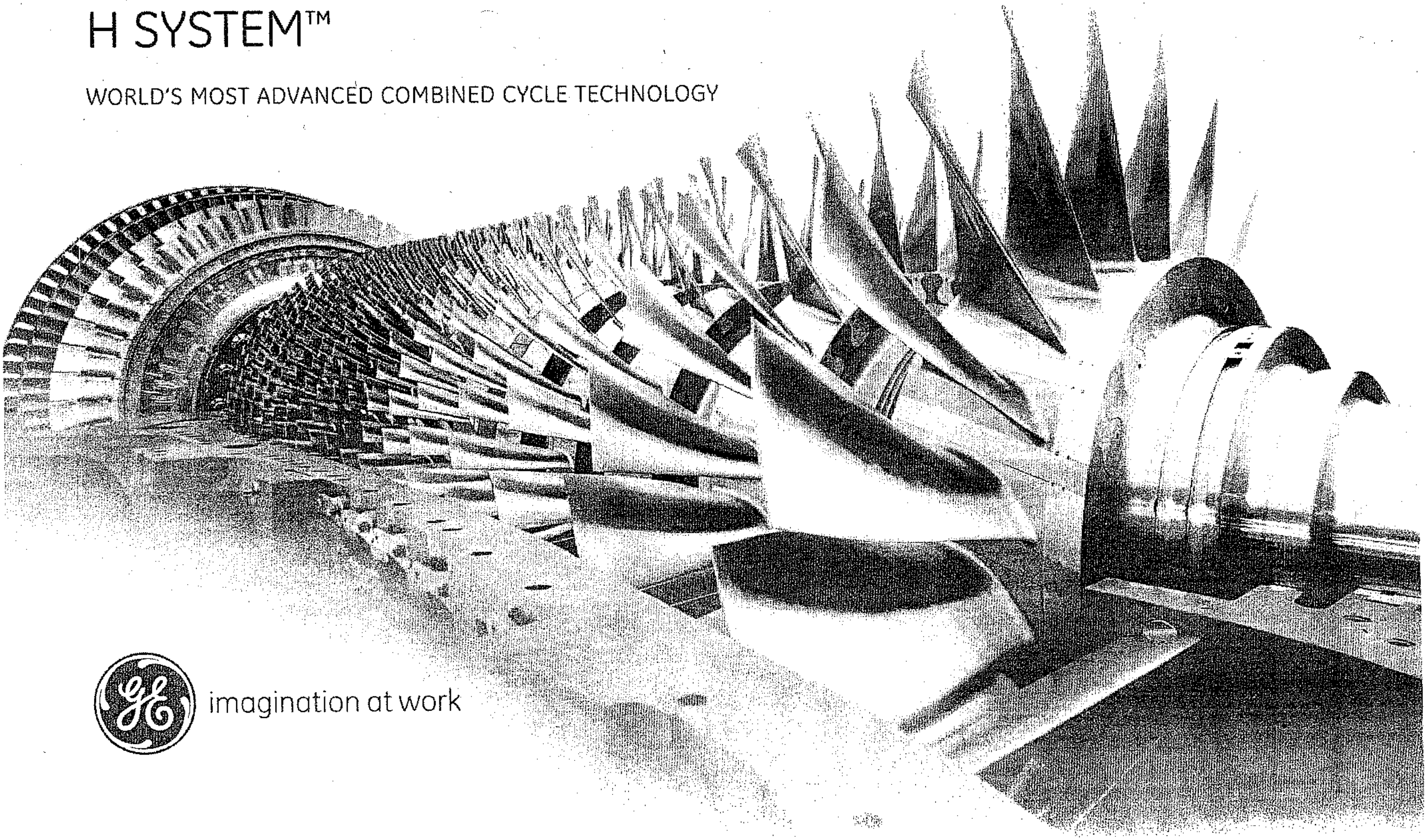

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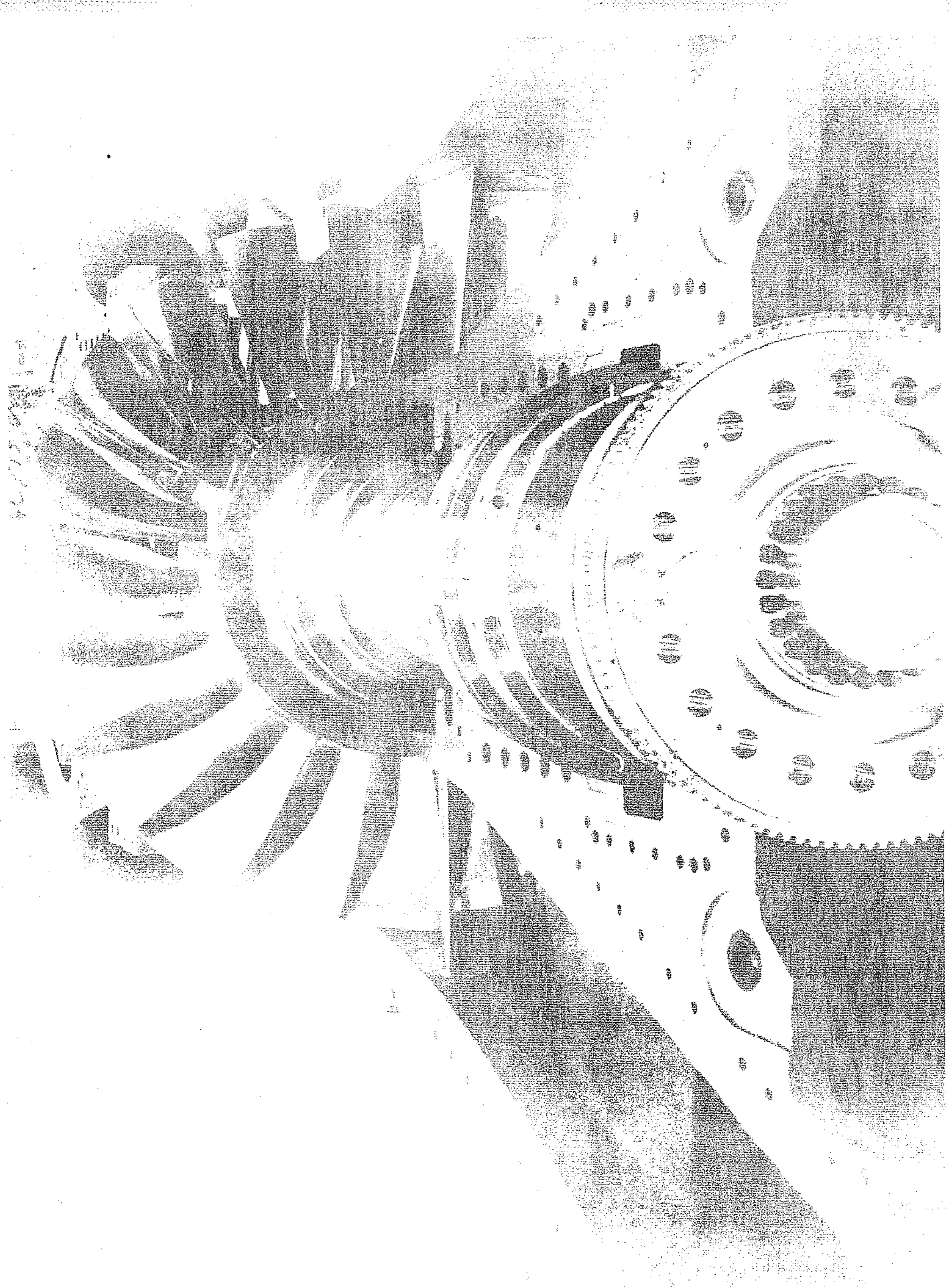

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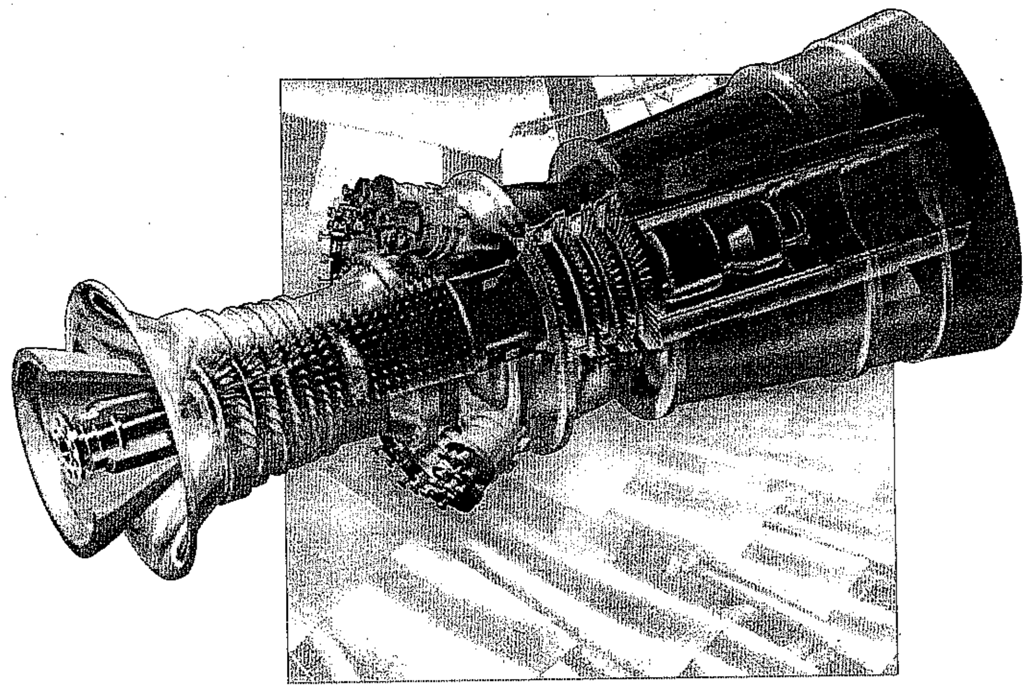
GE's H System™—the world's most advanced combined cycle system and the first capable of breaking the 60% efficiency barrier—integrates the gas turbine, steam turbine and heat recovery steam generator into a seamless system, optimizing each component's performance. Undoubtedly the leading technology for both 50 and 60 Hz applications, the H delivers higher efficiency and output to reduce the cost of electricity of this gas-fired power generation system.



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Single Crystal Materials

The use of these advanced materials, on the first stage nozzles and buckets, and Thermal Barrier Coatings, on the first and second stage nozzles and buckets, ensures that these components will stand up to high firing temperatures while meeting maintenance intervals.

Dry Low NO_x Combustors

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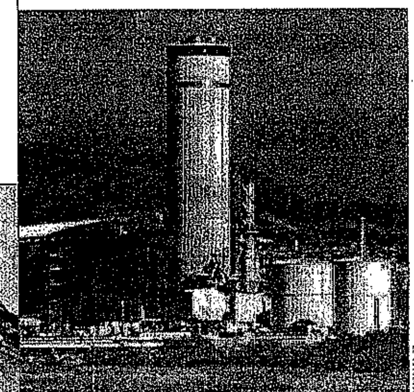

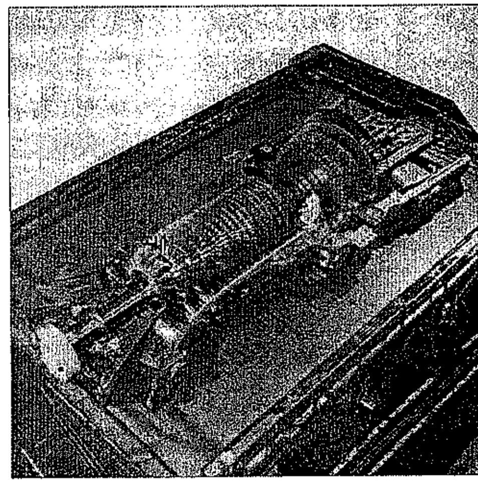

An MS9001H is seen during assembly in the factory.

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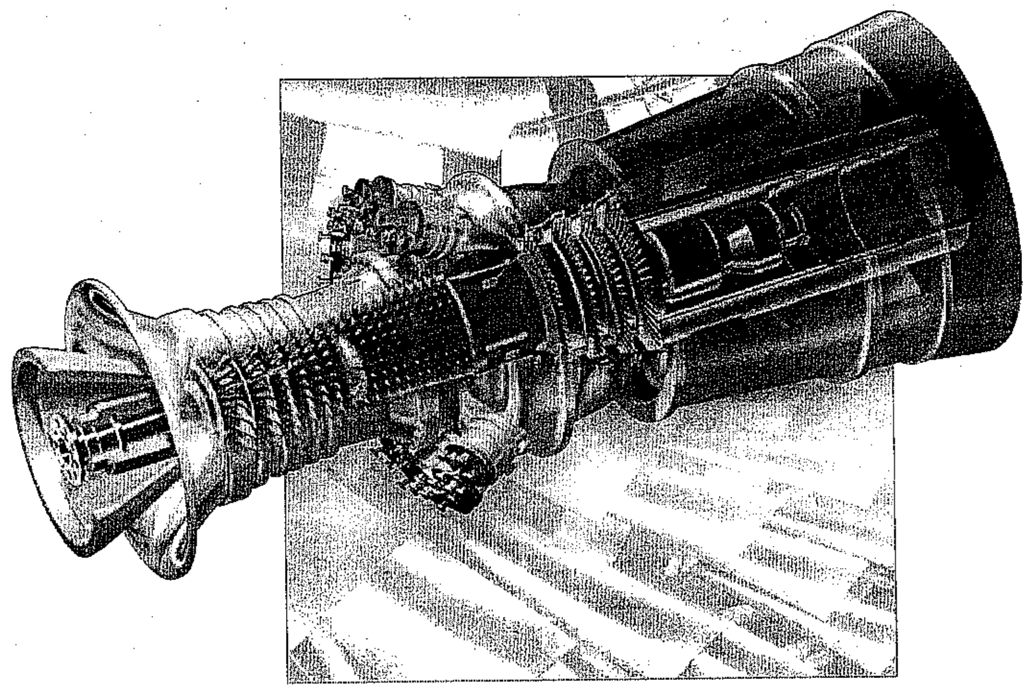

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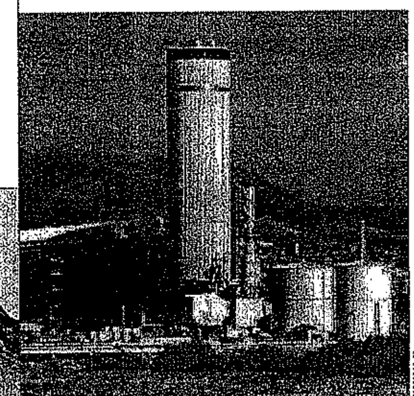

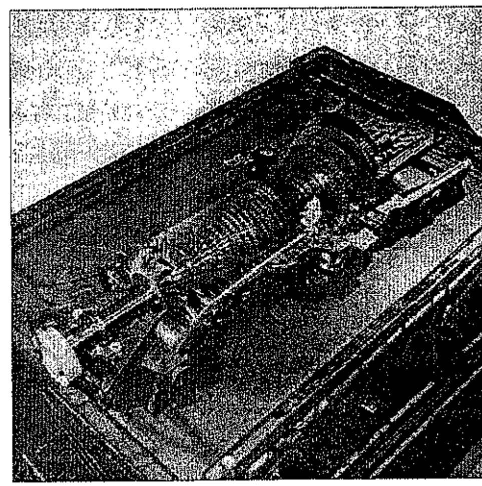

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Small Footprint/High Power Density

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Thoroughly Tested

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MS9001H/MS7001H Combined Cycle Performance

		Net Plant Output (MW)	Heat Rate (Btu/kWh)	Heat Rate (kJ/kWh)	Net Plant Efficiency	GT Number & Type
50 Hz	S109H	520	5,690	6,000	60.0%	1 x MS9001H
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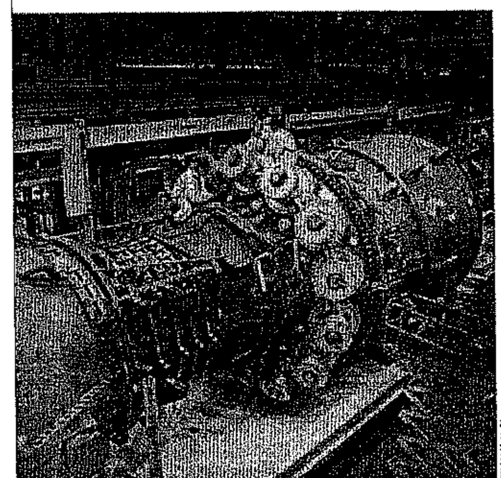

A 9H gas turbine is readied for testing.

Baglan Bay Power Station Port Talbot, Wales*

100% GE-owned investment in validation of the revolutionary H System™ technology and turnkey construction—comprised of two power plants.

109H System Combined Cycle Power Plant

- 520 MW; single shaft
- Firing temperature class: 1430°C (2600°F)
- 18 stage compressor w/23:1 pressure ratio; airflow 1510 lbs/sec
- 14 can DLN 2.5; NO_x emissions: < 25 ppm

Steam Turbine: GE design; reheat, single flow exhaust; co-mfg. with Toshiba

Generator: GE 550 MW LSTG; 660 MVA liquid cooled

HRSG: 3 pressure level reheat

LM2500 Combined Heat and Power Plant

- 33 MW GE LM2500
- HRSG; auxiliary boiler and 2 cell process cooling tower
- Plant provides utility supply to Baglan Energy Park**
  — Electricity, steam, demineralized and attemperated water, process cooling
- Blackstart capability

Other Baglan Power Station Features

- GE Mark VI-based Integrated Control System
- 10 cell cooling tower
- Chimney: triple flue; slip form poured
- GE Water Technologies Treatment Plant
- 275 kV switchyard connecting to National Transmission (Electricity) System
- 33 kV switchyard with local supply to Baglan Energy Park
- Pipeline Reception Facility (PRF)
  — For 12 km Baglan pipeline spur to National Transmission (Gas) System
  — Gas compression and pressure reduction capability, featuring GE centrifugal compressors

* Plant located on site leased from BP
** Baglan Energy Park
• Joint development among BP, Welsh Development Agency and Neath Port Talbot County Borough Council

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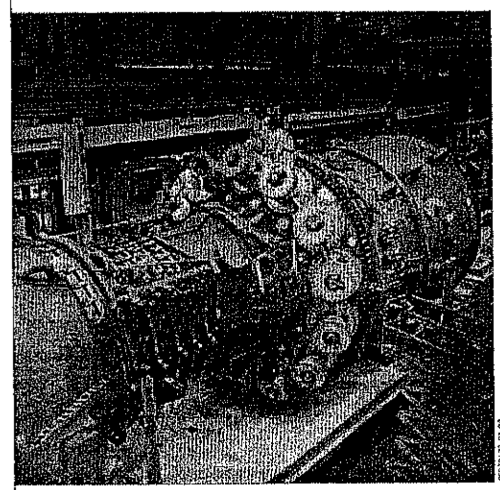

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Cover Photo: PSP30502-01, Inside Cover Photos: PSP30502-02, PSP30336 Designed by GE Energy's Creative Services team.

GE Products and Services Used at Baglan Include:

9H Gas Turbine, LP Steam Turbine, Generator and other Power Train Equipment and Accessories

EPC Project Management

Technical Advisors

Operations & Maintenance; Monitoring and Diagnostics

LM2500, Plant Compressors, Gas Compressors

Water Treatment Systems

2 MW Diesel Generator

Construction and Testing Power (Energy Rentals)

Switchyard Control System; GT Instruments

BOP PLCs and Operator Interfaces

Plant-Merchant Systems Integration Software

IT Integration Support

Plant Financing

Integrated Control System with Mark VIs

6.9 kV Switchgear

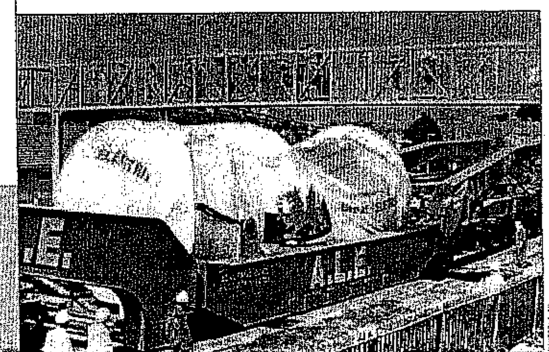
Various Pump and Valve Motors

Turbine Hall and BOP Lighting

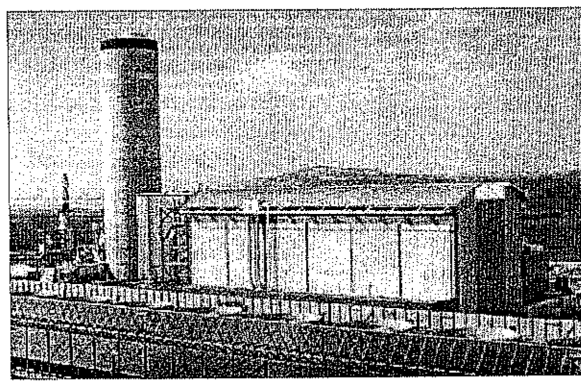
PRF Control Systems Integration

Commissioning

Pipe Installation Technical Advisors



World's first 9H gas turbine is transported through Wales to Baglan Bay Power Station.



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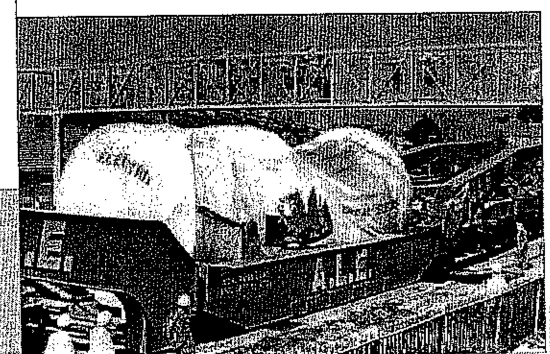

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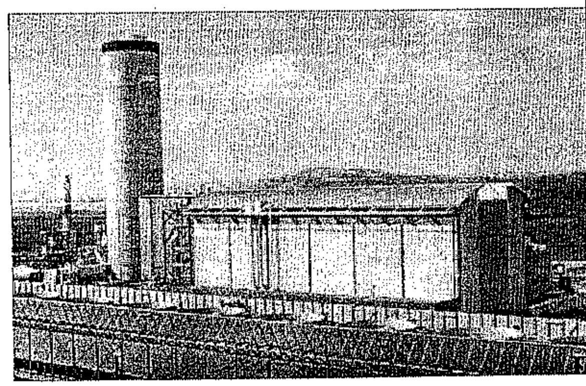

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GE Power Systems

Power Systems for the 21st Century – "H" Gas Turbine Combined-Cycles

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Contents

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Abstract

This paper provides an overview of GE's *H System*™ technology and describes the intensive development work necessary to bring this revolutionary technology to commercial reality. In addition to describing the magnitude of performance improvement possible through use of *H System*™ technology, this paper discusses the technological milestones during the development of the first 9H (50 Hz) and 7H (60 Hz) gas turbines.

To illustrate the methodical product development strategy used by GE, this paper discusses several technologies which are essential to the introduction of the *H System*™. Also included herein are analyses of the series of comprehensive tests of materials, components and subsystems which necessarily preceded full-scale field testing of the *H System*™. This paper validates one of the basic premises on which GE started the *H System*™ development program: Exhaustive and elaborate testing programs minimize risk at every step of this process, and increase the probability of success when the *H System*™ is introduced into commercial service.

In 1995, GE, the world leader in gas turbine technology for over half a century, introduced its new generation of gas turbines. This *H System*™ technology is the first gas turbine ever to achieve the milestone of 60% fuel efficiency. Because fuel represents the largest individual expense of running a power plant, an efficiency increase of even a single percentage point can substantially reduce operating costs over the life of a typical gas-fired, combined-cycle plant in the 400 to 500 megawatt range.

The *H System*™ is not simply a state-of-the-art gas turbine. It is an advanced, integrated, combined-cycle system every component of which is optimized for the highest level of performance.

The unique feature of an H technology, combined-cycle system is the integrated heat transfer system, which combines both the steam plant reheat process and gas turbine bucket and nozzle cooling. This feature allows the power generator to operate at a higher firing temperature, which in turn produces dramatic improvements in fuel-efficiency. The end result is generation of electricity at the lowest, most competitive price possible. Also, despite the higher firing temperature of the *H System*™, combustion temperature is kept at levels that minimize emission production.

GE has more than two million fired hours of experience in operating advanced technology gas turbines, more than three times the fired hours of competitors' units combined. The *H System*™ design incorporates lessons learned from this experience with knowledge gleaned from operating GE aircraft engines. In addition, the 9H gas turbine is the first ever designed using "Design for Six Sigma" methodology, which maximizes reliability and availability throughout the entire design process. Both the 7H and 9H gas turbines will achieve the reliability levels of our F-class technology machines.

GE has tested its *H System*™ gas turbine more thoroughly than any system previously introduced into commercial service. The *H System*™ gas turbine has undergone extensive design validation and component testing. Full-speed, no-load testing (FSNL) of the 9H was achieved in May 1998 and pre-shipment testing was completed in November 1999. This *H System*™ will also undergo approximately a half-year of extensive demonstration and characterization testing at the launch site.

Testing of the 7H began in December 1999, and full-speed, no-load testing was completed in February 2000. The 7H gas turbine will also be subjected to extensive demonstration and characterization testing at the launch site.

Background and Rationale for the H System™

The use of gas turbines for power generation has been steadily increasing in popularity for more than five decades. Gas turbine cycles are inherently capable of higher power density, higher fuel efficiency, and lower emissions than the competing platforms. Gas turbine performance is driven by the firing temperature, which is directly related to specific output, and inversely related to fuel consumption per kW of output. This means that increases in firing temperature provide higher fuel efficiency (lower fuel consumption per kW of output) and, at the same time, higher specific output (more kW per pound of air passing through the turbine).

The use of aircraft engine materials and cooling technology has allowed firing temperature for GE's industrial gas turbines to increase steadily. However, higher temperatures in the combustor also increase NO_x production. In the "Conceptual Design" section of this paper, we describe how the GE *H System*™ solved the NO_x problem, and is able to raise firing temperature by 200°F / 110°C over the current "F" class of gas turbines and hold the NO_x emission levels at the initial "F" class levels.

The General Electric Company is made up of a number of different businesses. The company has thrived and grown due, in part, to the rapid transfer of improved technology and business practices among these businesses. The primary technology transfer channel is the GE Corporate Research & Development (CR&D) Center located in Schenectady, NY. The *H System*™ new product introduction (NPI) team is also located in Schenectady, facilitating the efficient transfer of technology from CR&D to the NPI team. Formal technology councils, including, for instance, the Thermal Barrier Coatings Council, High Temperature Materials Council, and the Dry Low NO_x (DLN) Combustion Council, also promote synergy among the businesses, fostering development of advanced technology.

GE Power Systems (GEPS) and GE Aircraft Engines (GEAE) share many common links, including testing facilities for DLN, compressor components, and steam turbine components. In a move which could only have occurred within GE, with its unique in-house resources, over 200 engineers were transferred from GEAE and CR&D to GEPS, to support the development of the *H System*™. These transfers became the core of the *H System*™*'s* "Design and Systems" teams. *H System*™ technology is shared in its entirety between GEPS and GEAE, including test data and analytical codes.

In contrast to the free exchange of core technical personnel between GEPS and GEAE, several of GE's competitors have been forced to purchase limited aircraft engine technology from outside companies. This approach results in the acquisition of a specific design with limited detail and flexibility, but with no understanding of the underlying core technology.

In contrast, the transfer from GE Aircraft Engines to GEPS includes, but is not limited to, the following technologies, which are described later in the paper:

- Compressor aerodynamics, mechanical design and scale model rig testing
- Full-scale combustor testing at operating pressures and temperatures
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- Processing for turbine blade and wheel superalloys

Abstract

This paper provides an overview of GE's *H System*™ technology and describes the intensive development work necessary to bring this revolutionary technology to commercial reality. In addition to describing the magnitude of performance improvement possible through use of *H System*™ technology, this paper discusses the technological milestones during the development of the first 9H (50 Hz) and 7H (60 Hz) gas turbines.

To illustrate the methodical product development strategy used by GE, this paper discusses several technologies which are essential to the introduction of the *H System*™. Also included herein are analyses of the series of comprehensive tests of materials, components and subsystems which necessarily preceded full-scale field testing of the *H System*™. This paper validates one of the basic premises on which GE started the *H System*™ development program: Exhaustive and elaborate testing programs minimize risk at every step of this process, and increase the probability of success when the *H System*™ is introduced into commercial service.

In 1995, GE, the world leader in gas turbine technology for over half a century, introduced its new generation of gas turbines. This *H System*™ technology is the first gas turbine ever to achieve the milestone of 60% fuel efficiency. Because fuel represents the largest individual expense of running a power plant, an efficiency increase of even a single percentage point can substantially reduce operating costs over the life of a typical gas-fired, combined-cycle plant in the 400 to 500 megawatt range.

The *H System*™ is not simply a state-of-the-art gas turbine. It is an advanced, integrated, combined-cycle system every component of which is optimized for the highest level of performance.

The unique feature of an H technology, combined-cycle system is the integrated heat transfer system, which combines both the steam plant reheat process and gas turbine bucket and nozzle cooling. This feature allows the power generator to operate at a higher firing temperature, which in turn produces dramatic improvements in fuel-efficiency. The end result is generation of electricity at the lowest, most competitive price possible. Also, despite the higher firing temperature of the *H System*™, combustion temperature is kept at levels that minimize emission production.

GE has more than two million fired hours of experience in operating advanced technology gas turbines, more than three times the fired hours of competitors' units combined. The *H System*™ design incorporates lessons learned from this experience with knowledge gleaned from operating GE aircraft engines. In addition, the 9H gas turbine is the first ever designed using "Design for Six Sigma" methodology, which maximizes reliability and availability throughout the entire design process. Both the 7H and 9H gas turbines will achieve the reliability levels of our F-class technology machines.

GE has tested its *H System*™ gas turbine more thoroughly than any system previously introduced into commercial service. The *H System*™ gas turbine has undergone extensive design validation and component testing. Full-speed, no-load testing (FSNL) of the 9H was achieved in May 1998 and pre-shipment testing was completed in November 1999. This *H System*™ will also undergo approximately a half-year of extensive demonstration and characterization testing at the launch site.

Testing of the 7H began in December 1999, and full-speed, no-load testing was completed in February 2000. The 7H gas turbine will also be subjected to extensive demonstration and characterization testing at the launch site.

Background and Rationale for the H System™

The use of gas turbines for power generation has been steadily increasing in popularity for more than five decades. Gas turbine cycles are inherently capable of higher power density, higher fuel efficiency, and lower emissions than the competing platforms. Gas turbine performance is driven by the firing temperature, which is directly related to specific output, and inversely related to fuel consumption per kW of output. This means that increases in firing temperature provide higher fuel efficiency (lower fuel consumption per kW of output) and, at the same time, higher specific output (more kW per pound of air passing through the turbine).

The use of aircraft engine materials and cooling technology has allowed firing temperature for GE's industrial gas turbines to increase steadily. However, higher temperatures in the combustor also increase NO_x production. In the "Conceptual Design" section of this paper, we describe how the GE *H System*™ solved the NO_x problem, and is able to raise firing temperature by 200°F / 110°C over the current "F" class of gas turbines and hold the NO_x emission levels at the initial "F" class levels.

The General Electric Company is made up of a number of different businesses. The company has thrived and grown due, in part, to the rapid transfer of improved technology and business practices among these businesses. The primary technology transfer channel is the GE Corporate Research & Development (CR&D) Center located in Schenectady, NY. The *H System*™ new product introduction (NPI) team is also located in Schenectady, facilitating the efficient transfer of technology from CR&D to the NPI team. Formal technology councils, including, for instance, the Thermal Barrier Coatings Council, High Temperature Materials Council, and the Dry Low NO_x (DLN) Combustion Council, also promote synergy among the businesses, fostering development of advanced technology.

GE Power Systems (GEPS) and GE Aircraft Engines (GEAE) share many common links, including testing facilities for DLN, compressor components, and steam turbine components. In a move which could only have occurred within GE, with its unique in-house resources, over 200 engineers were transferred from GEAE and CR&D to GEPS, to support the development of the *H System*™. These transfers became the core of the *H System*™*'s* "Design and Systems" teams. *H System*™ technology is shared in its entirety between GEPS and GEAE, including test data and analytical codes.

In contrast to the free exchange of core technical personnel between GEPS and GEAE, several of GE's competitors have been forced to purchase limited aircraft engine technology from outside companies. This approach results in the acquisition of a specific design with limited detail and flexibility, but with no understanding of the underlying core technology.

In contrast, the transfer from GE Aircraft Engines to GEPS includes, but is not limited to, the following technologies, which are described later in the paper:

- Compressor aerodynamics, mechanical design and scale model rig testing
- Full-scale combustor testing at operating pressures and temperatures
- Turbine aerodynamics, heat transfer, and nozzle cascade testing
- Transfer of materials and coating data
- Processing for turbine blade and wheel superalloys

- Gas turbine instrumentation application and monitoring.

Technology contributed by CR&D includes:

- Development of heat transfer and fluid flow codes
- Process development for thermal barrier coatings
- Materials characterization and data
- Numerous special purpose component and subsystem tests
- Design and introduction of non-destructive evaluation techniques.

Conceptual Design

The GE *H System*™ is a combined-cycle plant. The hot gases from the gas turbine exhaust proceed to a downstream boiler or heat recovery steam generator (HRSG). The resulting steam is passed through a steam turbine and the steam turbine output then augments that from the gas turbine. The output and efficiency of the steam turbine's "bottoming cycle" is a function of the gas turbine exhaust temperature.

For a given firing temperature class, 2600°F / 1430°C for the *H System*™, the gas turbine exhaust temperature is largely determined by the work required to drive the compressor, that is, in turn, affected by the "compressor pressure ratio". The *H System*™*'s* pressure ratio of 23:1 was selected to optimize the combined-cycle performance, while at the same time allowing for an uncooled last-stage gas turbine bucket, consistent with past GEPS practice.

The 23:1 compressor-pressure ratio, in turn, determined that using four turbine stages would provide the optimum performance and cost solution. This is a major change from the earlier "F" class gas turbines, which used a 15:1 compressor-pressure ratio and three turbine stages. With the *H System*™*'s* higher pressure ratio, the use of only three turbine stages would have increased the loading on each stage to a point where unacceptable reduction in stage efficiencies would result. By using four stages, the H turbine is able to specify optimum work loading for each stage and achieve high turbine efficiency.

The Case for Steam Cooling

The GE *H System*™ gas turbine uses closed-loop steam cooling of the turbine. This unique cooling system allows the turbine to fire at a higher temperature for increased performance, yet without increased combustion temperatures or their resulting increased emissions levels. It is this closed-loop steam cooling that enabled the combined-cycle GE *H System*™ to achieve 60% fuel efficiency while maintaining adherence to the strictest, low NO_x standards (*Figure 1*).

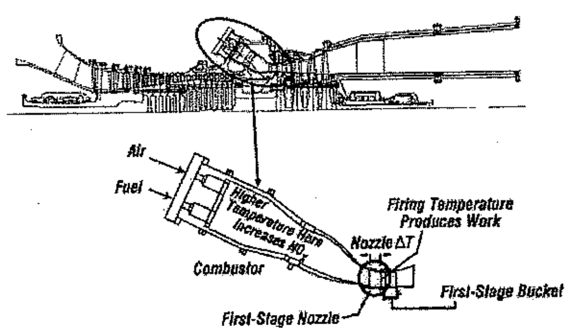

Figure 1. Combustion and firing temperatures

Combustion temperature must be as low as possible to establish low NO_x emissions, while the firing temperature must be as high as possible for optimum cycle efficiency. The goal is to adequately cool the stage 1 nozzle, while minimizing the decrease in combustion product temperature as it passes through the stage 1 nozzle. This is achieved with closed-loop steam cooling.

In conventional gas turbines, with designs predating the *H System*™, the stage 1 nozzle is cooled with compressor discharge air. This cooling process causes a temperature drop across the stage 1 nozzle of up to 280°F/155°C. In H System™ gas turbines, cooling the stage 1 nozzle with a closed-loop steam coolant reduces the temperature drop across that nozzle to less than 80°F/44°C (*Figure 2*). This results in a firing temperature class of 2600°F/1430°C, or 200°F/110°C higher than in preceding systems, yet with no increase in combustion temperature. An additional benefit of the *H System*™ is that while the steam cools the nozzle, it picks up heat for use in the steam turbine, transferring what was traditionally waste heat into usable output. The third advantage of closed-loop cooling is that it minimizes parasitic extraction

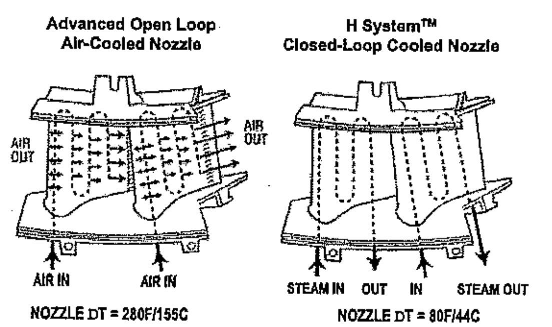

Figure 2. Impact of stage 1 nozzle cooling method

of compressor discharge air, thereby allowing more to flow to the head-end of the combustor for fuel premixing.

In conventional gas turbines, compressor air is also used to cool rotational and stationary components downstream of the stage 1 nozzle in the turbine section. This air is traditional labeled as "chargeable air", because it reduces cycle performance. In *H System*™ gas turbines, this "chargeable air" is replaced with steam, which enhances cycle performance by up to 2 points in efficiency, and significantly increases the gas turbine output, since all the compressor air can be channeled through the turbine flowpath to do useful work. A second advantage of replacing "chargeable air" with steam accrues to the *H System*™*'s* cycle through recovery of the heat removed from the gas turbine in the bottoming cycle.

H Technology, Combined-Cycle System

The H technology, combined-cycle system consists of a gas turbine, a three-pressure-level HRSG and a reheat steam turbine.

The features of the combined-cycle system, which include the coolant steam flow from the steam cycle to the gas turbine, are shown in *Figure 3*. The high-pressure steam from the HRSG is expanded through the steam turbine's high-pressure section. The exhaust steam from this turbine section is then split. One part is returned to the HRSG for reheating; the other is combined with intermediate-pressure (IP) steam and used for cooling in the gas turbine.

Steam is used to cool the stationary and rotational parts of the gas turbine. In turn, the heat transferred from the gas turbine increases the steam temperature to approximately reheat temperature. The gas turbine cooling steam is returned to the steam cycle, where it is mixed with the reheated steam from the HRSG and introduced to the IP steam turbine section. Further details about the H combined-cycle system and its operation can be found in GER 3936A, "Advanced Technology Combined-Cycles" and will not be repeated in this paper.

H Product Family and Performance

The H technology, with its higher pressure ratio and higher firing temperature design, will establish a new family of gas turbine products. The 9H and 7H combined-cycle specifications

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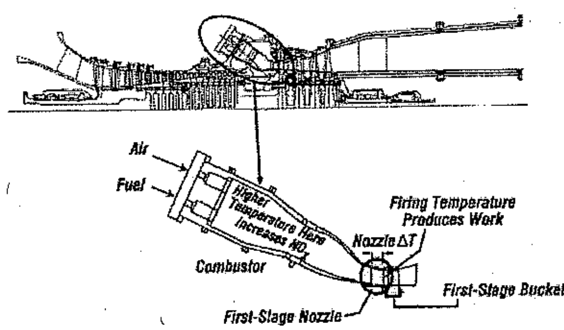

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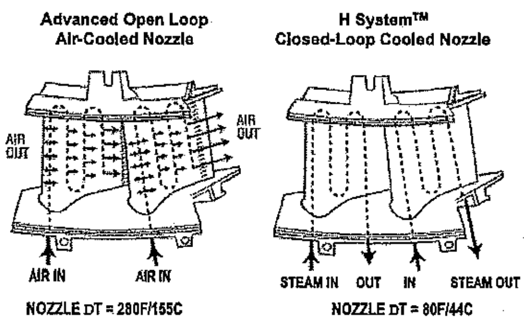

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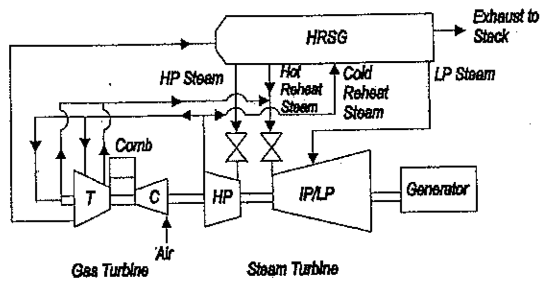

Figure 3. H Combined-cycle and steam description

are compared in *Tables 1 and 2* with the similar "F" technology family members.

The 9H and 7H are not scaled geometrically to one another. This is a departure from past prac-

	9FA	9H
Firing Temperature Class, F (C)	2400 (1316)	2600 (1430)
Air Flow, lb/sec (kg/sec)	1376 (625)	1510 (685)
Pressure Ratio	15	23
Combined Cycle Net Output, MW	391	480
Net Efficiency, %	56.7	60
NO_x (ppmvd at 15% O_2)	25	25

Table 1. H Technology performance characteristics (50 Hz)

	7FA	7H
Firing Temperature Class, F (C)	2400 (1316)	2600 (1430)
Air Flow, lb/sec (kg/sec)	953 (433)	1230 (558)
Pressure Ratio	15	23
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Table 2. H Technology performance characteristics (60 Hz)

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One extremely attractive feature of the H technology, combined-cycle power plants is the high specific output. This permits compact plant designs with a reduced "footprint" when compared with conventional designs, and consequently, the potential for reduced plant capital costs (*Figure 4*). In a 60 Hz configuration, the H technology's compact design results in a 54% increase in output over the FA plants with an increase of just 10% in plant size.

GE is moving forward concurrently with development of the 9H and 7H. However, in response to specific customer commitments, the 9H was

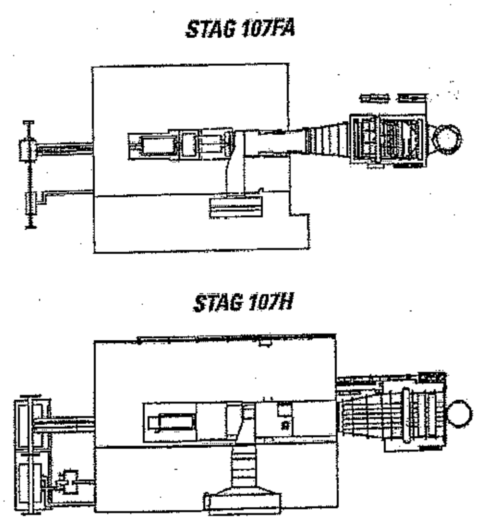

Figure 4. 7H and 7FA footprint comparison

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The 7H development has made progress as part of the Advanced Turbine Systems program of the U.S. Department of Energy and its encouragement and support is gratefully acknowledged.

System Strategy and Integration

While component and subsystem validation is necessary and is the focus of most NPI programs, other factors must also be considered in creating a successful product. The gas turbine must operate as a system, combining the compressor, combustor and turbine at design point (baseload), at part load turndown conditions, and at no load. The power plant and all power island components must also operate at steady state and under transient conditions, from start-up, to purge, to full speed.

Unlike traditional combined-cycle units, the *H System*™ gas turbine, steam turbine and HRSG are linked into one, interdependent system. Clearly, the reasoning behind these GE *H System*™ components runs contrary to the traditional approach, which designs and specifies each component as a stand-alone entity. In the *H System*™, the performance of the gas turbine, combined-cycle and balance of plant has been modeled, both steady state and transient; and analyzed in detail, as one large, integrated system, from its inception.

The GE *H System*™ concept incorporates an integrated control system (ICS) to act as the glue, which ties all the subsystems together (*Figure 5*).

Systems and controls teams, working closely with one another as well as with customers, have formulated improved hardware, software, and control concepts. This integration was facilitated by a new, third-generation, full-authority digital system, the Mark VI controller. This control system was designed with and is supplied by GE Industrial Systems (GEIS), which is yet another GE business working closely with GEPS.

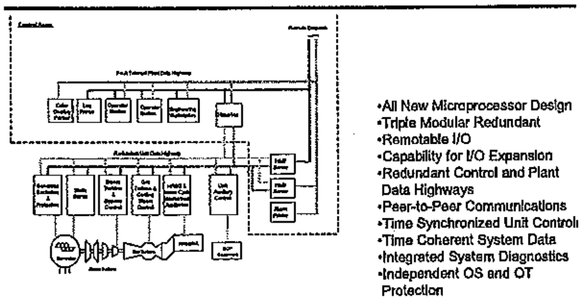

Figure 5. Mark VI – ICS design integrated with *H Systems*™ design

The control system for the *H System*™ manages steam flows between the HRSG, steam turbine and gas turbine. It also schedules distribution of cooling steam to the gas turbine. A diagnostic capability is built into the control system, which also stores critical data in an electronic historian for easy retrieval and troubleshooting.

The development of the Mark VI and integrated control system has been deliberately scheduled ahead of the H gas turbine to reduce the gas turbine risk. With the help of GE CR&D, the Mark VI followed a separate and rigorous NPI risk abatement procedure, which included proof of concept tests and shake down tests of a full combined-cycle plant at GE Aircraft Engines in Lynn, Massachusetts.

The Systems and controls teams have state-of-the-art computer simulations at their disposal to facilitate full engineering of control and fall-back strategies. Digital simulations also serve as a training tool for new operators.

Simulation capability was used in real time during the 9H Full-Speed No-Load (FSNL)-1 test in May 1998. This facilitated revision of the accelerating torque demand curves for the gas turbine and re-setting of the starter motor current and gas turbine combustor fuel schedule. The end result was an automated, one-button, soft-start for the gas turbine, which was used by the TEPCO team to initiate the May 30, 1998 customer witness test.

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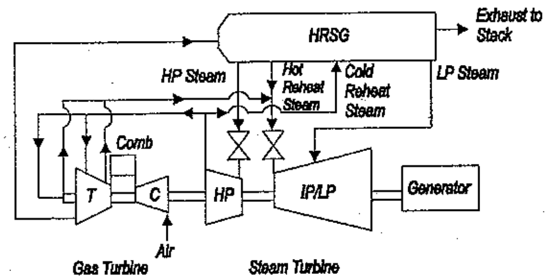

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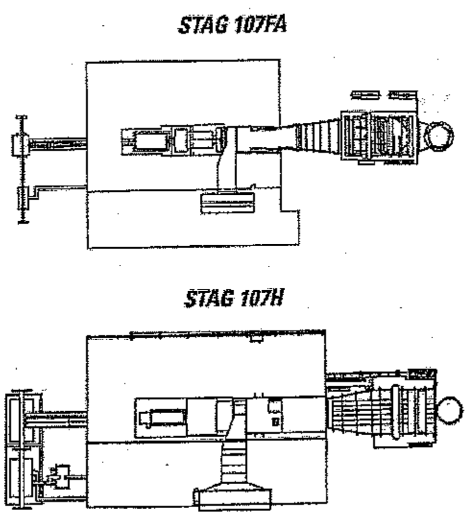

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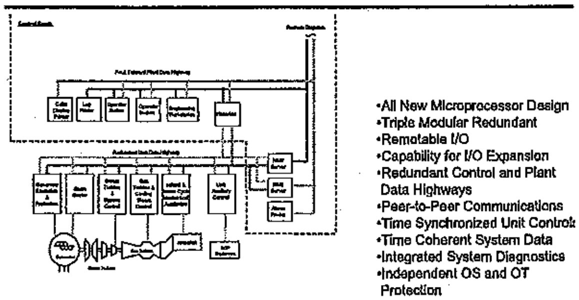

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H Gas Turbine

The heart of the GE *H System*™ is the gas turbine. The challenges, design details, and validation program results follow. We start with a brief overview of the 9H and 7H gas turbine components (*Figure 6*).

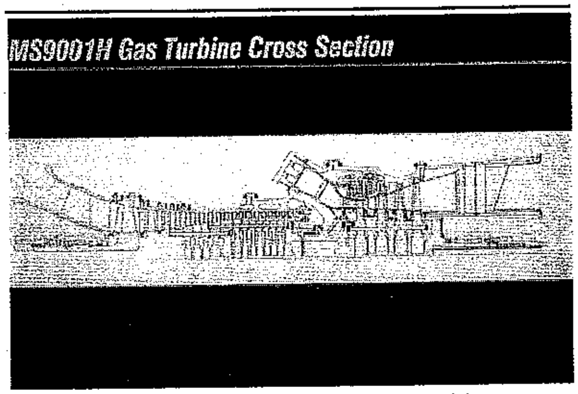

Figure 6. Cross-section H gas turbine

Compressor Overview

The H compressor provides a 23:1 pressure ratio with 1510 lb/s (685 kg/s) and 1230 lb/s (558 kg/s) airflow for the 9H and 7H gas turbines, respectively. These units are derived from the high-pressure compressor GE Aircraft Engines (GEAE) used in the CF6-80C2 aircraft engine and the LM6000 aeroderivative gas turbine. For use in the H gas turbines, the CF6-80C2 compressor has been scaled up (2.6:1 for the MS7001H and 3.1:1 for the MS9001H) with four stages added to achieve the desired combination of airflow and pressure ratio. The CF6 compressor design has accumulated over 20 million hours of running experience, providing a solid design foundation for the *H System*™ gas turbine.

In addition to the variable inlet guide vane (IGV), used on prior GE gas turbines to modulate airflow, the H compressors have variable stator vanes (VSV) at the front of the compressor. They are used, in conjunction with the IGV, to control compressor airflow during turndown, as well as to optimize operation for variations in ambient temperature.

Combustor Overview

The *H System*™ can-annular combustion system is a lean pre-mix DLN-2.5 *H System*™, similar to the GE DLN combustion systems in FA-class service today. Fourteen combustion chambers are used on the 9H, and twelve combustion chambers are used on the 7H. DLN combustion systems have demonstrated the ability to achieve low NO_x levels in field service and are capable of meeting the firing temperature requirements of the GE *H System*™ gas turbine while obtaining single-digit (ppm) NO_x and CO emissions.

Turbine Overview

The case for steam cooling was presented earlier under Conceptual Design. The GE *H System*™ gas turbine's first two stages use closed-loop steam cooling, the third stage uses air cooling, while the fourth and last stage is uncooled.

Closed-loop cooling eliminates the film cooling on the gas path side of the airfoil, and increases the temperature gradients through the airfoil walls. This method of cooling results in higher thermal stresses on the airfoil materials, and has led GEPS to use single-crystal super-alloys for the first stage, in conjunction with thin ceramic thermal barrier coatings (*Figure 7*). This is a combination that GEAE has employed in its jet engines for 20 years. GEPS reached into the extensive GEAE design, analysis, testing and production database and worked closely with GEAE, its supplier base, and CR&D to translate this experience into a reliable and effective feature of the *H System*™ gas turbine design.

GE follows a rigorous system of design practices which the company has developed through hav-

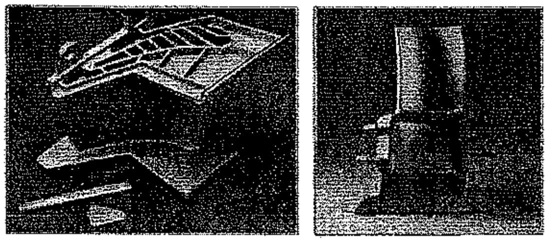

Figure 7. H Stage 1 nozzle and bucket – single crystal

ing a wide range of experiences with gas turbines in the last 20 years. For instance, GEAE's experience base of over 4000 parts indicates that thermal barrier coating on many airfoils is subject to loss early in operation, and that maximization of coating thickness is limited by deposits from environmental elements, evidenced by coating spallation when thickness limits are exceeded. Through laboratory analyses and experience-based data and knowledge, GE has created an airfoil that has shown, during field tests, that it maintains performance over a specific minimum cyclic life coatings, even with localized loss of coatings, as has been noted during field service.

Gas Turbine Validation: Testing to Reduce Risk

Although GEPS officially introduced the *H System*™ concept and two product lines, the 9H and 7H gas turbines, to the industry in 1995, *H System*™ technology has been under development since 1992. The development has been a joint effort among GEPS, GEAE, and CR&D, with encouragement and support from the U.S. Department of Energy, and has followed GE's comprehensive design and technology validation plan that will, when complete, have spanned 10 years from concept to power plant commissioning.

The systematic design and technology-validation approach described in this paper has proved to be the aerospace and aircraft industry's most reliable practice for introduction of complex, cutting-edge technology products. The approach is costly and time consuming, but is designed to deliver a robust product into the field for initial introduction. At its peak, the effort to develop and validate the *H System*™ required the employment of over 600 people and had annual expenses of over $100 million.

Other suppliers perceive that design and construction of a full-scale prototype may be a faster development-and-design approach. However, it is difficult, if not impossible, for a prototype to explore the full operating process in a controlled fashion. For example, prototype testing limits the opportunity to evaluate alternative compressor stator gangs and to explore cause-and-effect among components when problems are encountered. The prototype approach also yields a much greater probability of failure during the initial field introduction of a product than does the comprehensive design approach, coupled with "Six Sigma" disciplines and the technology validation plan used by GE (*Figure 8*).

The first phase in the *H System*™ development process was a thorough assessment of product options, corresponding design concepts, and system requirements. Also crucial in the first phase was careful selection of materials, components and subsystems. These were sorted into categories of existing capabilities or required technology advancements. All resources and technological capabilities of GEAE and CR&D were made available to the Power Systems' H-technology team.

For each component and subsystem, risk was assessed and abatement analyses, testing, and

H Gas Turbine

The heart of the GE *H System*™ is the gas turbine. The challenges, design details, and validation program results follow. We start with a brief overview of the 9H and 7H gas turbine components (*Figure 6*).

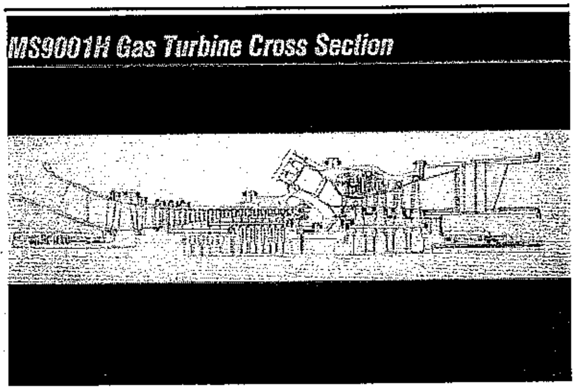

Figure 6. Cross-section H gas turbine

Compressor Overview

The H compressor provides a 23:1 pressure ratio with 1510 lb/s (685 kg/s) and 1230 lb/s (558 kg/s) airflow for the 9H and 7H gas turbines, respectively. These units are derived from the high-pressure compressor GE Aircraft Engines (GEAE) used in the CF6-80C2 aircraft engine and the LM6000 aeroderivative gas turbine. For use in the H gas turbines, the CF6-80C2 compressor has been scaled up (2.6:1 for the MS7001H and 3.1:1 for the MS9001H) with four stages added to achieve the desired combination of airflow and pressure ratio. The CF6 compressor design has accumulated over 20 million hours of running experience, providing a solid design foundation for the *H System*™ gas turbine.

In addition to the variable inlet guide vane (IGV), used on prior GE gas turbines to modulate airflow, the H compressors have variable stator vanes (VSV) at the front of the compressor. They are used, in conjunction with the IGV, to control compressor airflow during turndown, as well as to optimize operation for variations in ambient temperature.

Combustor Overview

The *H System*™ can-annular combustion system is a lean pre-mix DLN-2.5 *H System*™, similar to the GE DLN combustion systems in FA-class service today. Fourteen combustion chambers are used on the 9H, and twelve combustion chambers are used on the 7H. DLN combustion systems have demonstrated the ability to achieve low NO_x levels in field service and are capable of meeting the firing temperature requirements of the GE *H System*™ gas turbine while obtaining single-digit (ppm) NO_x and CO emissions.

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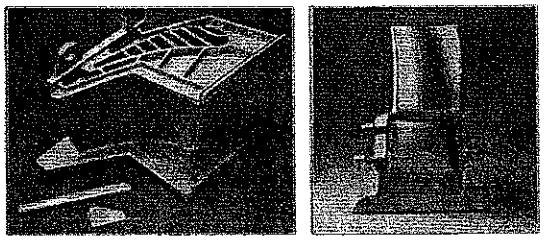

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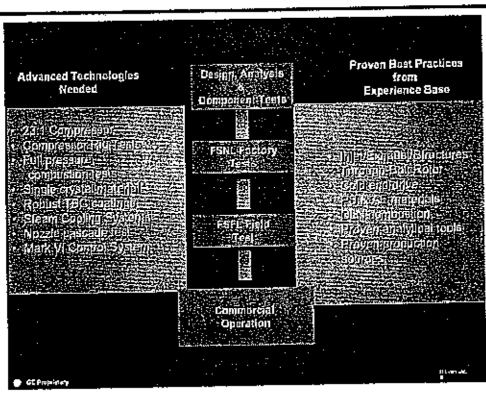


Figure 8. GE validation process

data were specified. Plans to abate risk and facilitate design were arranged, funded, and executed.

The second development phase covered product conceptual and preliminary designs, and included the introduction of knowledge gained through experience, materials data, and analytical codes from GEPS and GEAE.

The *H System*™ development program is currently in its third and final phase, technology readiness demonstration. This phase includes execution of detailed design and product validation through component and gas turbine testing. A high degree of confidence has been gained through component and subsystem testing and validation of analysis codes. Completion of the development program results in full-scale gas turbine testing at our factory test stand in Greenville, SC, followed by combined-cycle power plant testing at the Baglan Energy Park launch site, in the United Kingdom.

Compressor Design Status

Modifications and proof-of-design are made through a rigorous design process that includes GEAE and GEPS experience-based analytical tools, component tests, compressor rig tests and instrumented product tests. The aerodynamic design process uses pitchline design and off-design performance evaluation, axisymmetric streamline curvature calculations with empiricism for secondary flows and mixing, two-dimensional inviscid blade-to-blade analysis and three dimensional viscous CFD blade row analysis. The aerodynamic design is iterated in concert with the aeromechanical design of the individual blade stages, optimizing on GEAE and GEPS experience-supported limits on blade loading, stage efficiency, surge margin, stress limits, etc.

The program has completed the third and final compressor rig test at GEAE's Lynn, MA test facility.

Tests are run with CF6 full-scale hardware, which amounts to a one-third scale test for the 9H and 7H gas turbines. Each rig test is expensive, approximately $20M, but provides validation and flexibility, significantly surpassing any other test options. The 7H rig test had over 800 sensors and accumulated over 150 hours to characterize the compressor's aerodynamic and aeromechanical operations (*Figure 9*). Key test elements include optimum ganging of the variable guide vanes and stators; performance mapping to quantify airflow, efficiency, and stall margins; stage pressure and temperature splits; start-up, acceleration, and turndown character-

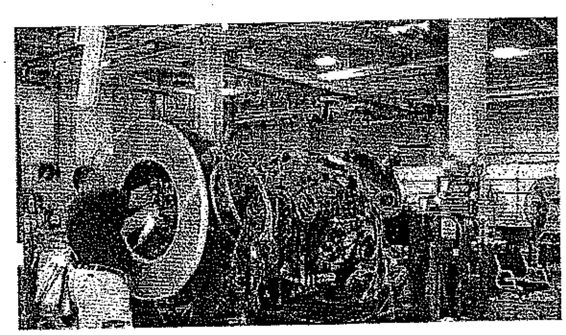


Figure 9. 7H compressor test rig

istics; and identification of flutter and vibratory characteristics of the airfoils (aeromechanics).

The three-test series has accomplished the following:

- Proof of concept, with four stages added to increase pressure ratio, and initial power generation operability – completed August 1995.
- 9H compressor design validation and maps including tri-passage diffuser performance and rotor cooling proof-of-concept – completed August 1997.
- 7H compressor design validation – completed August 1999, (*Figure 10*)

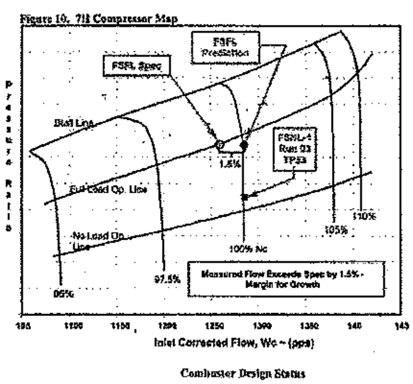
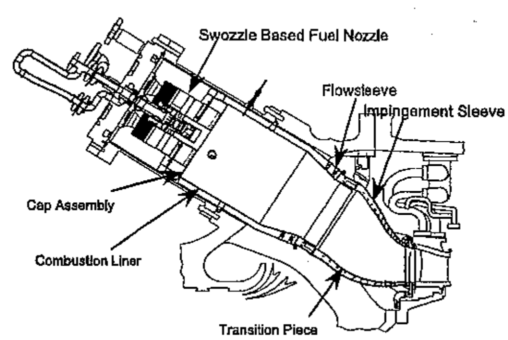


Figure 10. Compressor map

Combustor Design Status

Figure 11 shows a cross-section of the combustion system. The technical approach features a tri-passage radial prediffuser which optimizes the airflow pressure distribution around the combustion chambers, a GTD222 transition piece with an advanced integral aft frame mounting arrangement, and impingement sleeve cooling of the transition piece. The transition piece seals are the advanced cloth variety for minimum leakage and maximum wear resistance. The flow sleeve incorporates



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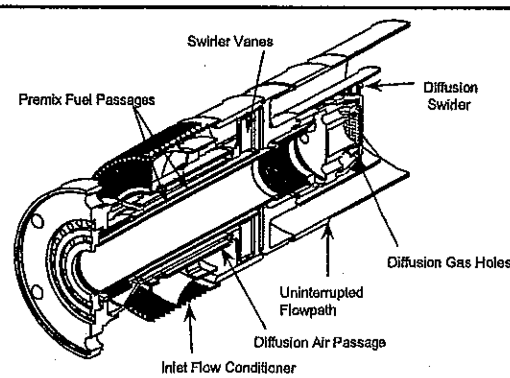
impingement holes for liner aft cooling. The liner cooling is of the turbolator type so that all available air can be allocated to the reaction zone to reduce NO_X. Advanced 2-Cool™ composite wall convective cooling is utilized at the aft end of the liner. An effusion-cooled cap is utilized at the forward end of the combustion chamber.

Fuel Injector Design Status

The *H System*™ fuel injector is shown in *Figure 12* and is based on the swozzle concept. The term swozzle is derived by joining the words "swirler" and "nozzle." The premixing passage of the swozzle utilizes swirl vanes to impart rotation to the admitted airflow, and each of these swirl vanes also contains passages for injecting fuel into the premixer airflow. Thus, the premixer is very aerodynamic and highly resistant



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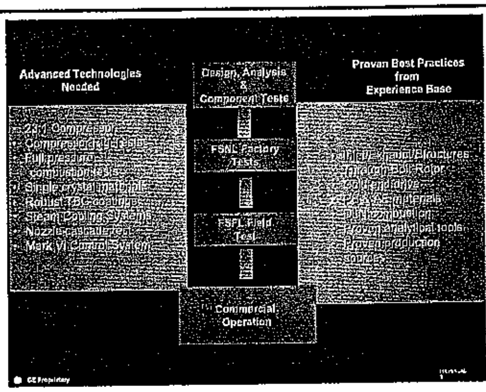

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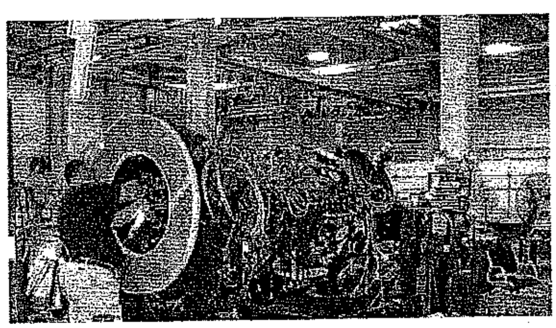

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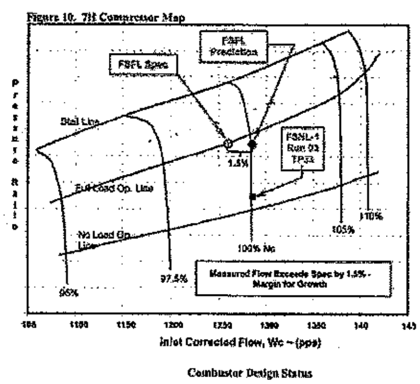

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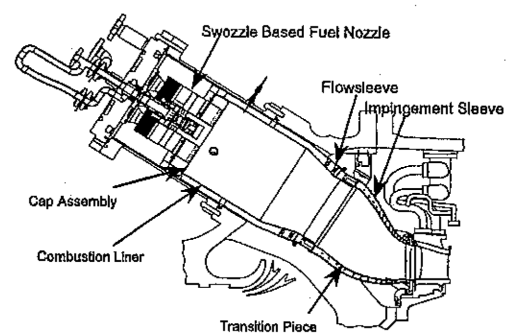

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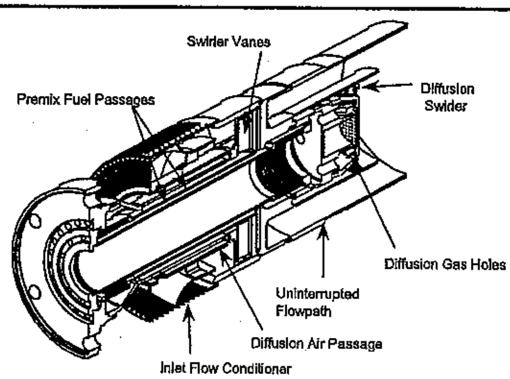

Figure 12. Fuel injector system cross-section

to flashback and flameholding. Downstream of the swozzle vanes, the outer wall of the premixer is integral to the fuel injector to provide added flameholding resistance. Finally, for diffusion flame starting and low load operation, a swirl cup is provided in the center of each fuel injector.

The *H System*™ combustor uses a simplified combustion mode staging scheme to achieve low emissions over the premixed load range while providing flexible and robust operation at other gas turbine loads. *Figure 13* shows a schematic diagram of the staging scheme. The most significant attribute is that there are only

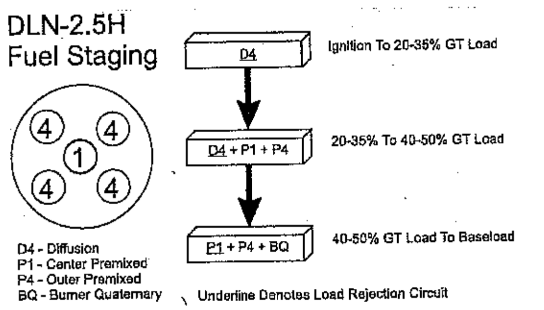

Figure 13. Combustion mode staging scheme

three combustion modes: diffusion, piloted premix, and full premix mode. These modes are supported by the presence of four fuel circuits: outer nozzle premixed fuel (P4), center nozzle premixed fuel (P1), burner quaternary premixed fuel (BQ), and diffusion fuel (D4). The gas turbine is started on D4, accelerated to Full-Speed No-Load (FSNL), and loaded further. At approximately 20-35% gas turbine load, two premixed fuel streams P1, and P4, are activated in the transfer into piloted premix. After loading the gas turbine to approximately 40-50% load, transfer to full premix mode is made and all D4 fuel flow is terminated while BQ fuel flow is activated. This very simplified staging strategy has major advantages for smooth unit operability and robustness.

The *H System*™ combustor was developed in an extensive test series to ensure low emissions, quiet combustion dynamics, ample flashback/flameholding resistance, and rigorously assessed component lifing supported by a complete set of thermal data. In excess of thirty tests were run at the GEAE combustion test facility, in Evendale, OH, with full pressure, temperature, and airflow. *Figure 14* shows typical NO_x baseload emissions as a function of combustor exit temperature, and *Figure 15* shows the comparable combustion dynamics data. The H components have significant margin in each case. In addition, hydrogen torch

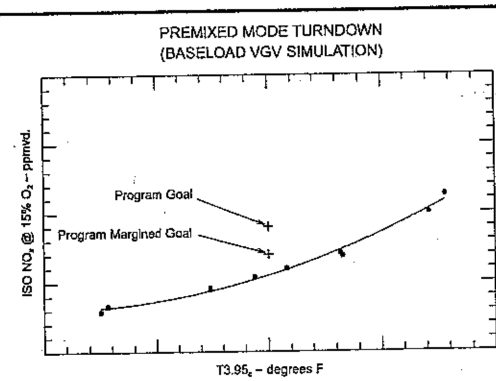

Figure 14. NO_x baseload emissions as a function of combustor exit temperature

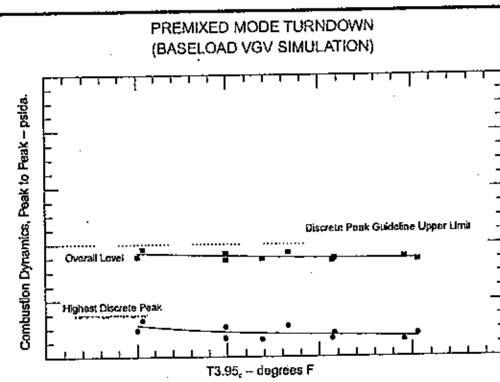

Figure 15. Comparable combustion dynamics data

ignition testing was performed on the fuel injector premixing passages. In all cases the fuel injectors exhibited well in excess of 30 ft/s flameholding margin after the hydrogen torch was de-activated. In addition, lifing studies have shown expected combustion system component lives with short term Z-scores between 5.5 and 7.5 relative to the combustion inspection intervals on a thermal cycles to crack initiation basis. Thus, there is a 99.9% certainty that component lifing goals will be met.

Turbine Design Status

The turbine operates with high gas path temperatures, providing the work extraction to drive the compressor and generator. Two of the factors critical to reliable, long life are the turbine airfoil's heat transfer and material capabilities. When closed circuit steam cooling is used, as on the H turbine, the key factors do not change. However, the impact of steam on the airfoil's heat transfer and material capabilities must also be considered.

For many years, the U.S. Department of Energy (DOE) Advanced Turbine System has provided cooperative support for GE's development of the H System™ turbine heat transfer materials capability and steam effects. Results have fully defined and validated the factors vital to successful turbine operation. A number of different heat transfer tests have been performed to fully characterize the heat transfer characteristics of the steam-cooled components. *Figure 16* shows results for stage 1 nozzle internal cooling heat transfer. An extensive array of material tests has been performed to validate the material characteristics in a steam environment. Testing has included samples of base material and joints and the testing has addressed the following mechanisms: cyclic oxidation, fatigue crack propagation, creep, low-cycle fatigue and notched low-cycle fatigue (*Figure 17*).

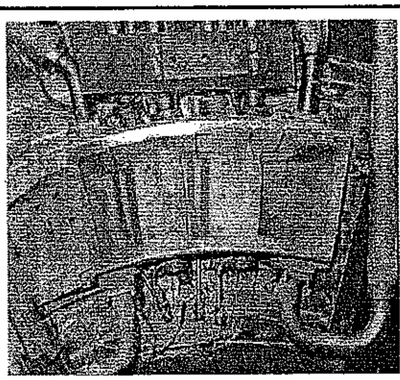

Figure 16. Full-scale stage 1 nozzle heat transfer test validates design and analysis predictions

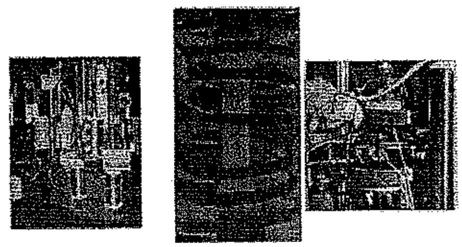

Figure 17. Materials validation testing in steam

Thermal barrier coating (TBC) is used on the flowpath surfaces of the steam-cooled turbine airfoils. Life validation has been performed using both field trials (*Figure 18*) and laboratory analysis. The latter involved a test that duplicates thermal-mechanical conditions, which the TBC will experience on the H System™ airfoils.

Long-term durability of the steam-cooled components is dependent on avoidance of internal deposit buildup, which is, in turn, dependent on steam purity. This is accomplished through system design and filtration of the gas turbine cooling steam. Long-term validation testing,

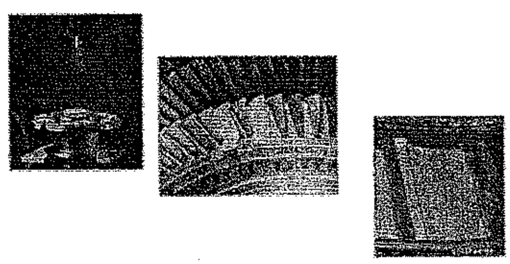

Figure 18. Thermal barrier coating durability

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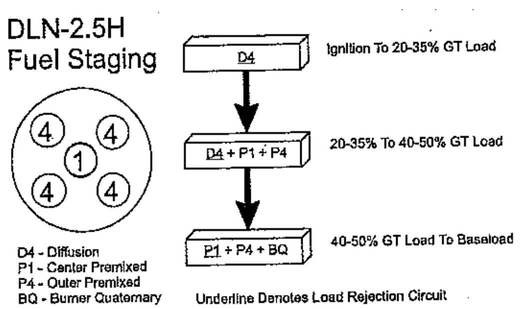

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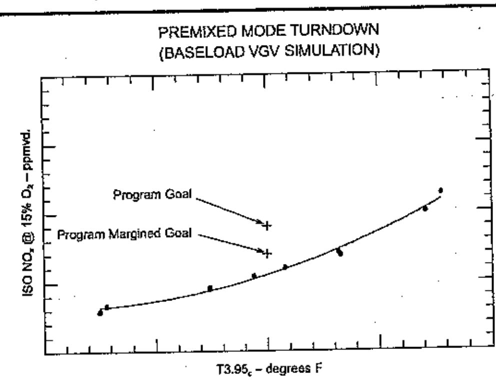

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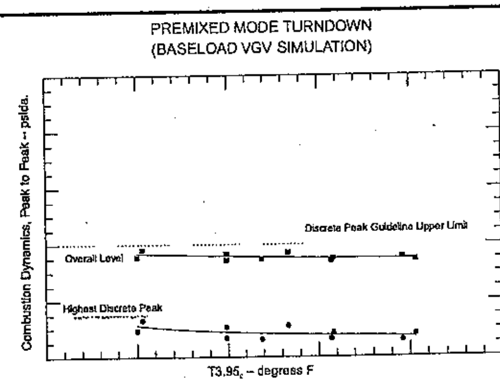

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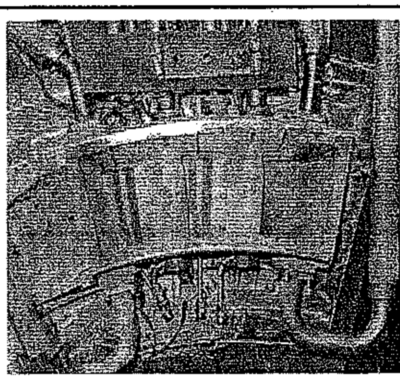

Figure 16. Full-scale stage 1 nozzle heat transfer test validates design and analysis predictions

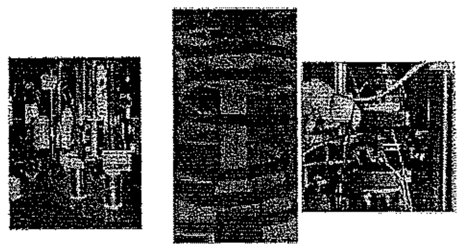

Figure 17. Materials validation testing in steam

Thermal barrier coating (TBC) is used on the flowpath surfaces of the steam-cooled turbine airfoils. Life validation has been performed using both field trials (*Figure 18*) and laboratory analysis. The latter involved a test that duplicates thermal-mechanical conditions, which the TBC will experience on the H System™ airfoils.

Long-term durability of the steam-cooled components is dependent on avoidance of internal deposit buildup, which is, in turn, dependent on steam purity. This is accomplished through system design and filtration of the gas turbine cooling steam. Long-term validation testing,

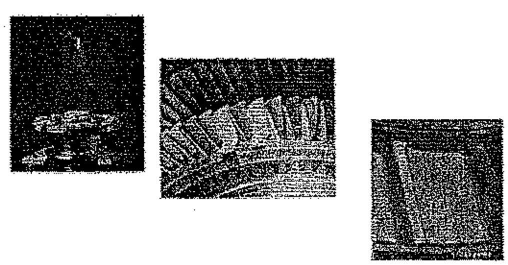

Figure 18. Thermal barrier coating durability

currently underway at an existing power plant, has defined particle size distribution and validated long-term steam filtration. As further validation, specimens duplicating nozzle cooling passages have initiated long-term exposure tests. A separate rotational rig is being used for bucket validation.

The H turbine airfoils have been designed using design data and validation test results for heat transfer, material capability and steam cooling effects. The durability of ceramic thermal barrier coatings has been demonstrated by three different component tests performed by CR&D:

- Furnace cycle test
- Jet engine thermal shock tests
- Electron beam thermal gradient testing

The electron beam thermal gradient test was developed specifically for GEPS to accurately simulate the very high heat transfers and gradients representative of the *H System*™ gas turbine. Heat transfers and gradients representative of the *H System*™ gas turbine have also been proven by field testing of the enhanced coatings in E- and F-class gas turbines.

The stage 1 nozzle, which is the H System™ component subjected to the highest operating temperatures and gradients, has been validated by another intensive component test. A nozzle cascade facility was designed and erected at GEAE (*Figure 19*). It features a turbine segment carrying two closed-loop steam-cooled nozzles downstream from a full-scale H System™ combustor and transition piece. This testing facility accurately provides the actual gas turbine operating environment. Two prototype nozzles complete with pre-spalled TBC were tested in April 1998. Data was obtained validating the aerodynamic design and heat transfer codes. Accelerated endurance test data was also obtained. A second test series, with actual 9H production nozzles, is scheduled to start in the 4th quarter of 2000).

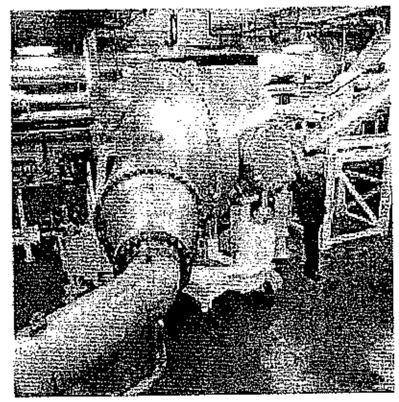

Figure 19. Nozzle cascade test facility

The rotor steam delivery system delivers steam for cooling stage 1 and 2 turbine buckets. This steam delivery system relies on "spoolies" to deliver steam to the buckets without detrimental leakage, which would lead to performance loss and adverse thermal gradients within the rotor structure. The basic concept for power system steam sealing is derived from many years of successful application of spoolies in the GE CF6 and CFM56 aircraft engine families.

In the conceptual design phase, material selection was made only after considering the effects of steam present in this application. Coatings to improve durability of the spoolie were also tested. These basic coupon tests and operational experience provided valuable information to the designers.

In the preliminary design phase, parametric analysis was performed to optimize spoolie configuration. Component testing began for both air and steam systems. The spoolie was instrumented to validate the analysis. Again, the combination of analysis and validation tests provided confirmation that the design(s) under consideration were based on the right concept.

Over 50 component tests have been conducted on these spoolies, evaluating coatings, lateral loads, fits, axial motion, angular motion, temperature and surface finish.

The detailed design phase focused on optimization of the physical features of the subsystem, spoolie-coating seat. In addition, refined analysis was performed to allow for plasticity lifecycle calculations in the region of the highest stresses. This analysis was again validated with a spoolie cyclic life test, which demonstrated effective sealing at machine operating conditions with a life over of 20,000 cycles.

Spoolies were also used on the *H System*™ FSNL gas turbine tests. During the 9H FSNL-2 testing, compressor discharge air flowed through the circuit. This is typical of any no-load operation. Assembly and disassembly tooling and processes were developed. The spoolies were subjected to a similar environment with complete mechanical G loading. Post-testing condition of the seals was correlated to the observation made on the component tests. This provided another opportunity for validation.

A rotating steam delivery rig (*Figure 20*) has been designed and manufactured to conduct cyclic endurance testing of the delivery system under any load environment. The rotating rig will subject components to the same centrifugal forces and thermal gradients that occur during actual operation of the turbine. This system testing will provide accelerated lifecycle testing.

Leakage checks will be completed periodically to monitor sealing effectiveness. Test rig instrumentation will insure that the machine matches the operating environment. The rig has been installed in the test cell, and testing should resume in April 2000.

Gas Turbine Factory Tests

The first six years of the GE H System™ validation program focused on sub-component and component tests. Finally, in May 1998, the program moved on to the next stage, that of full-scale gas turbine testing at the Greenville, South Carolina factory (*Figure 21*). The 9H gas turbine achieved first fire and full speed and, then, over a space of five fired tests, accomplished the full set of objectives. These objectives included confirmation of rotor dynamics: vibration levels and onset of different modes; compressor airfoil aero-mechanics; compressor performance, including confirmation of airflow and efficiency scale-up effects vs. the CF6 scale rig tests; measurement of compressor and turbine rotor clearances; and demonstration of the gas turbine with the Mark VI control system.

The testing also provided data on key systems:

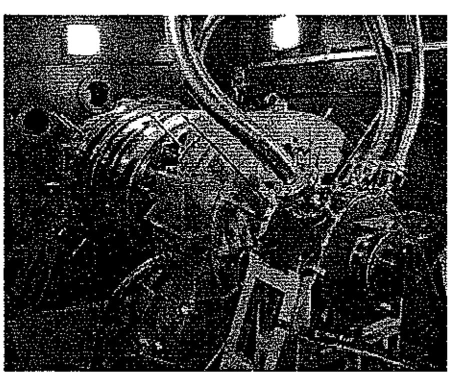

Figure 20. Rotating rig installed in test stand

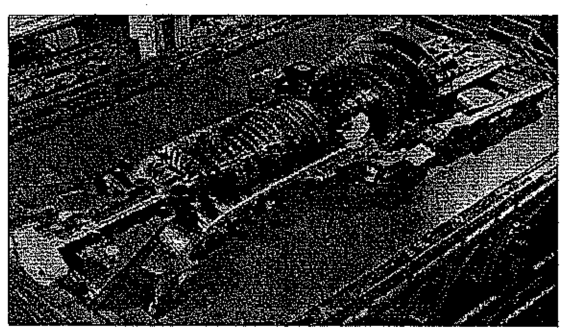

Figure 21. 9H gas turbine in half shell prior to first FSNL test

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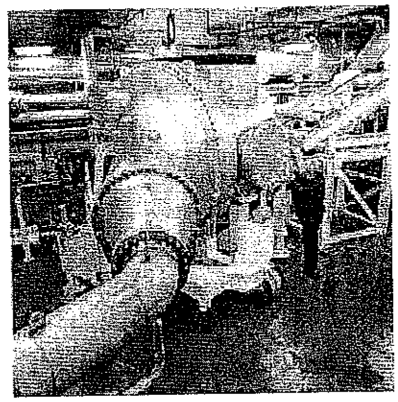

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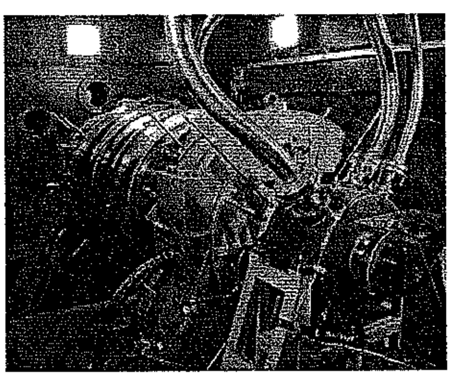

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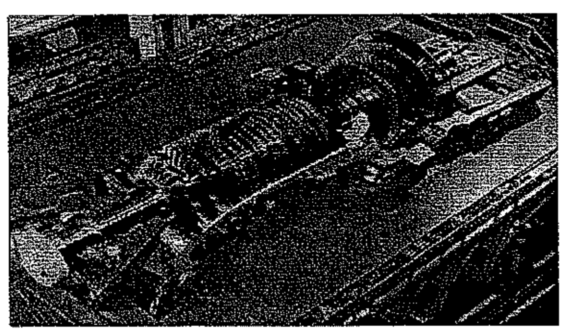

Figure 21. 9H gas turbine in half shell prior to first FSNL test

bearings, rotor cooling, cavity temperatures and effectiveness of the clearance control systems.

Following the testing, the gas turbine was disassembled in the factory and measured and scrutinized for signs of wear and tear. The hardware was found to be in excellent condition.

The 9H gas turbine was rebuilt with production turbine airfoils and pre-shipment tests performed in October and November 1999. This unit was fully instrumented for the field test to follow and, thus, incorporated over 3500 gauges and sensors (*Figure 22*).

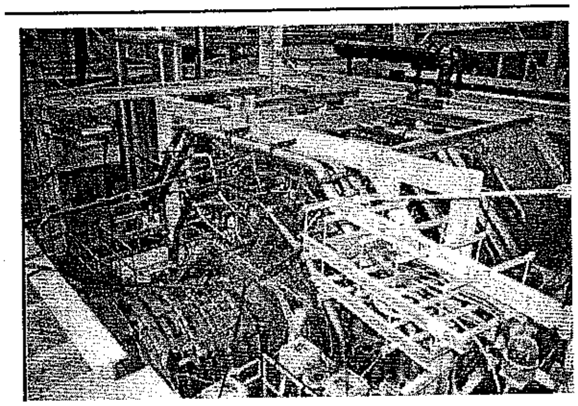

Figure 22. 9H gas turbine in test stand for pre-shipment test

This second 9H test series took seven fired starts and verified that the gas turbine was ready to ship to the field for the final validation step. Many firsts were accomplished. The pre-shipment test confirmed that the rotating air/steam cooling system performed as modeled and designed. In particular, leakage, which is critical to the cooling and life of the turbine airfoils and the achievement of well-balanced and predictable rotor behaviors, was well under allowable limits.

Compressor and turbine blade aeromechanics data were obtained at rates of up to 108% of the design speed, clearing the unit to run at design and over-speed conditions. Rotor dynamics were once again demonstrated, and vibration levels were found to be acceptable without field balance weights.

The Mark VI control system demonstrated full control of both the gas turbine and the new *H System*™ accessory and protection systems.

The first 7H gas turbine was assembled and moved to the test stand in December 1999 (*Figure 23*). This 7H went through a test series similar to that for the first 9H factory test. However, the 7H not only covered the 9H test objectives described earlier, but also ran separately with deliberate unbalance at compressor and turbine ends to characterize the rotor sensitivity and vectors. The rotor vibrations showed excellent correlation with the rotor dynamic model and analysis.

The 7H gas turbine is now back in the factory for disassembly and inspection, following the same sequence used for the 9H.

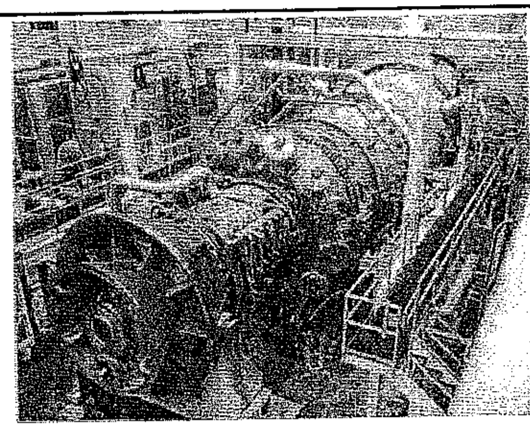

Figure 23. 7H gas turbine being installed in test stand

Validation Summary

GE is utilizing extensive design data and validation test programs to ensure that a reliable *H System*™ power plant is delivered to the customer. A successful baseline compressor test program has validated the *H System*™ compressor design approach. As a result of the 9H and

7H compressor tests, the H compressors have been fully validated for commercial service. The H turbine airfoils have been validated by extensive heat tests, materials testing in steam, TBC testing and steam purity tests. Test results have been integrated into detailed, three-dimensional, aerodynamic, thermal and stress analysis. Full size verification of the stage 1 nozzle design is being achieved through the steam-cooled nozzle cascade testing.

Both 9H and 7H gas turbines have undergone successful factory testing and the 9H is now poised for shipment to the field and final validation test.

Conclusion

The rigorous design and technology validation of the *H System*™ is an illustration of the GE NPI process in its entirety. It began with a well-reasoned concept that endured a rigorous review and validation process. This ensures the highest probability of success, even before the product or shipping to customers and/or the product has begun operation in the field.

The H technology, combined-cycle power plant creates an entirely new echelon of power generation systems. Its innovative cooling system allows a major increase in firing temperature, which allows the turbine to reach record levels of efficiency and specific work while retaining low emissions capability.

The design for this "next generation" power generation system is now established. Both the 50 Hz and 60 Hz family members are currently in the production and final validation phase. The extensive component test validation program, already well underway, will ensure delivery of a highly reliable, combined-cycle power generation system to the customer.

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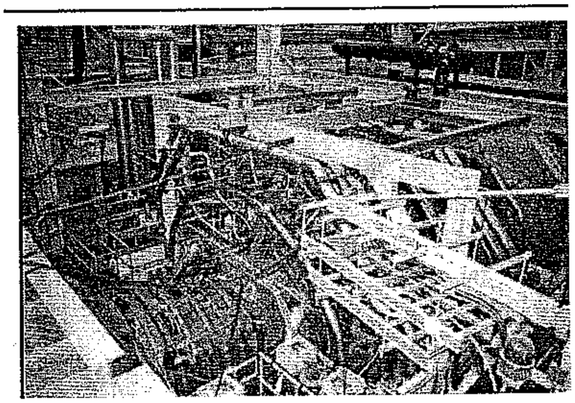

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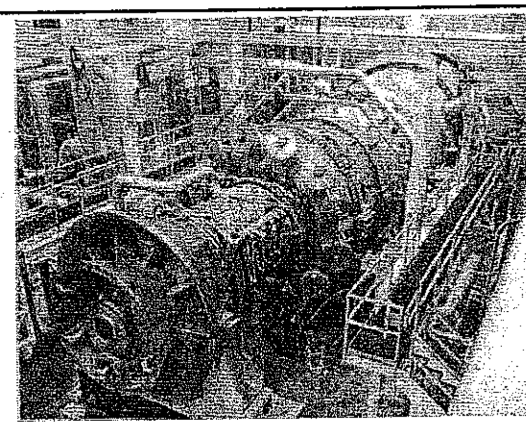

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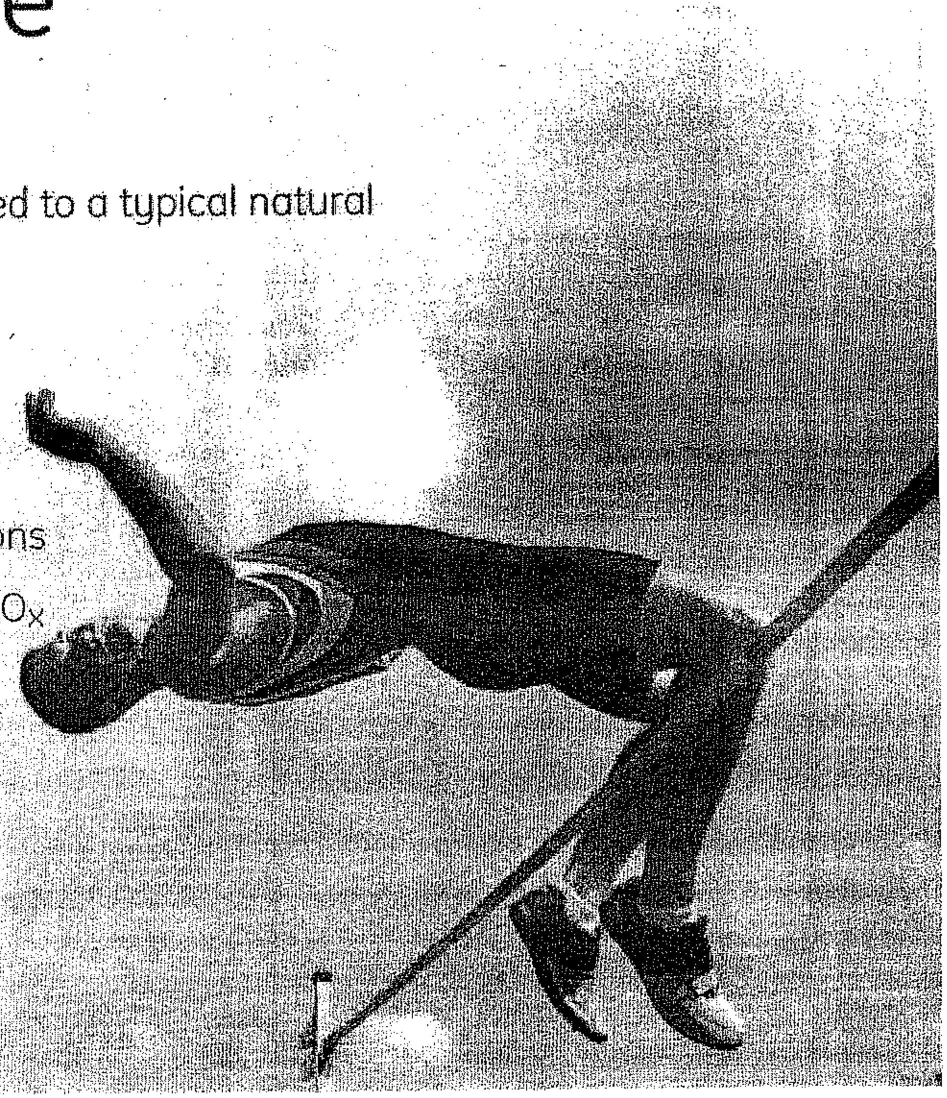
GE Energy

H System™ – Raising the Bar for Large Combined Cycle

- 9,000 fired hours experience at Baglan Bay
- Lower NO_x and CO_2 per unit of electricity when compared to a typical natural gas fired combined cycle power plant
  - New rating: 520MW @ 60% efficiency
- Operational flexibility similar to F Class
  - 50% combined cycle part load operation at ISO
  - 24,000 hour hot gas path; 48,000 hour major inspections
  - 12,000 hour combustion inspection with 30mg/Nm^3 NO_x
  - 60 minute hot start-up time

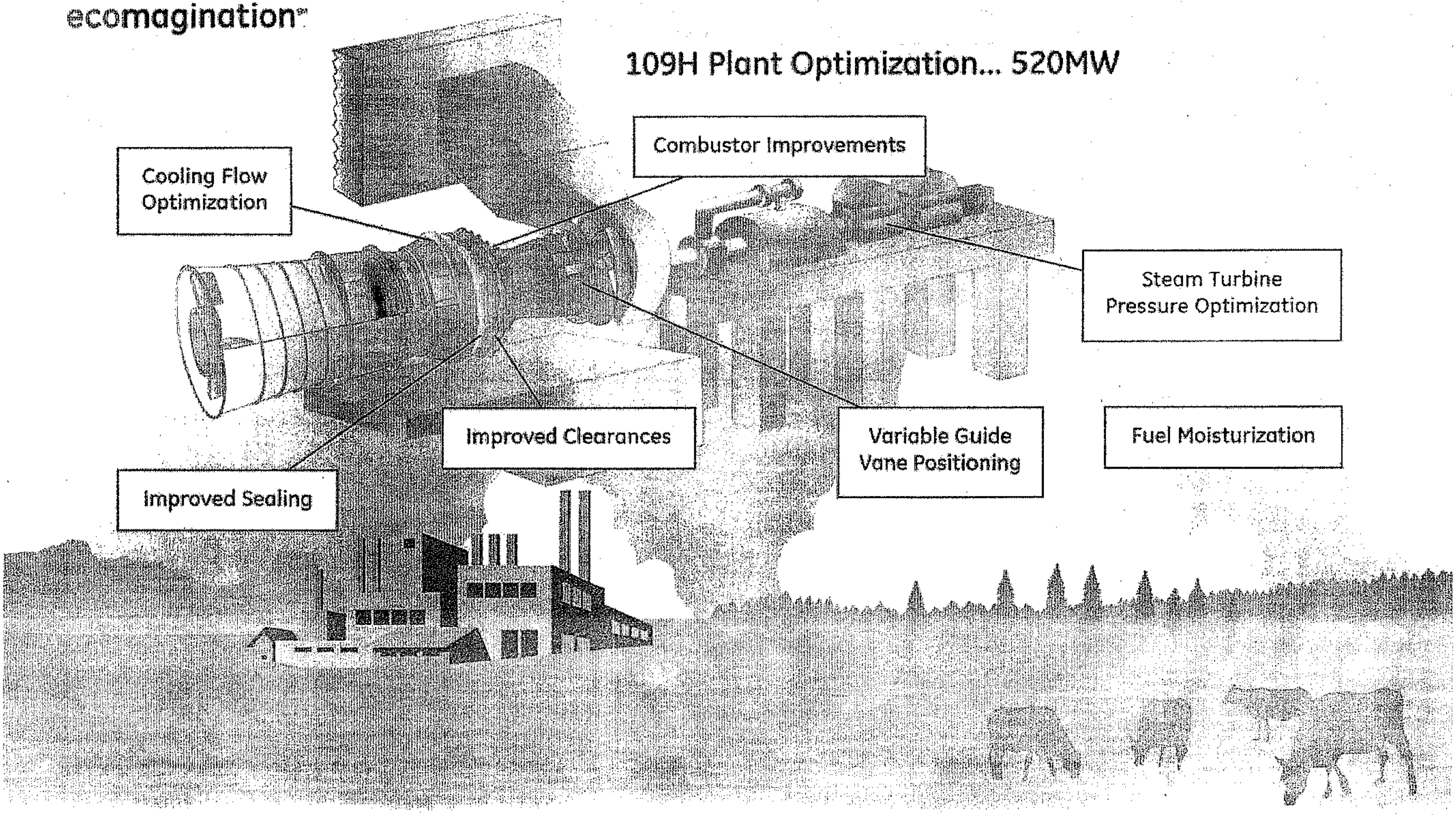


gepower.com

GE imagination at work

a product of
ecomagination℠

109H Plant Optimization... 520MW



GE imagination at work

At GE, we believe some of the world's most pressing environmental challenges present an opportunity to do what we do best: imagine and build innovative solutions that benefit our customers and society at large. Ecomagination is our commitment to help solve environmental challenges profitably, today and for generations to come.

GEA-14150 (06/05)

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Energy

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Press Release

GE's H System* Gas Turbine Hits Project Milestone In Japan

First Firing at TEPCO Plant

NEW ORLEANS, LA - December 11, 2007 : – GE Energy's first commercial H System gas turbi achieved first firing at Tokyo Electric Power Company's Futtsu Thermal Power Station. TEPCO F first commercial site for GE's most advanced, gas turbine combined-cycle system.

Futtsu Thermal Power Station will feature three H Systems, each including GE Energy's 9H gas t with a steam turbine and generator provided by Toshiba under an agreement with GE. The three cycle blocks will enter commercial operation between 2008 and 2010, with a total output of 1,520

"This successful milestone of unit 1 for the Futtsu project is a key step in the commercial develop H System gas turbine," said Steve Bolze, vice president-power generation for GE Energy. "It is a chapter in an on-going relationship with TEPCO, which has been implementing our technology fo years."

With a total production of 60 gigawatts, TEPCO is one of the largest utilities in the world, and is o largest customers. Other TEPCO sites utilizing GE Energy's gas turbine combined-cycle technolc Yokohama, Chiba and Shinagawa.

Futtsu Thermal Power Station marks the second location where GE Energy's H System gas turbi operation. The world's first 50-hertz 9H combined-cycle system entered service in 2003 at Baglar South Wales, and has surpassed 26,500 operating hours. The first 60-hertz project is the Inland I Energy Center in California, scheduled to begin service in 2008.

H System gas turbine
The H System gas turbine integrates a gas turbine, steam turbine and heat recovery steam gene GE Energy's most advanced gas turbine combined-cycle system. The technology features an inn closed-loop steam cooling system that allows the turbine to fire at higher temperatures, enabling efficiency, reduced emissions and less fuel consumption per megawatt of power generated.

The H System gas turbine is the industry's first combined-cycle system designed with the capabil achieve 60 percent thermal efficiency, an industry milestone. It also offers 40 percent improveme density per installed megawatt compared to other combined-cycle systems, reducing the overall producing electricity.

The H system gas turbine is capable of producing 87,000 fewer metric tons of greenhouse gases when compared to a typical gas turbine combined-cycle plant generating an equivalent amount o The H System gas turbine is ecomagination certified, a GE product-line certification based on op environmental performance.

* H System gas turbine is a trademark of the General Electric Company.

About GE Energy
GE Energy (www.ge.com/energy) is one of the world's leading suppliers of power generation and delivery technologies, with 2006 revenue of $19 billion. Based in Atlanta, Georgia, GE Energy wc areas of the energy industry including coal, oil, natural gas and nuclear energy; renewable resou water, wind, solar and biogas; and other alternative fuels. Numerous GE Energy products are ce

ecomagination, GE's corporate-wide initiative to aggressively bring to market new technologies th customers meet pressing environmental challenges.

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GE Energy

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Press Release

GE'S First 60-Hertz H System* Gas Turbine Project Moves Toward Commercial Startu Year

Milestones Mark Progress at Inland Empire Energy Center

ATLANTA, GEORGIA - September 10, 2007 :- The world's first installation of GE Energy's 60-h System* gas turbine, the Inland Empire Energy Center in southern California, remains on target f commercial startup in the summer of 2008.

In a recent project milestone, back feed power was provided to one of the two GE Frame 107H g at the site, clearing the way for startup and commissioning of the power plant auxiliary systems.

A GE-designed demineralization water system is currently being commissioned. This system will demineralized water purified from recycled water feedstock to provide all needed steam plant ma for the entire site operation.

The first 107H gas turbine at the site (unit #1) is expected to achieve first firing by the end of this unit #2 first firing expected in early 2008. Unit #1 will be heavily instrumented and will undergo ex validation testing throughout the first half of 2008, to validate the 107H combined-cycle system.

An innovative, closed-loop steam cooling system and advanced coating materials are key feature System gas turbine's ability to achieve the higher firing temperatures required for increased effici also translates into improved environmental performance. For every unit of electricity generated, System gas turbine uses less fuel and produces fewer greenhouse gases and other emissions w compared to other large gas turbine combined-cycle systems. The H System gas turbine is a key GE ecomagination, a corporate-wide initiative to develop and market technologies that will help c meet pressing environmental challenges.

Operating on natural gas, the two GE 107H combined-cycle systems at Inland Empire will produc 775 megawatts, or enough power to supply nearly 600,000 households. Located in Romoland, ne Riverside, the plant will come on line in the summer of 2008, in time to help offset state-forecaste shortfalls in southern California.

"We're extremely pleased with the progress to date on the Inland Empire project," said John Reir manager of gas turbine and combined-cycle products for GE Energy. "Southern California, with it focus on finding more efficient methods to meet its growing power requirements, is an ideal place showcase our most advanced 60-hertz combined-cycle technology."

GE is financing and will own the Inland Empire Energy Center. Calpine Power Services is manag construction and Calpine Energy Services will market the plant's output and manage fuel requirei a long-term marketing arrangement with GE. Following an extended period of GE ownership, Cal expects to purchase the plant and become its sole owner and operator, with GE continuing to prc maintenance services under a contractual agreement with Calpine.

The 50-hertz version of GE's H System gas turbine made its global commercial debut in 2003 at Bay Power Station in South Wales, where it recently surpassed 24,000 hours of service. The wor installation of 109H technology is Tokyo Electric Power Company's Futtsu Thermal Power Statioı where the first of three 109H combined-cycle systems will enter service in 2008.

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* H System is a trademark of General Electric Company.

Baglan Bay begins

It's been 12 years from drawing board to commercial operation, but GE's revolutionary H System gas turbine is now up and running at a combined-cycle plant in Wales. [illegible] visits Baglan Bay.

The 510MW Baglan Bay power station in Port Talbot, Wales.

Without doubt, the 9H is the most carefully designed, engineered, tested and validated gas turbine in power generation history.

Its specifications also make it the largest, most powerful and efficient such machine in the world. Using the 50Hz 9H or 60Hz 7H turbine, GE's H System combined-cycle configuration is the first capable of breaking the 60 per cent thermal efficiency barrier. The turbine was more than a decade in the making; it finally saw its commercial launch in September at Baglan Bay power plant in the UK (see sidebar page 12).

The higher thermal efficiency of the H System will translate into lower generating costs and less plant emissions. GE estimates that a natural gas-fired CCGT plant using the technology has the capability of realising fuel cost savings of US$2 million a year, compared to existing combined-cycle plant, which operate in the range of 57-58 per cent at best.

The $500m Baglan Bay power station, is built on land leased from BP Chemicals, and provides electricity and process steam to the adjacent Baglan Energy Park and BP's isopropanol plant. Remaining electricity goes to the UK national grid.

Baglan Energy Park is a joint development between BP, Neath Port Talbot County Borough Council and the Welsh Development Agency. The Energy Park currently comprises approximately 200 acres of development land and will feature business and manufacturing facilities. The Baglan Bay redevelopment is the largest single such site in the UK and is made up of several phases, to be developed over the next 20 years.

The availability of clean, low-cost power is expected to play a significant role in attracting new businesses to the park. With the power plant's proximity and high efficiency, businesses in the Energy Park can potentially benefit from up to a 30 per cent saving in electrical costs.

Development programme

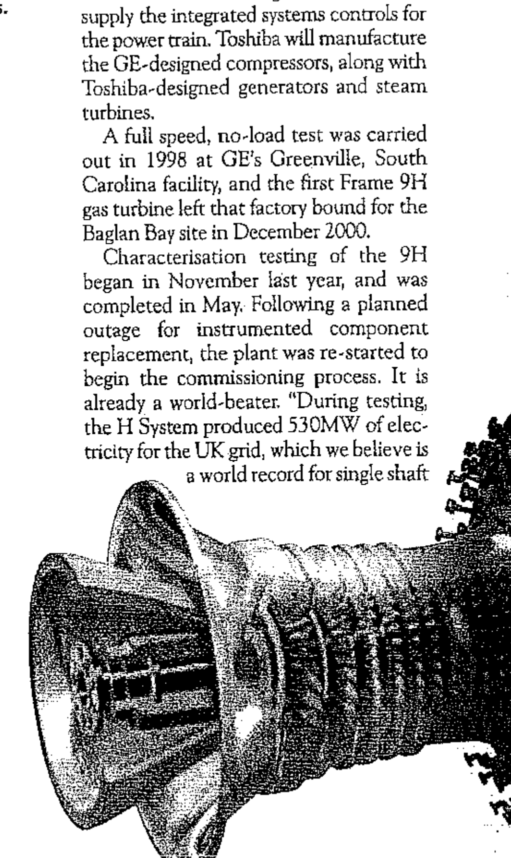
The energy source behind the Park started many years before however. GE engineers produced the H System concept in 1991. It took four years refining the turbine technology before a development programme was announced in 1995.

This was done as part of the US Department of Energy's Advanced Turbine System programme, and included GE Aircraft Engines and the company's Global Research Centre. Two years later the compressor was tested and the first set of single crystal airfoils produced.

Future shipments for the H System will be covered under a previously announced agreement signed by GE and Toshiba of Japan in 1998. Under this agreement, GE has H System integration and performance responsibility, and will design and manufacture the H gas turbines and supply the integrated systems controls for the power train. Toshiba will manufacture the GE-designed compressors, along with Toshiba-designed generators and steam turbines.

A full speed, no-load test was carried out in 1998 at GE's Greenville, South Carolina facility, and the first Frame 9H gas turbine left that factory bound for the Baglan Bay site in December 2000.

Characterisation testing of the 9H began in November last year, and was completed in May. Following a planned outage for instrumented component replacement, the plant was re-started to begin the commissioning process. It is already a world-beater. "During testing, the H System produced 530MW of electricity for the UK grid, which we believe is a world record for single shaft



combined-cycle power generation," says Mark Little, vice-president, Energy Products at GEPS. That recorded output was achieved at site conditions of 7°C, even on a warmer day, the H still produced in excess of 500MW.

The H System integrates gas and steam turbine (single-shaft configuration at Baglan Bay), repressure heat recovery steam generator (HRSG) and 660MVA liquid-cooled generator into one unit; optimising each component's performance. The steam turbine is a D10 three-pressure reheat, single-flow exhaust machine, co-manufactured with Toshiba. Baglan Bay also uses a ten cell cooling tower with low plume, and has its own 2MW diesel generator for black start capability, also used by the CHP plant. The 9H transformer is 22kV, stepped up to 275kV for transmission to the UK national grid.

In addition to the H System, the power station also includes a 33MW combined heat and power plant based on a GE LM2500 gas turbine (see right sidebar).

World's largest turbine

But it is the gas turbine represents the heart and focus of the project. The 50Hz 480MW-rated Frame 9H gas turbine measures 12 metres long, five meters in diameter; and weighing 370 metric tonnes – it is the largest gas turbine in the world. Much of the H design is based on proven turbine technology.

The compressor system is derivative of GE's Aircraft Engine business, the CF6-80C2 engine (and its aero-derivative LM6000 turbine), a core machine with more than 10 million flight hours.

Building on GE's design experience, the H employs a can-annular lean premix DLN-2.5 dry low NOx (DLN) combustor system. Fourteen combustion chambers are used on the 9H, and 12 combustion chambers are used on the 7H. It mixes fuel and air prior to ignition to reduce emissions to 25ppm.

This type of combustion system has been proven in millions of hours of operation on other GE gas turbines around the world. It produces more than a million horsepower alone and is the key energy source for the entire plant, including the power turbine, HRSG and steam turbine.

But the revolution so far as gas turbine design is concerned is the firing temperature and cooling system. The 60 per cent plant thermal efficiency is made possible by an increase in gas turbine firing temperature of more than 212°F (100°C) above the most efficient combined-cycle systems currently operating, including GE's own F-technology. Current combined-cycle systems achieve a firing temperature at the gas turbine inlet of around 1,300°C; the new H System increases that to 1,430°C (2,606°F).

This higher firing temperature is made possible by a series of technological advances including the world's largest single crystal airfoils, superior component and coating materials, and an advanced closed-loop steam cooling system.

"It is conditions friendly because the steam cooling in the H System allows the combustion system of the engine to run essentially at the same temperatures as our current F-technology," says Jon Ebacher, vice president of power systems technology at GEPS. "While the turbine inlet is 110°C above that and this is the section that produces power in the gas turbine."

Use of single crystal materials on the first stage nozzles and blades plus the special coatings used ensures that the parts can withstand the high temperatures – temperatures that are significantly higher than the melting point of most metals.

The most critical element of an advanced gas turbine is its hot gas path. The compressor discharge air and fuel are mixed and combusted in a chamber at a specific condition-combustion temperature. The flow stream of high-pressure, high-temperature combustion products is accelerated as it passes through the first stationary airfoil (stage 1 nozzle segment). The firing temperature – the flow stream temperature at the inlet to the first rotational state (stage 1 blade) – establishes the power output. The difference between firing temperature and combustion temperature entering the first stage nozzle is the temperature drop across the stage 1 nozzle.

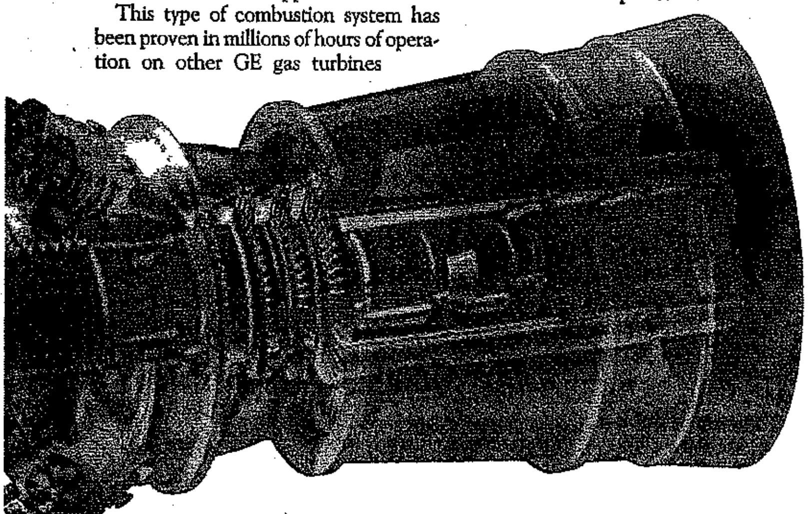
Cooling process

In current advanced gas turbines, the stage 1 nozzle is cooled with compressor discharge air flowing through the airfoil and discharging out into the combustion gas stream as the airfoil is cooled. The cooling process causes a temperature drop of up to 155°C across the stage 1 nozzle. If the nozzle can be cooled with a closed-loop coolant without film cooling, the temperature drop across the stage 1 nozzle would be less than 44°C, which would permit a 110°C rise in firing temperature with no increase in combustion temperature. That in turn, of course, means no increase in NOx emissions. This is the basis behind GE's steam cooling with the H System.

Steam exiting the HP turbine flows through gas turbine blades, nozzles and other parts, cooling them, and simultaneously re-heating the steam before it enters the IP steam turbine.

The steam cooling concept has a dual effect, allowing higher firing temperatures to be achieved without combustion temperature increases and permitting more compressor discharge air to flow to the head-end of the combustor for fuel premixing.

"The benefit is that for about 8 per cent



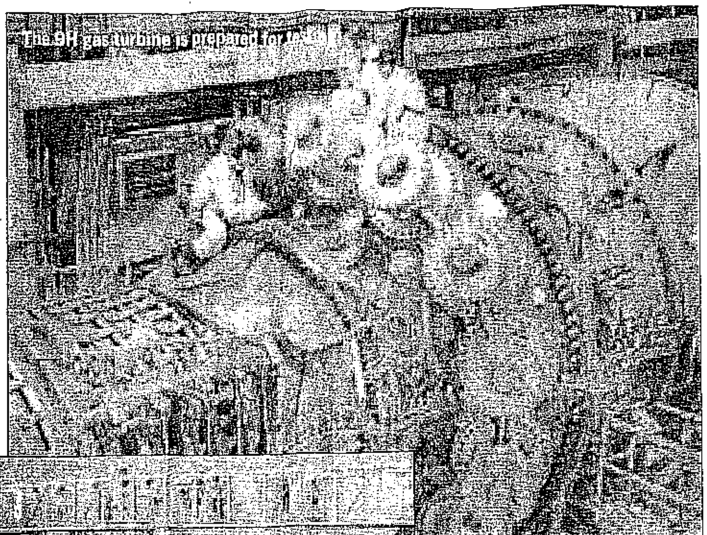
The cogeneration plant

The CHP station at Baglan provides steam and electricity to a BP Chemicals process plant, situated close by.

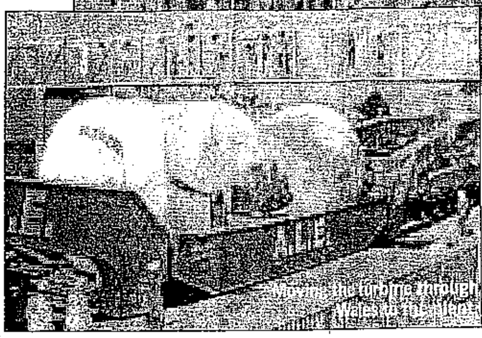
In terms of configuration, the plant is powered by a GE LM2500 aero-derivative gas turbine, with a bypass stack and a heat recovery steam generator on the back end; this is also connected up to a three flue common chimney (for the LM and 9H). "The third flue is for the auxiliary boiler, which provides redundancy for the process steam that is supplied to BP," says Brian Ray, managing director of Baglan Generating Ltd.

The LM2500 also provides the Baglan Bay Power Station (including the H System) with black start capability, so it has its own diesel generator. "Power from the CHP plant is provided not only to BP Chemicals but also to the surrounding Baglan Energy Park," says Ray. "There is still room for expansion; there are a few tenants already in the Energy Park and some more on the way, but at present it's not fully populated."

The CHP plant also provides process cooling for BP Chemicals, so there is a separate two cell cooling tower for that purpose. In addition, an attemperated feedwater line also gives BP that product along with demineralised water from the site's water treatment plant.



The 9H gas turbine is prepared for



more airflow than a 50Hz 9F we get 25 per cent more power with similar conditions," says Ebacher. "As the combustor is running at about the same temperature, there's 200°F less drop across the stage 1 nozzle, so as we go into the first stage blade, that generates the real power, 200°F hotter than we do in the F machine, and that's why we get more power.

"We start the machine on air-cooling, waste heat generates steam and at about 10 per cent power we do a transition to steam cooling. When we first looked at this system we knew that the control system would be challenging to make sure that there was no load transients visible to the grid during the transition to steam cooling."

Most tested turbine

With revolutionary steam cooling capability and the new materials and use of high temperatures, it is little wonder that GE has been extremely cautious with the commercial introduction of the H-technology. The H System represents the most thoroughly tested industrial gas turbine technology in the company's 100-year-plus history. Tests, which involved more than 7,000 sensors placed on the equipment, validated GE's closed-loop steam cooling system.

Following the successful conclusion of the tests, instrumented components used to gather data were replaced with commercial non-instrumented components. The system has been restarted for commercial operation.

The H benefits from four years of extensive testing and design validation," says Mark Little. "From compressor blade tests, combustion tests and launch system integrated control test. Prior to shipping to the Baglan site the 9H gas turbine underwent two full speed no-load tests in the factory, which fully met our design expectations.

"Here at Baglan, GE has undertaken a further five months of full characterisation testing during which time we've validated key technologies at the heart of the H turbine."

This testing phase encompassed materials, component, subsystem, and system testing of the compressor rigs, as well as tests of the combustion, inlet aero, and Mark VI-based integrated control systems.

First firing

First firing of the turbine occurred in November, with validation testing lasting until May. Having met its expectations, GE is naturally proud of the new machine's performance. "As anyone involved in commissioning combined-cycle plant knows it is a difficult process," says Don Hoffmann, H System product line manager.

"Since first firing in November 2002, we've had 29 start attempts and everyone of those has been successful, no failures at all." And after 12 years of design, engineering and testing commercial launch of the Baglan Bay CCGT plant took place in September.

The H System gas turbine plant has been the most eagerly awaited project for many years. On its launch GE executives and UK politicians lauded the technology. Known for its caution and procrastination, the power industry as a whole will watch with close interest the performance of the turbine at Baglan. IPG

The plant launch

Over 200 customers, executives, politicians, invited guests and media were in South Wales in September for the launch of the Baglan Bay project.

The opening conference was addressed by the Secretary of State for Wales, Peter Hain, plus John Rice, GE Power Systems president and CEO, and local Welsh politicians. Hain brought a stark note of reality to the event, "I have noticed that GE's turnover is bigger than the entire Welsh budget!

"Within two years UK gas imports will outstrip its production making it imperative that there is an efficient use of gas. The 9H CCGT plant is capable of 60 per cent efficiency compared to 21-39 per cent for coal-fired power stations, and produces 30 per cent less carbon emissions than a typical coal plant."

These words were eagerly echoed by GE's ensemble of executives. "We have much to celebrate," said Del Williamson, GEPS president of global sales. "This H System is a new technology platform that significantly advances large-scale power generation."

Rice spoke about the teamwork that went into the H System and Baglan Bay, "I can't be prouder of the team that brought the H System to life. In truth, this is a total team effort spanning a multitude of companies, countries and political bodies."

But it didn't entirely go to plan. A couple of days before the launch there was an alarm indicating a localised temperature increase that caused the unit to be taken offline.

As part of the recommissioning process GE found that there were three turbine blades out of 120, in one section, that appear to have restricted steam flow. "That was not present in the earlier testing but it is being addressed and the machine will run again and produce those high powers," said Jon Ebacher, vice president of power systems technology at GEPS.

Subsequent thorough inspection of the stage two blades re-confirmed that the elevated temperature was the result of a localised cooling flow restriction caused by foreign material collecting in the steam cooling path during the supplier's manufacturing process.

The milestone 60 per cent thermal efficiency figure was not realised at Baglan. GE's prime purpose here has been to run and validate the gas turbine technology.

Also announced at the September launch was that GE expects to begin offering the H System as a commercial product beginning in the last quarter of this year. It already has an order from TEPCO to supply three 109H systems for a project in Japan. Meanwhile GE is actively looking for a launch site for its 60Hz 7H gas turbine.

GE Energy

WORLDWI

H System Launch Site

Baglan Bay Power Station Port Talbot, Wales*
100% GE-owned investment in validation of the revolutionary technology and turnkey construction-comprised of two power

View the 9H photo gallery

Features

109H System Combined Cycle Power Plant
- 480 MW; single shaft; 60% CC efficiency platform
- Firing temperature class: 1430°C (2600°F)
- 18 stage compressor w/23:1 pressure ratio; airflow 1510 lbs/sec
- 14 can DLN 2.5; NO_x emissions: 25 ppm

Steam Turbine: GE design; reheat, single flow exhaust; co-mfg. with Toshiba
Generator: GE 550 MW LSTG; 660 MVA liquid cooled
HRSG: 3 pressure level reheat

LM2500 Combined Heat and Power Plant
- 33 MW GE LM2500
- HRSG; auxiliary boiler and 2 cell process cooling tower
- Plant provides utility supply to Baglan Energy Park** and BP Chemical Plant*** - electricity, steam, demineralized and attemperated water, process cooling
- Blackstart capability

Other Baglan PowerStation Features
- GE Mark VI based Integrated Control System
- 10 cell cooling tower
- Chimney: triple flue; slip form poured
- GE Water Technologies treatment plant
- 275 kV switchyard connecting to National Transmission (Electricity) System
- 33 kV switchyard with local supply to BP Chemicals and Baglan Energy Park
- Pipeline Reception Facility (PRF)
  - For 12 km Baglan pipeline spur to National Transmission (Gas) System
  - Gas compression and pressure reduction capability, featuring GE centrifugal compressors

GE Products & Services Used at Baglan

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H System: The World's M Advanced Combined Cyc Technology Brochure (98 PDF)

Power Systems for the 2' Century: "H" Gas Turbine Combined Cycles (252KE

MPG Video: H System: W Most Advanced Combine Gas Turbine (19MB ZIP)

GE
- 9H gas turbine, LP steam turbine, generator, other power train equipment and accessories
- EPC project management
- Technical advisors
- Operations & maintenance; monitoring and diagnostics
- LM2500, plant compressors, gas compressors
- Water treatment systems
- 2 MW diesel generator
- Construction and testing power (GE Rentals)
- Switchyard control system; GT instruments
- BOP PLCs and operator interfaces
- Plant-merchant systems integration software

GE Capital
- IT integration support
- Plant financing

GE Industrial Systems
- Integrated control system with Mark VIs
- 6.9 kV switchgear
- Various pump and valve motors

GE Lighting
- Turbine hall and BOP lighting

Silvertech
- PRF control systems integration

Penpower
- Commissioning

QCI
- Pipe installation technical advisors

* Plant located on site leased from BP

** Baglan Energy Park is a joint development among BP, Welsh Development Agency and Neal Talbot County Borough Council

*** BP Chemicals Limited - Isopropanol plant adjacent to power station

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Attachment E

WESTINGHOUSE'S ADVANCED TURBINE SYSTEMS PROGRAM

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ABSTRACT

The paper describes the goals of the Westinghouse Advanced Turbine Systems program. This program is being undertaken in response to the DOE Fossil Energy requirements for improved efficiency, lower cost of electricity, lower emissions, and state-of-the-art reliability levels.

It describes in detail the objectives of the program and the approach taken by Westinghouse to achieve those goals. The evolutionary approach taken by Westinghouse is explained together with the development program and component testing undertaken in the last year.

The benefits of this new advanced turbine are discussed and the future activities of the program are explained.

INTRODUCTION

U.S. Department of Energy, Office of Fossil Energy Advanced Turbine Systems Program is a multi-year effort to develop the necessary technologies, which will result in a significant increase in natural gas-fired power generation plant efficiency, a decrease in cost of electricity and a decrease in harmful emissions. In Phase 1 of the ATS Program, preliminary investigations on different gas turbine cycles demonstrated that net plant efficiency greater than 60% is achievable. The more promising cycles were evaluated in greater detail in Phase 2 and the closed-loop cooled combined cycle was selected because it offered the best solution with the least risk for achieving the ATS Program goals of net plant efficiency, emissions, cost of electricity, reliability-availability-maintainability (RAM), as well as commercial operation by the year 2000.

The Westinghouse ATS plant is based on an enhanced technology gas turbine design combined with an advanced steam turbine and a high efficiency generator. To meet the challenging performance, emissions, and RAM goals, existing technologies were extended and new technologies developed. The attainment of ATS performance goal necessitated advancements in aerodynamics, sealing, cooling, coatings, and materials technologies. To reduce emissions to the required levels, demanded a development effort in the following combustion technology areas: lean premixed ultra-low NOx combustion, catalytic combustion, combustion instabilities, and optical diagnostics. To achieve the RAM targets, required the utilization of proven design features, with quantified risk analysis, and advanced materials, coatings, and cooling technologies.

The 501ATS engine is the next frame in the series of successful utility turbines developed by Westinghouse over the last 50 years. During that time, Westinghouse engineers made significant contributions in advancing gas turbine technology as applied to heavy-duty industrial and utility engines. Some of the innovations included single-shaft two-bearing engine design, cold-end drive, axial exhaust, first cooled turbine airfoils in an industrial engine, and tilting pad bearings, features which all major gas turbine manufacturers have incorporated in their designs. The evolution of large gas turbines started at Westinghouse with the introduction of the 45 MW 501A engine in 1968 (see Table 1). Continuous enhancements in performance were made up to the 100 MW 501D5 introduced in 1981. The next engine was the 160 MW 501F introduced in 1991. The 230 MW 501G was next in the series and is the initial step in ATS engine development. Each successive engine design was based on the proven concepts used in the previous design.

The 501F was introduced at 160 MW and a simple cycle efficiency of 36%. Its current uprated rating is 167 MW and its combined cycle net efficiency is greater than 55%. The first four 501F engines that entered service with Florida Power and Light have demonstrated 99% reliability and 94% availability in over 33,000 operating hours each.

The 501G produces 230 MW in simple cycle and its combined cycle net efficiency is 58%. This engine incorporates further advancements in materials, cooling technology, and component aerodynamic design. The 19:1 pressure ratio compressor uses advanced profile high efficiency airfoils. The combustion system incorporates 16 dry low NOx combustors, with similar flame temperature as in the 501F, and hence, the same low emissions. This was made possible by the closed-loop steam cooled transition design, which eliminated transition cooling air ejection into the gas path. The four-stage 501G turbine uses full 3-D design airfoils and proven aeroderivative materials and coatings.

Westinghouse's strategy to achieve, and exceed, the ATS Program goals is to build on the proven technologies used in the successfully operating fleet of its utility gas turbines, such as the 501F, and to extend the technologies developed for the 501G.

ATS DESCRIPTION

The ATS plant consists of the gas turbine, generator, and steam turbine, connected together in an in-line arrangement with a clutch located between the generator and the steam turbine. The gas turbine exhaust gases produce steam in the three-pressure level heat recovery steam generator. The high pressure steam turbine exhaust steam is used to cool the transitions and two rows of stators. The reheated steam is then returned to the steam cycle for induction into the intermediate pressure steam turbine.

The ATS engine is a state-of-the-art 300 MW class design incorporating many proven design features used in previous Westinghouse gas turbines and new design features and technologies required to achieve the ATS Program goals.

Compressor

The compressor shares many common parts with the 501G 16-stage compressor. The mass flow is identical, but the ATS higher rotor inlet temperature and closed-loop cooling has required an increase in pressure ratio from 19:1 to 29:1. This increased pressure ratio was achieved by adding stages to the rear of the 501G compressor. The latest 3-D viscous codes and custom-designed airfoils were used in the compressor aerodynamic design. Variable stators have been added to stages 1 and 2 to improve starting capability and part-load performance.

Combustion System

The 501ATS incorporates 16 combustors based on the lean premixed multi-stage piloted ring design. The burner outlet temperature was kept at the same level as in the 501F and 501G, by using closed-loop steam cooling (with air as an alternate coolant) in the transitions and turbine stators, so that more compressor delivery air was available in the combustor head end. Therefore, this allowed very lean, premixed combustion and hence single digit NOx emissions.

To aid in ATS combustor design and development, extensive use was made of computational fluid dynamics (CFD) analysis. Using CFD analysis expedited combustion system development and allowed screening of modifications prior to testing. This resulted in combustors with more predictable performance and reliability.

Turbine

The four-stage turbine design was based on 3-D design philosophy and viscous analysis codes. The airfoil loadings were optimized to enhance aerodynamic performance while minimizing airfoil solidity. The reduced solidity resulted in lower cooling requirements and increased efficiency. To further enhance plant efficiency, the following features were included: turbine airfoil closed-loop cooling, active blade tip clearance control on the first two stages, improved rotor sealing, and optimum circumferential alignment of airfoils.

The ATS engine utilized advanced thin wall designs with thermal barrier coatings and the state-of-the-art aero engine cooling technology. The first and second stage vanes used closed-loop steam cooling and the first two stages of blades used closed-loop air cooling. Air was chosen for blade cooling because it does not have the risks of steam corrosion, deposition, and complexity that closed-loop cooling with steam poses. In addition, the air can be cooled after it is removed from the combustor shell so that only relatively small amounts of cooling air are needed for the rotor. The cooling air is filtered to remove dirt particles before being ducted to the rotor blades. The difference in plant thermal efficiency between blade closed-loop cooling by air instead of steam is about 0.2%. Thus, based on a cost benefit analysis and RAM analysis, closed-loop air cooling is the preferred approach.

Westinghouse has been using thermal barrier coatings (TBC) on turbine airfoils since 1986 and has built an extensive experience base. It is a standard "bill of material" for new 501D5, 501F, and 251B11/12 engines. Recent field trials have demonstrated excellent results after operation for 24,000 hours. In the 501ATS engine, further improvements in TBC coating, with improved bond coats and new ceramic materials, will be utilized.

The 501ATS turbine design used the latest aero engine blade and vane nickel-based alloys. Single crystal nickel alloy, CMSX-4, was employed on the first stage vanes and blades to provide increased creep strength and fatigue resistance compared to conventional materials.

Rotor Design

The power level transmitted through the rotor and the resulting high stresses make rotor design an extremely important component of the engine. The 501ATS rotor consists of four ruggedized alloy steel discs clamped together with 12 through-bolts. Alloy steel was used to extend the excellent past operating experience with this material to the ATS engine and to reduce engine cost. In this design, torque transmission and alignment are achieved by the use of a Curvic™ clutch, which is a beveled male and female tooth form. This design has been proven by use on all Westinghouse-designed gas turbines over the past 40 years.

During the rotor design process, extensive finite element analysis modeling was carried out to calculate rotor critical speeds and cyclic life. In order to ensure rotor stability, a transient analysis from startup to baseload was carried out to verify that there was no slipping or gapping of the torque carrying members. The analysis has demonstrated that during all conditions analyzed, the torque carrying Curvic™ clutch arms do not come out of engagement. This virtually eliminates frettage or slippage which could give rise to vibration or cracking.

The compressor rotor is a series of discs clamped together with 12 through-bolts. However, the torque transmission is via friction and radial keys between all discs. This method was also used on the 501F and shown to be reliable. Alignment of the discs is maintained by a spigot at the base of the discs and by the shoulder on the radial pins. Computer modeling was used to ensure the rotor stability over its complete operating range with no chance of slippage or gapping.

TECHNOLOGY VERIFICATION PROGRAMS

To ensure that ATS program goals are achieved, an extensive technology verification program is in progress in the following areas: combustion, cooling, aerodynamics, leakage control, coatings, and materials.

Combustion

The 501ATS piloted ring combustor is the most successful candidate of combustors developed by Westinghouse over the past 10 years. It consists of a pilot and two separate premixed zones arranged axially, the primary and secondary zones. Premixed fuel and air enter the primary zone where combustion is stabilized by a swirl-produced recirculation zone and a centrally located pilot. The second zone is located downstream and is fed premixed fuel and air through an annular passage surrounding the primary zone. This combustor, which achieved single digit NOx emissions and excellent stability on low pressure tests, is currently undergoing evaluation at high pressures.

Cooling

Elimination of cooling air injection into the turbine flow path, as a result of closed-loop steam cooling, is the major contributor to the increase in ATS plant efficiency. This results in an increase in gas temperature downstream of the first stage vane and hence an increase in gas energy level during the expansion process. A secondary contributor is the elimination of mixing losses associated with cooling air ejection. The combination of these effects results in a significant increase in ATS plant efficiency. In addition, NOx emissions are reduced because more air is available for the lean premixed combustor at the same burner outlet temperature. Achieving acceptable blade metal temperatures in a closed-loop cooling design is a challenge due to the absence of a cooling air film to shield the turbine airfoil and shroud wall, and no shower-head or trailing edge ejection to provide enhanced cooling in the critical leading and trailing edge regions. To produce an optimized closed-loop cooling design, the following approaches were utilized: (1) airfoil aerodynamic design tailored to provide minimum gas side heat transfer coefficients, (2) minimum coolant inlet temperature, (3) thermal barrier coating applied on airfoil and end wall surfaces to reduce heat input, (4) maximized cold side surface area, (5) turbulators to enhance cold side heat transfer coefficients, and (6) minimum outside wall thicknesses to reduce wall temperature gradients and hence the internal heat transfer coefficients required to cool the airfoil.

The thin-wall closed-loop cooled first stage vane and blade design was completed and casting development started at Allison-Single Crystal Operations. To verify the critical cooling designs, a three part program was undertaken. The internal heat transfer coefficients and pressure drops are being measured on plastic models of the different vane and blade cooling features at Carnegie Mellon University. A liquid crystal thermochromic paint technique was used to measure the internal heat transfer coefficients. The outside heat transfer coefficients will be measured on model turbine tests. The first stage vane cooling design will be verified at ATS operating conditions in a hot cascade test rig in the Westinghouse high pressure combustion test facility located at the Arnold Engineering Development Center, in Arnold AFB, Tennessee.

Compressor Aerodynamics Development

To determine its performance and operating characteristics over the complete operating range, the full-scale ATS compressor was tested in a specially designed facility located at the

U.S. Navy Base in Philadelphia. The facility was designed for subatmospheric inlet pressure to reduce the power required to drive the compressor. The inlet system consisted of a filter house, straight pipe with a flow straightener and a flow meter, inlet throttle valve, diffuser with flow straightening devices, 90° bend with turning vanes, and a silencer. Because of the subatmoshperic operation, two stages of compressor bleed air were ducted into the inlet diffuser, after passing through coolers. The exhaust system included a large diameter back pressure valve to provide control on the test pressure ratio. A small diameter quick-acting valve, located in a bypass line around the large back pressure valve, was used for recovery from compressor surge.

The compressor was instrumented with static pressure taps, fixed temperature and pressure rakes, thermocouples, tip clearance probes, blade vibration monitoring probes, rotor vibration probes, acoustic probes, and strain gauges. Provisions were made for radial traverses in eight axial locations in the compressor and four radial locations in the inlet duct. More than 500 individual measurements were recorded. A dedicated data acquisition system was used to collect and reduce the test data. Important performance and health monitoring parameters were displayed on computer screens in real time. After the compressor test facility was commissioned, an extensive test program was performed. The test program included design point performance verification, blade vibration and diaphragm strain gauge measurements, inlet guide vane and variable stator optimization, compressor map definition and starting characteristics optimization.

Turbine Aerodynamic Development

The first two 501ATS turbine stages will be tested at 1/3-scale in a model turbine test rig, located at Ohio State University, to verify aerodynamic performance with reduced airfoil solidity, to quantify performance benefits due to optimum circumferential alignment of turbine airfoils, and to measure outside heat transfer coefficients on the airfoils of this advanced 3-D aero design turbine. The model turbine component manufacture was completed. Pressure sensor and thermocouple installation on the model turbine airfoils was also completed. The heat flux gauge installation is nearing completion. The test facility, which was moved from Buffalo to Ohio State University, was commissioned and is ready for model turbine testing.

Leakage Control

To reduce air leakage, as well as hot gas ingestion into turbine disc cavities, brush seals were incorporated under the compressor diaphragms, turbine disc front, turbine rim, and turbine interstage locations. A development program was initiated to incorporate an effective, reliable, and long-lasting brush seal system into a heavy-duty industrial gas turbine. Tests were performed to select the appropriate bristle materials, to quantify wear characteristics and to determine leakage. The brush seal performance under the compressor diaphragms was verified during the 501ATS compressor testing. To test their performance over long operating times, turbine interstage seals were installed on a new 501F engine and will be retrofitted into 501D5 engines.

A face seal was designed to prevent rotor cooling air leakage as it is introduced at the rotor rear. Seal hardware has been ordered and a test rig is being constructed. Tests will be carried out to verify the face seal performance.

Coatings

The ATS engine turbine component coatings must be capable of operation for 24,000 hours. To ensure this, a program is in progress to develop an improved bond coat/TBC system. Different bond coats are being evaluated under accelerated oxidation test conditions. New ceramic candidate materials are also undergoing testing. The objective of this program is to combine the optimum bond coat with the best performing TBC to provide a coating system with maximum service life at the ATS operating conditions. An advanced bond coat/TBC system has accumulated more than 20,000 hours in cyclic testing at 1010°C (1850°F) with excellent results.

Materials

To enhance performance and reliability, single crystal (SC) blades are used in the ATS engine. A casting development program was carried out to demonstrate castability of large industrial turbine blades in CMSX-4 material. Existing 501F engine tooling was used to cast single crystal blades. The castings were evaluated by grain etching, selected NDE methods and dimensional inspection methods to determine their metallurgical acceptability. After several trials, excellent results were obtained on a solid and a cored blade thus demonstrating that SC blades are castable in CMSX-4 alloy. Further process development is in progress to optimize post-cast heat treatment, evaluate effects of grain defects, generate SC material design data, and further develop the casting process.

FUTURE ACTIVITIES

Technology development efforts to date have demonstrated that ATS Program goals are obtainable. The results have been incorporated into the 501ATS design. Future ATS Phase 3 activities will complete the technology verification process. High pressure testing on the ATS piloted ring combustor will be carried out to optimize the design and demonstrate single digit NOx emissions. Catalytic combustion development will proceed toward full-scale testing of catalytic combustor by the end of the year. The two-stage model turbine tests, to verify aerodynamic performance and to measure outside heat transfer coefficients, will be completed. Rig testing will be completed on the turbine brush seals and rotor face seal. Abradability tests will be carried out on the turbine blade tip treatments, which will be applied to blade tips for wear protection. Pre-production casting development will continue on the single crystal thin wall stage 1 vanes and blades and thick wall stage 2 blades. Long term verification tests on advanced bond coat/TBC system will be carried out on test rigs and rainbow tests with coated blades on operating engines. The next phase of the ATS Program includes building the prototype 501ATS engine and carrying out extensive testing to verify its performance and mechanical integrity.

ACKNOWLEDGMENTS

The research discussed in this paper is sponsored by the U.S. Department of Energy's Federal Energy Technology Center (FETC), under Contract DE-FC21-95MC32267 with Westinghouse Electric Corporation, 4400 Alafaya Trail, Orlando, Florida 32826-2399; telefax 407-281-5633. The period of performance is from September 1995 to December 1997. This program is administered under the guidance of FETC's Program Manager, Dr. Richard A. Johnson.

Engine	501A	501B	501D	501D5	501D5A	501F	501G	501/ATS
Commercial Operation	1968	1973	1976	1982	1994	1993	1997	2000
Power, MW	45	80	95	107	120	160	230	420*
Rotor Inlet Temp.,°F	1615	1819	2005	2070	2150	2330	2583	2750
Air Flow, Lb/Sec	548	746	781	790	832	961	1200	1200
Pressure Ratio	7:5	11:2	12:6	14:1	15:1	15:1	19:1	29:1
No. Comp. Stages	17	17	19	19	19	16	16	20
No. Turbine Stages	4	4	4	4	4	4	4	4
No. Cooled Rows	1	3	4	4	4	6	6	6
Exhaust Temp., °F	885	907	956	981	1004	1083	1100	1100
Heat Rate (Btu/kWh) Simple Combined	 12,600 9,000	 11,600 7,350	 10,925 7,280	 10,040 7,055	 9,900 7,024	 9,610 6,429	 8,860 5,881	 -- 5,686

*Combined cycle output power

Attachment F

Linda S. Adams
Secretary for Environmental Protection

Air Resources Board

Mary D. Nichols, Chairman
1001 I Street • P.O. Box 2815
Sacramento, California 95812 • www.arb.ca.gov

Arnold Schwarzenegger
Governor

December 17, 2007

Mr. Wayne Nastri
Regional Administrator
Region 9
U.S. Environmental Protection Agency
75 Hawthorne Street
San Francisco, California 94105-3901

Dear Mr. Nastri:

We are transmitting our recommendations for area designations and boundaries under the federal air quality standards for particulate matter 2.5 microns or less in diameter (PM2.5) as requested in your July 10, 2007 letter to Governor Schwarzenegger.

PM2.5 Nonattainment Areas
We base our recommendations on ambient PM2.5 concentrations measured from 2004 through 2006 by 81 Federal Reference Method (FRM) monitors located throughout California. The Air Resources Board's (ARB) recommendation is that the U.S. Environmental Protection Agency (U.S. EPA) designate seven areas as nonattainment for the revised PM2.5 24-hour standard:

- South Coast Air Basin.
- San Joaquin Valley Air Basin.
- Bay Area Air Quality Management District.
- Sacramento Metropolitan Air Quality Management District.
- The combined cities of Yuba City/Marysville within the Feather River Air Quality Management District.
- The City of Chico within the Butte County Air Quality Management District.
- The City if Calexico within the Imperial County Air Pollution Control District.

We also recommend that U.S. EPA designate twelve areas as attainment, where air quality data are sufficient to determine that they meet the federal standard. Finally, 28 areas should be deemed unclassifiable, where air quality data are insufficient to make a determination.

Nonattainment Area Boundaries
Regarding nonattainment area boundaries, ARB staff has the following recommendations:

- Retaining the existing nonattainment area boundaries for South Coast and San Joaquin Valley.
- Establishing nonattainment area boundaries for the Bay Area and Sacramento consistent with the air district boundary for each region.
- Establishing focused nonattainment areas for the cities of Chico, and the combined cities of Marysville and Yuba City to reflect the localized nature of the PM2.5 problem in these regions.

We also recommend a focused nonattainment area for the city of Calexico. ARB staff believes that violations of the daily PM2.5 standard in Calexico during the 2004 – 2006 period result from emissions in the densely populated city of Mexicali across the border. We believe that the City of Calexico would attain the PM2.5 air quality standard but for emissions emanating from outside of the United States. ARB plans to use the provisions in the Clean Air Act for dealing with air quality problems along international border areas.

Enclosures
We include the following materials in this package:

- Recommended nonattainment/attainment/unclassifiable areas (Enclosure 1).
- Staff Report (Enclosure 2).
- Information supporting recommendations for nonattainment areas (Enclosure 3).
- Boundary descriptions (Enclosure 4).
- 2004 – 2006 data for all of California's PM2.5 monitoring sites (Enclosure 5).

If you have any questions, please call Lynn Terry, Deputy Executive Officer, at (916) 322-2739, or have your staff contact Karen Magliano, Chief, Air Quality Data Branch, at (916) 322-7137.

Sincerely,

Original signed by

James N. Goldstene
Executive Officer

Enclosures

cc: See next page.

cc: Stephen Birdsall, APCO
Imperial County Air Pollution Control District
150 South 9th Street
El Centro, California 92243

Jack Broadbent, APCO
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, California 94109-7799

Larry Green, APCO
Sacramento Metropolitan Air Quality Management District
777 12th Street, Third Floor
Sacramento, California 95814-1908

Seyed Sadredin, APCO
San Joaquin Valley Air Pollution Control District
1990 E. Gettysburg
Fresno, California 93736

Dave Valler, APCO
Feather River Air Quality Management District
938 14th Street
Marysville, California 95901-4149

W. James Wagoner, APCO
Butte County Air Quality Management District
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Chico, California 95928-7184

Barry Wallerstein, APCO
South Coast Air Quality Management District
21865 E. Copley Drive
Diamond Bar, California 91765-4182

Lynn Terry
Air Resources Board

Karen Magliano
Air Resources Board

Enclosure 1

State of California
Initial Recommendations for Area Designations under the Revised Federal PM2.5 Standard
(based on 2004 – 2006 monitoring data)

Recommended PM2.5 Nonattainment Areas in California			
Nonattainment Area	**24-Hour Design Value**	**High Monitor Location**	**Areas Included**
South Coast Air Basin	57	Riverside County – Rubidoux	Western Los Angeles, Orange, Southwestern San Bernardino, and Western Riverside Counties
San Joaquin Valley Air Basin	64	Kern County – Bakersfield	San Joaquin, Stanislaus, Merced, Madera, Fresno, Kings, Tulare, and Western Kern Counties
San Francisco Bay Area	39	Santa Clara County - San Jose	Southern Sonoma, Napa, Marin, San Francisco, Contra Costa, Alameda, Santa Clara, San Mateo, and Western Solano Counties
Sacramento Metropolitan Air District	49	Sacramento County – Del Paso Manor	Sacramento County
City of Calexico	40	Imperial County Calexico – Ethel St.	City of Calexico
Combined Cities of Marysville and Yuba City	40	Sutter County – Yuba City	Cities of Marysville and Yuba City
City of Chico	56	Butte County - Chico	City of Chico

Recommended PM2.5 Attainment Areas in California			
Attainment Area	**24-Hour Design Value**	**High Monitor Location**	**Areas included**
Calaveras County	21	San Andreas	Calaveras County
Imperial County	25	El Centro	Imperial County excluding the recommended Calexico nonattainment area
Colusa County	27	Colusa	Colusa County
Shasta County	22	Redding	Shasta County
Plumas County	30	Portola	Plumas County
Mendocino County	16	Ukiah	Mendocino County
Lake County	14	Lakeport	Lake County
Nevada County	16	Truckee	Nevada County
Placer County	31	Roseville	Placer County
Yolo/Solano Air District	30	Woodland	Yolo and Eastern Solano Counties
Ventura County	30	Simi Valley	Ventura County
San Diego County	28	Chula Vista	San Diego County

Recommended PM2.5 Unclassifiable Areas in California
Butte County (excluding the recommended nonattainment area for the city of Chico)
Sutter County (excluding the recommended nonattainment area for the combined cities of Marysville and Yuba City)
Yuba County (excluding the recommended nonattainment area for the combined cities of Marysville and Yuba City)
Alpine County
Glenn County
Humboldt County
Del Norte County
El Dorado County
Inyo County
Lassen County
Mariposa County
Monterey County
Modoc County
Mono County
San Benito County
Santa Cruz County
San Luis Obispo County
Santa Barbara County
Siskiyou County
Sierra County
Tehama County
Trinity County
Tuolumne County
Amador County
Eastern Kern County
Northern Sonoma County
Eastern Los Angeles County
Eastern Riverside County
Northeastern San Bernardino County

State of California

California Environmental Protection Agency
AIR RESOURCES BOARD

Nonattainment Area Designations for the Revised Federal PM2.5 24-Hour Standard

Release Date: December 4, 2007
Public Meeting Date: December 6 - 7, 2007

CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC MEETING TO HEAR A REPORT ON STAFF'S NONATTAINMENT AREA RECOMMENDATIONS FOR THE REVISED FEDERAL PM2.5 STANDARD

The Air Resources Board (the Board or ARB) staff will present nonattainment area recommendations for the new federal 35 ug/m^3 24-hour $PM_{2.5}$ standard. ARB will submit these recommendations to the United States Environmental Protection Agency (U.S. EPA) by December 18, 2007.

DATE:	December 6 & 7, 2007
TIME:	9:00 a.m.
PLACE:	Air Resources Board Auditorium 9530 Telstar Avenue El Monte, California 91731

This item will be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., December 6, and will continue at 8:30 a.m., December 7, 2007. This item is expected to be considered on December 7, 2007. Please consult the agenda for the meeting, which will be available at least 10 days before December 6, 2007, to determine the day on which this item will be considered.

For individuals with sensory disabilities, this document is available in Braille, large print, audiocassette or computer disk. Please contact ARB's Disability Coordinator at (916) 323-4916 by voice or through the California Relay Services at 711, to place your request for disability services. If you are a person with limited English and would like to request interpreter services, please contact ARB's Bilingual Manager at (916) 323-7053.

BACKGROUND

The federal Clean Air Act requires U.S. EPA to set health-based National Ambient Air Quality Standards. On December 18, 2006, the U.S. EPA lowered the 24-hour $PM_{2.5}$ standard from 65 ug/m^3 to 35 ug/m^3. Due to the standard revision, ARB is required to submit nonattainment area recommendations and appropriate boundaries to U.S. EPA for this standard by December 18, 2007. The nonattainment area recommendations are based on 2004-2006 $PM_{2.5}$ air quality monitoring data.

U.S. EPA plans to finalize nonattainment area designations effective April 2009, based on 2005-2007 $PM_{2.5}$ air quality monitoring data. State implementation plans will be due three years after the effective date of designations. Attainment for this new standard will be required by April 2019.

PROPOSED ACTION

ARB staff will recommend that the South Coast Air Quality Management District, the San Joaquin Valley Air Pollution Control District, the Bay Area Air Quality Management District, the Sacramento Air Quality Management District, the combined cities of Yuba City/Marysville, the city of Chico, and the city of Calexico be designated as nonattainment for the new 35 ug/m^3 24-hour $PM_{2.5}$ standard.

AVAILABILITY OF DOCUMENTS

ARB staff will prepare a written Staff Report prior to the meeting. Copies of the Staff Report may be obtained from the Board's Public Information Office, 1001 "I" Street, 1st Floor, Environmental Services Center, Sacramento, California 95814, (916) 322-2990. This notice and Staff Report may also be obtained from ARB's internet site at www.arb.ca.gov/desig/pm25desig/pm25desig.htm.

SUBMITTAL OF COMMENTS

Interested members of the public may also present comments orally or in writing at the meeting, and in writing or by e-mail before the meeting. To be considered by the Board, written comment submissions not physically submitted at the meeting must be received **no later than 12:00 noon, December 5, 2007,** and addressed to the following:

Postal mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

Facsimile submittal: (916) 322-3928

Please note that under the California Public Records Act (Government Code section 6250 et seq.), your written and oral comments, attachments, and associated contact information (e.g., your address, phone, email, etc.) become part of the public record and can be released to the public upon request. Additionally, this information may become available via Google, Yahoo, and any other search engines.

The Board requests, but does not require that 30 copies of any written statement be submitted and that written and e-mail statements be filed at least 10 days prior to the meeting so that ARB staff and Board members have time to fully consider each comment. Further inquiries regarding this matter should be directed to Ms. Sylvia Zulawnick, Manager of the Particulate Matter Analysis Section, Planning and Technical Support Division, 1001 I Street, Sacramento, California 95814 or by e-mail at szulawni@arb.ca.gov, or Jill Glass, Air Pollution Specialist, Planning and Technical Support Division at (916) 322-6161, 1001 I Street, Sacramento, California 95814 or by e-mail at jglass@arb.ca.gov.

CALIFORNIA AIR RESOURCES BOARD

/S/

James N. Goldstene
Executive Officer

Date: November 20, 2007

Background

On December 18, 2006, the U.S. EPA strengthened the federal 24-hour average air quality standard for particulate matter 2.5 microns or less in diameter (PM2.5) from 65 ug/m^3 to 35 ug/m^3. The State of California is required to submit nonattainment area recommendations and appropriate boundaries to U.S. EPA for this standard by December 18, 2007. The purpose of this report is to share with the Board the staff's technical analysis and nonattainment recommendations that will be sent to U.S. EPA. U.S. EPA will make final designations in April 2009.

ARB staff has performed an analysis to determine appropriate nonattainment areas throughout the state using criteria outlined in the U.S. EPA's guidance memorandum (*June 8, 2007, Area Designations for the Revised 24-Hour Fine Particle National Ambient Air Quality Standards, Memorandum from Robert J. Meyers, Acting Assistant Administrator, Office of Air and Radiation to Regional Administrators, Regions I-X*). Determination of attainment/nonattainment is based on comparing a three-year average of the 98th percentile 24-hour average concentration to the level of the standard. The nonattainment area recommendations contained in this report are based on 2004-2006 PM2.5 air quality monitoring data.

U.S. EPA guidance recommends that in making boundary recommendations for nonattainment areas, states evaluate each area on a case-by-case basis in consideration of the following nine factors:

- Emissions
- Air quality data
- Population density
- Traffic and commuting patterns
- Expected growth
- Meteorology
- Geography/topography
- Jurisdictional boundaries
- Level of emission control

The Clean Air Act requires that a nonattainment area must include not only the area that is violating the standard, but also nearby areas that contribute to the violation. Accordingly, ARB's recommended nonattainment boundaries are sufficiently large to include both the areas that violate the standard and the areas that contribute to the violations.

The guidance further states that air quality monitoring data affected by exceptional events may be excluded from use in identifying a violation if they meet certain criteria. In 2007, wildfires may have impacted PM2.5

concentrations throughout the State. ARB will submit the required documentation to U.S.EPA in accordance with federal policy.

Air Quality Analysis

ARB maintains a comprehensive PM2.5 monitoring network, including Federal Reference Method (FRM) mass samplers, continuous mass samplers, and chemical speciation samplers. We use FRM monitoring data to determine PM2.5 concentrations in relation to the federal standard, and we use speciation samplers to determine the nature of the PM2.5 pollution. We base our initial recommendations on ambient PM2.5 concentrations measured from 2004 through 2006 by 81 FRM, sited and operated in accordance with federal requirements, located throughout the State. Table 1 provides the 24-hour PM2.5 design value for air districts with monitors violating the standard.

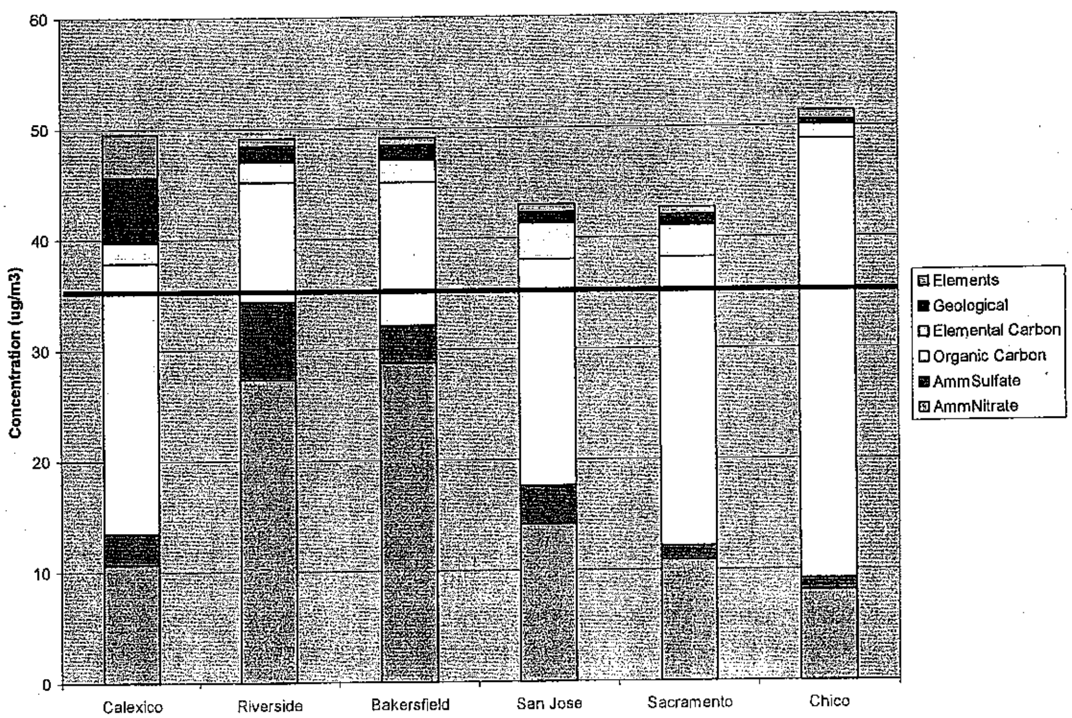
Table 1: Violating Area Design Values

Violating Area	24-hour Design Value	Air District
Riverside – Rubidoux, Riverside County	57 ug/m3	South Coast Air District
Bakersfield, Kern County	64 ug/m3	San Joaquin Valley Air District
Chico, Butte County	56 ug/m3	Butte County Air District
Calexico – Ethel St., Imperial County	40 ug/m3	Imperial County Air District
Sacramento – Del Paso Manor, Sacramento County	49 ug/m3	Sacramento Metropolitan Air District
San Jose – Jackson, Santa Clara County	39 ug/m3	Bay Area Air District
Vallejo, Solano County	36 ug/m3	Bay Area Air District
Yuba City, Sutter County	40 ug/m3	Feather River Air District

Figure 1 displays the average chemical composition on days with PM2.5 concentrations greater than the 35 ug/m3 standard in these areas. As shown, ammonium nitrate and organic carbon are the two greatest contributors to the total PM2.5 concentration. Ammonium nitrate is a secondary pollutant, formed from reactions of NOx and ammonia. Recent studies conducted during the California Regional Particulate Matter Air Quality Study (CRPAQS), have demonstrated that ammonium nitrate is regionally distributed, with similar concentrations in both urban and rural areas (Chow 2005, Turkiewicz 2006). The majority of the emissions that cause high ammonium nitrate are dominated by mobile sources. ARB's statewide mobile source strategy is currently, and will continue to reduce emissions leading to ammonium nitrate formation.

In contrast, organic carbon is a localized pollutant and typically is not transported beyond a small source region. In northern California, concentrations of organic carbon are highest during the winter months, November through February, suggesting that residential wood combustion is a key source, along with other combustion emissions from vehicles, agricultural and prescribed burning, and stationary sources. Conditions during the winter months are cold and stagnant, with light winds (Chow 2006, Turkiewicz 2006). CRPAQS research indicates that organic and elemental carbon is low at rural sites, consistent with a weak source of primary emissions in rural areas (Chow 2006). In addition transport does not play a large role in patterns of wintertime organic carbon. MacDonald 2006 found that "Particulate OM [organic matter] concentrations were high at the urban core sites and low at most rural sites. At distances >50 km from the urban areas, OM concentrations typically declined by a factor of 3-7. Overall, these spatial patterns of OM suggest the impact of urban emissions was largely confined to the urban areas..." Finally, analysis conducted by the Desert Research Institute during CRPAQS on the spatial zone of influence of different source types found that residential wood burning, a large contributor to wintertime carbon concentrations, typically had a zone of influence of only 4 to 5 miles (Chow 2005).

Figure 1: PM2.5 Chemical Composition at Six Nonattainment Areas



Boundary Analysis

In California, the primary considerations for air quality planning are air basin and air district boundaries if the pollution problem is regional in nature. Under State law, air basins are based on a rigorous scientific assessment of geography and meteorology, with consideration of political jurisdictions. Basin boundaries are formally adopted by ARB in regulation. Air districts were established by State statute. ARB typically uses a combination of air basin and air district lines to set boundaries for areas that violate California air quality standards, with exceptions when a single city or community has a unique air pollution problem distinct from the region.

ARB staff recommends retaining the existing nonattainment area boundaries for South Coast and San Joaquin Valley. Ammonium nitrate is the dominant constituent in both the South Coast and the San Joaquin Valley, indicating a region-wide pollution problem. In addition, monitors distributed throughout these two areas record violations of the standard. We recommend the nonattainment areas include the entire air basin for South Coast and San Joaquin Valley to reflect the regional nature of PM2.5 pollution in these areas.

Because organic carbon is primarily an urban scale problem, we are focusing the nonattainment area boundaries for those areas dominated by organic carbon on the urbanized region of each air district. Violations of the PM2.5 standard in San Jose and Vallejo are representative of the broad, urbanized Bay Area. The Bay Area Air Quality Management District is made up of several highly urbanized counties. In addition, speciation data for the Bay Area exhibits a larger contribution from ammonium nitrate and sulfate, reflecting a regional aspect. For these reasons we recommend designating the entire District nonattainment of the PM2.5 standard. Likewise, Sacramento County is predominantly one continuous urbanized area, with multiple monitors violating the standard. While there are urbanized areas on the periphery of Sacramento County, monitors in these areas do not violate the standard. Therefore, ARB staff recommends the Sacramento Metropolitan Air Quality Management District be designated nonattainment of the PM2.5 standard.

In contrast, the Feather River and Butte Air Districts have large rural portions, therefore, we are proposing designating only the primary urbanized area within each district where the population density is sufficient to contribute to localized wood smoke problems. Other small communities in the Sacramento Valley with PM2.5 monitoring show concentrations below the standard, suggesting that the problem is limited to the identified urban areas. ARB staff recommends a focused nonattainment area for the cities of Chico, and Yuba City/Marysville to reflect the localized nature of the PM2.5 problem in these regions.

In the case of Calexico, we believe that the City of Calexico would attain the PM2.5 air quality standard but for emissions emanating from outside of the

United States. Calexico is on the U.S. – Mexico border, at the southern end of Imperial County. Based on the available information, we believe that violations of the PM2.5 standard are localized in Calexico and the much larger adjacent city of Mexicali, Mexico. ARB plans to use the provisions in the Clean Air Act for dealing with plans along international border areas.

Designation Recommendations

After careful evaluation of nine factors, ARB recommends that the U.S. EPA designate seven areas as nonattainment for the PM2.5 standard:

- South Coast Air Basin
- San Joaquin Valley Air Basin
- Bay Area Air Quality Management District
- Sacramento Metropolitan Air Quality Management District
- The combined cities of Yuba City/Marysville within the Feather River Air Quality Management District
- The City of Chico within the Butte County Air Quality Management District
- The City if Calexico within the Imperial County Air Pollution Control District

References

MacDonald, C.P. et al, 2006, "Transport and Dispersion During Wintertime Particulate Matter Episodes in the San Joaquin Valley, California", *J. A&WMA*. 56:961-976.

Chow. J.C. et al, 2006, "PM2.5 Chemical Composition and Spatiotemporal Variability During the California Regional PM10/PM2.5 Air Quality Study", *J. Geo. Res.* DOI:10.1029.

Turkiewicz, K. et al, 2006, "Comparison of Two Winter Air Quality Episodes During the California Regional Particulate Air Quality Study", *J. A&WMA*, 56:467-473.

Chow, J.C. et al, 2005, "California Regional PM10/PM2.5 Air Quality Study Initial Data Analysis of Field Program Measurements", prepared for the San Joaquin Valleywide Air Pollution Study Agency.

Enclosure 3

State of California
Information to Support Recommendations for Federal PM2.5 Nonattainment Area Boundaries

EXISTING NONATTAINMENT AREAS

South Coast Air Basin
In 2004, the South Coast Air Basin was designated nonattainment of the 24-hour PM2.5 standard of 65ug/m3. Based on 2004 – 2006 monitoring data, the South Coast Air Basin remains in nonattainment of the revised PM2.5 standard with a design value of 57 ug/m3 measured at the Riverside – Rubidoux monitoring site. Consideration of U.S. EPA's nine factors indicates broad regional contribution to elevated PM2.5 levels and supports the use of the air basin boundary. ARB staff recommends that the boundaries remain consistent with the previous PM2.5 nonattainment boundary.

The recommended South Coast Air Basin PM2.5 nonattainment area includes Western Los Angeles (excluding Catalina and San Clemente Islands), Orange, Southwestern San Bernardino, and Western Riverside Counties. This area is under the jurisdiction of the South Coast Air Quality Management District.

San Joaquin Valley Air Basin
In 2004, the San Joaquin Valley Air Basin was designated nonattainment of the 24-hour PM2.5 standard of 65ug/m3. Based on 2004 – 2006 monitoring data, the San Joaquin Valley Air Basin remains in nonattainment of the revised PM2.5 standard with a design value of 64 ug/m3 measured at the Bakersfield – Golden monitoring site. Consideration of U.S. EPA's nine factors indicates broad regional contribution to elevated PM2.5 levels and supports the use of the air basin boundary. ARB staff recommends that the boundaries remain consistent with previous PM2.5 nonattainment boundary.

The recommended San Joaquin Valley PM2.5 nonattainment area consists of San Joaquin, Stanislaus, Merced, Madera, Fresno, Kings, Tulare and Western Kern Counties. The area is under the jurisdiction of the San Joaquin Valley Unified Air Pollution Control District.

NEW NONATTAINMENT AREAS

Sacramento Metropolitan Air Quality Management District

Jurisdictional boundary
The presumptive boundary for the PM2.5 nonattainment area includes all of Sacramento County under the jurisdiction of the Sacramento Metropolitan Air Pollution Control District.

ARB staff believes that a district level nonattainment area boundary is appropriate due to the localized nature of the PM2.5 problem. The two key components of PM 2.5 are ammonium nitrate and organic carbon. While ammonium nitrate is regional, most NOx emissions are from mobile sources which are controlled at a statewide level by ARB. Organic carbon is more localized and most effectively controlled at the district level.

Air Quality
Our initial recommendation for the Sacramento Metropolitan Air Quality Management District is based on ambient PM2.5 concentrations measured from 2004 through 2006. Three monitoring sites throughout Sacramento County monitor for PM2.5, however only two sites – Del Paso Manor and Stockton Boulevard – have complete data to support designations. Our nonattainment recommendation is based on a design value of 49 ug/m3 measured at the Del Paso Manor monitoring site. The Stockton Boulevard monitor is also exceeding the federal standard with a design value of 39 ug/m3.

Areas surrounding Sacramento County include the counties of Yolo, Solano, Placer, El Dorado, Sutter, Yuba, and San Joaquin. Exceedance of the PM2.5 standard in Yuba, Sutter, and San Joaquin County will be included in the recommended nonattainment area for Marysville/Yuba City, and San Joaquin Valley APCD, respectively. Solano County is divided between two air districts, the Bay Area AQMD and Yolo-Solano AQMD. The design value for Solano County is 36 ug/m3 measured at the Vallejo monitoring site, which is under the jurisdiction of the Bay Area AQMD and will therefore be included in the recommended Bay Area nonattainment area. Yolo County is in attainment of the standard with a design value of 30 ug/m3 measured at the Woodland monitoring site. Placer County is in attainment with a design value of 31 ug/m3 measured at the Roseville monitoring site.

The chemical makeup of PM2.5 in Sacramento is dominated by organic carbon and ammonium nitrate. Figure 2 and Figure 3 illustrate the seasonal pattern and chemical composition of PM2.5 at the Del Paso Manor and T Street sites with highest concentrations occurring in the winter time. Organic carbon is the largest component of PM2.5 and increases considerably during the winter months. As shown in Figure 4, organic carbon accounts for roughly 50 percent of the 2004 –

2006 average PM2.5 composition on exceedance days. The majority of organic carbon is suspected to be due to directly emitted carbon from combustion sources. Key sources include vehicles, residential wood combustion, agricultural and prescribed burning and stationary combustion sources. Concentrations of organic carbon are highest during the winter months, November through February, suggesting that emissions are likely a result of residential wood combustion.

Ammonium nitrate is another significant contributor to the total PM2.5 composition, accounting for about 22 – 27 percent of the average composition on exceedance days. During the fall and winter, the ammonium nitrate fraction of PM2.5 is higher than during the spring and summer, while ammonium sulfate and dust contribute slightly more to ambient PM2.5 during the spring and summer. Cool temperatures, low wind speeds, low inversion layers, and high humidity during the late fall and winter favor the formation of ammonium nitrate, while sunny, warmer conditions during the spring and summer favor the formation of ammonium sulfate, as well as the formation of secondary organic aerosols.

Figure 2: Seasonal Pattern of PM2.5 Chemical Components

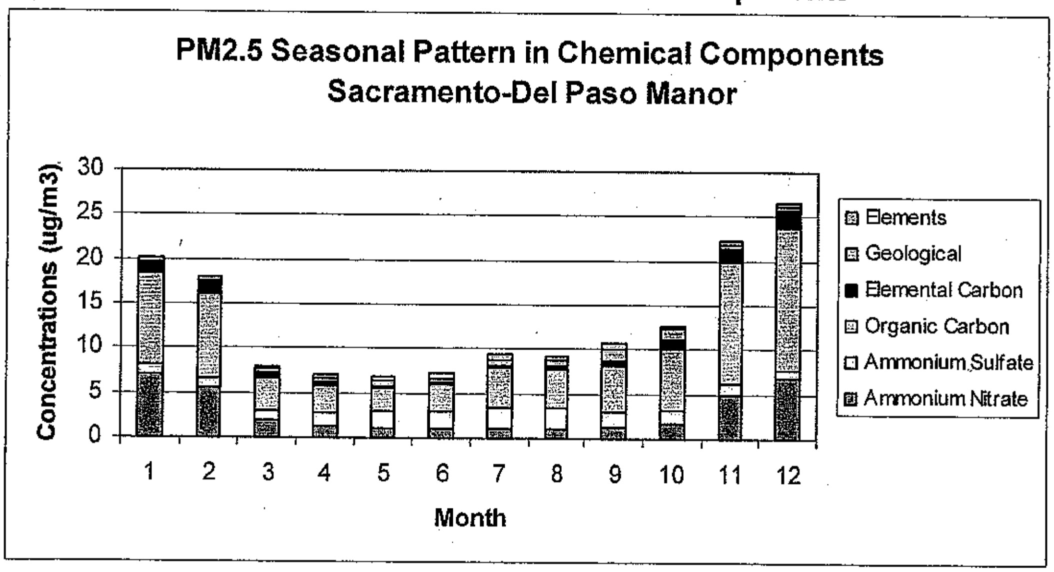


Figure 3: Seasonal Pattern of PM2.5 Chemical Components

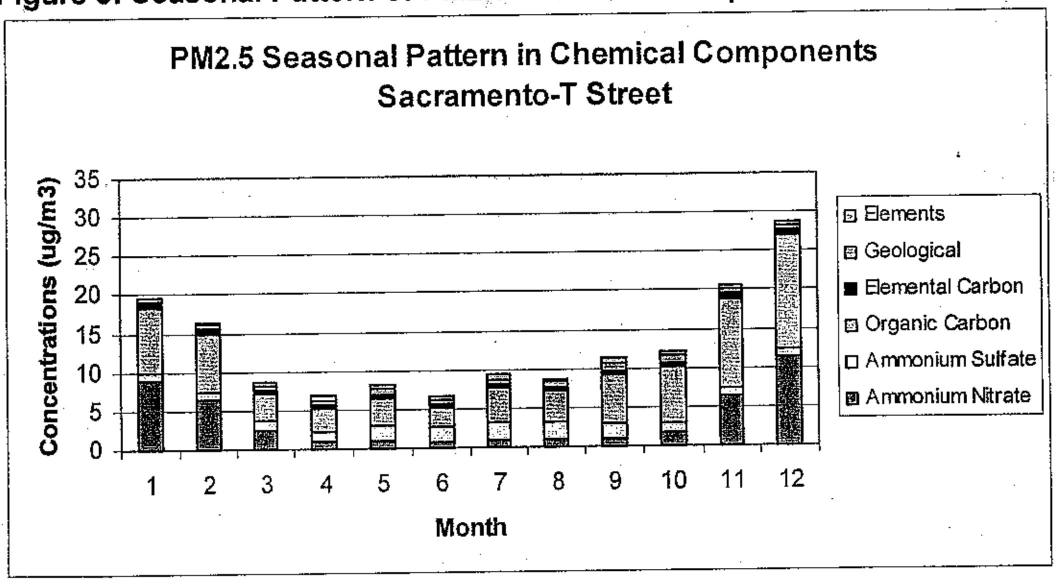
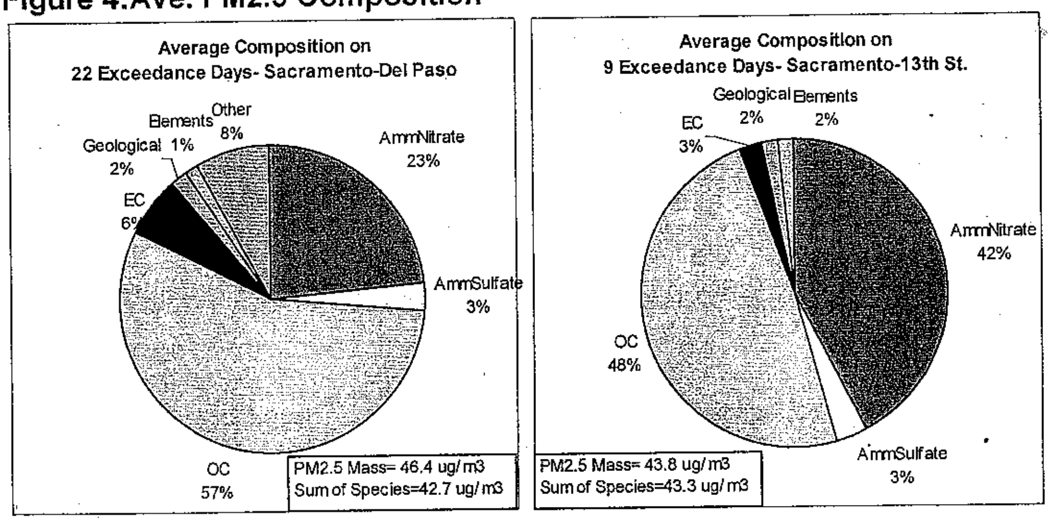


Figure 4:Ave. PM2.5 Composition



Geography/Topography/Meteorology

Sacramento County encompasses approximately 994 square miles in the heart of California's Central Valley. Sacramento County is bounded by the Sierra Nevada foothills to the northeast and the Sacramento-San Joaquin River Delta to the southwest. The lower Sacramento Valley extends through the western and central portions of the county. Elevations range from sea level in the southwest to approximately 400 feet about sea level in the eastern areas of the county.

High PM2.5 concentrations in the Sacramento area appear to be dependant upon calm-to-light winds and not as dependent upon wind direction. This suggests that there is enough activity within the Sacramento area to generate high PM2.5 concentrations under many conditions, and that high concentrations are not being caused by adjacent areas such as Placer, Sutter or Yolo Counties.

Emissions

The presumptive boundary for the PM2.5 nonattainment area includes all of Sacramento County under the jurisdiction of the Sacramento Metropolitan Air Pollution Control District. All potential emission sources are included within the recommended nonattainment area. Adjacent counties to Sacramento include Yolo, Solano, Sutter, Placer, El Dorado, Amador, San Joaquin, and a small portion of Contra Costa. The nature of the PM2.5 problem in Sacramento County is primarily a result of local emission sources such as smoke; therefore, emissions from neighboring counties would not impact the air quality data for Sacramento County. Emissions generated in Sutter County and San Joaquin County are included in the recommended Marysville/Yuba City and San Joaquin Valley Air District nonattainment areas, respectively. Table 1 provides emissions in tons per day of a primary pollutant contributing to PM2.5 from stationary, area and mobile sources. The majority of NOx emissions are under the mobile source category which is regulated by ARB.

Table 1: NOx Winter Emissions Sacramento and Surrounding Counties

Sacramento County	**2006**	**2010**	**2020**
Stationary Sources	3.9	3.9	4.3
Area Sources	4.0	4.0	4.1
Mobile Sources	75.1	62.5	34.5
Yolo County			
Stationary Sources	3.0	2.9	2.8
Area Sources	0.7	0.7	0.7
Mobile Sources	21.3	17.3	9.9
Solano County			
Stationary Sources	6.3	6.5	7.1
Area Sources	1.6	1.7	1.7
Mobile Sources	42.4	36.0	21.8
Placer County			
Stationary Sources	4.5	4.7	5.1
Area Sources	1.6	1.6	1.6
Mobile Sources	28.2	23.4	13.7
El Dorado County			
Stationary Sources	0.4	0.4	0.4
Area Sources	1.3	1.3	1.4
Mobile Sources	8.8	7.4	4.3
Sutter County			
Stationary Sources	3.6	3.9	3.9
Area Sources	0.9	0.8	0.8
Mobile Sources	14.3	12.9	6.9

Table 1 (cont.)

Amador County	2006	2010	2020
Stationary Sources	2.0	2.1	2.3
Area Sources	0.3	0.3	0.3
Mobile Sources	3.2	2.7	1.7
San Joaquin County			
Stationary Sources	14.8	15.2	17.3
Area Sources	2.7	2.6	2.5
Mobile Sources	88.8	72.9	40.3

Population Density and Degree of Urbanization

According to the U.S Census Bureau, the population of Sacramento County in 2006 is estimated to be 1,374,724 based on 2000 census data. This represents an 11 percent increase in population since 2000, and a 25 percent increase since 1990.

Table 2: Sacramento County Population

	1990	2000	2006
Population	1,041,219	1,223,499	1,374,724
Population Density	1078 persons/sq mile	1267 persons/sq mile	1423 persons/sq mile

Traffic and Commuting Patterns

The estimates of daily vehicle miles traveled for the years 1990 through 2020 are found in ARB's revised motor vehicle emissions inventory model. In Sacramento County, traffic is expected to increase by 7 percent by 2010 and by 11 percent by 2020. Vehicle miles traveled is projected to increase roughly twice as fast as population, yet NOx emissions from mobile sources are expected to continue along a downward trend. This illustrates the effectiveness of statewide mobile source controls, and supports the need for local control measures to reduce PM2.5 levels.

Table 3: Sacramento County Daily Vehicle Miles Traveled

	1990	1995	2000	2005	2010	2015	2020
Ave. Daily VMT/1000	24774	27057	27090	30519	33091	35567	37370

Expected Growth

Sacramento County is expected to grow by 10 percent from 2005 to 2010, and by 28 percent by 2020. Surrounding counties are expected to have similar growth patterns; however, we do not expect surrounding areas to contribute to PM2.5 concentrations in Sacramento County. Ammonium nitrate emissions are controlled on a statewide level and are expected to decrease over time. Organic carbon is a localized source, therefore the most effective control measures focus on a centralized nonattainment area.

Table 4: Sacramento County Projected Growth

	2000	2005	2010	2015	2020
Population	1,233,560	1,392,930	1,555,848	1,751,264	1,946,679

Level of Control of Emissions Sources

Sacramento County has motor vehicle emission controls that are consistent with the rest of California. Vehicles must meet California standards; therefore, new vehicles will be controlled through statewide measures. Both cars and heavy trucks are subject to in-use inspection programs. The Sacramento Metropolitan Air District administers a smoke management program for open burning, consistent with ARB's statewide regulation. In addition, the district recently adopted a comprehensive control strategy to reduce emissions from residential wood burning, a key source of localized particulate matter emissions. Areas surrounding Sacramento County have similar level of control regarding smoke management and control of NOx sources.

Bay Area Air Quality Management District

Jurisdictional Boundary

The presumptive boundary for the PM2.5 nonattainment area includes the counties of Sonoma, Napa, Solano, Marin, Contra Costa, San Francisco, Alameda, San Mateo, and Santa Clara under the jurisdiction of the Bay Area Air Quality Management District (AQMD). The two key components of PM2.5 are ammonium nitrate and organic carbon. While ammonium nitrate is regional, most NOx emissions are from mobile sources which are controlled at a statewide level by ARB. Organic carbon is more localized and most effectively controlled at the district level.

Air Quality

Our initial recommendation for the Bay Area AQMD is based on ambient PM2.5 concentrations measured from 2004 through 2006. Our nonattainment recommendation is based on a design value of 39 ug/m3 measured at the San Jose – Jackson Street monitoring site in Santa Clara county, and a design value of 36 ug/m3 measured at the Vallejo monitoring site in Solano county.

Areas surrounding the Bay Area AQMD include the counties of Mendocino, Lake, Yolo, Sacramento, San Joaquin, Stanislaus, Merced, San Benito, and Monterey. Exceedances of the PM2.5 standard in Sacramento will be included in the recommended Sacramento Metropolitan AQMD nonattainment area. Exceedances of the standard in San Joaquin, Stanislaus, and Merced counties will be included in the recommended San Joaquin Valley APCD nonattainment area. Mendocino, Lake, Yolo, San Benito, and Monterey counties are all in attainment of the standard.

The chemical makeup of PM2.5 in the Bay Area is dominated by organic carbon and ammonium nitrate. Figure 5 illustrates the seasonal pattern and chemical composition of PM2.5 at the San Jose monitoring site, with highest concentrations occurring in the winter time. As shown in Figure 6, organic carbon accounts for roughly 44 percent of the 2004 – 2006 average PM2.5 composition on exceedance days. The majority of organic carbon is suspected to be due to directly emitted carbon from combustion sources. Key sources include vehicles, residential wood combustion, agricultural and prescribed burning, and stationary combustion sources. Concentrations of organic carbon are highest during the winter months, November through February, suggesting that emissions are likely a result of residential wood combustion.

Ammonium nitrate is another significant contributor to the total PM2.5 composition, accounting for about 32 percent of the average composition on exceedance days. During the fall and winter, the ammonium nitrate fraction of PM2.5 is higher than during the spring and summer, while ammonium sulfate and dust contribute slightly more to ambient PM2.5 during the spring and summer.

Figure 5: Seasonal Patten of PM2.5 Chemical Components

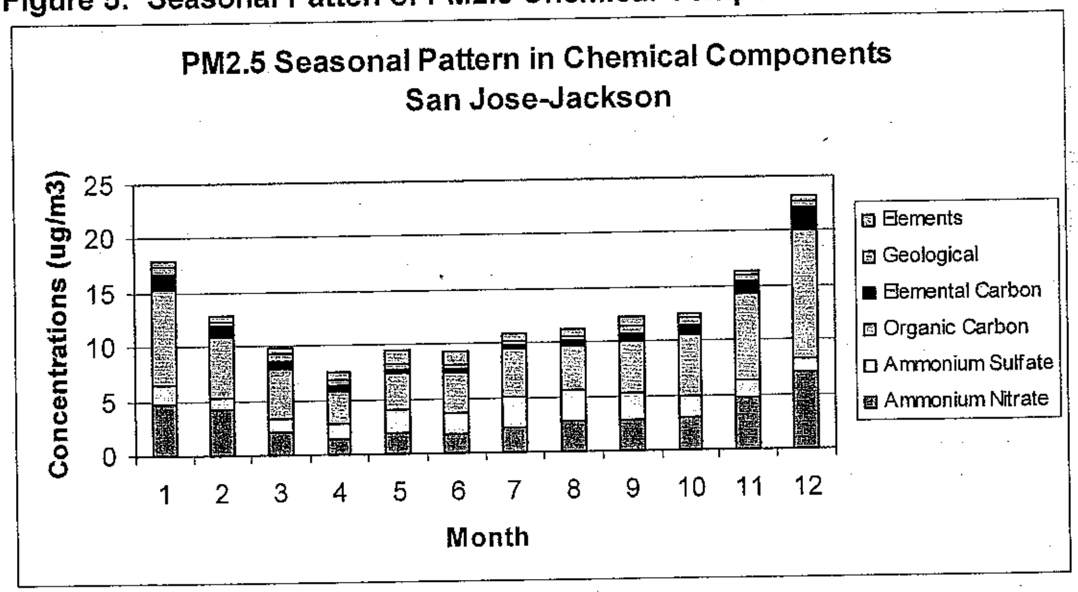
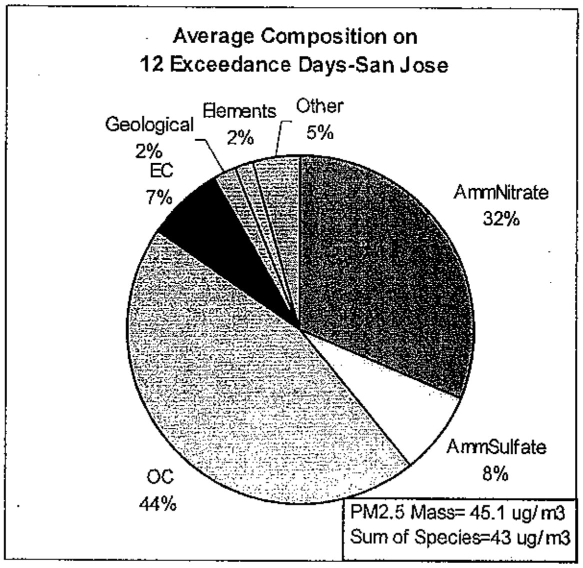


Figure 6: Ave PM2.5 Composition



Geography/ Topography/Meteorology

The San Francisco Air Basin encompasses approximately 5,430 square miles and consists of all of Alameda, Contra Costa, Marin, Napa, San Francisco, San Mateo, and Santa Clara counties, the southern half of Sonoma County and the southwestern portion of Solano County. The region is characterized by complex terrain, consisting of coastal mountain ranges, rugged hillsides, and inland valleys and bays. Elevations can range from sea level to 1500 feet. The coastal zones tend to be more windy and cooler in the summer that the hotter, drier interior regions with a reversal in the winter months. Precipitation is more typical of a Mediterranean climate with dry summers and wet winters.

The summer climate is dominated by a high pressure center over the Pacific Ocean. Storms rarely affect the coast during the summer, thus the conditions that persist during the summer are a northwest air flow and negligible precipitation. A thermal low pressure area from the Sonoran – Mojave Desert also causes air to flow onshore over the San Francisco Bay Area much of the summer. Air flow over cool Pacific Ocean temperatures produces condensation – a high incidence of fog and stratus clouds are common along the coast in summer.

In winter, the Pacific High weakens and shifts southward, winter storms become frequent. Almost all of the Bay Area's annual precipitation takes place in the November through April period. During the winter rainy periods, inversions are weak or nonexistent, winds are often moderate and air pollution potential is very low. During winter periods when the Pacific High becomes dominant, inversions become strong, winds are light and pollution potential is high. These periods are characterized by winds that flow out of the Central Valley into the Bay Area and often include tule fog.

Emissions
The presumptive boundary for the PM2.5 nonattainment area includes the counties of Sonoma, Napa, Solano, Marin, Contra Costa, San Francisco, Alameda, San Mateo, and Santa Clara under the jurisdiction of the Bay Area AQMD. All potential emission sources are included within the recommended nonattainment area. Adjacent counties to the Bay Area AQMD include Mendocino, Lake, Yolo, San Joaquin, Stanislaus, Merced, San Benito, and Monterey. The nature of the PM2.5 problem in the Bay Area is primarily a result of local emission sources such as smoke; therefore, emissions from neighboring counties would not impact the air quality data for the Bay Area. Emissions generated in San Joaquin, Stanislaus, and Merced counties are included in the recommended San Joaquin Valley APCD nonattainment area. Table 5 provides emissions in tons per day of a primary pollutant contributing to PM2.5 from stationary, area, and mobile sources. The majority of NOx emissions are under the mobile source category which is regulated by ARB.

Table 5: NOx Winter Emissions Bay Area and Surrounding Counties

Solano County	**2006**	**2010**	**2020**
Stationary Sources	6.3	6.5	7.1
Area Sources	1.6	1.7	1.7
Mobile Sources	42.4	36.0	21.8
Santa Clara County			
Stationary Sources	11.8	12.2	13.2
Area Sources	6.9	7.1	7.5
Mobile Sources	87.8	71.5	41.0
Sonoma County			
Stationary Sources	0.8	0.8	0.8
Area Sources	1.9	1.9	2.0
Mobile Sources	23.4	18.7	9.8
Napa County			
Stationary Sources	0.5	0.6	0.6
Area Sources	0.6	0.6	0.7
Mobile Sources	10.5	8.4	4.5
Marin County			
Stationary Sources	0.4	0.4	0.4
Area Sources	1.6	1.6	1.7
Mobile Sources	16.4	14.6	12.5

Table 5 (cont.)

Contra Costa County	**2006**	**2010**	**2020**
Stationary Sources	24.3	25.2	28.0
Area Sources	4.5	4.6	4.8
Mobile Sources	62.2	50.9	30.4
San Francisco County			
Stationary Sources	1.6	1.6	1.6
Area Sources	3.5	3.6	3.8
Mobile Sources	46.6	42.3	37.0
Alameda County			
Stationary Sources	5.9	6.1	6.7
Area Sources	5.9	6.1	6.4
Mobile Sources	128.5	106.3	67.1
San Mateo County			
Stationary Sources	1.7	1.7	1.8
Area Sources	3.4	3.5	3.7
Mobile Sources	46.6	42.3	37.0
San Joaquin County			
Stationary Sources	14.8	15.2	17.3
Area Sources	2.7	2.6	2.5
Mobile Sources	88.8	72.9	40.3
Stanislaus County			
Stationary Sources	9.3	9.4	10.2
Area Sources	2.7	2.6	2.5
Mobile Sources	47.7	38.0	19.4
Merced County			
Stationary Sources	6.0	5.9	5.8
Area Sources	1.6	1.6	1.5
Mobile Sources	53.7	41.5	20.5
Mendocino County			
Stationary Sources	0.9	0.9	1.0
Area Sources	0.8	0.9	0.9
Mobile Sources	24.1	23.1	24.2
Lake County			
Stationary Sources	0.3	0.4	0.4
Area Sources	0.6	0.6	0.6
Mobile Sources	5.7	5.0	3.1
San Benito County			
Stationary Sources	0.7	0.7	0.7
Area Sources	0.2	0.2	0.2
Mobile Sources	12.9	9.8	4.2

Table 5 (cont.)

Monterey County	**2006**	**2010**	**2020**
Stationary Sources	11.6	12.0	13.0
Area Sources	1.5	1.4	1.4
Mobile Sources	48.9	44.4	41.1
Yolo County			
Stationary Sources	3.0	2.9	2.8
Area Sources	0.7	0.7	0.7
Mobile Sources	21.3	17.3	9.9

Population Density and Degree of Urbanization

The Bay Area Air Basin has an estimated population of 6,953,438 as of 2005, based on data derived from reports developed by the California Department of Finance, Demographic Research Unit. This represents approximately a 4 percent increase in population since 2000, and a 15 percent increase since 1990.

Table 6: San Francisco Bay Area Air Basin Population

	1990	**2000**	**2005**
Population	5,874,353	6,646,727	6,953,438
Population Density	1100 persons/sq mile	1245 persons/sq mile	1302 persons/sq mile

Traffic and Commuting Patterns

The estimates of daily vehicle miles traveled for the years 1990 through 2020 are found in ARB's revised motor vehicle emissions inventory model. In the Bay Area Air Basin traffic is expected to increase by 11 percent by 2010 and by 20 percent by 2020. Vehicle miles traveled is projected to increase faster than the population, yet NOx emissions from mobile sources are expected to continue along a downward trend. This illustrates the effectiveness of statewide mobile source controls, and supports the need for local control measures to reduce PM2.5 levels.

Table 7: Bay Area Air Basin Vehicle Miles Traveled

	1990	**1995**	**2000**	**2005**	**2010**	**2015**	**2020**
Ave. Daily VMT/1000	133,990	144,854	159,271	172,581	193,300	202,212	213,900

Expected Growth

The Bay Area AQMD is expected to grow by 5 percent from 2005 to 2010 and by 15 percent by 2020. Surrounding counties are expected to have similar growth patterns; however, we do not expect surrounding areas to contribute to PM2.5 concentrations in the Bay Area. Ammonium nitrate emissions are controlled on a statewide level and are expected to decrease over time. Organic carbon is a localized source, therefore the most effective control measures focus on a centralized nonattainment area.

Table 8: Bay Area Air Basin Projected Growth

	2000	2005	2010	2015	2020
Population	6,646,727	6,953,438	7,337,485	7,736,635	8,135,781

Level of Control of Emissions Sources

The Bay Area has motor vehicle emission controls that are consistent with the rest of California. Vehicles must meet California standards; therefore, new vehicles will be controlled through statewide measures. Both cars and heavy trucks are subject to in-use inspection programs. The Bay Area AQMD administers a smoke management program for open burning. Areas surrounding the Bay Area AQMD have similar levels of control regarding smoke management and control of NOx sources.

The Combined Cities of Marysville and Yuba City within the Feather River Air Quality Management District

Jurisdictional Boundary

The presumptive boundary for the PM2.5 nonattainment area includes the cities of Marysville and Yuba City under the jurisdiction of the Feather River Air Quality Management District (AQMD).

ARB staff believes that a city level PM2.5 nonattainment area boundary is appropriate due to the localized nature of the PM2.5 problem. The cities of Marysville and Yuba City together form one urban area separated only by the county line along the Feather River. The two key components of PM2.5 are ammonium nitrate and organic carbon. While ammonium nitrate is regional, most NOx emissions are from mobile sources which are controlled at a statewide level by ARB. Organic carbon is more localized and most effectively controlled at the district level.

Air Quality

Our initial recommendation for Marysville/Yuba City is based on ambient PM2.5 concentrations measured from 2004 through 2006. The Feather River AQMD has only one monitor to measure PM2.5, located in Yuba City in Sutter County. Our nonattainment recommendation is based on a design value of 40 ug/m3 measured at the Yuba City monitoring site. Due to the close proximity of the city of Marysville in Yuba County, we recommend the Marysville/Yuba City urbanized region be included in the nonattainment area.

Areas surrounding Feather River AQMD include the counties of Butte, Glenn, Colusa, Yolo, Sacramento, Placer, Nevada, and Sierra. Exceedance of the PM2.5 standard in Sacramento County will be included in the recommended nonattainment area for the Sacramento Metropolitan AQMD. Exceedance of the standard in Butte County will be included in the recommended nonattainment area for the City of Chico. Yolo County is in attainment of the standard with a design value of 30 ug/m3 measured at the Woodland monitoring site. Placer County is in attainment with a design value of 31 ug/m3 measured at the Roseville monitoring site. Likewise, Glenn, Colusa, Nevada and Sierra counties all are in attainment of the standard.

Speciation data for the Yuba City monitor is not available; however, we believe the speciation data from Sacramento and Chico to be representative of the chemical makeup of PM2.5 in the Maryville/Yuba City urbanized area. The chemical composition of PM2.5 in Sacramento is dominated by organic carbon and ammonium nitrate. Figure 7 and Figure 8 illustrate the seasonal pattern and chemical composition of PM2.5 at the Del Paso Manor site in Sacramento County, and the Chico site in Butte County, with the highest concentrations occurring in the winter time. As shown in Figure 9, organic carbon accounts for roughly 57 percent and 75 percent of the average PM2.5 composition on exceedance days at the Del Paso Manor and Chico monitoring sites, respectively. The majority of organic carbon is suspected to be due to directly emitted carbon from combustion sources. Key sources include vehicles, residential wood combustion, agricultural and prescribed burning and stationary combustion sources. Concentrations of organic carbon are highest during the winter months, November through February, suggesting that emissions are likely a result of residential wood combustion.

Ammonium nitrate is another significant contributor to the total PM2.5 composition, accounting for about 16 to 23 percent of the 2004 – 2006 average at Sacramento and Chico. During the fall and winter the ammonium nitrate fraction of PM2.5 is higher than during the spring and summer, while ammonium sulfate and dust contribute slightly more to ambient PM2.5 during the spring and summer. Cool temperatures, low wind speeds, low inversion layers, and high humidity during the late fall and winter favor the formation of ammonium nitrate, while sunny, warmer conditions during the spring and summer favor the formation of ammonium sulfate, as well as the formation of secondary organic aerosols.

Figure 7: Seasonal Pattern of PM2.5 Chemical Components

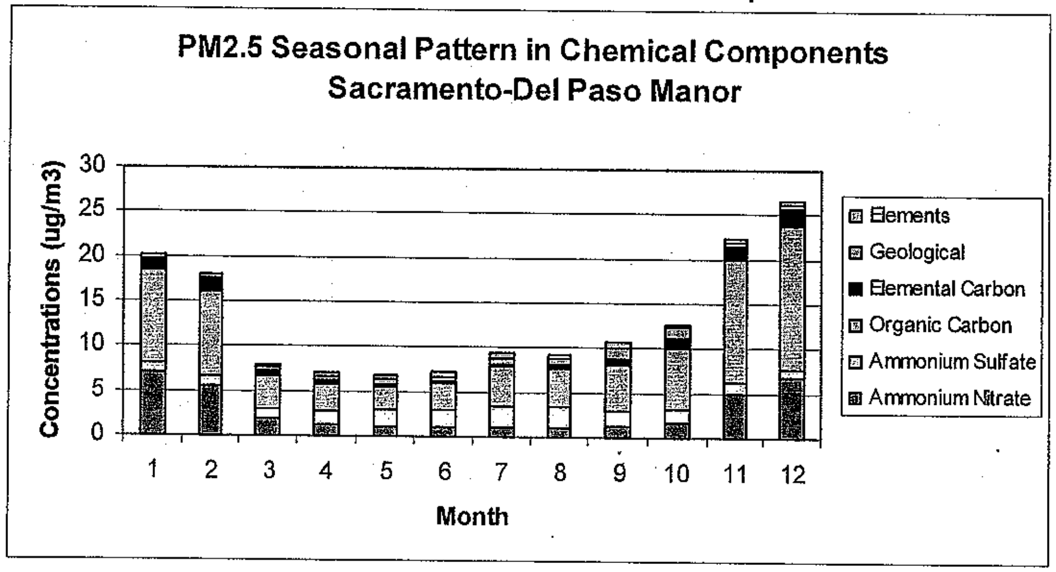


Figure 8: Seasonal Pattern of PM2.5 Chemical Components

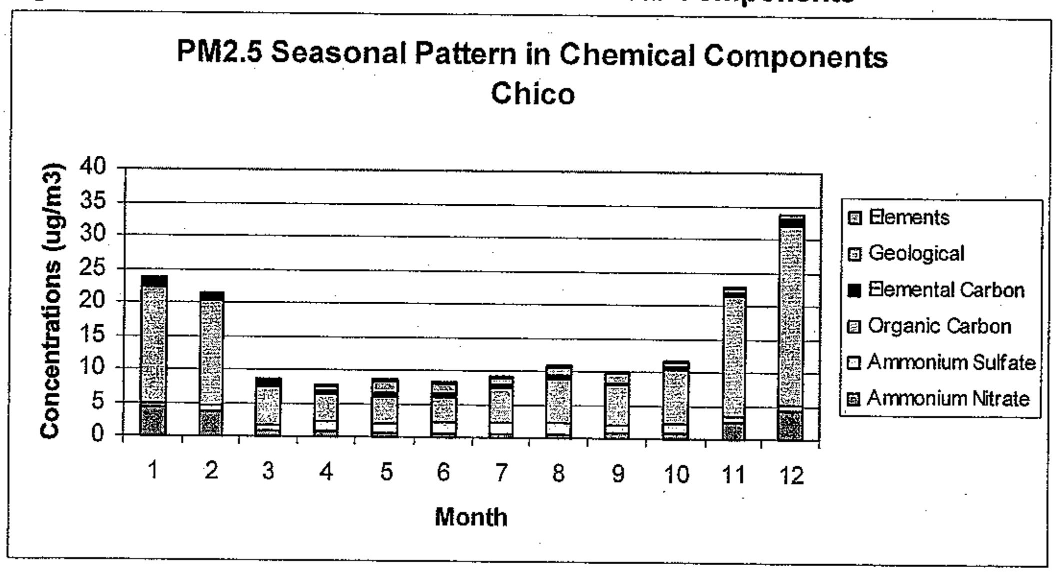
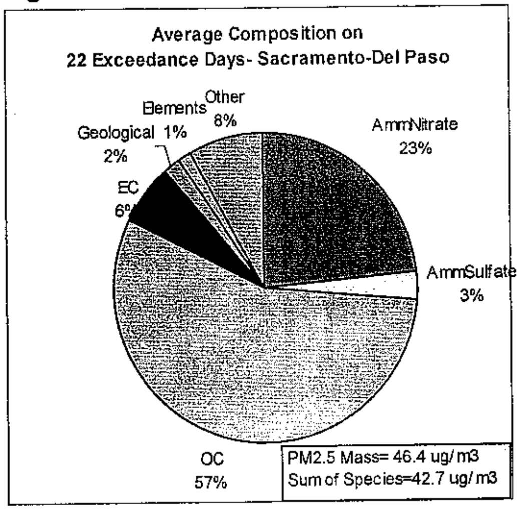
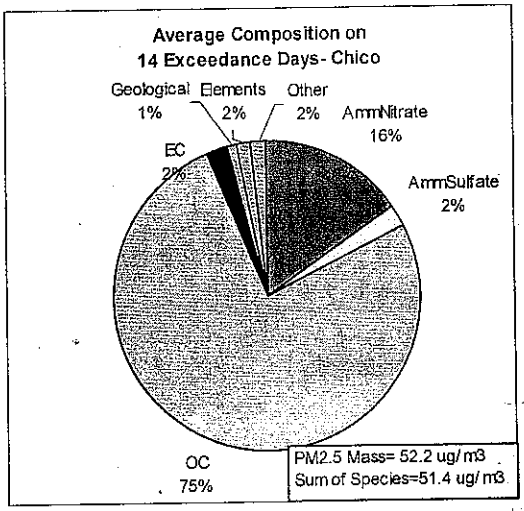


Figure 9: Ave. PM2.5 Composition





Geography/Topography/Meteorology

The city of Marysville is in Yuba County, while Yuba City is in Sutter County. Marysville and Yuba City are considered one metropolitan area, separated only by the Feather River. Yuba and Sutter counties form the Feather River AQMD. Together, the two counties encompass 1,234 square miles. The Feather River AQMD is part of the larger Northern Sacramento Valley Air Basin (NSVAB), and includes the counties of Butte, Colusa, Glenn, Shasta, and Tehama. The NSVAB is bounded on the north and west by the Coastal Mountain Range and on the east by the southern portion of the Cascade Mountain Range and the northern portion of the Sierra Nevada Mountains. These mountain ranges reach heights in excess of 6000 feet with peaks rising much higher. This provides a substantial physical barrier to locally created pollution. Although a significant area of the NSVAB is above 1000 feet sea level, the majority of the Feather River AQMD is located in the Valley floor and foothill regions. The valley is often subjected to inversion layers that, coupled with geographic barriers and high summer temperatures, create a high potential for air pollution problems.

Emissions

The presumptive boundary for the PM2.5 nonattainment area includes the cities of Marysville and Yuba City under the jurisdiction of the Feather River AQMD. All potential emission sources are included within the recommended nonattainment area. Adjacent counties to Feather River AQMD include Butte, Glenn, Colusa, Yolo, Sacramento, Placer, Nevada, and Sierra. The nature of the PM2.5 problem in Marysville/Yuba City is primarily a result of local emission sources such as smoke; therefore, emissions from neighboring counties would not impact the air quality data for Feather River AQMD. Table 9 provides NOx emissions in tons per day from stationary, area, and mobile sources. The majority of NOx emissions are under the mobile source category which is regulated by ARB.

Table 9: NOx Winter Emissions Feather River AQMD and Surrounding Counties

Yuba County	**2006**	**2010**	**2020**
Stationary Sources	0.7	0.7	0.7
Area Sources	0.5	0.5	0.5
Mobile Sources	6.2	6.6	4.9
Sutter County			
Stationary Sources	3.6	3.9	3.9
Area Sources	0.9	0.8	0.8
Mobile Sources	14.3	12.9	6.9
Sacramento County			
Stationary Sources	3.9	3.9	4.3
Area Sources	4.0	4.0	4.1
Mobile Sources	75.1	62.5	34.5
Yolo County			
Stationary Sources	3.0	2.9	2.8
Area Sources	0.7	0.7	0.7
Mobile Sources	21.3	17.3	9.9
Butte County			
Stationary Sources	1.4	1.4	1.4
Area Sources	1.7	1.7	1.6
Mobile Sources	23.3	19.9	11.3
Glenn County			
Stationary Sources	3.5	3.6	3.6
Area Sources	0.1	0.1	0.1
Mobile Sources	7.6	6.2	3.7
Colusa County			
Stationary Sources	5.1	5.1	5.0
Area Sources	0.9	0.9	0.9
Mobile Sources	8.4	6.7	4.0
Placer County			
Stationary Sources	4.5	4.7	5.1
Area Sources	1.6	1.6	1.6
Mobile Sources	28.2	23.4	13.7
Nevada County			
Stationary Sources	0.2	0.2	0.3
Area Sources	1.6	1.6	1.6
Mobile Sources	12.8	10.1	5.5
Sierra County			
Stationary Sources	0.5	0.5	0.5
Area Sources	0.1	0.5	0.5
Mobile Sources	0.6	0.6	0.5

Population Density and Degree of Urbanization
According to the US Census Bureau, the population of Yuba County in 2006 is estimated to be 70,396 based on 2000 census data. This represents a 15 percent increase in population since 2000, and a 17 percent increase since 1990. The 2006 population of Sutter County is estimated to be 91,410 based on 2000 census data. This represents a 14 percent increase in population since 2000, and a 30 percent increase since 1990.

Table 10: Yuba County and Sutter County Population

	1990	2000	2006
Yuba County			
Population	58,228	60,219	70,396
Population Density	92 persons/sq mile	96 persons/sq mile	112 persons/sq mile
Sutter County			
Population	64,415	78,930	91,410
Population Density	107 persons/sq mile	131 persons/sq mile	152 persons/sq mile

Traffic and Commuting Patterns
The estimates of daily vehicle miles traveled for the years 1990 through 2020 are found in ARB's revised motor vehicle emissions inventory model. Traffic is expected to increase by 18 percent from 2005 to 2010, and by 39 percent by 2020 in Yuba County. Sutter County is expected to experience a 20 percent increase in traffic from 2005 to 2010, and a 44 percent increase by 2020. Vehicle miles traveled in Feather River AQMD is projected to increase roughly twice as fast as population, yet NOx emissions from mobile sources is expected to continue along a downward trend. This illustrates the effectiveness of statewide mobile source controls, and supports the need for local control measures to reduce PM 2.5 levels.

Table 11: Yuba County and Sutter County Vehicle Miles Traveled

	1990	2000	2005	2010	2015	2020
Yuba County						
Ave. Daily VMT/1000	1137	1278	1510	1842	2157	2485
Sutter County						
Ave. Daily VMT/1000	1616	1921	2333	2922	3534	4196

Expected Growth
Feather River is expected to grow by 6 percent from 2005 to 2010, and by 21 percent by 2020. Surrounding counties are expected to have similar growth patterns; however, we do not expect surrounding areas to contribute to PM2.5 concentrations in Feather River AQMD. Ammonium nitrate emissions are controlled on a statewide level and are expected to decrease over time. Organic

carbon is a localized source, therefore the most effective control measures focus on a centralized nonattainment area.

Table 12: Yuba County and Sutter County Projected Growth

	2000	2005	2010	2015	2020
Yuba County					
Population	60,411	67,102	71,506	78,161	84,816
Sutter County					
Population	79,526	88,905	95,757	103,807	111,856

Level of Control of Emissions Sources

Yuba and Sutter Counties have motor vehicle emission controls that are consistent with the rest of California. Vehicles must meet California Standards; therefore new vehicles will be controlled through statewide measures. Both cars and heavy trucks are subject to in-use inspection programs. The Sacramento Valley Basinwide Air Pollution Control Council, which includes the Feather River AQMD, administers a smoke management program for open burning, consistent with the ARB's statewide regulation. Areas surrounding Yuba and Sutter Counties have similar level of control regarding smoke management and control of NOx sources.

City of Chico within the Butte County Air Quality Management District

Jurisdictional Boundary

The presumptive boundary for the PM2.5 nonattainment area includes the city of Chico under the jurisdiction of the Butte County Air Quality Management District (AQMD). Chico is located within the Sacramento Valley Air Basin.

ARB staff believes that the Chico city level nonattainment boundary is appropriate due to the localized nature of the PM2.5 problem. The city of Chico is the largest urbanized area in Butte County and is located on the Sacramento Valley floor. Several small communities throughout the Sacramento Valley meet the standard, so ARB staff does not believe it is a broad regional problem. Due to the localized nature of the PM2.5 problem in the urbanized area, we believe the violating area to be restricted to this small geographic region and not extending into the rural and mountainous regions of Butte County. The two key components of PM2.5 are ammonium nitrate and organic carbon. While ammonium nitrate is regional, most NOx emissions are from mobile sources which are controlled at a statewide level by ARB. Organic carbon is more localized and most effectively controlled at the district level.

Air Quality

Our initial recommendation for the city of Chico is based on ambient PM2.5 concentrations measured from 2004 through 2006. Our nonattainment recommendation is based on a design value of 56 ug/m3 measured at the Chico monitoring site. Butte County has two monitors measuring PM2.5, located in Chico and Gridley, however, only Chico can be used for federal purposes.

Areas surrounding the city of Chico include the counties of Plumas, Tehama, Glenn, Colusa, Sutter and Yuba. Exceedance of the PM2.5 standard in Sutter and Yuba counties will be included in the recommended nonattainment area for the cities of Marysville/Yuba City. Glenn, Colusa, Tehama, and Plumas counties all are in attainment of the standard.

The chemical makeup of PM2.5 in the city of Chico is dominated by organic carbon and ammonium nitrate. Figure 10 illustrates the seasonal pattern and chemical composition of PM2.5 at the Chico monitoring site with highest concentrations occurring in the winter time. As shown if Figure 11, organic carbon accounts for roughly 75 percent of the PM2.5 composition on exceedance days. The majority of organic carbon is suspected to be due to directly emitted carbon from combustion sources. Key sources include vehicles, residential wood combustion, agricultural and prescribed burning and stationary combustion sources. Concentrations of organic carbon are highest during the winter months, November through February, suggesting that emissions are likely a result of residential wood combustion.

Ammonium nitrate is another significant contributor to the total PM2.5 composition, accounting for about 16 percent on exceedance days. During the fall and winter the ammonium nitrate fraction of PM2.5 is higher than during the spring and summer, while ammonium sulfate and dust contribute slightly more to ambient PM2.5 during the spring and summer. Cool temperatures, low wind speeds, low inversion layers, and high humidity during the late fall and winter favor the formation of ammonium nitrate, while sunny, warmer conditions during the spring and summer favor the formation of ammonium sulfate, as well as the formation of secondary organic aerosols.

Figure 10: PM2.5 Chemical Composition in Chico

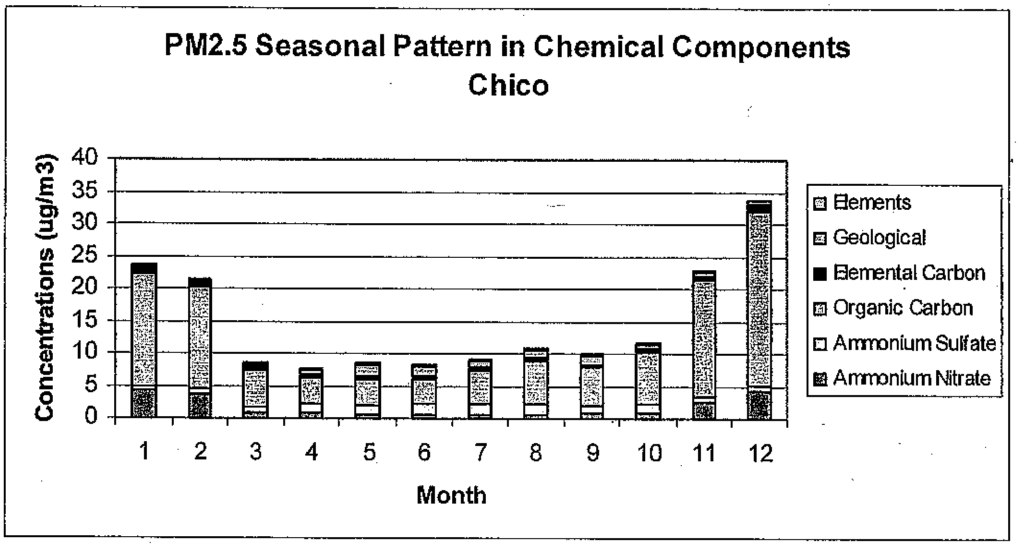
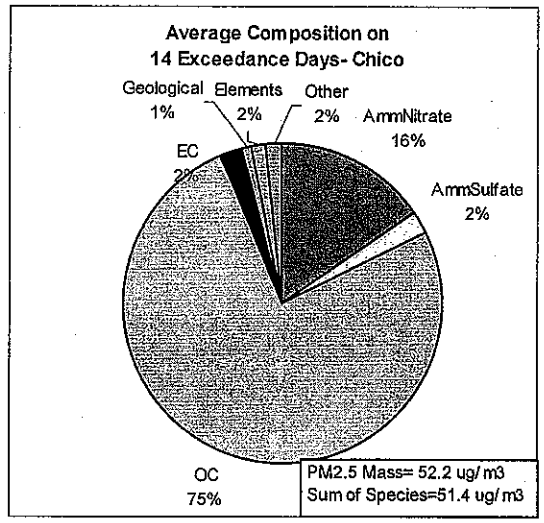


Figure 11: Average Chemical Composition



Geography/Topography/Meteorology

The city of Chico is located at the northeast edge of the Sacramento Valley. The Sierra Nevada Mountains lie to the east, and the Sacramento River lies to the west. Chico sits primarily on the valley floor and is on the whole very flat, but several miles of the eastern city limits venture into the increasingly hilly terrain of the Sierra Nevada foothills. The city limits encompass an area of 30 square miles. Butte County encompasses an area of 1,639 square miles.

Chico is part of the larger Northern Sacramento Valley Air Basin (NSVAB), which includes the counties of Butte, Colusa, Glenn, Shasta, and Tehama. The NSVAB is bounded on the north and west by the Coastal Mountain Range and on the east by the southern portion of the Cascade Mountain Range and the northern portion of the Sierra Nevada Mountains. These mountain ranges reach heights in excess of 6000 feet with peaks rising much higher. This provides a substantial physical barrier to locally created pollution. The valley is often subjected to inversion layers that, coupled with geographic barriers and high summer temperatures, create a high potential for air pollution problems.

Emissions

The presumptive boundary for the PM2.5 nonattainment area includes the city of Chico under the jurisdiction of the Butte County AQMD. All potential emission sources are included within the recommended nonattainment area. Adjacent counties include Plumas, Tehama, Glenn, Colusa, Sutter and Yuba. The nature of the PM2.5 problem in Chico is primarily a result of local emission sources such as smoke; therefore, emissions from neighboring counties would not impact the air quality data for Butte County. Emissions generated in Sutter and Yuba Counties are included in the recommended Marysville/Yuba City nonattainment area. Table 13 provides emissions in tons per day of the primary pollutant contributing to PM2.5 from stationary, area and mobile sources. The majority of NOx emissions are under the mobile source category which is regulated by ARB.

Table 13: NOx Winter Emissions Butte County AQMD and Surrounding Counties

Butte County	**2006**	**2010**	**2020**
Stationary Sources	1.4	1.4	1.4
Area Sources	1.7	1.7	1.6
Mobile Sources	23.3	19.9	11.3
Sutter County			
Stationary Sources	3.6	3.9	3.9
Area Sources	0.9	0.8	0.8
Mobile Sources	14.3	12.9	6.9
Yuba County			
Stationary Sources	0.7	0.7	0.7
Area Sources	0.5	0.5	0.5
Mobile Sources	6.2	6.6	4.9
Glenn County			
Stationary Sources	3.5	3.6	3.6
Area Sources	0.1	0.1	0.1
Mobile Sources	7.6	6.2	3.7
Colusa County			
Stationary Sources	5.1	5.1	5.0
Area Sources	0.9	0.9	0.9
Mobile Sources	8.4	6.7	4.0

Table 13 (cont.)

Plumas County	**2006**	**2010**	**2020**
Stationary Sources	1.8	1.8	1.8
Area Sources	0.4	0.4	0.4
Mobile Sources	4.8	4.3	3.7
Tehama County			
Stationary Sources	1.8	1.8	1.8
Area Sources	0.5	0.5	0.5
Mobile Sources	17.6	13.6	7.5

Population Density and Degree of Urbanization
According to the U.S. Census Bureau, the city of Chico has a 2006 population of 73,316. The population of Butte County in 2006 is approximately 215,881 based on 2000 Census data. This represents a 6 percent increase in population since 2000, and a 16 percent increase since 1990.

Table 14: Population Butte County and City of Chico

Butte County	**1990**	**2000**	**2006**
Population	182,120	203,171	215,881
Population density	111 persons/sq mile	124 persons/sq mile	132 persons/sq mile
City of Chico			
Population	40,079	59,954	73,316
Population density	1,336 persons/sq mile	1,998 persons/sq mile	2,444 persons/sq mile

Traffic and Commuting Patterns
The estimates of daily vehicle miles traveled for the years 1990 through 2020 are found in ARB's revised motor vehicle emissions inventory model. Traffic is expected to increase by 13 percent from 2005 to 2010, and by 30 percent by 2020 in Butte County. Vehicle miles traveled in Butte County is projected to increase roughly twice as fast as population, yet NOx emissions from mobile sources is expected to continue along a downward trend. This illustrates the effectiveness of statewide mobile source controls, and supports the need for local control measures to reduce PM2.5 levels.

Table 15: Average Daily Vehicle Miles Traveled Butte County

	1990	**2000**	**2005**	**2010**	**2015**	**2020**
Ave. Daily VMT/1000	4320	4496	4996	5762	6456	7138

Expected Growth
Butte County is expected to grow by 5 percent from 2005 to 2010, and by 12 percent by 2020. Population growth in surrounding areas is not expected to contribute to PM2.5 concentrations in Chico. Ammonium nitrate emissions are controlled on a statewide level and are expected to decrease over time. Organic

carbon is a localized source, therefore the most effective control measures focus on a centralized nonattainment area.

Table 16: Projected Future Population Butte County

	2000	2005	2010	2015	2020
Population	203,855	215,558	228,020	244,375	260,730

Level of Control of Emissions Sources

The city of Chico has motor vehicle emission controls that are consistent with the rest of California. Vehicles must meet California standards; therefore, new vehicles will be controlled through statewide measures. Both cars and heavy trucks are subject to in-use inspection programs. The Sacramento Valley Basinwide Air Pollution Control Council, which includes Butte County AQMD, administers a smoke management program for open burning consistent with ARB's statewide regulation. Areas surrounding Butte County have similar level of control regarding smoke management and control of NOx sources.

City of Calexico within the Imperial County Air Pollution Control District

Jurisdictional Boundary

The presumptive boundary for the PM2.5 nonattainment area includes the City of Calexico, under the jurisdiction of the Imperial County Air Pollution Control District, and within the Salton Sea Air Basin.

ARB staff believes that the Calexico city level nonattainment boundary is appropriate due to the unique international pollutant transport problem between Calexico and Mexicali, Mexico. The two key components of PM2.5 are ammonium nitrate and organic carbon. Ammonium nitrate is a regional pollutant primarily derived from reactions with NOx emissions from mobile sources. ARB regulates sources of NOx emissions at a statewide level. Organic carbon is more localized and can be effectively controlled at the district level. However, we have no jurisdiction over these pollutant emission sources in Mexico.

Air Quality

Our initial recommendation for the city of Calexico is based on ambient PM2.5 concentrations measured from 2004 through 2006. Four monitoring sites throughout Imperial County monitor for PM2.5, however only two sites – Calexico-Ethel Street and El Centro-9th Street – have sufficient data to support designations. Our nonattainment recommendation is based on a design value of 40 ug/m3 measured at the Calexico-Ethel Street monitoring site. The El Centro monitoring site is well below the federal standard with a design value of 25 ug/m3.

Areas surrounding Imperial County include San Diego County to the west, Riverside County to the north, Arizona to the east, and Mexico to the south.

Exceedances of the PM2.5 standard in Riverside are included in the nonattainment area for the South Coast Air Pollution Control District. San Diego County is in attainment of the standard with a design value of 28 ug/m3 measured at the Chula Vista monitoring site.

The chemical makeup of PM2.5 in Calexico is dominated by organic carbon and ammonium nitrate. Figure 12 illustrates the seasonal pattern and chemical composition of PM2.5 at the Calexico-Ethel Street site with highest concentrations occurring in the winter time. Organic carbon is the largest component of PM2.5 and increases considerably during the winter months, however, it is significant throughout the year. Waste burning is prevalent throughout Mexicali and contributes to the year-round organic carbon concentrations. As shown in Figure 13, organic carbon accounts for roughly 48 percent of the 2004 – 2006 average PM2.5 composition on exceedance days. The majority of organic carbon is suspected to be due to directly emitted carbon from combustion sources. Key sources include vehicles, residential wood combustion, agricultural and prescribed burning and stationary combustion sources. Concentrations of organic carbon are highest during the winter months, November through February, suggesting that emissions are likely a result of wood combustion.

Ammonium nitrate is another significant contributor to the total PM2.5 composition, accounting for about 22 percent of the average composition on exceedance days. The primary source of ammonium nitrate is motor vehicles, which are regulated statewide by ARB. The motor vehicle fleets in Calexico and Mexicali differ substantially. Calexico vehicle fleets are equipped with state of the art emission control technologies. In contrast, Mexicali has a large number of late model vehicles lacking emission controls. The Calexico/Mexicali border is a major corridor for vehicle traffic resulting in a significant amount of motor vehicle emissions.

Figure 12: Seasonal Pattern of PM2.5 Chemical Components

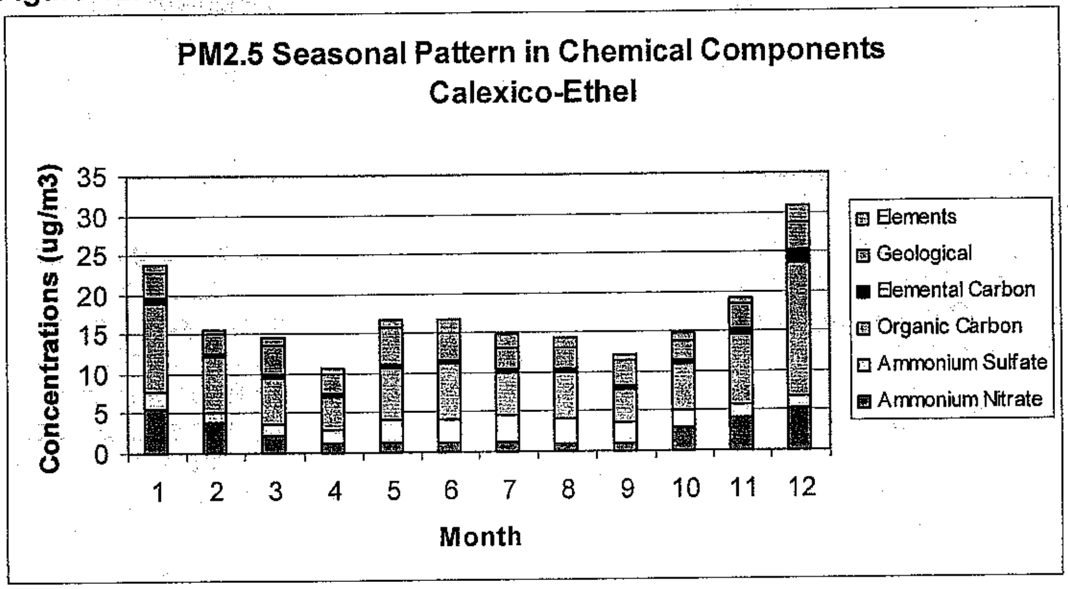
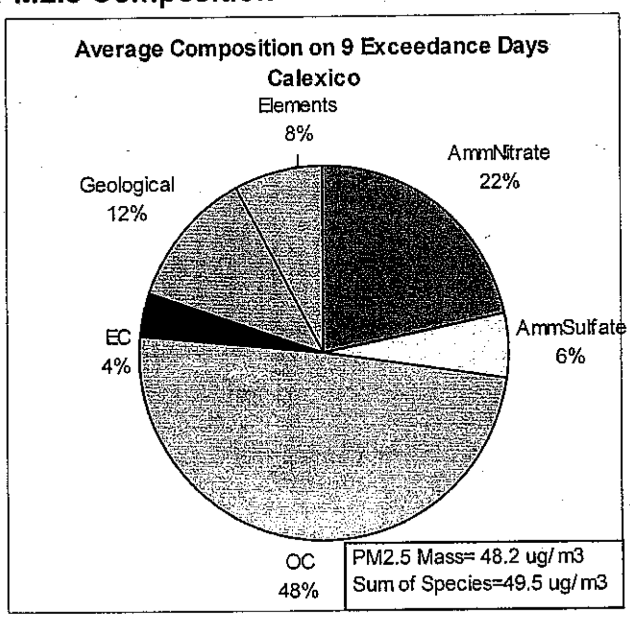


Figure 13: Ave. PM2.5 Composition



Geography/Topography/Meteorology

Imperial County is located within the Salton Sea Air Basin along with the desert portion of Riverside County. Imperial County consists of 4,175 square miles, bordering Mexico to the south, Riverside County to the north, San Diego County to the west, and the State of Arizona on the east.

The Imperial Valley is a part of the larger Salton Trough. Also included in the Salton Trough is the western half of the Mexicali Valley and the Colorado River delta in Mexico. This trough is a very flat basin surrounded by mountains: the Peninsular Ranges to the west, the Chocolate, Orocopia and Cargo Muchacho Mountains to the east. Most of the trough is below seas level and is predominantly desert with agricultural land.

Climatic conditions in the Salton Sea Air Basin are governed by the large-scale sinking and warming air in the subtropical high-pressure center of the Pacific Ocean. The high-pressure ridge blocks most mid-latitude storms except in the winter when the high-pressure ridge is weakest and farthest south. Similarly, the coastal mountains prevent the intrusion of any cool damp marine air from the coast. Because of the weakened storms and the mountainous barrier, the Salton Sea Air Basin has hot summers, mild winters, and little rainfall. The flat terrain of the valley and the strong temperature differentials, created by intense solar heating produces moderate winds and deep thermal convection.

Emissions

The presumptive boundary for the PM2.5 nonattainment area includes the City of Calexico in Imperial County under the jurisdiction of the Imperial County Air Pollution Control District. Calexico (and Mexicali) are distinct from the rest of Imperial County based on the distribution and nature of emission sources. Imperial County is largely rural with widespread agricultural activity. ARB staff believes that violation of the PM2.5 standard in Calexico results from emissions in the densely populated international Calexico/Mexicali border region. The level of urban activity and PM2.5 pollution in the Calexico/Mexicali area are distinct and not representative of the rest of Imperial County.

Table 17: NOx Winter Emissions Imperial and Surrounding Counties

Imperial County	**2006**	**2010**	**2020**
Stationary Sources	5.5	5.7	6.1
Area Sources	1.0	0.9	0.9
Mobile Sources	33.3	26.5	18.8
Riverside County			
Stationary Sources	11.6	12.1	14.2
Area Sources	3.5	3.4	3.9
Mobile Sources	180.7	134.6	76.2
San Diego County			
Stationary Sources	8.8	10.8	12.0
Area Sources	3.7	3.7	3.7
Mobile Sources	205.4	172.7	132.9

Population Density and Degree of Urbanization

From an air quality perspective, Calexico and Mexicali, Mexico form one urbanized region divided by an international border. According to 2000 U.S.

Census data, Calexico's population in 2000 was approximately 27,000. The official Mexican Census placed Mexicali's population in 2000 at 760,000, with 3 percent annual growth expected. In 2000, the entire Imperial County population was approximately 143,000. Considering the geographic size of the two areas as well, the Mexicali population density is two and a half times the density for all of Imperial County.

Table 18: Imperial County Population

	1990	2000	2005
Population	110100	143595	162599
Population Density	26 persons/sq mile	34 persons/sq mile	39 persons/sq mile

Table 19: City of Calexico Population

	1990	2000	2006
Population	18633	27102	37243

Table 20: Mexicali, Mexico Population

	2000	2004	2006
Population	764602	866277	922077

Traffic and Commuting Patterns
Calexico/Mexicali is home to a busy U.S. – Mexico border crossing. In 1996, the border crossing handled almost 7 million vehicles. Mexicali has over three times as many motor vehicles as all of Imperial County.

Expected Growth
Imperial County is expected to grow by about 9 percent from 2005 to 2010, and by about 24 percent by 2020. The city of Calexico has experienced a rapid population growth from 1990 to 2000, growing by approximately 40 percent during that time period. An even more dramatic growth of 50 percent is projected for the 2000 – 2010 period. Nonetheless, this rapid growth in Calexico and Imperial County is overwhelmed by the population and projected growth of Mexicali. According to the State Government of Baja Mexico, the 2006 population based on a 2000 census is 922,077. Assuming a constant rate of growth from 2000, the 2010 population is estimated to be approximately 1,045,000, and the 2020 estimated population is approximately 1,433,000.

Table 21: Imperial County Projected Growth

	2000	2005	2010	2015	2020
Population	143,595	162,599	178,201	196,294	214,386

Table 22: Mexicali, Mexico Projected Growth

	2000	2006	2010	2020
Population	764,602	922,077	1,045,842	1,432,892

Level of Control of Emissions Sources
Imperial County has motor vehicle emission controls that are consistent with the rest of California. Vehicles must meet California standards; therefore, new vehicles will be controlled through statewide measures. Both cars and heavy trucks are subject to in-use inspection programs. The Imperial County District administers a smoke management program for open burning consistent with ARB's statewide regulation. Vehicles in Mexicali are typically older than California vehicles and there is no in-use inspection program. Finally, Mexicali open burning is widespread and uncontrolled. This is particularly significant given the large organic fraction found in Calexico PM2.5.

Based on all of these factors, ARB staff has concluded that Calexico exceedances of the federal PM2.5 standards are the result of urban activity associated with the densely populated international Calexico/Mexicali border region. Within Imperial County, the level of urban activity is unique to the area and is not representative of the air quality of the rest of Imperial County or the Salton Sea Air Basin.

Enclosure 4

State of California
Boundary Descriptions for Recommended Nonattainment Areas under the Federal PM2.5 Standards

South Coast Air Basin

Los Angeles County (part) - that portion of Los Angeles County which lies south and west of a line described as follows: Beginning at the Los Angeles – San Bernardino County boundary and running west along the Township line common to Township 3 North and Township 2 North, San Bernardino Base and Meridian; then north along the range line common to Range 8 West and Range 9 West; then west along the Township line common to Township 4 North and Township 3 North; then north along the range line common to Range 12 West and Range 13 West to the southeast corner of Section 12, Township 5 North and Range 13 West; then west along the south boundaries of Sections 12, 11, 10, 9, 8, and 7, Township 5 North and Range 13 West to the boundary of the Angeles National Forest which is collinear with the range line common to Range 13 West and Range 14 West; then north and west along the Angeles National Forest boundary to the point of intersection with the Township line common to Township 7 North and Township 6 North (point is at the northwest corner of Section 4 in Township 6 North and Range 14 West); then west along the Township line common to Township 7 North and Township 6 North; then north along the range line common to Range 15 West and Range 16 West to the southeast corner of Section 13, Township 7 North and Range 16 West; then along the south boundaries of Sections 13, 14, 15, 16, 17, and 18, Township 7 North and Range 16 West; then north along the range line common to Range 16 West and Range 17 West to the north boundary of the Angeles National Forest (collinear with the Township line common to Township 8 North and Township 7 North); then west and north along the Angeles National Forest boundary to the point of intersection with the south boundary of the Rancho La Liebre Land Grant; then west and north along this land grant boundary to the Los Angeles-Kern County boundary.

Orange County

Riverside County (part) - that portion of Riverside County which lies to the west of a line described as follows: Beginning at the Riverside - San Diego County boundary and running north along the range line common to Range 4 East and Range 3 East, San Bernardino Base and Meridian; then east along the Township line common to Township 8 South and Township 7 South; then north along the range line common to Range 5 East and Range 4 East; then west along the Township line common to Township 6 South and Township 7 South to the southwest corner of Section 34, Township 6 South, Range 4

East; then north along the west boundaries of Sections 34, 27, 22, 15, 10, and 3, Township 6 South, Range 4 East; then west along the Township line common to Township 5 South and Township 6 South; then north along the range line common to Range 4 East and Range 3 East; then west along the south boundaries of Sections 13, 14, 15, 16, 17, and 18, Township 5 South, Range 3 East; then north along the range line common to Range 2 East and Range 3 East; to the Riverside – San Bernardino County line.

San Bernardino County (part) - that portion of San Bernardino County which lies south and west of a line described as follows: Beginning at the San Bernardino - Riverside County boundary and running north along the range line common to Range 3 East and Range 2 East, San Bernardino Base and Meridian; then west along the Township line common to Township 3 North and Township 2 North to the San Bernardino - Los Angeles County boundary.

San Joaquin Valley

San Joaquin County
Stanislaus County
Merced County
Madera County
Fresno County
Kings County
Tulare County
Kern County (part) - That portion of Kern County which lies west and north of a line described as follows: Beginning at the Kern-Los Angeles County boundary and running north and east along the northwest boundary of the Rancho La Libre Land Grant to the point of intersection with the range line common to R. 16 W. and R. 17 W., San Bernardino Base and Meridian; north along the range line to the point of intersection with the Rancho El Tejon Land Grant boundary; then southeast, northeast, and northwest along the boundary of the Rancho El Tejon Land Grant to the northwest corner of S. 3, T. 11 N., R. 17 W.; then west 1.2 miles; then north to the Rancho El Tejon Land Grant boundary; then northwest along the Rancho El Tejon line to the southeast corner of S. 34, T. 32 S., R. 30 E., Mount Diablo Base and Meridian; then north to the northwest corner of S. 35, T. 31 S., R. 30 E.; then northeast along the boundary of the Rancho El Tejon Land Grant to the southwest corner of S. 18, T. 31 S., R. 31 E.; then east to the southeast corner of S. 13, T. 31 S., R. 31 E.; then north along the range line common to R. 31 E. and R. 32 E., Mount Diablo Base and Meridian, to the northwest corner of S. 6, T. 29 S., R. 32 E.; then east to the southwest corner of S. 31, T. 28 S., R. 32 E.; then north along the range line common to R. 31 E. and R. 32 E. to the northwest corner of S. 6, T. 28 S., R. 32 E., then west to the southeast corner of S. 36, T. 27 S., R. 31 E., then north along the range line common to R. 31 E. and R. 32 E. to the Kern-Tulare County boundary.

Sacramento County

City of Calexico

ARB is developing the cartographic description of this boundary and will transmit it to Region 9 staff under separate cover.

City of Chico

ARB is developing the cartographic description of this boundary and will transmit it to Region 9 staff under separate cover.

Combined cities of Marysville and Yuba City

ARB is developing the cartographic description of this boundary and will transmit it to Region 9 staff under separate cover.

San Francisco Bay Area

Sonoma County (part)- That portion of Sonoma County which lies south and east of a line described as follows: Beginning at the southeasterly corner of the Rancho Estero Americano, being on the boundary line between Marin and Sonoma Counties, California; thence running northerly along the easterly boundary line of said Rancho Estero Americano to the northeasterly corner thereof, being an angle corner in the westerly boundary line of Rancho Canada de Jonive; thence running along said boundary of Rancho Canada de Jonive westerly, northerly and easterly to its intersection with the easterly line of Graton Road; thence running along the easterly and southerly line of Graton Road, northerly and easterly to its intersection with the easterly line of Sullivan Road; thence running northerly along said easterly line of Sullivan Road to the southerly line of Green Valley Road; thence running easterly along the said southerly line of Green Valley Road and easterly along the southerly line of State Highway 116, to the westerly line of Vine Hill Road; thence running along the westerly and northerly line of Vine Hill Road, northerly and easterly to its intersection with the westerly line of Laguna Road; thence running northerly along the westerly line of Laguna Road and the northerly projection thereof to the northerly line of Trenton Road; thence running westerly along the northerly line of said Trenton Road to the easterly line of Trenton-Healdsburg Road; thence running northerly along said easterly line of Trenton-Healdsburg Road to the easterly line of Eastside Road; thence running northerly along said easterly line of Eastside Road to its intersection with the southerly line of Rancho Sotoyome; thence running easterly along said southerly line of Rancho Sotoyome to its intersection with the Township line common to Townships 8 and 9 North, M.D.M.; thence running easterly along said township line to its intersection with the boundary line between Sonoma and Napa Counties.

Napa County

Solano County (part) - Portion of Solano County which lies south and west of a line described as follows: Beginning at the intersection of the westerly boundary of Solano County and the 1/4 section line running east and west through the center of Section 34, T6N, R2W, M.D.B. & M., thence east along said 1/4 section line to the east boundary of Section 36, T6N, R2W, thence south 1/2 mile and east 2.0 miles, more or less, along the west and south boundary of Los Putos Rancho to the northwest corner of Section 4, T5N, R1W, thence east along a line common to T5N and T6N to the northeast corner of Section 3, T5N, R1E, thence south along section lines to the southeast corner of Section 10, T3N, R1E, thence east along section lines to the south 1/4 corner of Section 8, T3N, R2E, thence east to the boundary between Solano and Sacramento Counties.

Contra Costa County
Alameda County
Santa Clara County
San Mateo County
San Francisco County
Marin County

Enclosure 5

State of California

PM2.5 Monitoring Data Summary

(based on 2004 - 2006)

Basin	County	Site	PM2.5 98th percentile 24-hour (ug/m3)			3-Year Average 24-Hour 98th	Data Complete/ Valid
			2004	2005	2006		
Great Valley Basin	Inyo	Keeler-Cerro Gordo Road	22.0	13.0	22.0	19	No/No
	Mono	Mammoth Lakes-Gateway HC	26.0	27.0			No/No
Lake County	Lake	Lakeport-Lakeport Blvd.	9.0	10.5	21.4	14	Yes/Yes
Lake Tahoe	El Dorado	South Lake Tahoe-Sandy Way	20.0				No/No
Mountain Counties	Calaveras	San Andreas-Gold Strike Road	21.0	18.0	23.0	21	Yes/Yes
	Nevada	Grass Valley-Litton Building	10.0	10.0	24.0	15	No/No
		Truckee-Fire Station	18.0	16.0	15.0	16	Yes/Yes
	Plumas	Portola-161 Nevada Street	33.0	26.0	31.0	30	Yes/Yes
		Quincy-N Church Street	28.0	27.0	25.0	27	No/No
Mohave Desert	Kern	Mojave-923 Poole Street	16.8	15.7	21.3	18	No/No
		Ridgecrest-100 West California Avenue	15.2	16.2	13.0	15	No/No
	Los Angeles	Lancaster-43301 Division Street	15.0	16.0	13.0	15	No/No
	San Bernardino	Victorville-14306 Park Avenue	20.0	19.0	19.0	19	No/No
North Coast	Humboldt	Eureka-I Street	23.1	31.8	35.0	30	No/No
		Eureka-Jacobs			21.2		No/No
	Mendocino	Ukiah-County Library	14.4	15.2	17.4	16	Yes/Yes
North Central Coast	Monterey	Salinas #3	15.5	14.2	13.0	14	No/No
	Santa Cruz	Santa Cruz-2544 Soquel Avenue	14.9	21.7	12.6	16	No/No
Northeast Plateau	Siskiyou	Yreka-Foothill Drive		26.0	22.0		No/No
South Coast	Los Angeles	Azusa	53.8	53.2	38.4	48	No/Yes
		Burbank-W Palm Avenue	49.3	50.5	43.4	48	No/Yes
		Long Beach-East Pacific Coast Highway	42.0	37.7	35.2	38	No/Yes
		Los Angeles-North Main Street	54.3	53.3	38.9	49	Yes/Yes
		Lynwood	53.0	48.4	44.4	49	Yes/Yes
		North Long Beach	45.8	41.4	34.9	41	No/Yes
		Pasadena-S Wilson Avenue	46.5	43.0	32.0	41	Yes/Yes
		Pico Rivera	52.1	51.4			No/No
		Pico Rivera-4144 San Garbriel		58.2	43.0		No/No
		Reseda	53.2	35.7	31.9	40	No/Yes
	Orange	Anaheim-Pampas Lane	48.2	41.8	40.5	44	Yes/Yes
		Mission Viejo-26081 Via Pera	38.5	31.4	25.7	32	No/No
	Riverside	Riverside-5130 Poinsettia Place			52.5		No/No
		Riverside-Magnolia	53.7	41.0	47.7	47	No/Yes
		Riverside-Rubidoux	59.5	58.3	54.4	57	No/Yes
	San Bernardino	Big Bear City-501 W. Valley Blvd	23.1	38.7	40.0	34	No/No
		Fontana-Arrow Highway	62.6	48.2	43.7	52	No/Yes
		Ontario-1408 Francis Street	59.9	49.5	41.5	50	No/Yes
		San Bernardino-4th Street	72.4	43.4	49.0	55	No/Yes
South Central Coast	San Luis Obispo	Atascadero-Lewis Avenue	19.6	25.2	22.2	22	Yes/Yes
		San Luis Obispo-3220 South Higuera St		11.4	21.4		No/No
		San Luis Obispo-Marsh Street	12.7	18.6			No/No
	Santa Barbara	Santa Barbara-700 East Canon Perdido	22.2	28.3	23.9	25	No/No
		Santa Maria-906 S Broadway	12.9	29.8	12.7	18	No/No
	Ventura	El Rio-Rio Mesa School #2	27.0	23.8	23.5	25	Yes/Yes
		Piru-3301 Pacific Avenue	22.4	20.3	21.4	21	Yes/Yes
		Simi Valley-Cochran Street	36.7	26.3	27.6	30	Yes/Yes
		Thousand Oaks-Moorpark Road	35.4	22.5	23.4	27	Yes/Yes
San Diego County	San Diego	Chula Vista	30.7	30.2	24.0	28	Yes/Yes
		El Cajon-Redwood Avenue	36.3	27.4	25.7	30	No/No
		Escondido-E Valley Parkway	37.4	32.2	28.3	33	No/No
		San Diego-1110 Beardsley Street		33.7	28.4		No/No
		San Diego-12th Avenue	33.7	26.6			No/No
		San Diego-Overland Avenue	25.2	23.1	20.8	23	No/No
San Francisco Bay Area	Alameda	Fremont-Chapel Way	33.0	27.6	30.4	30	No/No
		Livermore-793 Rincon Avenue	35.3	28.7	36.6	34	No/Yes
	Contra Costa	Concord-2956 A Treat Blvd		40.9	16.0		No/No
		Concord-2975 Treat Blvd	38.1	33.4	33.6	35	No/Yes
	San Francisco	San Francisco-Arkansas Street	32.2	32.6	27.8	31	No/No
	San Mateo	Redwood City	27.9	29.4	30.9	29	No/No
	Santa Clara	San Jose-Jackson Street	39.8	39.8	36.0	39	No/Yes
		San Jose-Tully Road	36.5	38.7	23.8	33	No/No
	Solano	Vallejo-304 Tuolumne Street	36.9	35.6	34.3	36	No/Yes
	Sonoma	Santa Rosa-5th Street	25.2	29.7	31.2	29	No/No

Enclosure 5

State of California
PM2.5 Monitoring Data Summary
(based on 2004 - 2006)

Basin	County	Site	PM2.5 98th percentile 24-hour (ug/m3)			3-Year Average 24-Hour 98th	Data Complete/Valid
			2004	2005	2006		
San Joaquin Valley	Fresno	Clovis-N Villa Avenue	52.4	63.0	51.3	56	No/Yes
		Fresno-1st Street	52.0	71.0	51.0	58	Yes/Yes
		Fresno-Hamilton and Winery	49.4	71.2	55.0	59	Yes/Yes
	Kern	Bakersfield-410 E Planz Road	47.6	66.4	64.7	60	No/Yes
		Bakersfield-5558 California Avenue	61.5	63.2	60.5	62	No/Yes
		Bakersfield-Golden State Highway	53.9	74.9	64.4	64	Yes/Yes
	Kings	Corcoran-Patterson Avenue	49.4	74.5	50.1	58	Yes/Yes
	Merced	Merced-2334 M Street	43.0	48.3	43.8	45	Yes/Yes
	San Joaquin	Stockton-Hazelton Street	36.0	44.0	42.0	41	Yes/Yes
	Stanislaus	Modesto-14th Street	45.0	55.0	52.0	51	Yes/Yes
	Tulare	Visalia-N Church Street	54.0	65.0	50.0	56	No/Yes
Salton Sea	Imperial	Brawley-220 Main Street	23.6	23.5	20.3	22	No/No
		Calexico-Ethel Street	31.9	41.1	46.0	40	No/Yes
		El Centro-9th Street	25.1	22.1	27.1	25	Yes/Yes
	Riverside	Indio-Jackson Street	26.8	25.0	19.0	24	No/No
		Palm Springs-Fire Station	23.3	25.0	15.8	21	No/No
Sacramento Valley	Butte	Chico-Manzanita Avenue	54.0	54.0	59.0	56	Yes/Yes
	Colusa	Colusa-Sunrise Blvd	34.0	16.0	30.0	27	Yes/Yes
	Placer	Roseville-N Sunrise Blvd	30.0	28.0	36.0	31	Yes/Yes
	Sacramento	Sacramento-Del Paso Manor	42.0	49.0	55.0	49	Yes/Yes
		Sacramento-Health Dept Stockton Blvd	35.0	42.0	39.0	39	Yes/Yes
		Sacramento-T Street	37.0	47.0	39.0	41	No/Yes
	Shasta	Redding-Health Dept Roof	18.0	19.0	29.0	22	Yes/Yes
	Sutter	Yuba City-Almond Street	38.0	42.0	41.0	40	Yes/Yes
	Yolo	Woodland-Gibson Road	31.0	24.0	36.0	30	Yes/Yes

Attachment G

Linda S. Adams
Secretary for Environmental Protection

Air Resources Board

Mary D. Nichols, Chairman
1001 I Street • P.O. Box 2815
Sacramento, California 95812 • www.arb.ca.gov

Arnold Schwarzenegger
Governor

October 15, 2008

Mr. Wayne Nastri
Regional Administrator
Region 9
U.S. Environmental Protection Agency
75 Hawthorne Street
San Francisco, California 94105-3901

Dear Mr. Nastri:

This is in response to your letter to Governor Arnold Schwarzenegger, transmitting the United States Environmental Protection Agency's (U.S. EPA) modifications to the California Air Resources Board's (ARB) recommendations for area designations under the federal air quality standards for particulate matter 2.5 microns or less in diameter (PM2.5).

We based the original recommendations on ambient PM2.5 data measured from 2004 through 2006, considering both emissions impacting elevated PM2.5 levels and public exposure to those levels. Reevaluation of these recommendations, based on 2005 through 2007 data, confirms our original assessment and recommendations for nonattainment area boundaries. We request that U.S. EPA modify the proposed nonattainment area boundaries to be consistent with California's recommendations. At issue are the proposed boundaries for the City of Calexico, Sacramento County, City of Chico, and the combined Cities of Yuba City/Marysville. We are in agreement on the boundaries for the South Coast Air Basin, San Joaquin Valley Air Basin, and San Francisco Bay Area. We have provided additional information to document the extent of international transport which causes localized impacts in Imperial County, and the localized impact of wood smoke in the other areas at issue.

An underlying premise for U.S. EPA's proposed PM2.5 boundaries is to provide consistency with existing ozone and PM10 nonattainment area boundaries. While that may be convenient from an administrative standpoint, the primary considerations in setting these boundaries should be scientific in nature. Our recommendations reflect the nature of the PM2.5 problem in each area. Where the problem is more localized than regional, we have recommended technically based nonattainment area boundaries that differ from ozone area boundaries. We note several areas elsewhere in the country where proposed designations are not consistent with ozone and PM10 nonattainment area boundaries, such as those in the New York, New Jersey, Connecticut, and Tennessee. We request the same consideration.

If you have any questions, please call Ms. Lynn Terry, Deputy Executive Officer, at (916) 322-2739, or have your staff contact Ms. Karen Magliano, Chief, Air Quality Data Branch, at (916) 322-7137.

Sincerely,

James N. Goldstene
Executive Officer

Enclosures

cc: See next page.

cc: Brad Poirez, APCO
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Lynn Terry
Air Resources Board

Karen Magliano
Air Resources Board

Technical Support

PM2.5 Designation Recommendations

The California Air Resources Board (ARB) continues to support our original recommendations transmitted to the United States Environmental Protection Agency (U.S. EPA) in December 2007. The U.S. EPA responded to the recommendation (U.S. EPA Response) on August 18, 2008. This document supplies additional support for ARB's recommendations.

In a memorandum dated June 8, 2007 from Robert Meyers, Acting Assistant Administrator, U.S. EPA identified the most important factors for States and Tribes to consider when making area designation recommendations. Specifically, demonstrations should show that,

1. violations are not occurring in the excluded portions of the recommended area, and
2. the excluded portions do not contain emission sources that contribute to the observed violations.

This addendum will address those two requirements in regard to the recommended nonattainment areas. In addition, prior to discussing each individual area, ARB is providing other issues that U.S. EPA should take into consideration when making the final nonattainment boundary decisions.

Size and Nature of Affected Areas

One of the primary issues that must be addressed when discussing the boundaries of a nonattainment area in California is the large size of California counties versus other states. The average area of a California county is 2,822 square miles, yet the average county size in the United States is 622 square miles. Alaska and Arizona are the only states with larger average county size (Table 1). The average California county is over 4 ½ times the average U.S. county; many as large, if not larger, than entire states. In many cases, California counties contain one or two urbanized regions and large stretches of sparsely populated areas.

Much of the nine-factor analysis utilized by U.S. EPA to determine PM2.5 nonattainment areas is based on a county level. This presents some unusual challenges for California. For instance, applying county-wide vehicle miles traveled (VMT) statistics to a large California county misrepresents differences that may exist in VMT urban and rural areas in that county, or between two widely separated urban areas in the same county. Throughout this submittal, we offer alternative approaches to analyzing the nine factors when county size presents a particular problem. This problem is most evident in Imperial County where the three main urban areas represent only one percent of the county (in square miles) recommended as a nonattainment area. The remaining 99 percent of the county is sparsely populated.

Table 1. Examples of County Area by State

State	**Mean County Area** (mi^2)
Alaska	39015
Arizona	7600
California	2822
Texas	1057
New York	880
Connecticut	693
Iowa	568
Ohio	509
Tennessee	444
Georgia	374
Rhode Island	243

Consistent Nonattainment Areas

Air quality planning in California is based primarily on air basin and air district boundaries if the pollution problem is of a regional nature. Although ARB generally uses a combination of air district and air basin lines to set the boundaries for areas violating California air quality standards, exceptions are made when a smaller area, such as a single city, exhibits an air quality issue distinct from the surrounding region. For example, due to the nature of the pollutant problem in Imperial County, only the City of Calexico is considered nonattainment for the State PM2.5 standard.

One of U.S. EPA's goals in designating nonattainment areas in California was to achieve a degree of consistency with existing ozone and PM10 nonattainment areas. Application of this goal in California led to differences between the State's recommended nonattainment areas and U.S. EPA's proposed designations. U.S. EPA expanded many of the State's recommended PM2.5 nonattainment areas boundaries to match 8-hour ozone nonattainment area boundaries. However, we do note areas throughout the country where U.S. EPA proposed PM2.5 nonattainment area designations are not consistent with existing 8-hour ozone nonattainment area boundaries. Examples are shown in Table 2.

Table 2. U.S. Examples of Excluded Areas Not Consistent With 8-Hour Ozone Nonattainment Boundaries

Excluded County, State	**Previous 8-hour Ozone Nonattainment Area**
Warren County NJ	New York-N. New Jersey-Long Island, NY-NJ-CT
Cecil County MD	Philadelphia-Wilmington-Atlantic City, PA-NJ-MD-DE
Salem County NJ	
Jefferson TN	Knoxville, TN
Sevier Counties TN	
Christian County KY	Clarksville-Hopkinsville, TN-KY
Geauga County OH	Cleveland-Akron-Lorain, OH
Clinton County OH	Cincinnati-Hamilton, OH-KY-IN
Knox and Madison Counties OH	Columbus, OH

Some of these areas were excluded based on the nature of the pollutant. PM2.5 is comprised of both primary and secondary components; the primary being more localized. ARB requests that U.S. EPA recognize the technical basis for different boundaries for regional ozone and localized PM2.5.

Additional Information – Area Specific

1. City of Calexico, Imperial County Air Pollution Control District

The only monitor in Imperial County violating the new federal PM2.5 standard is located in the City of Calexico. Data from air quality monitors in El Centro and Brawley, as shown in Figure 1-1, are well below the new standard and about 45% lower than Calexico (2007 Design Values are indicated in the colored circles). Calexico has 24% of the population of Imperial County within its boundaries (Table 1-1) with the second largest population and the highest population density. The largest population area, El Centro, only nine miles north of Calexico, is in attainment of the standard.

The majority of the county is largely unpopulated. Only 14% of the population resides outside of the urbanized areas, the majority of these still within the narrow area stretching from Mexico to the Salton Sea. Most of the population, however, lives in areas that attain the standard. Confining the nonattainment area to the City of Calexico would still ensure protection for the population exposed to unhealthy levels of PM2.5.

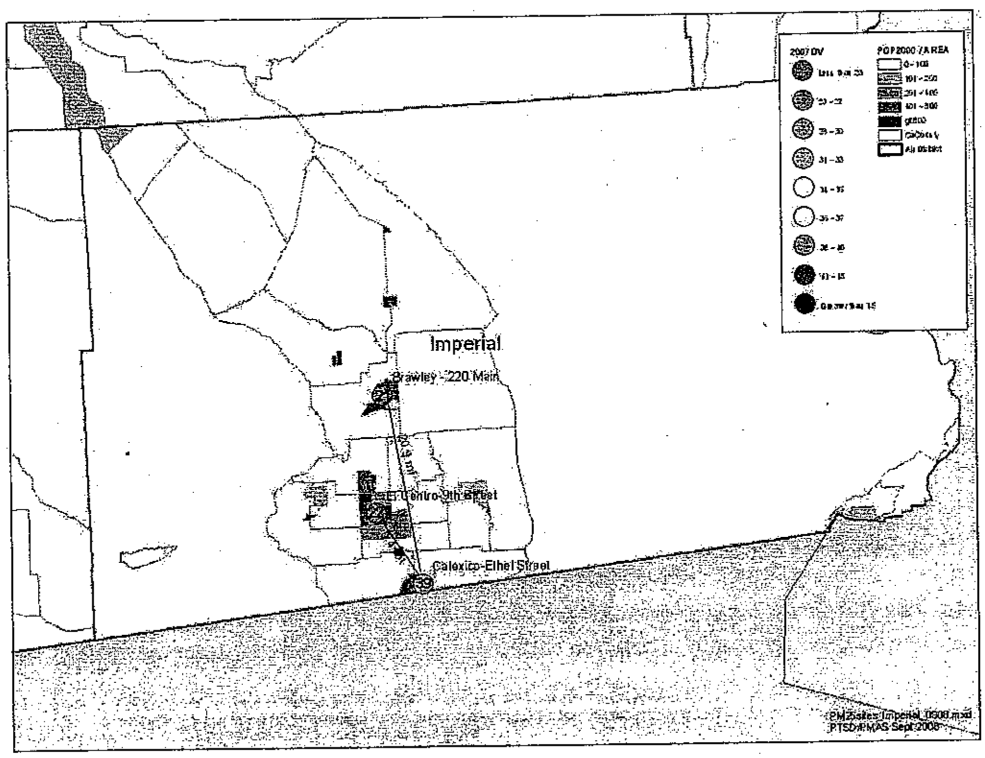

Figure 1-1: 2007 Design Values in Imperial County

The City of Calexico is located next to the Mexico international border. As seen in the satellite view in Figure 1-2, the urban area of Mexicali, Mexico is considerably larger than that of Calexico. Table 1-1 shows the disparity in both population and physical size; Calexico accounts for only 5% of the population and 4% of the land area of the combined Calexico/Mexicali urban area, a metropolis separated by a nonphysical international border. The population density of Imperial County is less than a fifth of the Municipality of Mexicali, in an area of roughly the same size. A similar situation is faced at the border area of Nogales, AZ (population: 21,746). The Mexican city of Nogales (population: 203,719), with a much higher population and population density, is separated from Nogales, AZ only by a political boundary. This population disparity was noted by U.S. EPA in considering the Nogales area as a focused nonattainment area for PM2.5, retaining the rest of Santa Cruz County in attainment. ARB believes that air quality in the City of Calexico is similarly overwhelmed by the much larger City of Mexicali across the border and requests similar consideration.

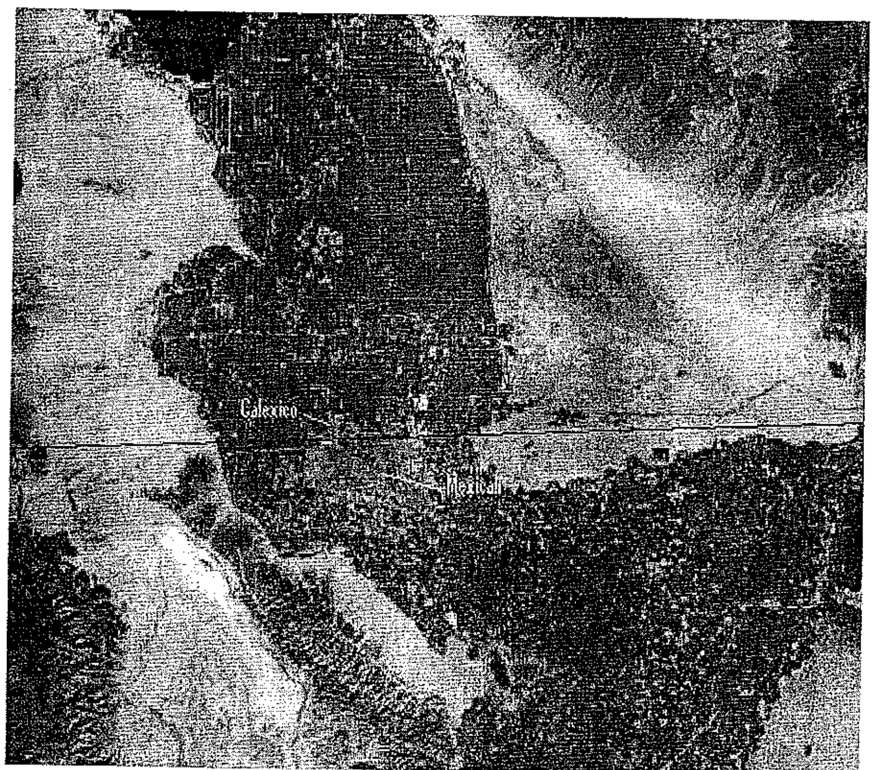

Figure 1-2: Calexico and Mexicali Satellite Image
[Source: maps.google.com]

Table 1-1: Population of Calexico/Mexicali Border Region

Area	Population (2006 est.)	Area (mi^2)
Imperial County	160,301	4,598
El Centro	40,563	10
Calexico	37,243	9
Mexicali Municipality	873,937	5,200
Mexicali	653,046	200

[Data Source: U.S. Census [www.census.gov/; CONAPO [www.conapo.gob.mx]

The U.S. EPA states, "Imperial County shows violations of the 24-hour PM2.5 standard. Therefore, this county is a candidate for a 24-hour PM2.5 nonattainment designation (U.S. EPA Response, p.8)." Calexico, the only violating area of Imperial County, comprises only 1% of the county area. When Imperial County was designated as nonattainment for both PM10 and ozone, consideration was given for both the regional nature of the pollution sources and the presence of violating monitors throughout the county. This is not the case, however, for PM2.5. Both the presence of a single violating monitor, as well as the impact from Mexicali, argue for a focused nonattainment area, as originally recommended by ARB.

The Imperial Valley operates as a channel running northwest to southeast. Wind flow patterns tend to flow along this channel, from the northwest into Mexicali, and from the southeast into Calexico. Although the geography of the Imperial Valley is such that there are no topographical barriers that separate the City of Calexico from the rest of Imperial County, the significantly lower concentrations to the north (Figure 1-1 and Table 1-2) show that distance is enough of a barrier to keep the northern urban population from being exposed to levels above the standard.

Table 1-2: Exceedance Days at Calexico-Ethel

Date	Concentrations (ug/m3)		
	Calexico	El Centro	Brawley
12/12/05	67.6	57.9	19.9
12/18/05	41.1	34.1	**37.8**
1/8/06	44.8	12.7	20.3
1/14/06	49.6	23.2	n/a
1/17/06	37.1	16.4	n/a
12/22/06	46.0	16.5	11.7
12/25/06	68.8	9.6	8.5
12/5/06	52.7	20.9	19.5

Hysplit model results (U.S. EPA Response, Attachment 2) implied a contribution from emissions throughout Imperial County to elevated levels at the Calexico-Ethel site. As noted above, however, other sites in the county showed much lower concentrations during Calexico exceedance days, indicating that the high concentrations at Calexico were unlikely to be due to a northern influence. In fact, the two highest PM2.5 exceedance days coincide with PM10 exceedances being documented by the Imperial County Air Pollution Control District as due to transport from Mexicali.

The U.S. EPA noted two days with potential northern influence. ARB staff conducted further analysis using two-dimensional wind trajectory models (Figure 1-3). The first part of the figure (a) shows stagnant conditions present on January 8, 2006. The blue trajectory line indicates that the air parcel moved very little during the day. The second part of the figure (b), from January 17, 2006, shows a more northern flow, but concentrations at El Centro were half that of Calexico (no data available from Brawley on that day), indicating very limited influence from the northern portion of the county.

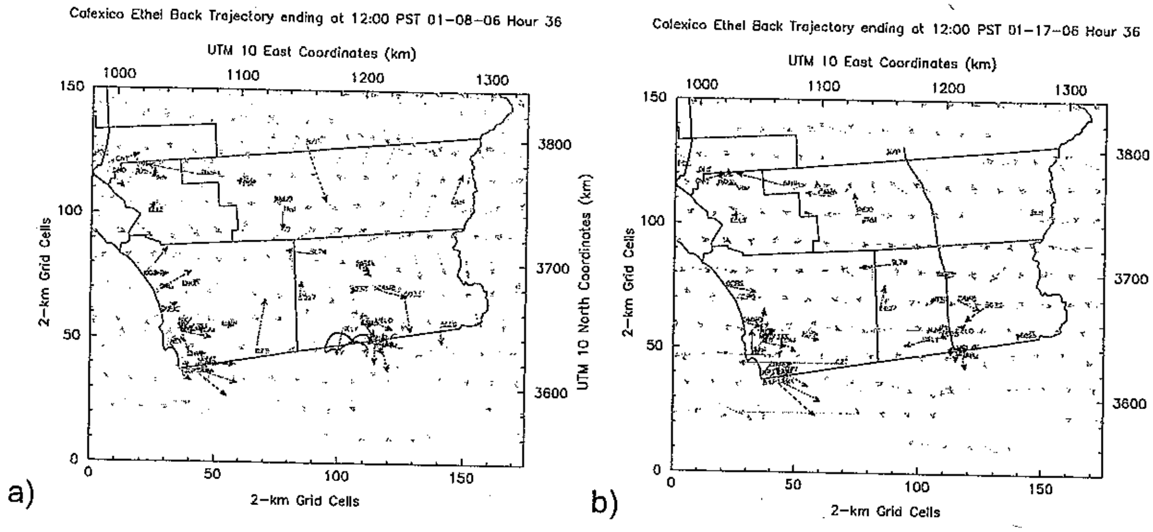

Figure 1-3: 2-D Wind Trajectory Model Results, Calexico-Ethel, Imperial County

Additionally, BAM concentrations on these two exceedance days show a strong correlation with wind from the south (Figure 1-4). The red boxes outline the flow from the south (90-270 degrees); the blue boxes indicate the increased PM2.5 concentrations associated with these winds.

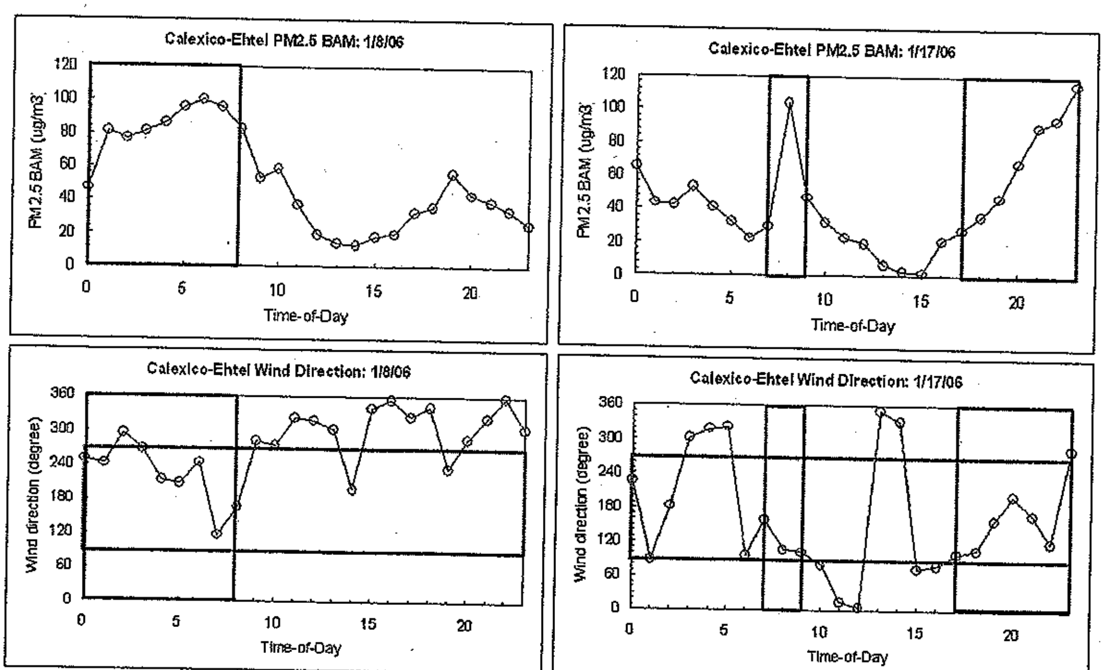

Figure 1-4: Correlation between PM2.5 BAM Concentrations and Wind Direction

Research into PM10 concentration differences between Mexicali and Calexico (Chow, et.al., 2000) showed that average cross-border transport of PM10 from Mexico was three times higher than from the U.S. The study showed that Mexicali's PM10 concentrations were almost double those at Calexico. Although the relative source contributions between the two sites were found to be similar, the absolute source contributions at the Mexicali site were three to seven times that at the Calexico site. The researchers suggested that increased charbroiling in Mexicali during the major holiday season (mid December to early January) accounted for the difference; the same period of time as the PM2.5 exceedances at Calexico-Ethel.

As noted in the U.S. EPA Response (Table 1, p.5) , the emissions inventory for Imperial County shows a 24% contribution from carbon. Chemical composition data for Calexico specifically from exceedance days at Calexico shows an organic carbon contribution of over 50% (Figure 1-5). The seasonal pattern (Figure 1-6) shows the strong wintertime increase in organic carbon. We believe the majority of these carbon emissions are the result of transport from the City and Municipality of Mexicali, Mexico, where residential trash and wood burning are largely unregulated. In addition, the majority of the exceedance days noted in Table 1-2 occurred during the December/January time period when there are increased volumes of smoke across the border, as evidenced in Figures 1-10 and 1-11. These emissions, while large, tend to remain in the local area, as shown by a comparison to PM2.5 concentrations at Brawley, a site further removed from the border influence (Figure 1-7). Very little variation in PM2.5 concentrations is seen throughout the year. Calexico, however, as indicated by the trend line shown in red, shows a distinct increase in winter.

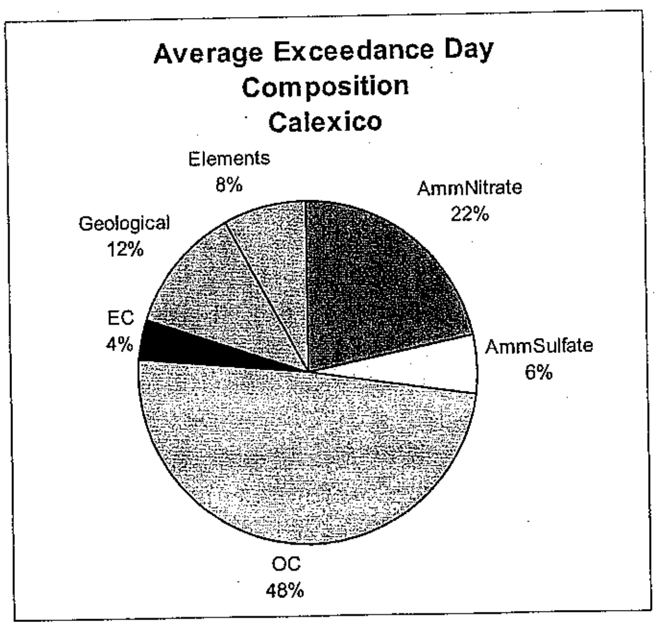

Figure 1-5: PM2.5 Composition, Calexico, Imperial County

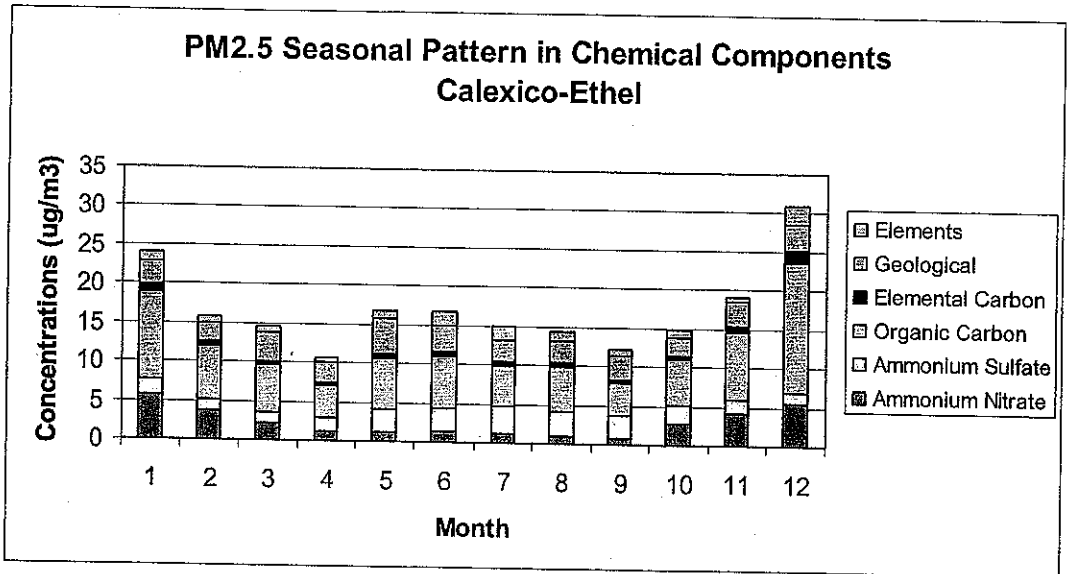

Figure 1-6: Seasonal Pattern of PM2.5 Composition, Calexico, Imperial County

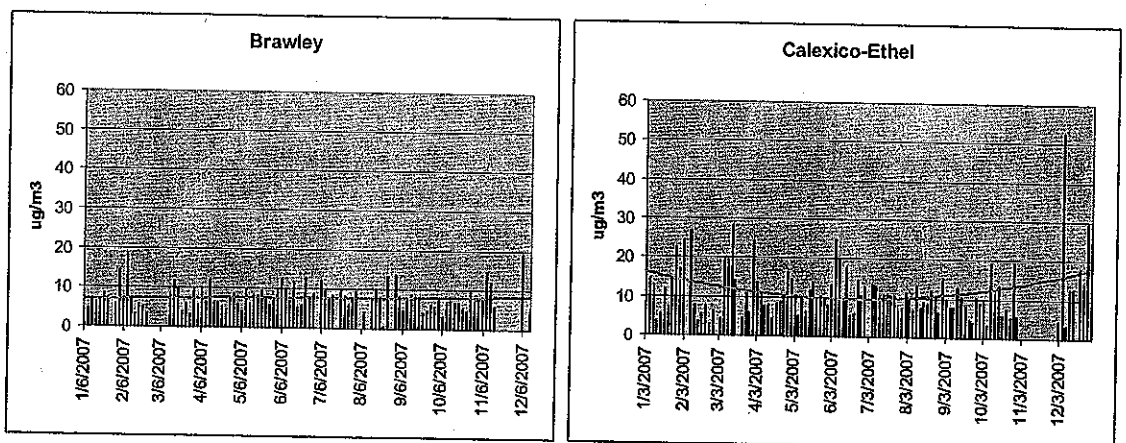

Figure 1-7: Seasonal variation in PM2.5 at two sites in Imperial County

Per a request in U.S. EPA Response, Table 1-3 includes 2005 Imperial County and Mexicali emissions. Imperial County PM2.5 emissions are higher than Mexicali mostly due to area sources, 65% due to windblown fugitive dust. In the absence of a more detailed inventory, it can be reasonably assumed that Calexico, with only 24% of the population of Imperial County, would account for less than half of the emissions of Imperial County as a whole. In addition, wind-blown dust emissions are not a factor during winter-time stagnation episodes. Table 1-3 illustrates the great disparity between Imperial County and Mexicali emissions. Mexicali total NOx emissions are twice those of Imperial, with SOx emissions are thirteen times those north of the border. A significant portion of the Mexicali emissions are from stationary sources. Figure 1-8 shows the large number of stationary sources located near the international border with several right on the border. In comparison, Figure 1-9 shows that there are only a few stationary sources (triangles) in Imperial County and none in the City of Calexico (blue squares are monitoring sites).

Table 1-3: 2005 Emissions Imperial County and Mexicali (tons/day)

Imperial County	**NOx**	**SOx**	**PM2.5**
Stationary Sources	7.1	0.2	1.3
Area Sources	0.9	0.1	37.5
Mobile Sources	30.2	0.6	1.7
Total	**38.3**	**0.9**	**40.4**
Mexicali			
Stationary Sources	39.4	12.7	0.4
Area Sources	3.7	0.5	18.5
Mobile Sources	35.8	0.6	3.3
Total	**78.9**	**13.8**	**22.2**

[Source: Imperial County Emissions- ARB Almanac; Mexicali Emissions-ERG 2005 Mexicali Emissions Inventory Draft Final, 10/3/08]

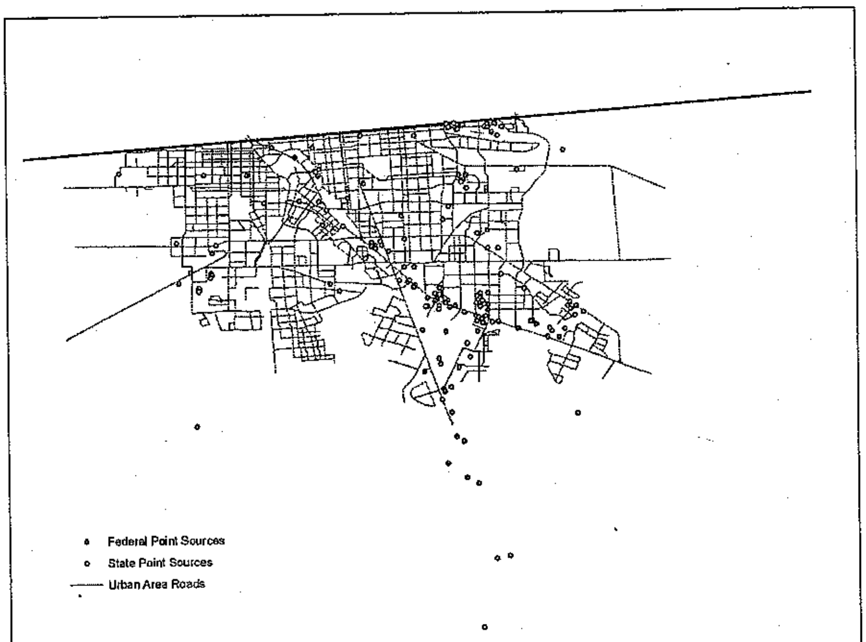

Figure 1-8: Location of Federal and State Jurisdiction Point Sources in the Urban Portion of Mexicali

[Source: Mexicali Emissions-ERG 2005 Mexicali Emissions Inventory Draft Final, 10/3/08]

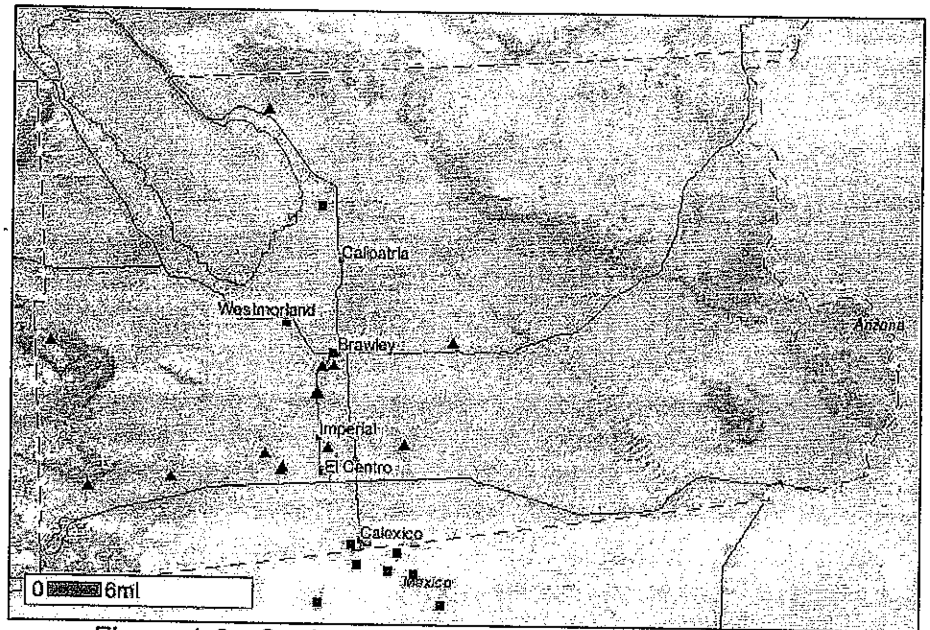

Figure 1-9: Stationary NOx Sources in Imperial County
[Source: CARB Almanac, Imperial County Emissions]

The possible source directions of the major PM2.5 components were investigated using Conditional Probability Function (CPF) Analysis (Kim and Hopke, 2004). CPF estimates the possible local source directions utilizing wind directions coupled with PM2.5 concentration and speciation data. The sources are likely to be located in the directions with high CPF values.

The Calexico-Ethel monitoring site experienced source impacts from primarily southern directions on exceedance days in the winter (Figure 1-10). These southern contributions indicate smoke and particulates from Mexicali.

The impact of smoke from Mexicali is further illustrated with the CPF analysis of potassium (K+) source contributions as illustrated in Figure 1-11. These figures also visually illustrate the transport of smoke from Mexicali into the City of Calexico.

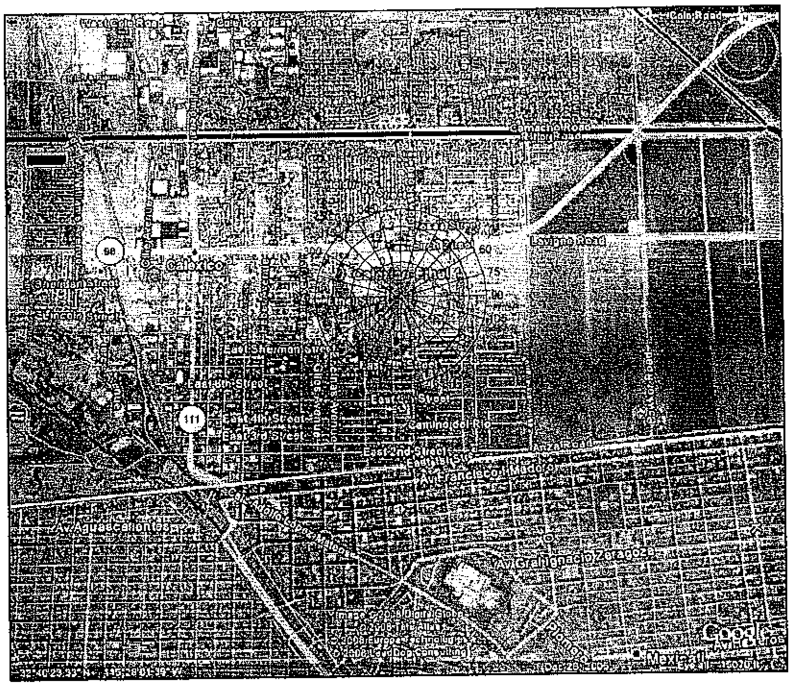

Figure 1-10: CPF Analysis of PM2.5 Concentration Source Contributions.

[Map Source: maps.google.com; 12/26/2005]

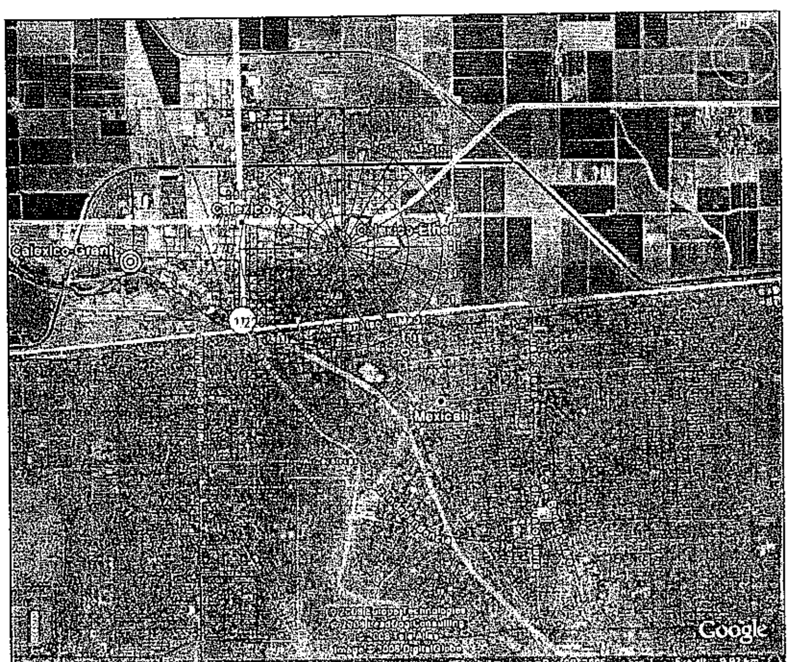

Figure 1-11: CPF Analysis of PM2.5 Potassium (K+) Concentration Source Contributions. *[Map Source: maps.google.com; 12/26/2005]*

Summary

In response to the two primary concerns of the U.S. EPA, ARB believes that the City of Calexico encompasses the population exposed to the high PM2.5 concentrations represented by the Calexico-Ethel site, and that the remainder of the county does not significantly contribute to PM2.5 exceedances at Calexico. ARB analysis continues to support that violations at Calexico are due to international transport from Mexico.

While U.S. EPA has used the argument that increased VMT across the county is a factor in a county-wide nonattainment area, we disagree. As noted above, the primary problem in Imperial County is international transport, which affects only the local Calexico area.

Finally, the regional background of ammonium nitrate is not sufficient to cause violations of the standard. Regional contributions of ammonium nitrate will be decreasing due to already adopted State-wide controls. Over the next ten years, these controls will reduce State-wide NOx emissions by 28%.

An updated map, encompassing the complete population of the City of Calexico, and incorporating potential growth is shown in Figure 1-13.

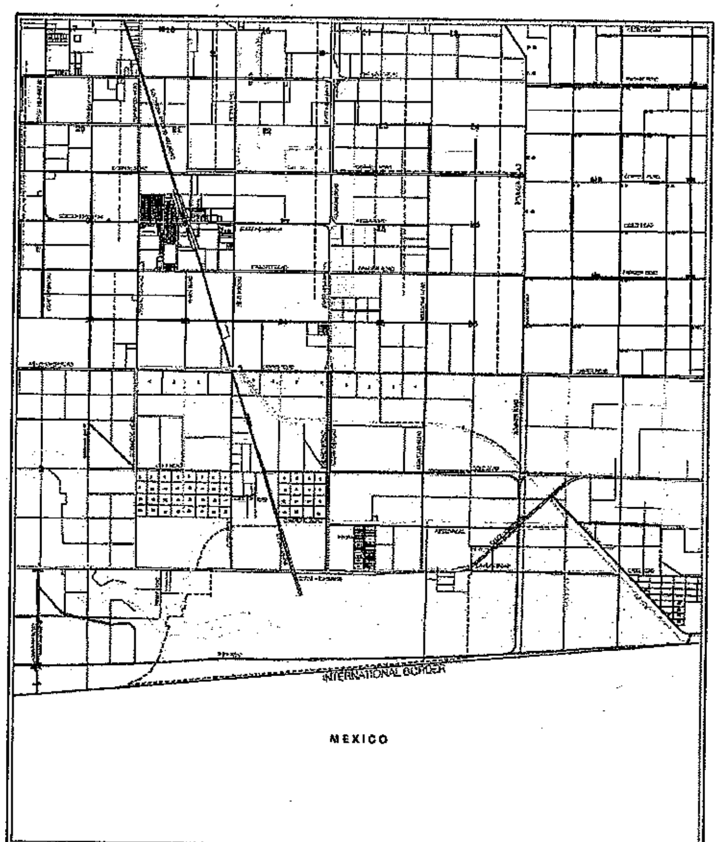

Figure 1-13: City of Calexico Sphere of Influence
[Source: Imperial County, CA]

2. Sacramento Air Quality Management District

The only violating monitors in the Sacramento area are located in the City of Sacramento; specifically, Sacramento-Del Paso, Sacramento-T Street, and Sacramento-Health Dept. Data from air quality monitors in surrounding counties, as shown in Figure 2-1, are well below the new standard (2007 Design Values are indicated in the colored circles) and far outside the zone of influence established by the Sacramento-Del Paso monitoring site. According to the CRPAQS study by Chow (Chow, et.al, 2006), a zone of influence is defined in which a concentration varies by 20%. Only the monitoring sites at Sacramento-T Street and Sacramento-Health Dept fall within this zone. The steep PM2.5 concentration gradients are illustrated in the figure below.

The U.S. EPA Response indicated that Placer County was in violation of the PM2.5 standard in 2006. The 2006 Design Value for the monitoring site in Placer County was, however, well below the standard at 31 ug/m3 (CARB iADAM website, 2008).

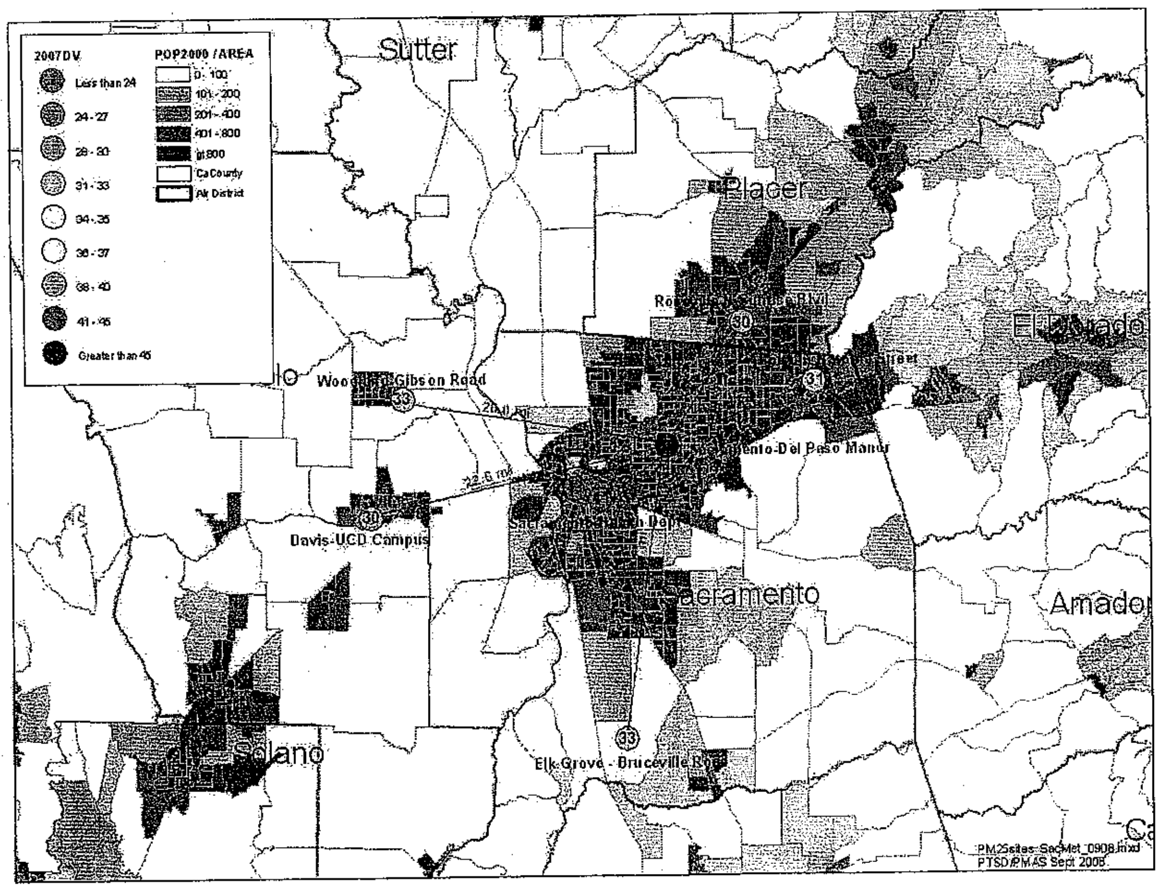

Figure 2-1: 2007 Design Values in Sacramento County Area

Air Quality and Emissions

As noted in the U.S. EPA Response and in Figure 2-2 below, during exceedance days in Sacramento, over 50% of the PM2.5 mass is organic carbon, primarily from residential wood burning. The seasonal pattern (Figure 2-3) shows the strong wintertime increases in organic carbon.

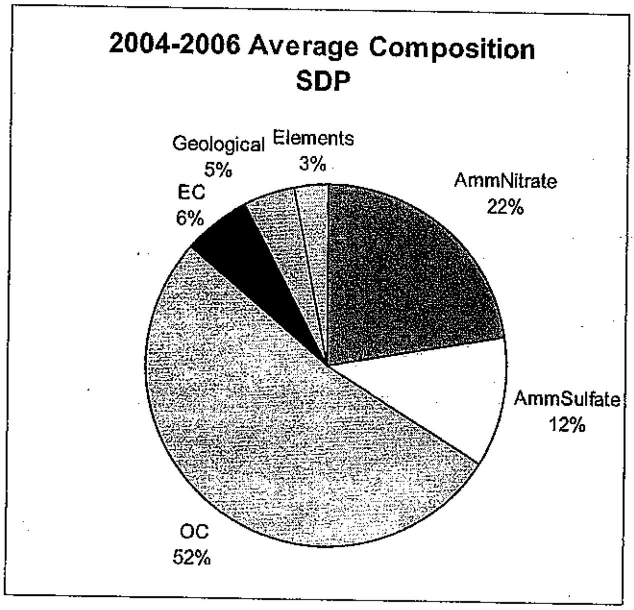

Figure 2-2: PM2.5 Composition,
Sacramento-Del Paso, Sacramento County

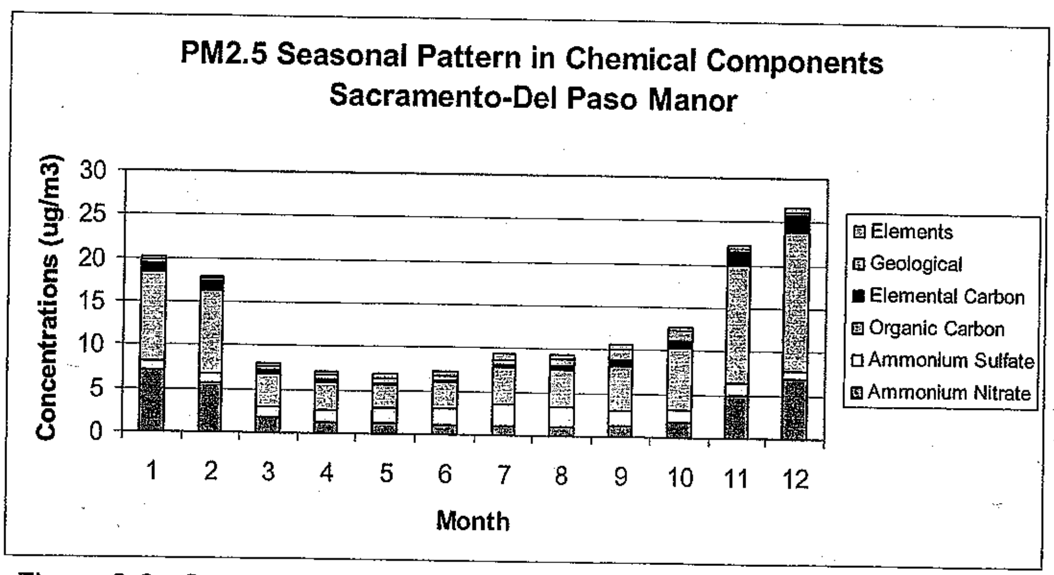

Figure 2-3: Seasonal Pattern of PM2.5 Composition, Sacramento-Del Paso

Chemical composition data is unavailable for other sites in the Sacramento region, but daily PM2.5 concentrations show the strong impact of winter PM2.5 emissions on the sites in the Sacramento urban area and the lesser impact at the more removed areas of Roseville and Woodland (Figure 2-4). These wintertime increases are due primarily to increased residential wood burning, as already noted in the area source emissions inventory in the U.S. EPA Response (Table 2, p.6). The Sacramento Metropolitan Air Quality Management District has already begun to address this issue. Mandatory wood burning controls were established in 2007. Their impact will be seen as early as 2008.

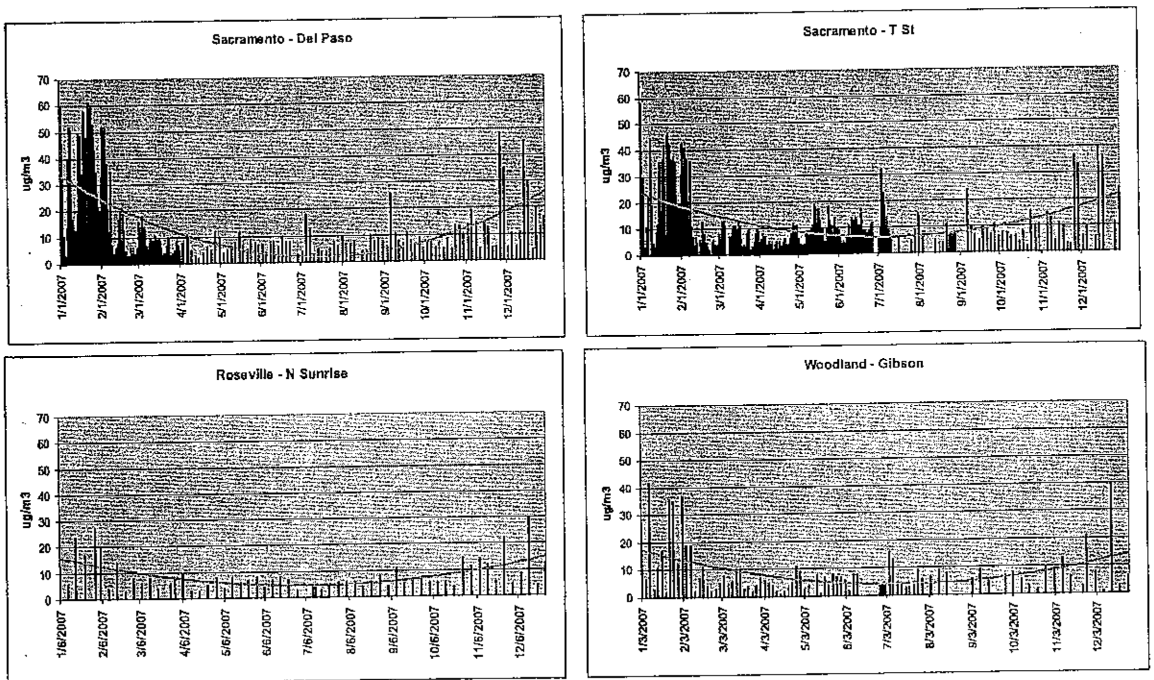

Figure 2-4: Seasonal Variation in PM2.5 at Four Sites in Sacramento Region

The use of county-wide emissions for areas such as Placer and El Dorado Counties, mountainous regions with large rural populations does not adequately reflect the reality of emissions within these areas. Although the majority of the population of El Dorado County resides in the western portion of the county, the population of the eastern portion, South Lake Tahoe and the surrounding mountainous areas, is over 25,000. The majority of the urban population of Placer County resides in the western part of the county, but almost a third reside in unincorporated areas.

Complete county emissions data was also used for Solano County, even though U.S. EPA split the county, overstating the contribution each adjacent portion may have on Sacramento County and the San Francisco Bay Area. Air quality monitoring data was split between the western and eastern parts of Solano County, the same care should be taken with the other factors contributing to the CES.

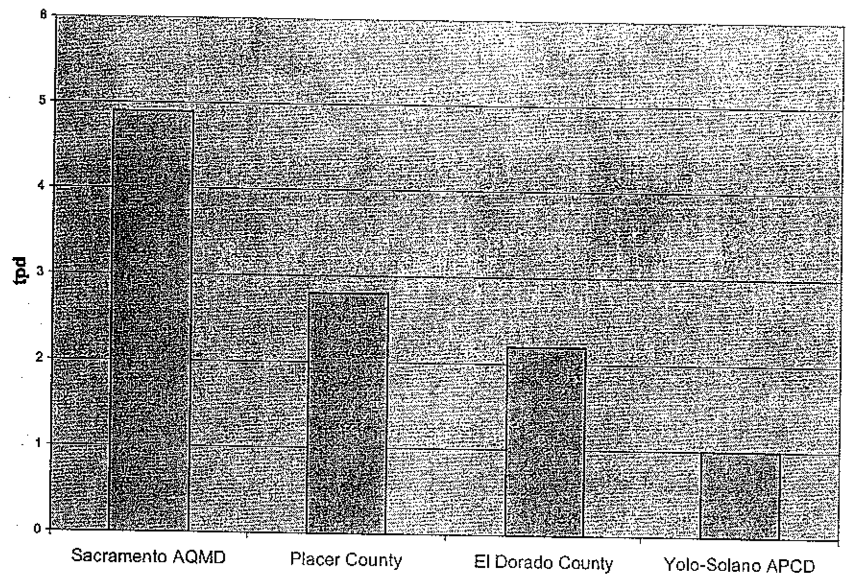

Figure 2-5: Wood smoke PM2.5 Emissions in the Sacramento Region

Recently, El Dorado County notified ARB that the residential wood combustion emissions in Table 2 of U.S. EPA's Response (p. 6) were incorrect and inaccurately indicated high residential burning emissions in El Dorado County. ARB staff worked to update these numbers, however, we were unable to separate the contribution from the Lake Tahoe Air Basin portion. Even including that portion, El Dorado County PM2.5 emissions for this category decreased significantly, from 5.3 to 2.2 tons/day. The chart above reflects the emissions and shows that PM2.5 emissions from Sacramento residential fuel combustion are significantly larger than any of the surrounding counties.

Meteorology and Transport

U.S. EPA notes that prevailing winds at Sacramento during exceedance days are from the northwest and southeast and during time periods with wind speeds of 4 miles per hour or less, concurring that high PM2.5 concentrations were dependent on calm-to-light winds. In other words, stagnant conditions were evident during the exceedance periods, an indication of local not transported pollutants.

ARB believes that exceedances were of a localized nature. Additional analysis (two exceedance days shown in Figure 2-6) shows little or no contribution from outlying areas. The trajectories (circled) indicate that air parcel movement was confined to the local area.

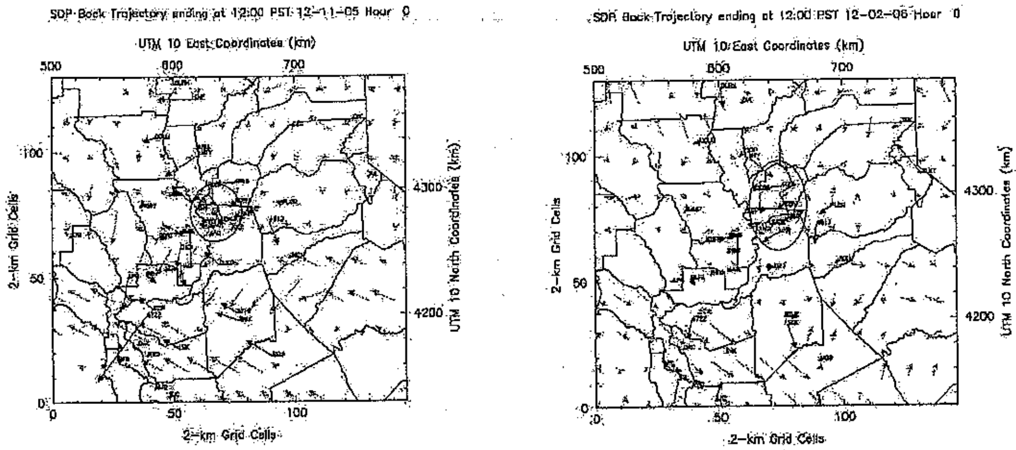

Figure 2-6: 2-D Wind Trajectories for Two Exceedance Days (12/11/05 and 12/2/06) at Sacramento-Del Paso

An examination of BAM data from Roseville and Sacramento-Del Paso are also indicative of the higher concentrations at Sacramento-Del Paso being due to local influence and not transport from Placer County (Figure 2-7).

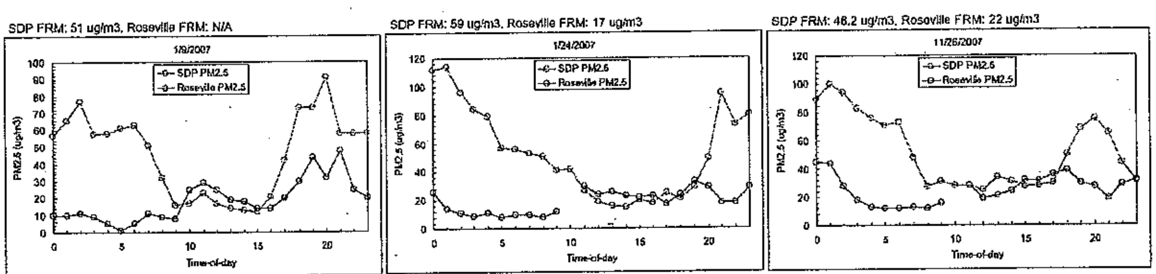

Figure 2-7: Diurnal PM2.5 Patterns at Sacramento-Del Paso and Roseville

The Roseville site remains fairly stable throughout each exceedance day. Some nighttime increases are noted on January 9, 2007, but are more likely the result of increased PM2.5 from local wood burning during stagnant conditions, which also resulted in local wood burning impacts at Sacramento-Del Paso. Local stagnant conditions for that day are further indicated by a HYSPLIT backward trajectory analysis (Figure 2-8).

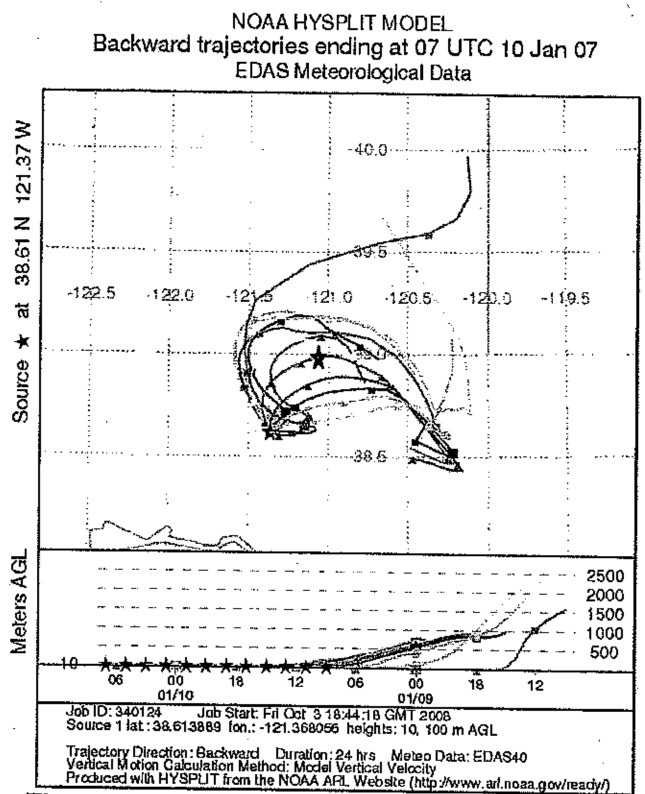

Figure 2-8: HYSPLIT Analysis of Wind Flow during Exceedance Day at Sacramento-Del Paso

Contributing Emission Scores (CES)

One of U.S. EPA's goals in designating nonattainment areas in California was to achieve a degree of consistency with existing ozone and PM10 nonattainment areas. Application of this goal in California led to differences between the State's recommended nonattainment areas and U.S. EPA's proposed designations. When U.S. EPA originally designated the 8-hour ozone area for the Sacramento area consideration was given to the regional nature of the pollutant and emission sources as well as the presence of violating monitors throughout the region. The Sacramento Metropolitan ozone nonattainment area therefore includes all of Sacramento and Yolo Counties, and portions of Solano, Sutter, Placer, and El Dorado Counties. This was not the case for PM10. In that case, violating monitors occurred only within Sacramento County, which was, in and of itself, declared an appropriate boundary area. For PM2.5, the localized nature of organic carbon, which is the key contributor to wintertime violations, as well as the lack of violating monitors outside of the City of Sacramento, argue for a more focused nonattainment boundary similar to that of PM10.

U.S. EPA based part of its decision to include more counties in the Sacramento nonattainment area on the comparable population densities of surrounding counties to Sacramento County. The analysis for CES Factor 3 states that the populations associated with Sacramento clearly extend into Placer, El Dorado, Solano, and Yolo Counties. The surrounding counties' populations range from 4% to 34% of Sacramento County (Table 2-1). Surrounding counties' population densities range from 7% (El Dorado) to 35% (Solano) of Sacramento County.

Table 2-1: Population and Population Density in Sacramento and Surrounding Counties

County/City	2005 Population	% of Own County	% of Sacramento County	% of Five County Region	Pop Density
Sacramento	1,363,423	100%	100%	55.6%	1343
Elk Grove	136,318	10.0%	10.0%	5.6%	
Folsom	70,835	5.2%	5.2%	2.9%	
Sacramento	467,343	34.3%	34.3%	19.1%	
El Dorado	176,319	100%	12.9%	7.2%	98
Placer	316,868	100%	23.2%	12.9%	210
Roseville	106,266	33.5%	7.8%	4.3%	
Solano	410,786	100%	30.1%	16.8%	471
Yolo	185,091	100%	13.6%	7.6%	179
Davis	64,938	35.1%	4.8%	2.7%	
Woodland	54,060	29.2%	4.0%	2.2%	

[Source: www.csac.counties.org; www.cacities.org; www.census.gov]

Population growth, another factor (Factor 5) in determining CES, indicated substantial growth in the Sacramento area. As noted in Table 2-2, however, the majority of this growth, over half, is occurring in Sacramento County. Although growth rates in surrounding counties range from 4% to 28%, these rates are based on county populations significantly less than Sacramento (Figure 2-9).

Table 2-2: Population Growth in the Sacramento and Surrounding Counties

County	2000 Population	2006 est. Population	County Growth	% Change of County	% of Regional Growth
Sacramento	1,223,499	1,374,724	139,924	11.4%	53.6%
El Dorado	156,299	178,066	20,020	12.8%	7.7%
Placer	248,399	326,242	68,489	27.6%	26.2%
Solano	394,542	411,680	16,244	4.1%	6.2%
Yolo	168,660	188,085	16,431	9.7%	6.3%
COMBINED	*2,191,399*	*2,478,797*	*261,088*	*11.9%*	*100.0%*

[Source: www.census.gov]

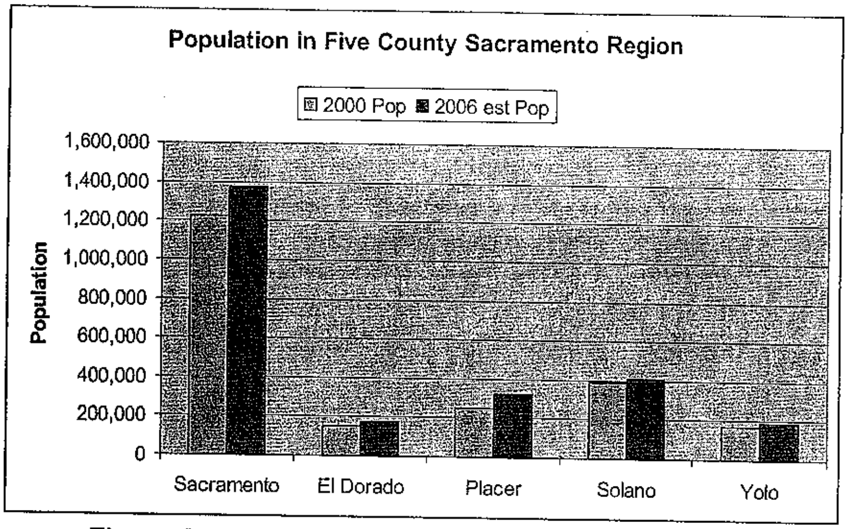

Figure 2-9: Population of the Sacramento Region
[Source: www.census.gov]

Although the CES is only one element in determining the nonattainment boundary areas, a high CES implies that a county has a high impact on the adjacent violating county. However, CES numbers are based on data for entire counties. The CES should be adjusted to reflect only those portions of a county to be included with an adjoining nonattainment area, such as Solano, El Dorado, and Placer Counties within the Sacramento nonattainment area.

The higher score of Solano was discounted, based on its contribution to the San Francisco Bay Area nonattainment area and the higher population in the western portion of the county. The high scores for Placer and El Dorado were based, partially, on analysis done for the entire counties. As noted in U.S. EPA Technical Document (Rizzo and Hunt, 2008), the CES methodology uses county-based emissions inventories which may be inaccurate in counties with large rural populations or with mountainous terrain, both of which occur in El Dorado and Placer. Although U.S. EPA took some of this into account in recommending only a part of each county for inclusion in the nonattainment area, it did not take into account the fact that the majority of PM2.5 emission are from residential wood burning. These emissions were recently found to be inaccurate (pages 17 and 18 of this report) and a significant portion may be occurring in the Lake Tahoe Air Basin segment of these counties.

Use of population and population growth as factor in U.S. EPA's decision-making was not consistent throughout the country. Warren County, New Jersey, is an example of a county not included with an adjacent violating area. According to U.S. EPA, "Warren County [New Jersey] ranks low in terms of population and in population density in comparison to counties located near the violating monitor in Northampton County, Pennsylvania. In comparison to the two counties that have been recommend as nonattainment for the Allentown, PA-NJ area, *Warren County's population and population density is below 50% that of Lehigh and Northampton.* (U.S. EPA Response to New Jersey, 2008)" Warren County's population density is, in fact, 32% of Lehigh

County and 40% of Northampton County. Although, the Sacramento County population is larger than the populations for counties around Warren County, NJ; Sacramento's population density is very similar. Both total populations and population densities for all surrounding counties are below those of Sacramento County and far below the U.S. EPA stated limit above of 50%.

In an additional example, Hamblen County, part of the Knoxville-Sevierville-LaFollette, TN CBSA, has a population density 44% of neighboring (and violating) Knox County. Hamblen County was designated in attainment (U.S. EPA Response to Tennessee, 2008). There are many other examples of counties with higher population densities than those adjoining Sacramento, within a MSA, but not designated nonattainment.

EPA has placed a high importance on the Contributing Emissions Scores (CES) in designating nonattainment areas. While several counties in California have a relatively low CES and no violating monitor, U.S. EPA has still proposed a nonattainment designation in tandem with neighboring violating counties. In several other areas throughout the country, however, counties with similar, or higher, CES are not wed to their adjacent nonattainment counties (Table 2-3). California requests similar flexibility as provided to other areas of the country.

Table 2-3: Sample of Counties with CES scores at or above 16 with Adjacent PM2.5 Nonattainment Areas

Attaining County, State	CES score	Adjacent Violating Area
Clinton County IA	52	Davenport-Moline-Rock Island, IA-IL 2006 CBSA
Cedar County IA	17	
Louisa County IA	36	Muscatine, IA 2006 CBSA
Johnson County IA	24	
Greenup County KY	24	Huntington-Ashland Area 2006 CBSA
Dickson County TN	19	Clarksville-Hopkinsville, KY-TN 2006 CBSA
Robertson County TN	17	
Posey County IN	19	Evansville Metropolitan Statistical Area
Pickaway County OH	19	Columbus Metropolitan Statistical Area
Ross County OH	18	
Adams County OH	18	
Jefferson County TN	17	Knoxville-Sevierville-LaFollette, NA area, 8-hour ozone

Summary

In response to the two primary concerns of the U.S. EPA, ARB believes that Sacramento County encompasses the population exposed to the high PM2.5 concentrations represented by the Sacramento-Del Paso, Sacramento-Health Dept., and Sacramento-T St. sites, and that the remainder of the region does not significantly contribute to PM2.5 exceedances in Sacramento County.

Sacramento County, which encompasses the majority of the population in the region, is the only area that violates the new PM2.5 standard. ARB analysis continues to support that violations in Sacramento are due to localized wood smoke emissions. Filter analysis shows that regional background ammonium nitrate is not sufficient to cause violations of the standard. Regional contributions of ammonium nitrate will be decreasing due to already adopted State-wide controls. Over the next ten years, these controls will reduce State-wide NOx emissions by 28%.

In other areas throughout the country, counties with CES scores comparable to those counties surrounding Sacramento, were not included as part of adjacent nonattainment areas. Following the same rationale, the non-violating Counties of Yolo, Solano, El Dorado, and Placer should not be part of the Sacramento PM2.5 nonattainment area.

Therefore, ARB continues to supports our original recommendation of a focused nonattainment area for the County of Sacramento.

3. City of Chico, Butte County Air Quality Management District

The only violating monitor in Butte County is located in the City of Chico, which has a 2007 Design Value (DV) of 55 ug/m3. A continuous beta attenuation monitor (BAM) located in the City of Gridley, a community to the south of Chico, shows a 2007 DV of 33 ug/m3 (Figure 3-1). Chico, the largest urban area in Butte County, has a population three-to-five times other areas in the county (Table 3-1). Based on the localized nature of the primary emission contribution to winter PM2.5 (Figures 3-2 through 3-4), ARB considers the urban area of Chico an appropriate nonattainment boundary for PM2.5.

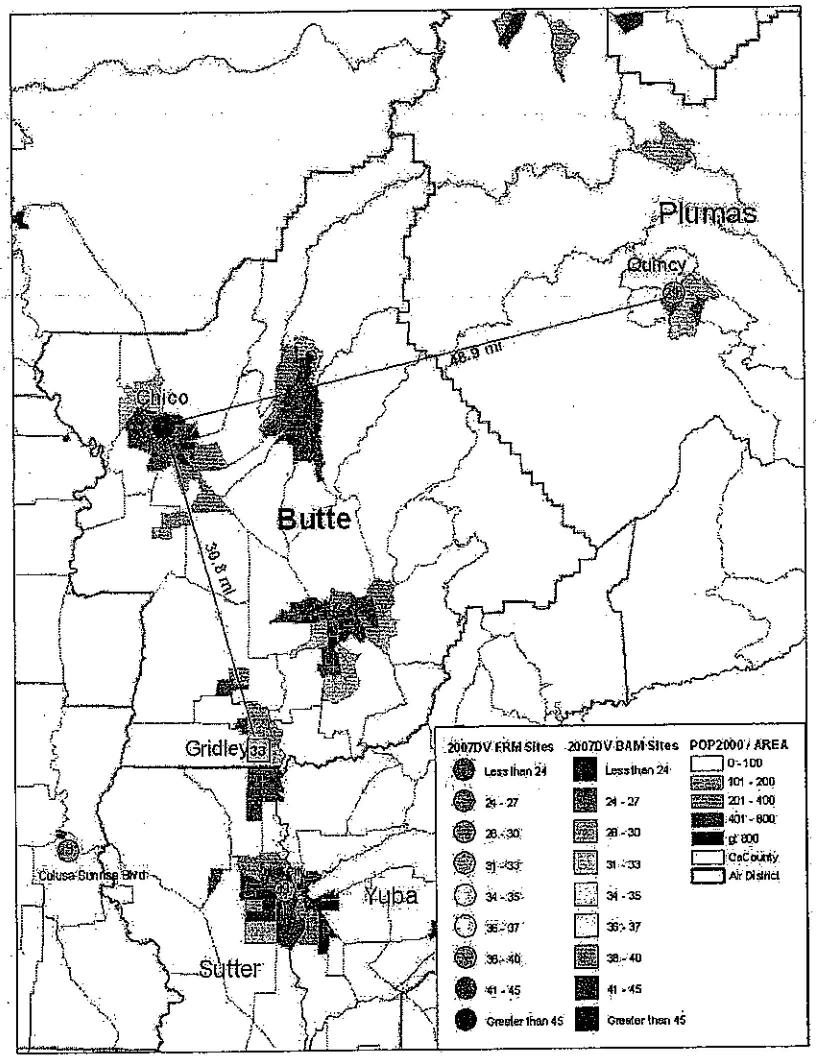

Figure 3-1: 2007 Design Values in Butte County

Table 3-1: Demographic Information, Butte County

County/City	Population	Population Density (pop./mi^2)
Butte County	219,101	132
Biggs	1,809	3471
Chico	84,396	2547
Gridley	6,167	3769
Oroville	14,443	1103
Paradise	26,725	1446

[Source: U.S. Census, www.census.gov; California State Association of Counties, www.csac.counties.org; League of California Cities,www.cacities.org]

As shown in Figure 3-2, 75% of PM2.5 on exceedance days in Chico is composed of organic carbon, primarily from residential wood combustion. The seasonal variation of PM2.5 chemical composition is seen in Figure 3-3. Although ammonium nitrate also shows a winter increase, by itself it would not be enough to cause Chico to exceed the new federal standard. Exceedances are due primarily to increased winter-time residential wood burning, a more localized pollutant. The low wind speeds exhibited during times of PM2.5 exceedances, as noted in the pollution wind rose on page 16 of the U.S. EPA Response, only reinforces that exceedances result from a localized source such as wood burning. Residential wood combustion, particularly during times of low winds or stagnant conditions, is the primary cause of Chico's PM2.5 exceedances.

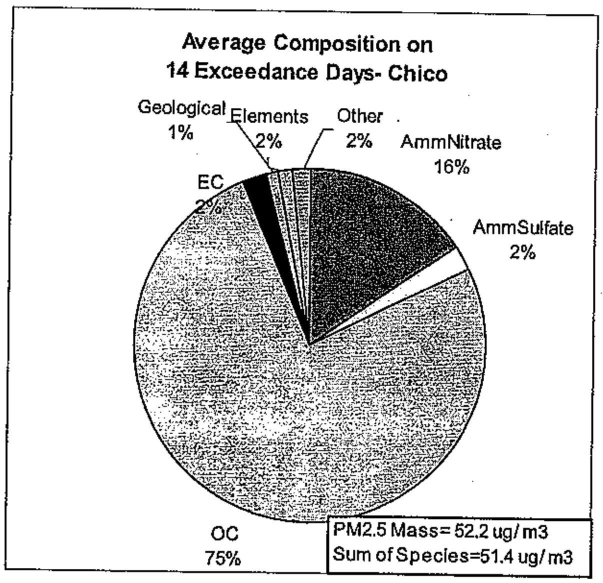

Figure 3-2: PM2.5 Composition, City of Chico, Butte County

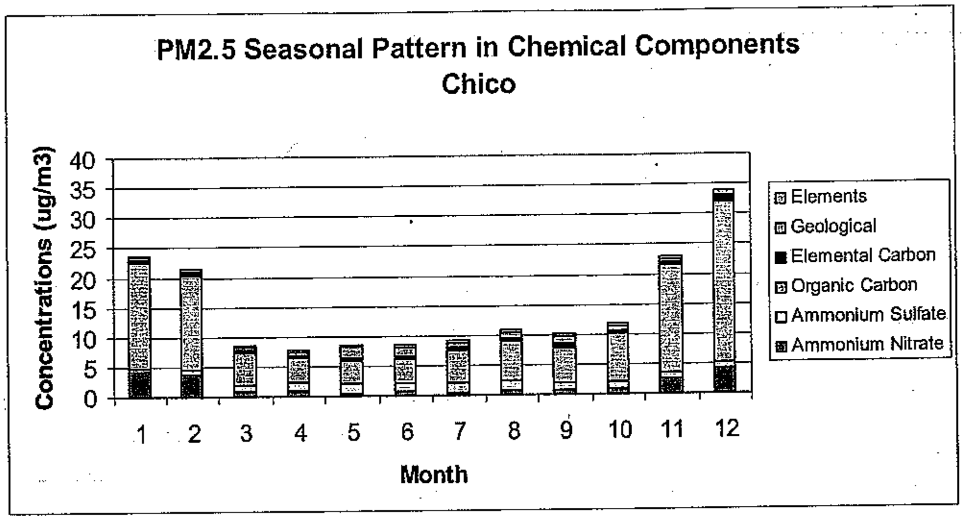

Figure 3-3: Seasonal Pattern of PM2.5 Composition, City of Chico, Butte County

A diurnal analysis of concentrations at Chico and Gridley, during Chico exceedance days, highlights the localized nature of the PM2.5 pollution episodes (Figure 3-4). The nighttime increases at Chico, the result of residential wood burning, are not reflected at the monitoring site at Gridley. As previously noted, the majority of exceedance days occur during periods of stagnant or low wind, keeping pollutants close to the emission source.

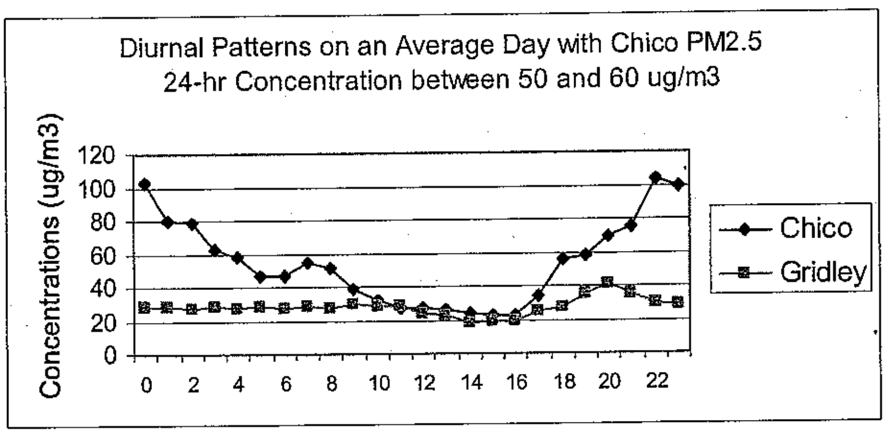

Figure 3-4: Diurnal PM2.5 Patterns at Chico and Gridley

Summary

In response to the two primary concerns of the U.S. EPA, ARB believes that the City of Chico encompasses the population exposed to the high PM2.5 concentrations represented by the Chico-Manzanita site, and that the remainder of the county does not significantly contribute to PM2.5 exceedances in the City of Chico.

The City of Chico, which encompasses the majority of the urban population in the county, is the only site that violates the new PM2.5 standard. ARB analysis continues to support that violations in Chico are due to localized wood smoke emissions. Filter analysis shows that regional background ammonium nitrate is not sufficient to cause violations of the standard. Regional contributions of ammonium nitrate will be decreasing due to already adopted State-wide controls. Over the next ten years, these controls will reduce State-wide NOx emissions by 28%.

While U.S. EPA has used the argument that increased VMT across the county is a factor in a county-wide nonattainment area, we disagree. As noted above, the primary problem is wood smoke, which affects the localized Chico urban core.

Therefore, ARB continues to supports our original recommendation of a focused nonattainment area for the City of Chico. Similar to our recommendation for the City of Calexico, we believe that the City of Chico's sphere of influence may be an appropriate boundary. The General Plan Diagram of the City of Chico, outlining the sphere of influence (gold boundary), is shown in Figure 3-5.

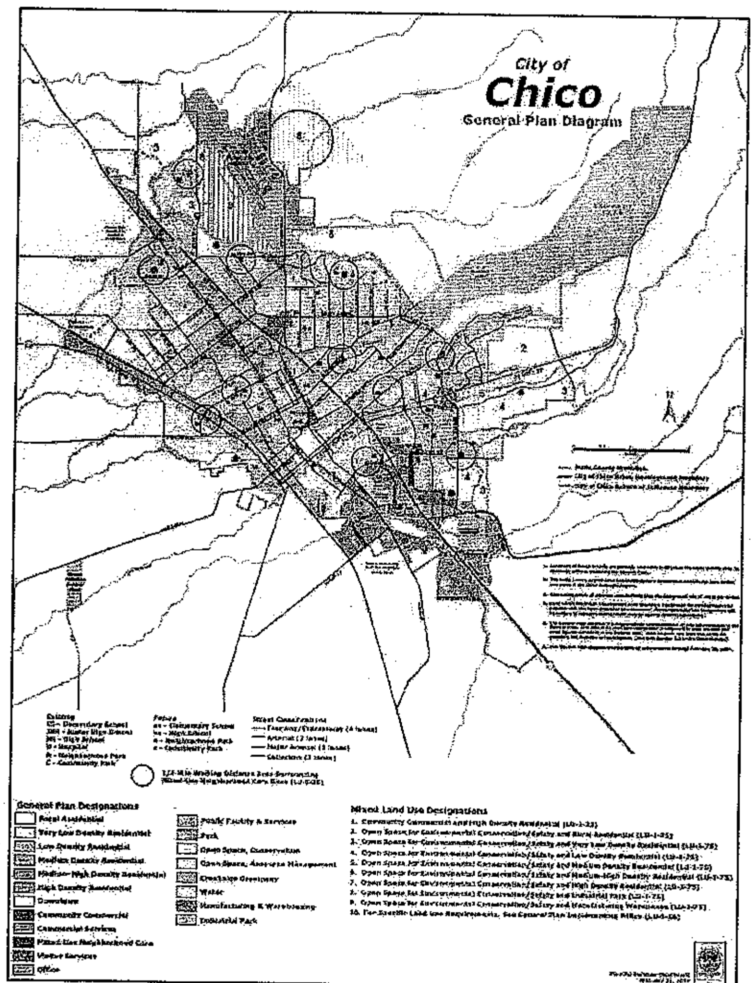

Figure 3-5. City of Chico, Sphere of Influence
[Source: City of Chico, www.chico.ca.us]

4. Combined Cities of Yuba City/Marysville, Feather River Air Quality Management District

The only violating monitor in the Feather River Air Quality Management District (Feather River) is located in Yuba City, which has a 2007 Design Value of 39 ug/m3 (Figure 4-1). Yuba City, the largest urban area in Sutter County, is home to over 65% of the County's population; 18% of Yuba County's residents live in Marysville, located in Yuba County but sharing a border with Yuba City. Combined, the two cities account for 44% of the population of the two counties. Based on the localized nature of the primary emission contribution to winter PM2.5 (Figures 4-2 through 4-4), ARB considers the combined urban areas of Yuba City/Marysville an appropriate nonattainment boundary for PM2.5.

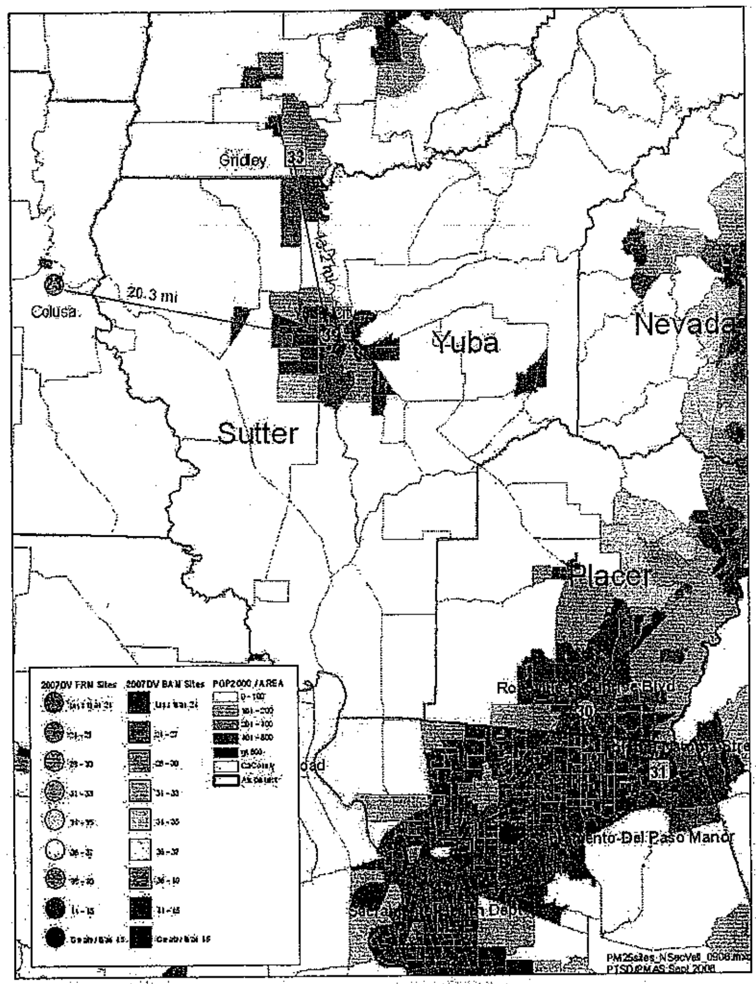

Figure 4-1: 2007 Design Values in Sutter and Yuba Counties

As shown in Figure 4-2, almost 55% of PM2.5 on exceedance days in Yuba City is composed of total carbon (tcm), primarily from residential wood combustion. A seasonal variation of PM2.5 chemical composition is not available for this site, but a look at the mass concentrations throughout the 2007 clearly show the higher concentrations experienced during the winter (Figure 4-3). Exceedances are due primarily to increased winter-time residential wood burning and ammonium nitrate. The low wind speeds exhibited during times of PM2.5 exceedances, as noted in the pollution wind rose on page 16 of the U.S. EPA Response, only reinforces the exceedances as resulting from a localized source such as residential wood burning.

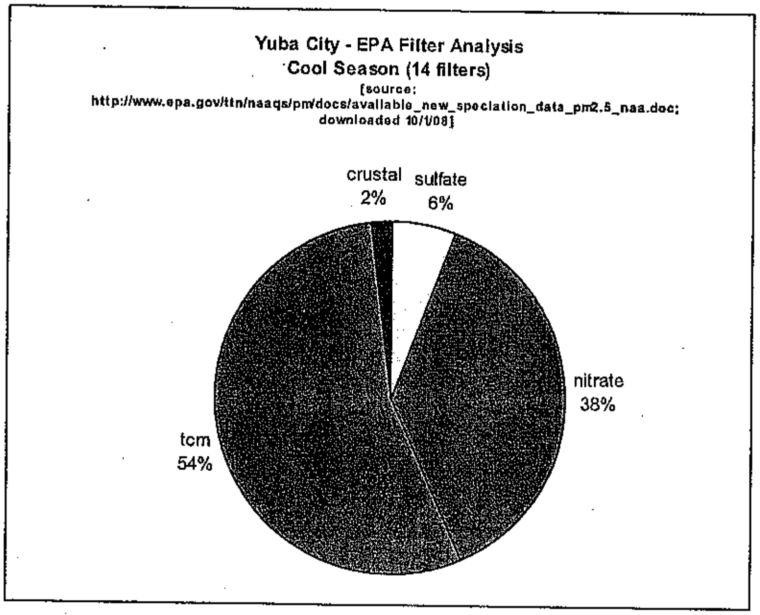

Figure 4-2: PM2.5 Composition, Yuba City, Sutter County

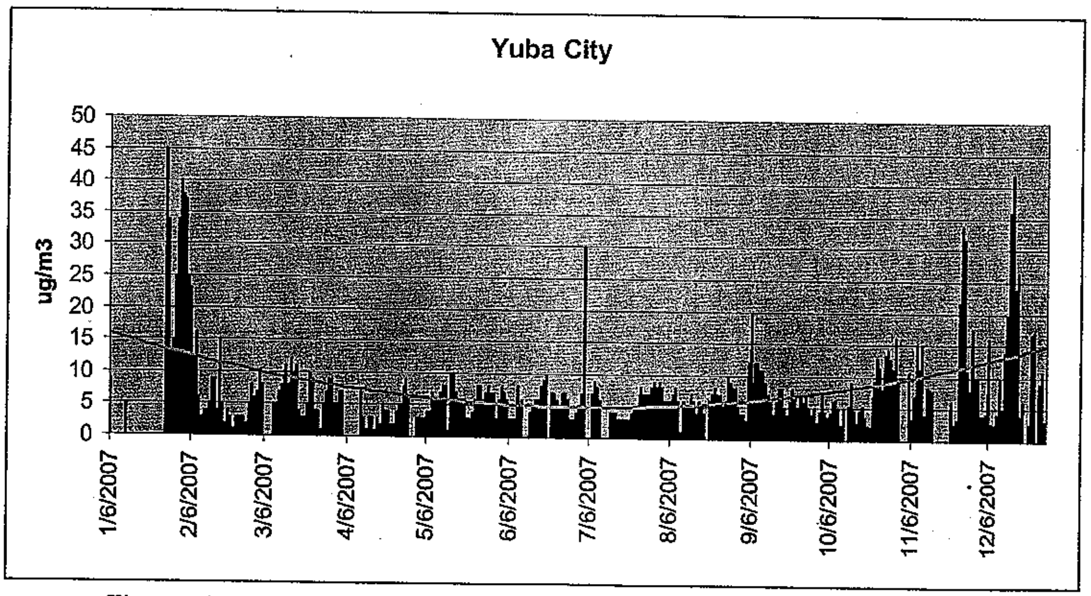

Figure 4-3: Seasonal Pattern of PM2.5, Yuba City, Sutter County

The localized nature of the PM2.5 pollution problem in Yuba City can also seen in this diurnal analysis (Figure 4-4) of concentrations at Yuba City for days that the standard was exceeded at Yuba City. The high nighttime concentrations at Yuba City reflect the diurnal pattern of residential wood burning, separate from the patterns exhibited by commuter traffic, which would show a decrease after peak commuter hours. As previously noted, the majority of exceedance days occur during periods of stagnant or low wind, keeping pollutants close to the emission source, in this case, Yuba City and Marysville.

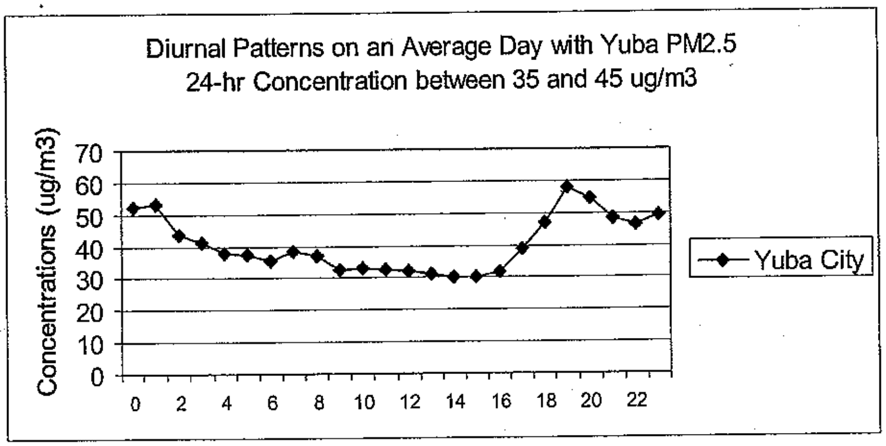

Figure 4-4: Diurnal PM2.5 Patterns at Yuba City

Summary

In response to the two primary concerns of the U.S. EPA, ARB believes that the urban area of Yuba City/Marysville encompasses the population exposed to the high PM2.5 concentrations represented by the Yuba City site, and that the remainder of the Sutter and Yuba Counties do not contribute significantly to PM2.5 exceedances in the combined Yuba City/Marysville urban area.

The combined Cities of Yuba City/Marysville, which encompass the majority of the urban population in the Counties of Sutter and Yuba, is the only site that violates the new PM2.5 standard. ARB analysis continues to support that violations in Yuba City/Marysville are due to localized wood smoke emissions. Filter analysis shows that regional background ammonium nitrate is not sufficient to cause violations of the standard. Regional contributions of ammonium nitrate will be decreasing due to already adopted State-wide controls. Over the next ten years, these controls will reduce State-wide NOx emissions by 28%.

While U.S. EPA has used the argument that increased VMT across the county is a factor in a county-wide nonattainment area, we disagree. As noted above, the primary problem is wood smoke, which affects the localized Yuba City/Marysville urban core.

Therefore, ARB continues to supports our original recommendation of a focused nonattainment area for Yuba City/Marysville. Similar to our recommendation for the City of Calexico, we believe that the combined Yuba City/Marysville sphere of influence may be an appropriate boundary. We are working with local agencies to obtain maps to document this area.

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    - New Jersey: .../rec/letters/02_NJ_EPAMOD.pdf
  - Region 4: www.epa.gov/pmdesignations/2006standards/rec/region4.htm
    - Tennessee: .../rec/letters/04_TN_EPAMOD.pdf

Attachment H

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

THE ADMINISTRATOR

JAN 1 4 2009

Mr. Paul R. Cort
Earthjustice
426 17th Street, 5th Floor
Oakland, California 94612

Dear Mr. Cort:

This letter is in response to your July 15, 2008, Petition for Reconsideration and request for a stay on behalf of the Natural Resources Defense Council (NRDC) and Sierra Club (SC) related to the U.S. Environmental Protection Agency's (EPA's) final rule titled "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)," which was published in the *Federal Register* on May 16, 2008, and effective on July 15, 2008. The specific provisions for which you requested reconsideration include (1) EPA's transition schedule and requirements for Prevention of Significant Deterioration (PSD) programs in State Implementation Plan (SIP)-approved states; (2) EPA's grandfathering provisions concerning use of the Particulate Matter Less Than 10 Micrometers (PM_{10}) surrogate policy contained in the regulations governing the federal PSD permitting program; (3) EPA's transition period for condensable particulate matter (CPM) emissions; and (4) EPA's preferred interpollutant trading ratios under the nonattainment NSR program. Due to the limited resources of the Agency, and for the reasons stated previously in support of the rule and as explained further below, EPA denies this petition for reconsideration and request for a stay.

The NRDC and SC petition requires EPA to consider the staff time and other resources that would be expended to reconsider this final rule in light of the many responsibilities of the Agency and the limited resources available to the Agency. EPA's conclusion is that the resources that would be required to complete the reconsideration process if the Agency granted your petition are more appropriately used on other matters.

Having considered your arguments with respect to each of the provisions for which you request reconsideration, EPA concludes that they do not demonstrate a need for reconsideration, for the reasons stated previously in support of the rule and as explained further below.

Transition Period for PSD Programs in SIP-approved States

In its petition, NRDC and SC claim that in our final rule we included new requirements governing the way in which states with SIP-approved PSD programs will come into compliance with the new PSD rules for $PM_{2.5}$ that are unlawful and arbitrary. The new PSD rules require states to submit revised programs within three years from the publication of amended requirements in the *Federal Register* in accordance with 40 CFR 51.166(a)(6)(i). During the interim period prior to EPA approval of the revised rules, states may continue to implement the PM_{10} surrogate policy as a means of satisfying the new requirements for $PM_{2.5}$.

Consistent with past practice, we believe that it is reasonable to allow states up to three years to revise and submit SIP revisions containing the new requirements for the $PM_{2.5}$ PSD program, while allowing states the opportunity to rely on the PM_{10} surrogate policy in the interim if it is necessary to do so. Reconsideration is not warranted because the public had notice of the potential that EPA would give states this amount of time to submit SIP revisions. The three-year period within which states must adopt the new $PM_{2.5}$ requirements into SIP-approved programs is provided by the pre-existing PSD rules to allow states to revise their own regulations to reflect newly amended requirements. As stated in the May 16, 2008, preamble, "This rule follows our established approach for determining when States must adopt and submit revised SIPs following changes to the NSR regulations, but does not revise otherwise applicable SIP submittal deadlines." 73 FR 28321, 28341. The May 16, 2008, rule requires revision to the initial "infrastructure" SIPs that EPA required states to submit within three years of the promulgation of the $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS). Thus, the deadline in section 110(a)(1) of the Act does not apply to the SIP revisions submitted in response to the May 16, 2008, rule. The Act does not specifically address the timeframe by which states must submit SIP revisions. Nevertheless, we looked to section 110(a)(1) of the Act to guide our development of the previous rule that allows up to a 3-year SIP development period for states to incorporate new or amended PSD program requirements.

Petitioners' recommendation that upon reconsideration EPA should impose new $PM_{2.5}$ requirements under the existing federal PSD program (40 CFR 52.21) for all states until adequate SIP revisions have been approved fails to account for the time required to legally act to disapprove all affected state programs and undertake the necessary rulemaking to begin implementation of federal PSD for $PM_{2.5}$. Many states have already indicated that they have the general authority to regulate $PM_{2.5}$ under their existing SIPs even though specific regulatory changes are needed to fully implement the program in accordance with EPA's newly amended rules.

Use of the PM_{10} surrogate policy does not "waive" or "exempt" sources from complying with the statutory requirements; states with existing authority to implement the new $PM_{2.5}$ program will not need to continue implementing the PM_{10} surrogate policy. The surrogate policy remains in place to provide states lacking clear authority in state law to directly regulate $PM_{2.5}$ with the ability to issue permits satisfying the $PM_{2.5}$ requirements without unnecessary delay. As we explained in the May 16, 2008, preamble, "PM_{10} will act as an adequate surrogate for $PM_{2.5}$ in most respects, because all new major sources and major modification that would trigger PSD requirements for $PM_{2.5}$ would also trigger PM_{10} requirements because $PM_{2.5}$ is a subset of PM_{10}." 73 FR 28321, 28341. Nevertheless, we disagree with your contention that "The new transition scheme purports to allow source [sic] to be constructed or expanded even if they result in long-term contributions to violations of the $PM_{2.5}$ NAAQS."

We emphasize that the continued use of the PM_{10} surrogate policy is not mandatory, and case-by-case evaluation of the use of PM_{10} in individual permits is allowed to determine its adequacy of as a surrogate for $PM_{2.5}$. If, under a particular permitting situation, it is known that a source's emissions would cause or contribute to a violation of the $PM_{2.5}$ NAAQS, we do not believe that it is acceptable to apply the PM_{10} surrogate policy in the face of such predicted violation. Accordingly, each permit that relies on the PM_{10} surrogate policy to satisfy the new $PM_{2.5}$ requirements is subject to review as to the adequacy of such presumption.

Continuation of PM_{10} Surrogate Policy for Certain Pending Permit Applications Under the Federal PSD Program ("Grandfathering Provision")

NRDC and SC contend that our policy of allowing sources with complete applications submitted prior to the July 15, 2008, effective date of the federal PSD regulations at 40 CFR 52.21 to continue relying upon the PM_{10} surrogate policy is unlawful and arbitrary. Your contention was in part that we failed to present this grandfathering provision and accompanying rationale to the public for comment, and also that the Clean Air Act (Act) provides no authority for EPA to ground the grandfathering provision on the date of a source's permit application. You stated that upon reconsideration we "must require that $PM_{2.5}$ be addressed in all permits for sources that did not commence construction before the effective date of the $PM_{2.5}$ NAAQS." Your approach would require that we retroactively review all permits issued since the effective date of the $PM_{2.5}$ NAAQS, i.e., either July 18, 1997 – the date of the original $PM_{2.5}$ NAAQS, or October 17, 2006 – the date we revised the original $PM_{2.5}$ NAAQS. We do not consider this the best use of limited agency resources.

With regard to the petition's premise that the Act does not authorize EPA to grandfather sources on the basis of a complete application, we disagree. Section 168(b) of the Act provides for certain grandfathering based on a commence construction date, but says nothing – either explicitly or implicitly – about whether other grandfathering may occur or what criteria should be applied in allowing for additional grandfathering by regulation. Moreover, we believe that a decision to re-evaluate sources already grandfathered would unnecessarily disrupt state permitting programs by requiring such permits to be re-evaluated for impacts on the $PM_{2.5}$ NAAQS.

Even if we were to consider eliminating the new grandfathering provision that became effective on July 15, 2008, it could be of little consequence because we have determined that only nine sources actually submitted applications relying on the PM_{10} surrogate policy prior to July 15, 2008, such that they fall within the grandfather provision. Of these, interested persons submitted comments on the use of the surrogate policy with respect to only six of these applications. Moreover, we believe that control technologies qualifying as Best Available Control Technology (BACT) for PM_{10} are likely in many cases to serve as BACT for $PM_{2.5}$ as well.

Finally, as we noted above, the use of the surrogate policy for the sources grandfathered under the federal PSD program does not "waive" or "exempt" sources from complying with statutory requirements; rather, it presumes that assessing control technologies and modeling air quality impacts for PM_{10} is an effective means of fulfilling those statutory requirements for $PM_{2.5}$ as well as for PM_{10} during the transition period being allowed.

Condensable Particulate Matter Emissions

NRDC and SC claim that our decision in the final NSR rule to allow states to exclude CPM from NSR applicability determinations and emissions control requirements until January 1, 2011, is unlawful and arbitrary. You further note that we did not propose such exclusion for public review and comment.

The final provisions on condensable particulate matter emissions were not adopted without notice, as you have claimed. As discussed in the notice of proposed rulemaking, the states and EPA have not consistently applied the NSR program to CPM. The final rule merely deferred the effective date of the proposed action and preserved the status quo in the interim – requiring continued enforcement of those SIPs and permits that clearly address CPM. Our decision in the final rules to allow states that have not previously addressed CPM to continue to exclude CPM during a transition period is the direct response to comments we received questioning whether available test methods and modeling techniques were reliable enough to support a requirement that all states immediately begin addressing CPM as originally proposed. See 73 FR at 28,335 (discussing comments and EPA's response).

The transition period is temporary, and the total time allowed could be shortened in conjunction with a faster-than-anticipated rulemaking for new or revised CPM test methods. Also, as discussed above, states with SIP provisions requiring CPM to be addressed are not allowed to exclude CPM, and other states at their discretion have opted to include CPM in their permit processes. In addition, some sources have elected to include CPM in their estimates of potential emissions in order to avoid possible delays (resulting from adverse public comment) in the issuance of needed permits.

Even where sources are not being required to address CPM, control technologies being selected as BACT for PM_{10} and $PM_{2.5}$ are capable of controlling CPM.

Interpollutant Trading Ratios

Finally, NRDC and SC claim that our decision to include preferred interpollutant trading ratios to facilitate the interpollutant trading of emissions offsets under the NSR program is unlawful and arbitrary. NRDC and SC assert that such ratios were developed and finalized without public input. Moreover, you claim that the Act does not permit interpollutant offset trading.

We believe the Act contains the necessary authority for us to regulate precursor emissions, including allowing offset trading of such precursors. As defined under section 302(g) of the Act, the term "air pollutant" "includes any precursors to the formation of any air pollutant, to the extent that the Administrator has identified such precursor or precursors for the particular purpose for which the term 'air pollutant' is used."

The rule does not require use of the preferred ratios, and public notice and comment is built into the process through which the interpollutant trading program is incorporated into the state NSR program. That is, each SIP revision containing an interpollutant trading program, including the preferred offset ratios or any other ratios independently adopted by the state, must be subjected to public notice and comment as part of the EPA approval process for the SIP (in addition to the public process required as part of the state's adoption of such provisions in their own rules.) Under 40 CFR part 51 appendix S, the interim authority for issuance of major permits in nonattainment areas by states, states may allow $PM_{2.5}$ precursor offsets "if such offsets comply with an interprecursor trading hierarchy and ratio approved by the Administrator." See new section IV.G.5 of appendix S. Moreover, each permit which relies on the interpollutant trading program to allow precursor emissions to offset new $PM_{2.5}$ emissions must undergo public review prior to approval and issuance.

Request for Stay of Implementation

NRDC and SC also request that EPA stay implementation of the final rule pending reconsideration or the rule. Because EPA is denying the petition for reconsideration in its entirety, a stay pending reconsideration is unnecessary.

We appreciate your comments and interest in this important matter.

Sincerely,

Stephen L. Johnson

cc: Mr. David S. Baron, Earthjustice
Mr. Timothy J. Ballo, Earthjustice

-----Original Message-----
From: PERLMUTTER, Michael [mailto:mperlmutter@audubon.org]
Sent: Thursday, January 22, 2009 12:52 PM
To: Weyman Lee
Cc: 'VACATIONPOMBO@aol.com'; TAYLOR, Dan; 'rscimino@earthlink.net'; 'evcormier@sbcglobal.net'
Subject: deny Prevention of Significant Deterioration permit for proposed Russell City Energy Center near sensitive Hayward Shoreline

Dear Mr. Lee,

Please consider the attached comments, on behalf of Audubon California, regarding the Prevention of Significant Deterioration permit for the proposed Russell City Energy Center in Hayward, CA.

Sincerely,

Mike Perlmutter

Bay Area Conservation Coordinator

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January 22, 2009

Weyman Lee
P.E.
Senior Air Quality Engineer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

RE: deny Prevention of Significant Deterioration permit for proposed Russell City Energy Center near sensitive Hayward Shoreline

Dear Mr. Lee:

On behalf Audubon California's nearly 100,000 members and supporters and our eight local Bay Area chapters, I write to request denial of a Prevention of Significant Deterioration permit for the proposed Russell City Energy Center, sited near sensitive endangered wetland species habitat along the Hayward shoreline in Hayward, California. Thus far, environmental review by the California Energy Commission (Commission) for the project has inadequately addressed potential environmental impacts to sensitive species and a full Biological Opinion by the United States Fish & Wildlife Service is required to ensure protection of sensitive species and their habitats that would be significantly and negatively impacted by the proposed project.

The Commission's 2002 Final Staff Assessment of the proposed Russell City Energy Center outlined numerous environmental impacts of the proposed project, requisite mitigation, and additional environmental review and permitting required by the Service, US Army Corps of Engineers, and the San Francisco Bay Regional Water Quality Control Board. These reviews are intended to provide additional guidance to ensure the maximum protection of sensitive biological resources that include threatened and endangered species, air and water quality, and sensitive wetland habitats. Since Calpine's petition to relocate the proposed power plant 1,300 feet away from its original proposed siting, staff reports by the Commission indicate that some of the originally mandated mitigation, as well as all environmental review and permitting by the Service, US Army Corps of Engineers, and the San Francisco Bay Regional Water Quality Control Board are no longer required due different conditions at the amended site location.

Although the amendment to the proposed project location and some design changes to the proposed project will mitigate some impacts identified in the Commission's 2002 staff report on the proposed Russell City Energy Center, other impacts remain and warrant further mitigation and biological review by the Service in the form of a Biological Opinion as originally called for in the Commission's 2002 report. According to the 2002 report background noise increases caused by 24 hour/day, 7 day/week operation of the proposed plant could "directly impact sensitive species breeding areas and wildlife using the surrounding areas." The report then went on to detail some of the possible impacts. Although the proposed project site has been moved by 1300 feet, the proposed project still remains nearby sensitive habitat. Warehouses situated between sensitive marsh habitat and the new proposed project location could, according to the Commission's 2007 report, "funnel the noise to the sensitive area without achieving the fully anticipated decrease in noise levels." Given the potential negative impacts caused by construction and operational noise of the proposed power plant omission of a Biological Opinion by the Service is a tremendous oversight, and could lead to permitting of activities that cause harm to sensitive species and habitats.

Neither the 2002 nor the 2007 Commission reports on the proposed Russell City Energy Center addressed the terrestrial habitat impacts of nitrogen deposition originating from nitrogen oxides emitted as air pollution from the proposed power plant. Recent studies by Dr. Stuart Weiss describe the habitat conversion effects of increased nitrogen deposition on sensitive plant habitats. Many of the San Francisco Bay Area's soils are nutrient limited. Native plants indigenous to the Bay Area are adapted to these nutrient depauparate conditions while many species of invasive plants are limited by local soil conditions. Increased nitrogen inputs from aerial pollution sources can modify soil conditions in ways that make invasive plants more competitive and facilitate type conversion of habitat from native to exotic plant-dominated systems.

The Hayward shoreline is a significant element of the San Francisco Bay South Important Bird Area and would be impacted by construction and operation of the proposed Russell City Energy Center. Important Bird Areas are part of a global and international network of bird conservation, representing the most critical habitats for bird populations worldwide. On behalf of the birds, other wildlife, and habitats of the Hayward Shoreline, Audubon California respectfully calls for the careful evaluation all environmental impacts of the Russell City Energy Center prior to proceeding any further with the process.

Thank you for your consideration of our views.

Sincerely,

Mike Perlmutter
Bay Area Conservation Coordinator, Audubon California

CC:

Rich Cimino, Ohlone Audubon Society
Ernie Pacheco, Citizens Against Pollution
Dan Taylor, Audubon California

The enhancement of local air pollution by urban CO_2 domes

Mark Z. Jacobson

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March 21, 2009

Data suggest that domes of high CO_2 levels form over cities. The effects of such domes on local temperatures and water vapor, and the resulting feedbacks to air pollution and health have never been examined. Here, such effects are studied for Los Angeles and California as a whole. It is found that local CO_2 emissions, in isolation, cause increases in local ozone and particulate matter. As such, reducing locally-emitted CO_2 will reduce local air pollution mortality even if CO_2 in adjacent regions is not controlled. This result contradicts the basis for all air pollution regulations worldwide, none of which considers controlling local CO_2 based on its local health impacts. It also suggests that the underlying assumption of the "cap and trade" policy, that CO_2 impacts are the same regardless of where emissions occur, is incorrect.

1. Introduction

Although CO_2 is generally well-mixed in the atmosphere, data indicate that its mixing ratios are higher in urban areas than in the background air, resulting in *urban CO_2 domes* (*1-4*). Measurements in Phoenix, for example, indicate that peak CO_2 levels in the city center are 75% higher, mean levels in the city center are 38-43% higher, and mean levels in the commercial sector are 23-30% higher than in surrounding rural areas (*1*).

Many studies have examined the impact on air pollution of changes in global greenhouse gases (*5-17*). However, no study has isolated the impact of locally-emitted CO_2 on local air pollution, health, or climate, through the creation of CO_2 domes. The issue is important, since if only changes in global-scale well-mixed CO_2 affect local air pollution, local air pollution due to CO_2 can be reduced only by reducing CO_2 emissions on a large scale (nationally or internationally). However, if locally-emitted CO_2 in isolation increases local air pollution, cities, counties, states, and small countries can reduce air pollution health problems by reducing their own CO_2 emissions, regardless of whether other air pollutants are reduced simultaneously.

2. Methodology

For this study, the nested global-through-urban 3-D model, GATOR-GCMOM was use to examine the effects of locally-emitted CO_2 on local climate and air pollution on two scales, California as a whole and the Los Angeles basin. The model and numerous comparisons with data have been described in detail in publications over the past 16 years, including several recent ones (*16-21*). Additional comparisons are shown here.

Three pairs of simulations were run: one pair nested from the globe to California for one year and two pairs nested from the globe to California to Los Angeles, each for three months (Aug-Oct; Feb-Apr). The resolutions of the global, California, and Los Angeles domains were 4° SN x 5° WE, 0.20° SN x 0.15° WE, and 0.45° SN x 0.05° WE, respectively. The global domain included 47 sigma-pressure layers up to 0.22 hPa (≈60 km), with very high resolution (15 layers) in the bottom 1 km. Such high vertical resolution was necessary to obtain the accurate ozone predictions shown in Fig. 1. The nested regional domains included 35 layers exactly matching the global layers up to 65 hPa (≈18 km).

Each simulation pair consisted of a baseline simulation and a sensitivity simulation in which only anthropogenic CO_2 emissions ($emCO_2$) were removed from the finest domain. Initial ambient CO_2 was the same in all domains of both simulations and $emCO_2$ was the same in the parent domains of both simulations. As such, all resulting differences were due solely to locally-emitted (in the finest domain) CO_2.

3. Results

Figure 1 compares modeled O_3, PM_{10}, and CH_3CHO from August 1-7 of the baseline (with $emCO_2$) and sensitivity (no $emCO_2$) simulations from the Los Angeles domain with paired-in-time-and-space data. The model was run without data assimilation or model spinup, thus the results indicate the ability of the model to predict air pollution hour by hour at exact locations. The comparisons indicate very good agreement with respect to ozone in particular. They also indicate that $emCO_2$ increased O_3, PM_{10}, and CH_3CHO almost immediately, during both day and night. The reasons for the increases are examined further, first with respect to California, then Los Angeles.

Figure 2a compares annually-averaged modeled spatial differences in ambient CO_2 in California obtained by subtracting no-$emCO_2$ results from the baseline results. The modeled CO_2 domes over Los Angeles, the San Francisco Bay Area, and parts of the Central Valley are evident and consistent with expectations from the measurement studies previously discussed. The largest annually-averaged CO_2 increase (5%, or 17.5 ppmv) was lower than observed CO_2 dome increases in cities (*1*) since the resolution of the California domain was coarser than the resolution of measurements. As shown shortly, an increase in model resolution for Los Angeles increases the magnitude of the largest CO_2 increase and the resulting effects on air pollution. Whereas the population-weighted (PW) and domain-averaged (DA) increases in surface CO_2 due to $emCO_2$ were 7.4 ppmv and 1.3 ppmv, respectively, the corresponding increases in column CO_2 were 6.0 g/m^2 and 1.53 g/m^2, respectively, indicating that changes in column CO_2 were spread more horizontally than were changes in surface CO_2. This is because local $emCO_2$ starts mixing with the larger scale soon after emissions, but the losses are quickly replaced with more local CO_2 emissions.

The local increases in CO_2 in California increased the PW air temperature by about 0.0063 K, more than it changed the domain-averaged air temperature (+0.00046) (Fig. 2b). Thus, local CO_2 domes had greater temperature impacts where the CO_2 was emitted and where people lived than they did on the domain average. This result holds true for the effects of $emCO_2$ on column water vapor (Fig. 2c - PW: +4.3 g/m^2; DA: +0.88 g/m^2), ozone (Fig. 2d – PW: +0.06 ppbv; DA: +0.0043 ppbv), $PM_{2.5}$ (Fig. 2f – PW: +0.08 μg/m^3; DA: -0.0052 μg/m^3), PAN (Fig. 2h – PW: +0.002 ppbv; DA: -

0.000005 ppbv) and particle nitrate (Fig. 2i – PW: +0.030 μg/m^3; DA: +0.00084 μg/m^3), among many other parameters.

Figure 3 elucidates correlations between changes in local ambient CO_2 caused by changes in emCO_2 and changes in other parameters. The figure shows that modeled temperatures, water vapor, ozone, and $PM_{2.5}$ increased more in the annual average in grid cells with larger ambient CO_2 increases than in cells with smaller ambient CO_2 increases. In other words, increases in ozone and $PM_{2.5}$ were correlated spatially with local CO_2 increases. Figure 2 further shows that increases in ozone were correlated spatially with increases in temperature and water vapor, a result consistent with (*16*), which found that higher temperature and water vapor increased ozone more in locations where ozone was already high due to the temperature and water-vapor-dependence on chemical reactions producing ozone.

The reasons for higher $PM_{2.5}$ resulting from higher CO_2 are more complex. Figure 2 shows that $PM_{2.5}$ correlated slightly negatively (R=0.017) with increases in temperature but more strongly positively (R=0.23) with increases in water vapor. Higher temperatures tended to decrease $PM_{2.5}$, in part by increasing vapor pressures thus PM evaporation and in part by enhancing precipitation in some locations. Some of the $PM_{2.5}$ decreases due to higher temperatures were offset by increases in biogenic organic emissions due to higher temperatures and oxidation of such organics to organic PM. But in California, biogenic emissions are much lower than the southeast U.S., so this factor was not so significant. Some of the $PM_{2.5}$ decreases were also offset by slower winds caused by enhanced boundary-layer stability from CO_2. While higher temperatures slightly decreased $PM_{2.5}$, higher water vapor due to emCO_2 increased $PM_{2.5}$ by increasing the liquid water content of aerosols, increasing the dissolution of gases such as nitric acid and ammonia, forming more particle nitrate (Fig. 2i) and ammonium. Also, higher ozone caused by higher water vapor increased oxidation rates of organic gases to organic PM. Since $PM_{2.5}$ increased overall due to emCO_2, the water vapor effect exceeded the temperature effect.

Health effect rates (y) due to ozone and $PM_{2.5}$ in each model domain during each simulation were determined from

$$y = y_0 \sum_i \left\{ P_i \sum_t \left(1 - \exp\left[-\beta \times \max\left(x_{i,t} - x_{th}, 0\right)\right]\right) \right\} \quad (1)$$

where $x_{i,t}$ is the mixing ratio or concentration in grid cell i at time t, x_{th} is the threshold value below which no health effect occurs, β is the fractional increase in risk per unit x, y_0 is the baseline health effect rate, and P_i is the grid cell population. Table 1 provides values of P (summed over each domain), β, y_0, and x_{th}.

Application of Equation 1 resulted in ~13 (6-19) additional ozone-related deaths/year due to local CO_2 emissions in California (Fig. 2e), or 0.3% above the baseline 4600 (2300-6900) deaths/year (Table 1). The higher particulate matter due to local CO_2 contributed another ~39 (13-60) deaths/year in California (Fig. 2g), 0.2% above the baseline death rate of 22,500 (5900-42,000) deaths/year. Changes in cancer due to emCO_2 were relatively small (Table 1).

Simulations for Los Angeles echo results for California as a whole but allow for a higher-resolution and more accurate picture of changes due to CO_2. The Feb-Apr panels in Fig. 4 indicate that the CO_2 dome that formed over Los Angeles peaked at about 34 ppmv, twice as high as over the coarser-resolution California domain. The column difference indicates a clear spreading of the dome over a larger area than the surface dome. In both Feb-Apr and Aug-Oct, emCO_2 enhanced PW ozone and $PM_{2.5}$, increasing mortality (Fig. 4, Table 1) and other health effects (Table 1). The causes of such increases, however, differed somewhat with season. From Feb-Apr, emCO_2 increased surface temperatures and water vapor over the Los Angeles basin (Fig. 4). This slightly enhanced ozone and $PM_{2.5}$, but the increase in the land-ocean temperature gradient also increased sea-breeze wind speeds, increasing resuspension of road and soil dust and moving particulate matter more to the eastern basin. From Aug-Oct, emCO_2 increased temperatures aloft, increasing the land-sea temperature gradient and wind speed aloft, increasing the flow of moisture from the ocean to land aloft, increasing water vapor and clouds over land, decreasing surface solar radiation, causing a net decrease in local ground temperatures and UV radiation but a net increase in water vapor at all altitudes due to the vertical diffusion of water vapor aloft to the surface. The higher water vapor triggered greater ozone formation and a higher relative humidity, which increased aerosol particle swelling, allowing an increase in gas growth onto aerosols, and reduced particle evaporation. In sum, the net effect of emCO_2 was to increase ozone and $PM_{2.5}$ and their corresponding health effects in both seasons, increasing air pollution death rates in California and Los Angeles by about 50-100 per year (Fig. 4, Table 1). Death rates for Los Angeles were similar or higher than those for California due to the greater accuracy of higher resolution (Los Angeles) simulations, as shown in Table 2 of (*18*); thus, these results are likely to be conservative for California as a whole.

The California mortality increase compares with a U.S. death rate increase of about 1000/yr per 1 K temperature rise due to globally-emitted anthropogenic CO_2, with about 300 deaths/yr occurring in California (*16*), which has 12% of the U.S. population. The greater death rates in California versus the rest of the U.S. are due to the fact that higher temperatures and water vapor due to CO_2 enhance air pollution the most where it is already high, and California has more than half of the top 10 most polluted cities in the U.S.

5. Implications

Worldwide, emissions of many pollutants (e.g., NO_x, HCs, CO, PM) that cause local air pollution health problems are regulated. The few CO_2 emission regulations proposed to date have been justified based on the large-scale climate effects that such emissions cause and the feedback of such large-scale changes to sea levels, water supply, and global air pollution. However, no regulation of CO_2 has been proposed based on the potential impact of locally emitted CO_2 on local air pollution as such effects have been assumed not to exist (*22*). The result here suggests that reducing local CO_2 will reduce local air pollution mortality by 50-100 deaths/yr in California alone even if CO_2 in adjacent regions is not controlled. Thus, CO_2 emission controls are justified on the same grounds that NO_x, HC, CO, and PM emission regulations are justified. Results further imply that the assumption behind the policy of "cap and trade," namely that CO_2 emissions in one location have the same impact as CO_2 emissions in another, is incorrect, as CO_2 emissions in populated cities have significantly larger impacts on health than do CO_2 emissions in unpopulated areas. As such, implementation of CO_2 cap and trade, if done, should consider the location of emissions to avoid additional health damage.

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30. Support came from the U.S. Environmental Protection Agency grant RD-83337101-O, NASA grant NX07AN25G, and the NASA High-End Computing Program.

Figure Captions

Figure 1. (a) Paired-in-time-and-space comparisons of modeled baseline (solid lines), modeled no-emCO$_2$ (dashed lines), and data (dots) for ozone, sub-10-μm particle mass, and acetaldehyde from the Los Angeles domain for August 1-7, 2006. Data from (*23*).

Figure 2. Modeled annually averaged difference for several parameters when two simulations (with and without emCO$_2$) were run. The numbers in parentheses are population-weighted changes.

Figure 3. Scatter plots of paired-in-space one-year-averaged changes between several parameter pairs, obtained from all near-surface grid cells of the California domain. Also shown is an equation for the linear fit through the data points in each case.

Figure 4. Same as Fig. 2., but for the Los Angeles domain and for Feb-Apr and Aug-Oct. Also shown are scatter plots for Aug-Oct similar to those for Fig. 3.

Table 1. Summary of locally-emitted CO_2's ($emCO_2$) effects on cancer, ozone mortality, ozone hospitalization, ozone emergency-room (ER) visits, and particulate-matter mortality in California. Results are shown for the with-$emCO_2$ emissions simulation ("Base") and the difference between the base and no $emCO_2$ emissions simulations ("Base minus no-$emCO_2$") for California and Los Angeles. The domain summed populations in the Los Angeles and California domains were 17.268 million and 35.35 million, respectively. All mixing ratios and concentrations are near-surface values weighted spatially by population. Los Angeles results were an average of Feb-Apr and Aug-Oct results.

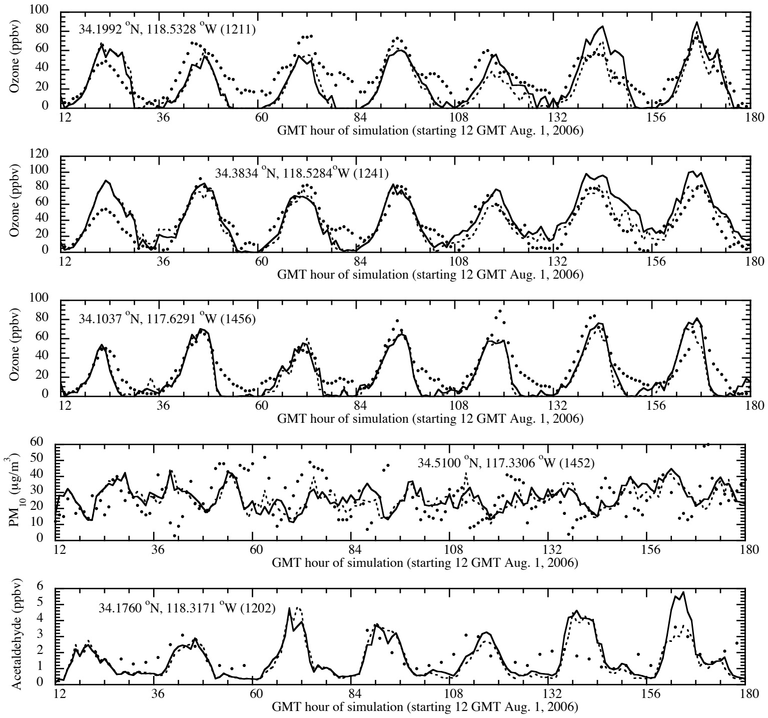
	Annual base Calif.	Base minus no $emCO_2$ Calif.	Annual Base LA	Base minus no $emCO_2$ LA
Ozone ≥ 35 ppbv (ppbv)	47.4	+0.060	44.7	+0.12
$PM_{2.5}$ ($\mu g/m^3$)	50.0	+0.08	36	+0.29
Formaldehyde (ppbv)	4.43	+0.0030	4.1	+0.054
Acetaldehyde (ppbv)	1.35	+0.0017	1.3	+0.021
1,3-Butadiene (ppbv)	0.11	-0.00024	0.23	+0.0020
Benzene (ppbv)	0.30	-0.00009	0.37	+0.0041
Cancer				
USEPA cancers/yr+	44.1	0.016	22.0	+0.28
OEHHA cancers/yr+	54.4	-0.038	37.8	+0.39
Ozone health effects				
High O_3 deaths/yr*	6860	+19	2140	+20
Med. O_3 deaths/yr*	4600	+13	1430	+14
Low O_3 deaths/yr*	2300	+6	718	+7
O_3 hospitalizations/yr*	26,300	+65	8270	+75
Ozone ER visits/yr*	23,200	+56	7320	+66
PM health effects				
High $PM_{2.5}$ deaths/yr^	42,000	+60	16,220	+147
Medium $PM_{2.5}$ deaths/yr^	22,500	+39	8500	+81
Low $PM_{2.5}$ deaths/yr^	5900	+13	2200	+22

(+) USEPA and OEHHA cancers/yr were found by summing, over all model surface grid cells and the four carcinogens (formaldehyde, acetaldehyde, 1,3-butadiene, and benzene), the product of individual CUREs (cancer unit risk estimates=increased 70-year cancer risk per $\mu g/m^3$ sustained concentration change), the mass concentration ($\mu g/m^3$) (for baseline statistics) or mass concentration difference (for difference statistics) of the carcinogen, and the population in the cell, then dividing by the population of the model domain and by 70 yr. USEPA CURES are 1.3×10^{-5} (formaldehyde), 2.2×10^{-6} (acetaldehyde), 3.0×10^{-5} (butadiene), 5.0×10^{-6} (=average of 2.2×10^{-6} and 7.8×10^{-6}) (benzene) (www.epa.gov/IRIS/). OEHHA CUREs are 6.0×10^{-6} (formaldehyde), 2.7×10^{-6} (acetaldehyde), 1.7×10^{-4} (butadiene), 2.9×10^{-5} (benzene) (www.oehha.ca.gov/risk/ChemicalDB/index.asp).

(*) High, medium, and low deaths/yr, hospitalizations/yr, and emergency-room (ER) visits/yr due to short-term O_3 exposure were obtained from Equation 1, assuming a threshold of 35 ppbv (*24*). The baseline 2003 U.S. death rate (y_0) was 833 deaths/yr per 100,000 (*25*). The baseline 2002 hospitalization rate due to respiratory problems was 1189 per 100,000 (*26*). The baseline 1999 all-age emergency-room visit rate for asthma was 732 per 100,000 (*27*). These rates were assumed to be the same in each U.S. county, although they vary slightly by county. The fraction increases (β) in the number of deaths from all causes due to ozone were 0.006, 0.004, and 0.002 per 10 ppbv increase in daily 1-hr maximum ozone (*28*). These were multiplied by 1.33 to convert the risk associated with a 10 ppbv increase in 1-hr maximum O_3 to that associated with a 10 ppbv increase in 8-hour average O_3 (*24*). The central value of the increased risk of hospitalization due to respiratory disease was 1.65% per 10 ppbv increase in 1-hour maximum O_3 (2.19% per 10 ppbv increase in 8-hour average O_3), and that for all-age ER visits for asthma was 2.4% per 10 ppbv increase in 1-hour O_3 (*28*) (3.2% per 10 ppbv increase in 8-hour O_3).

(^) The death rate due to long-term $PM_{2.5}$ exposure was calculated from Equation 1. Reference (*29*) provides increased death risks to those ≥30 years of 0.008 (high), 0.004 (medium), and 0.001 (low) per 1 $\mu g/m^3$ $PM_{2.5}$ >8 $\mu g/m^3$ based on 1979-1983 data. From 0-8 $\mu g/m^3$, the increased risks here were assumed =¼ those >8 $\mu g/m^3$ to account for reduced risk near zero $PM_{2.5}$ (*16*). The all-cause 2003 U.S. death rate of those ≥30 years was 809.7 deaths/yr per 100,000 total population.

Figure 1



Ozone (ppbv)
34.1992 °N, 118.5328 °W (1211)
GMT hour of simulation (starting 12 GMT Aug. 1, 2006)
Ozone (ppbv)
34.3834 °N, 118.5284°W (1241)
GMT hour of simulation (starting 12 GMT Aug. 1, 2006)
Ozone (ppbv)
34.1037 °N, 117.6291 °W (1456)
GMT hour of simulation (starting 12 GMT Aug. 1, 2006)
PM10 (μg/m3)
34.5100 °N, 117.3306 °W (1452)
GMT hour of simulation (starting 12 GMT Aug. 1, 2006)
Acetaldehyde (ppbv)
34.1760 °N, 118.3171 °W (1202)
GMT hour of simulation (starting 12 GMT Aug. 1, 2006)

Figure 2

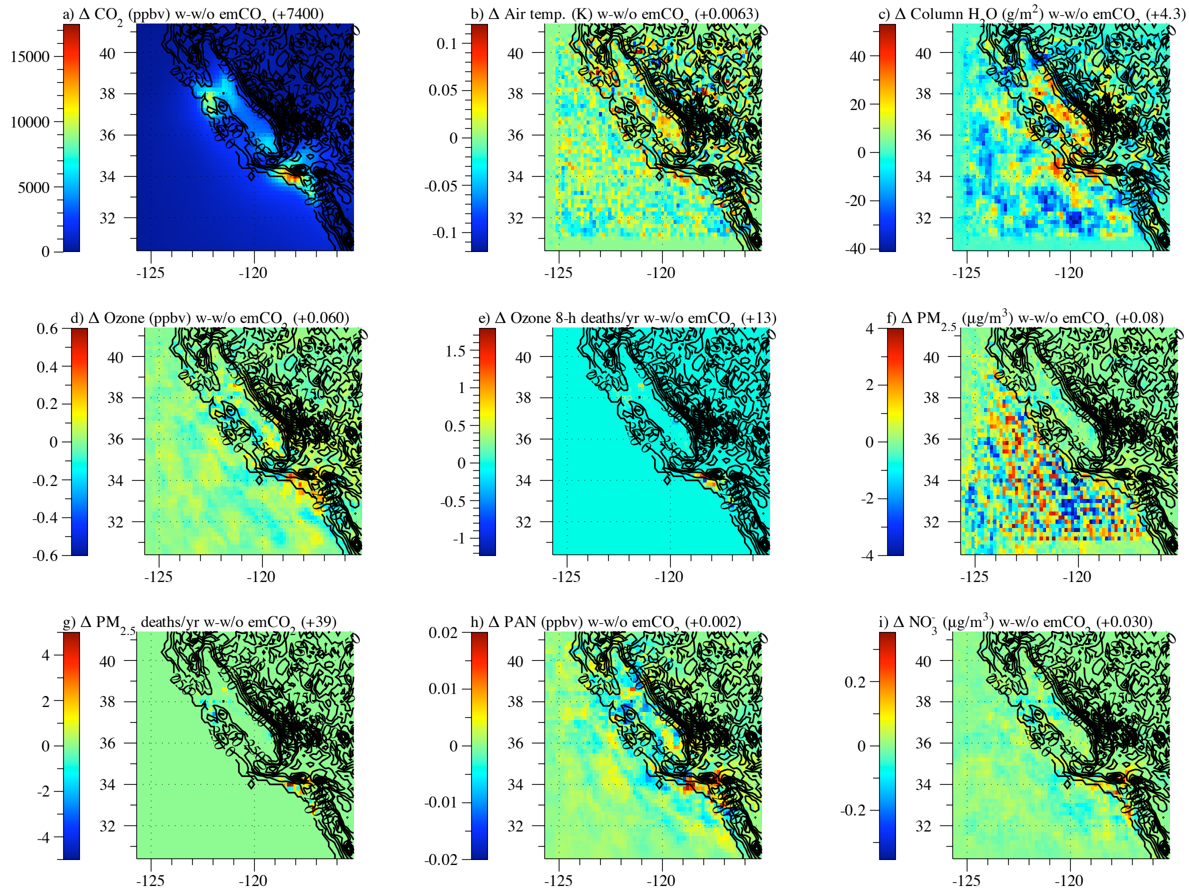

a) Δ CO_2 (ppbv) w-w/o $emCO_2$ (+7400)
b) Δ Air temp. (K) w-w/o $emCO_2$ (+0.0063)
c) Δ Column H_2O (g/m^2) w-w/o $emCO_2$ (+4.3)
d) Δ Ozone (ppbv) w-w/o $emCO_2$ (+0.060)
e) Δ Ozone 8-h deaths/yr w-w/o $emCO_2$ (+13)
f) Δ $PM_{2.5}$ ($\mu g/m^3$) w-w/o $emCO_2$ (+0.08)
g) Δ $PM_{2.5}$ deaths/yr w-w/o $emCO_2$ (+39)
h) Δ PAN (ppbv) w-w/o $emCO_2$ (+0.002)
i) Δ NO_3^- ($\mu g/m^3$) w-w/o $emCO_2$ (+0.030)
-125
-120

Figure 3

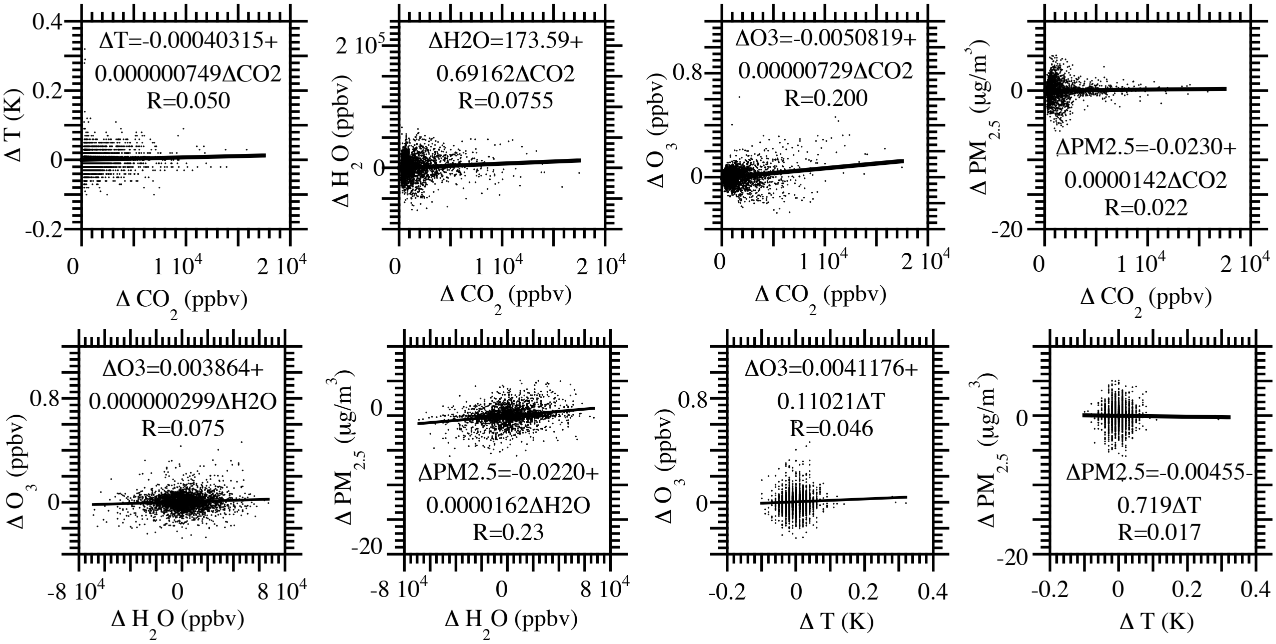
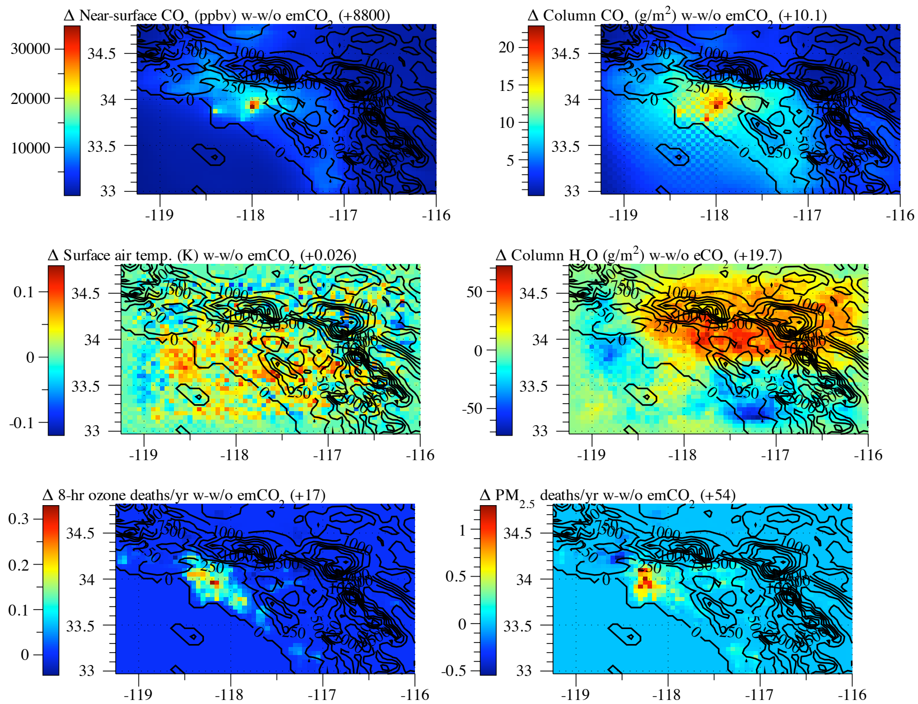
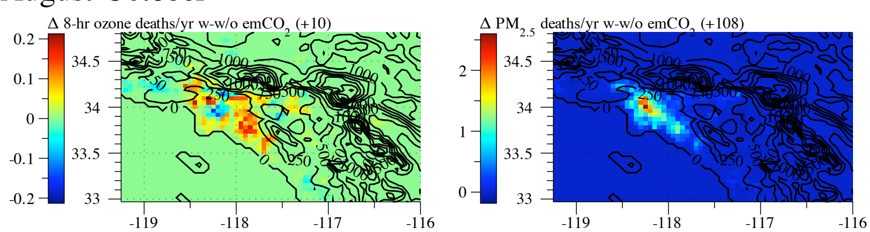

ΔT=-0.00040315+
0.000000749ΔCO2
R=0.050
Δ T (K)
Δ CO2 (ppbv)
ΔH2O=173.59+
0.69162ΔCO2
R=0.0755
Δ H2O (ppbv)
ΔO3=-0.0050819+
0.00000729ΔCO2
R=0.200
Δ O3 (ppbv)
ΔPM2.5=-0.0230+
0.0000142ΔCO2
R=0.022
Δ PM2.5 (μg/m3)
ΔO3=0.003864+
0.000000299ΔH2O
R=0.075
ΔPM2.5=-0.0220+
0.0000162ΔH2O
R=0.23
ΔO3=0.0041176+
0.11021ΔT
R=0.046
ΔPM2.5=-0.00455-
0.719ΔT
R=0.017

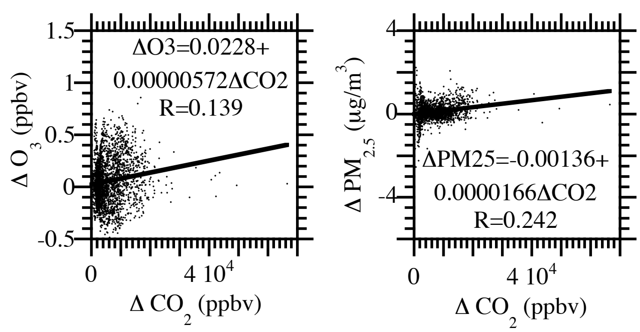
Figure 4

February-April



August-October





Reasons to Not Replace Aging Natural Gas Power Plants

Robert Freehling, CNRCC-ECC, Committee Member, January 21, 2009

San Francisco and other coastal cities have been struggling to shut down their old natural gas power plants. California's aging natural gas plants have a whole laundry list of problems beyond water consumption and destroying sea life. Replacing them with new plants is likely to continue these problems:

• Additional pollution in lower income, disadvantaged neighborhoods

• Air pollution in non-attainment regions; replacing old plants—which now supply only peak energy needs— with new peak power plants, would on average increase nominal efficiency by 19%, which is not enough to address the air pollution and carbon emission problem, especially when you factor in that these plants will be around for decades.

• Nearly all proposals for new plants would operate far more hours than current aging plants, thus burning more fuel and emitting more carbon and criteria pollutants than the existing plants, despite "efficiency" improvements

• 5000 megawatts worth of proposed new natural gas plants in the LA Basin were found in violation of air quality laws (CEQA), and were struck down. Building the plants would require weakening CEQA, which the developers—after defeat in court— have recently tried to do.

• The regulatory and statutory requirement is first to build higher priority (in California called "higher loading order") resources, such as renewables, efficiency and peak demand reduction.

• The CPUC staff has found that if we are to achieve a 33% renewable requirement—as CARB and the Governor have ordered, and the legislature is likely to put into law this year— then all new electricity procurement will need to be renewable.

The assumption that there is "need" for the electricity from all these natural gas plants is also questionable:

1. The retirement of these 19 aging power plants—totaling about 16,000 megawatts— has already been incorporated into the utility long-term procurement plans. The determined balance of procurement needs over the next decade is much smaller than 16,000 megawatts, after mandated renewables, efficiency and demand reduction programs are implemented. Since these plans were approved, new and higher green energy requirements are being adopted.

2. The state today has far more capacity than it needs, including 40,000 mw of natural gas plants, 14,000 mw of hydro, 4,000 mw of nuclear, a few thousand megawatts of renewables, for a total in-state generating capacity of 64,273 mw, according to the state's latest database. http://energyalmanac.ca.gov/powerplants/POWER_PLANTS.XLS

3. In addition, there was 18,170 mw of import capacity as of 2003, http://certs.lbl.gov/pdf/ca-grid-plan.pdf (today it may even be more), for a total conventional power capacity of about 82,443 mw.

4. This compares to the 2006 demand peak of 60,000 mw, which was during an extraordinary day in a 1-in-34-years heat storm. So, as of this point there is at least 22,000 mw of excess capacity.

5. The above counts only conventional power resources. In addition, there are about 4000 megawatts of

backup emergency generators, 400 mw of installed solar, and roughly 2000 mw of peak demand reduction capacity, and other small sources of distributed generation. In total, all California electric system resources today are about 90,000 mw, or 50% more than we need.

6. There are policies in place to increase local solar, add to peak demand reduction programs, new energy efficiency requirements, and increase other distributed clean generation. In sum these represents thousands of more megawatts that are due to come on-line over the next decade. This is all in addition to the requirement to increase renewable energy from 12% to 33%.

7. Another important answer to the question about whether there is an argument for replacing old power plants is: This has been happening on a vast scale. The state has already gone through a major program of building new natural gas power plants. About 16,000 megawatts have been brought on-line over the past decade, while nearly 8000 megawatts of old inefficient natural gas plants were retired.

8. In addition, 3263 megawatts of natural gas plants have been approved and are under construction, due online over the next 2 years.

9. In addition, another 7800 megawatts of natural gas plants have already been approved by the energy commission, but have not been built or are on hold.

10. Construction of natural gas “peaker plants” under 50 mw are not under the jurisdiction of the energy commission, and thus can be added for local reliability without going through the more elaborate licensing process, if they are actually needed (but that should have to be demonstrated, not taken for granted).

For data on CEC power plant approval process status, see:
http://www.energy.ca.gov/sitingcases/all_projects.html

In short, there has been a glut of natural gas power plants approved, built, under construction, and already online. So much capacity has already been approved that there is no conceivable market for that much power, even if we had no requirements for additional renewable energy. We do NOT need more natural gas plants to be approved, as this will undermine the state’s renewable energy commitments and air quality laws.

Requiring a retrofit of those plants that continue operating— to avoid once through cooling— would be recommended in any case; but we do not need a whole new round of natural gas power plants. The best position would be to continue operating existing plants, requiring them to meet air pollution and marine protection standards, and retire them as soon as replacement clean energy resources come on-line.

The urgency should be to build green energy, not a rush to build new natural gas power plants. Building new natural gas plants means a 30 to 50 year commitment to fossil fuel, while the pressure to retire the aging gas plants should be harnessed to assure that California’s promises (and requirements) for renewables, efficiency and conservation are actually fulfilled.

TO: CALIFORNIA-NEVADA REGIONAL CONSERVATION COMMITTEE, SIERRA CLUB CALIFORNIA

FM: ENERGY-CLIMATE COMMITTEE, CNRCC SIERRA CLUB CALIFORNIA

Resolution Opposing New Large Natural Gas Power Plants

Approved January 24, 2008

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Resolution: ***To achieve reductions in greenhouse gas emissions mandated by AB 32 and the Global Warming Solutions Act of 2006, and to meet the 33% Renewable Portfolio Standard by 2020 as the executive order signed by Governor Schwarzenegger requires, Sierra Club California opposes licensing of new natural gas-fired electrical generation power plants (larger than 50 MW) in California. This policy shall not apply to licensing of alternative technologies using natural gas fuel (such as cogeneration plants, renewables with natural gas backup, large fuel cell facilities, and biogas) if they significantly reduce fossil fuel consumption and carbon emissions, and protect air quality.***

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Background

California gets 45% of its electricity from natural gas, making it the state's primary source of electric power and greenhouse gas emissions in the electric sector. Natural gas power plants contribute to local air pollution, especially particulates and VOCs. Current state law requires electric utilities to increase renewable energy to 20% by 2010. The state's Energy Action Plan, the governor's recent executive order and the California Air Resources Board's Climate Protection Plan all call for 33% renewable energy by 2020. A new bill (AB64) would require all utilities to obtain 35% renewable energy by 2020, with a further goal of 50% renewables by 2035. A recent report by staff, California Public Utilities Commission, has stated that if these requirements are to be met, all new electric generation should be renewable. Thus, *large-scale development of new conventional natural gas power plants is not compatible with achieving the state's commitments to renewable energy, climate protection and air quality.*

The California Energy Commission licenses all thermal (heat-driven) power plants over 50 megawatts. Thus this resolution would not apply to smaller power plants and excludes a few categories:
1. Small peaking plants that run relatively few hours per year and that provide local reliability
2. Emergency generators that might run on natural gas
3. Small cogeneration systems that provide efficient power on-site and recycle the waste heat
4. Repowering old plants to increase efficiency

In addition, the policy is not intended to apply in a blanket manner to thermal plants that use alternative technologies or practices that may assist in conversion to a low-carbon energy system, such as cogeneration, backing up renewables with a limited amount of natural gas, solar reformation of natural gas to hydrogen, or use of biogas. It is recommended that the CNRCC direct committees to address these issues with a further policy or guidance document.

See attached paper "Reasons Not to Replace Aging Natural Gas Power Plants" for an explanation of why approval of more natural gas plants will undermine the state's renewable energy commitments and air quality laws.

Arguments For

1. Current state policy requires large increases in renewable energy, rooftop solar, energy efficiency, peak demand reduction; building more natural gas power plants is incompatible with these policies.
2. Natural gas power plants increase air pollution in regions of the state that are non-attainment for air quality, and particularly impact the health of neighborhoods where they are sited.
3. Building more natural gas plants is contrary to achieving California's climate protection goals.
4. The state already has a very large amount of natural gas power.
5. The Energy Commission has permitted so many new natural gas plants that dozens have not even been built due to lack of sufficient demand.
6. There are numerous alternatives for meeting grid reliability than large natural gas plants, including rooftop solar, battery storage, demand reductions, renewably powered peaker plants, etc. that will not contribute to global warming.
7. If the current efficiency requirements are implemented, demand should actually shrink.
8. We need to send a clear message to regulators and lawmakers that the current policy of unrestrained approval and building of more large-scale natural gas power plants is not acceptable.
9. Each additional approved 500 megawatt NG power plant that is built will emit approximately 2 million tons of carbon dioxide (plus other GHGs) for at least thirty years.
10. This is an opportune time to close down coastal natural gas plants that have been killing fish, and replace the air pollution with clean, renewable, non-GHG emitting energy sources.
10. Plants under 50 megawatts, including emergency generators and small peaking plants needed for local reliability, are excluded from this policy.
11. The cost of inaction against global warming will be devastating to California and the world.

Arguments Against

1. The state needs to assure sufficient power to meet growth in demand.
2. Natural gas plants provide grid reliability.
3. Alternatives are not scaling up fast enough.
4. Natural gas is much cleaner than coal.
5. NOx and other criteria emissions from natural gas plants represent a relatively small portion of total pollutants.

Who Has Approved This Resolution?

CNRCC's Energy-Climate Committee, in principle and substance on December 15, 2008.

Strategies and Action Plans:

The Committee envisions that this resolution would position Sierra Club California to lobby for state legislation that would halt the approval of additional new large (> 50 megawatts) natural gas-fired power plants by the California Energy Commission and/or an executive order by the Governor of California that would accomplish the same goal. Current legislation and executive orders do not specifically halt the CEC from approving additional large NG power plants. The CEC is currently reviewing 28 applications for additional power plants, and it will continue to approve nearly all of the applications until legislation or an executive order requires the CEC to halt their approvals. The Committee would seek to incorporate this issue in its 2009 volunteer work plan, would encourage the Club's Sacramento staff to include the issue in its dialogue with CEC and legislators, would seek allies among major environmental groups, and would communicate to state chapters and leaders appropriate talking points and alerts. No extra budget or staff would be required. This resolution would help arm local chapters already involved in opposing proposed superfluous and unneeded natural gas facilities.

###

TO: CALIFORNIA-NEVADA REGIONAL CONSERVATION COMMITTEE, SIERRA CLUB CALIFORNIA

FM: ENERGY-CLIMATE COMMITTEE, CNRCC SIERRA CLUB CALIFORNIA

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PACIFIC ▪ ENVIRONMENT

Protecting the living environment of the Pacific Rim

8 June 2009

Commissioner Jeffrey D. Byron
Commissioner Arthur Rosenfeld
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Re: Avenal Energy, Application for Certification (08-AFC-1)

Dear Commissioners Byron and Rosenfeld,

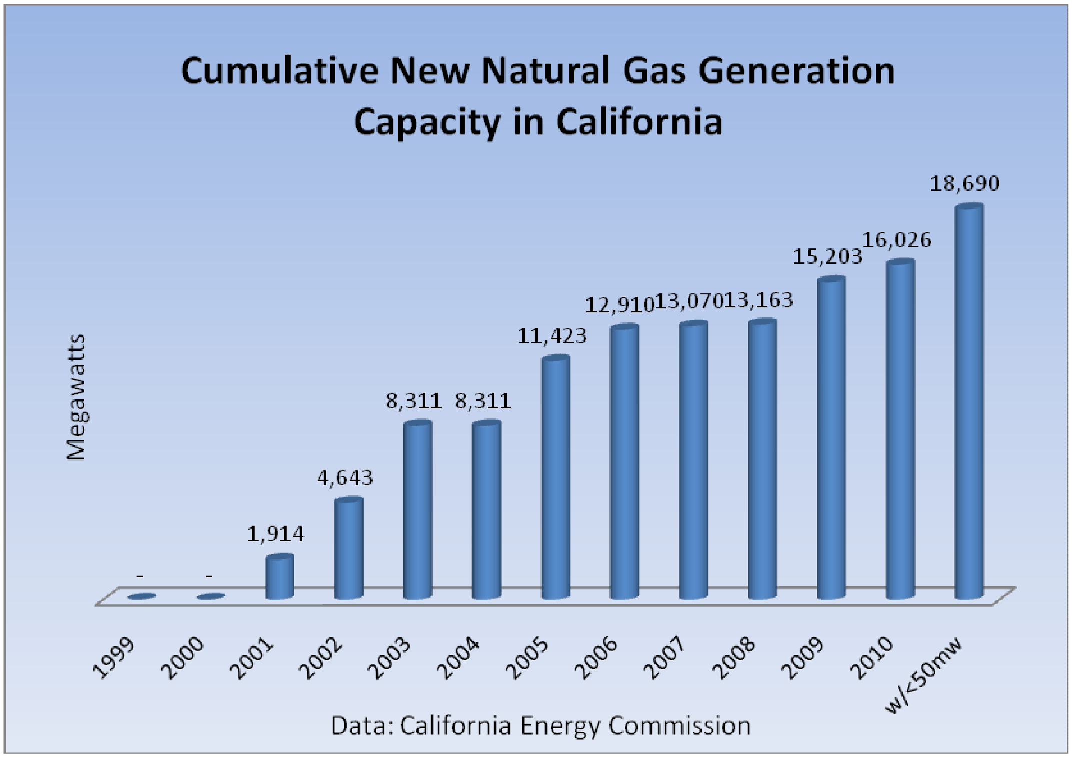
Pacific Environment is a non-profit organization with environmental programs around the Northern Pacific Rim. In California, we are dedicated to keeping the state's clean energy promise, and upholding the energy loading order which prioritizes meeting electrical demand with energy efficiency and renewable development over new fossil fuel projects.

The Avenal Energy project is inappropriate for California's energy future, and is in direct conflict with state renewable portfolio standard law. As detailed in comments submitted by Center on Race, Poverty and the Environment, this project will have significant negative impacts on the region's air basin. This letter will detail why those impacts are unnecessary.

I. Avenal will run counter to California's Renewable Portfolio Standard.
According to state law, California's investor owned utilities are required to procure 20 percent of their electricity from renewable energy by 2010, less than 7 months from now. The only way to ever accomplish this, or the proposed increase to 33 percent by 2020, will be to cease building new natural gas fired power plants, including the Avenal project.

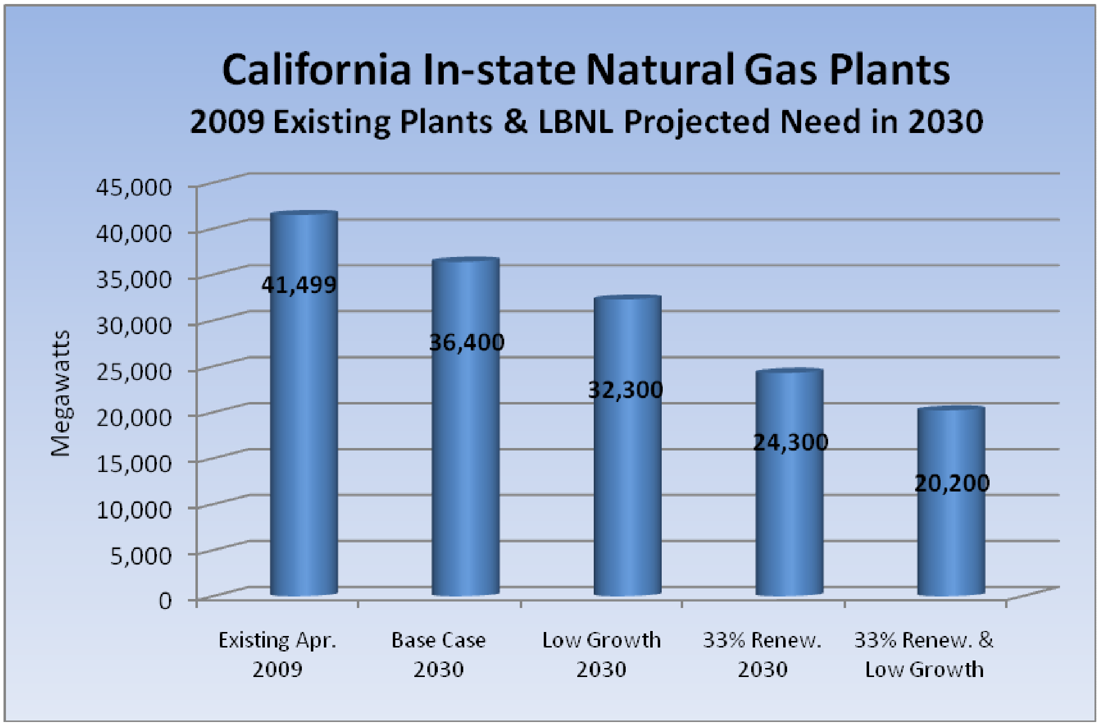
As the state has slipped year after year on meeting renewable energy targets, a spree of construction since 1999 has resulted in major investment for new natural gas electric generation, at least $15 billion so far. Many of these plants replaced older, less efficient power plants, and for a time actually reduced consumption of natural gas fuel. However, this improved efficiency is undermined by the fact that while 7,500 megawatts of plant capacity retired by 2008, over 18,000 megawatts have been built, or will be built, by the end of 2010. [1] Note that the following chart only shows new natural gas plant construction; this is far less than the total natural gas plant capacity—which exceeds 40,000 megawatts.

[1] Source data for the chart is in Appendix 1, from the California Energy Commission's Energy Facility Status database. The column on the far right adds in plants that are outside the jurisdiction of the commission's approval process, particularly plants under 50 megawatts built between 2000 and 2007.



The build-up of natural gas plants occurred just as the state was supposed to be implementing its renewables policy. But the capacity of natural gas plants will *need to decrease* if the clean energy policies are to achieve their goals.

II. Lawrence Berkeley National Lab Study. A study from 2003 by Lawrence Berkeley National Laboratory (LBNL) looked at the effects of increasing renewables, and reducing growth in energy demand, on the future need for natural gas plants in California. They found that by 2030 the state would need 8,000 megawatts less of natural gas plants if it were to adopt the proposed requirement to get 33% of electricity from renewable energy. Similarly, if aggressive energy efficiency policies can slow the rate of growth in electricity demand, then this could reduce the need for natural gas power plants by about 4,000 megawatts. The study did not consider the possibility of combining energy efficiency with renewables, but the state is actually in the process of adopting both of these requirements.



The chart above shows California's existing natural gas plants in April 2009 at 41,499 megawatts. [2] By 2030, the LBNL study projected that if the 33 percent renewables portfolio standard requirement is implemented, then far fewer natural gas plants will be needed. [3] If the state implements both the renewables requirement and aggressive efficiency programs, then over 20,000 megawatts would need to be retired. Adding more capacity, as the Avenal project will do, would reverse this effort by 600 megawatts. The policy to move to renewables directly conflicts with any new natural gas capacity beyond those already built or under construction.

It is important to realize how much "padding" is placed into the LBNL projections. The report looks at the need for natural gas power plant capacity in 2030, a full decade beyond the 2020 renewable program policy target. This allows up to a full decade of delay in meeting these targets, and also accomodates an extra decade of growth in demand. The report's made the following growth assumptions:

"To address California transmission interconnections for the future, this study focused on the year 2030. By that time, California is forecast to experience:

- Population growth to over 50 million, an increase of 18 million over 30 years;

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[2] California Power Plant Database (Excel File), http://energyalmanac.ca.gov/powerplants/POWER_PLANTS.XLS

[3] California's Electricity Generation and Transmission Interconnection Needs Under Alternative Scenarios, CERTS, LBNL, 2003. CEC, 500-03-106. The original study, however, shows only 32,100 megawatts of existing natural gas plants due to the fact that the report dates to 2003. Since that time thousands of megawatts of new plants have been built, as the previous chart illustrates.

• Electricity peak demand of 80 GW, an increase of 28 GW from current [2003] levels, or an average annual peak demand growth of 1.5 percent."

III. California has more than enough to meet electrical load. There are huge resources available to the state's electric power grid, including generation from natural gas, nuclear, hydroelectric and renewable power sources. For purposes of grid reliability, natural gas and some kinds of hydroelectric generation are "dispatchable," meaning they can be ramped up and down in a controlled manner to respond to changing needs for energy. A power plant operating in this manner is called "load following." Solar and wind are said to be "intermittent," generating power according to when the sun shines or the wind blows. The table below shows power supplies from different sources, including the aging power plants currently in operation, adjusted for a reliability factor called "effective load carrying capacity" (ELCC): [4]

Table 1: California In-State Generation Resources

	Capacity mw	elcc	reliable mw
Natural Gas [5]	41,499	100%	41,499
Coal	400	100%	400
Nuclear	4,472	100%	4,472
Hydro	10,420	100%	10,420
Pumped Storage [6]	4,132	100%	4,132
Biofuel	1,107	100%	1107
Geothermal	1,827	100%	1,827
Solar	357	60%	214
Wind	2,706	25%	676
Total Database	66,920		64,474

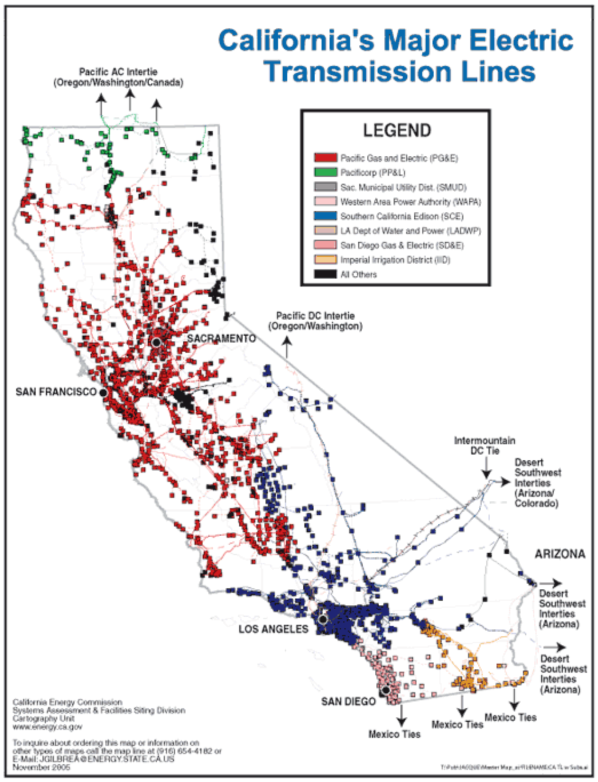
Conventional power sources such as natural gas, nuclear and hydroelectric plants are considered to count 100% of their capacity toward reliability needs, and thus are rated with 100% Effective Load Carrying Capacity (ELCC). About half of the state's renewable power is wind, which is quite variable and has a 25 percent ELCC in California, while solar thermal generation in the desert has a 60 percent ELCC. The Effective Load Carrying Capacity is calculated by measuring the reliable output of the wind or solar plants during the limited hours of peak energy demand.

The total reliable generation resource above, of 64,000 megawatts, exceeds the CAISO summer heat storm peak demand needs in 2006, which was just over 60,000

[4] Totals derived from California Power Plants Database, California Energy Commission.. http://www.energy.ca.gov/database/POWER_PLANTS.XLS
[5] Some of these plants list oil, diesel or distillate as alternate fuels, however nearly all the capacity runs on natural gas.
[6] This figure does not include SMUD's proposed 400 megawatt Iowa Hill pumped storage project in the Sierras.

megawatts. [7] That heat storm represented an event expected less than once in 30 years, a level of demand that is higher than the normal long term growth trend line. [8] Current state reliability criteria only require demand projections for a 1 in 2 year event, plus a margin of 15 to 17 percent for extra security. It is noteworthy that these planning criteria for electric system resources were more than sufficient to meet the needs for the extraordinary 2006 event.

In addition to the in-state power plants considered above, there are several other significant resources available to meet the demand for electricity. For example, Investor Owned Utilities (IOUs) are required by the California Public Utilities Commission to obtain 5 percent of peak energy needs from peak demand reduction programs, called Demand Response. Demand Response is a voluntary program where utilities have contracts with their large power customers to cut back their usage when the system is under strain, and the customers are compensated for this cutback. While the utilities have fallen short of meeting this target, other programs allowing the utility to curtail their customers' energy usage during power emergencies—called Interruptible Load—has more than picked up the slack. In all, 236,195 customer "Service Accounts" participated in the demand reduction programs offered by the Investor Owned Utilities. Another resource is the wide assortment of small customer-owned generation, particularly Backup Generators ("BUGS"), and rooftop solar photovoltaics (PV).



[7] The CAISO load accounts for nearly all of the state's electricity, but a few public utilities, LADWP, SMUD and IID operate outside of CAISO and add several thousand megawatts to the state peak load. On the hottest day in 2006, LADWP peaked at 5388 mw (http://www.ladwpnews.com/go/doc/1475/169933/); SMUD's peak is about 3000 mw (http://www.smud.org/en/board/Pages/compact-customer.aspx); and IID's peak is over 800 mw.

[8] The OTC Reliability Study cited correctly an expected long term growth rate in demand of 1.1 to 1.2 percent "for the foreseeable future" (p. 19), but did not point out that the cited peak demand in 2006 was an extraordinarily high anomaly, not a baseline for future expected growth.

Finally, there are several major power transmission lines that bring in electricity from out-of-state. [9] Import capacity includes 7,900 megawatts from the Pacific Northwest, 1,900 megawatts from Utah, 7,500 megawatts from the Desert Southwest, and 800 megawatts from Baja region of Mexico, for a total of over 18,000 megawatts. [10]

Table 2: Total Resources Available to California Electric Grid

Resource	mw
Instate Generation	64,474
Transmission Import	18,100
BUGS Database [11]	3,492
Peak Demand Resource (DR/IL) [12]	2,669
Rooftop Solar	120
Total All	88,855

If all these resources are included, the power capacity for the state is near a staggering 89,000 megawatts, about 50 percent higher than has ever been recorded as a peak demand. [13]

The chart below helps to picture what a "typical" day of demand looks like for the California ISO grid. [14] During the spring and fall daily electricity demand peaks at about 30,000 megawatts, while in the summer it can rise in the late afternoon to 40,000 megawatts or more. After the peak demand falls over a period of 10 to 12 hours to a low point in the early morning before dawn, when the demand begins to rise again. Note that the on-call resources available, even on a summer day, were over 12,000 megawatts higher than what was needed.

California ISO Forecast and Demand for June 24, 2004

[9] Map source: California Energy Commission, http://www.energy.ca.gov/maps/transmission_lines.html

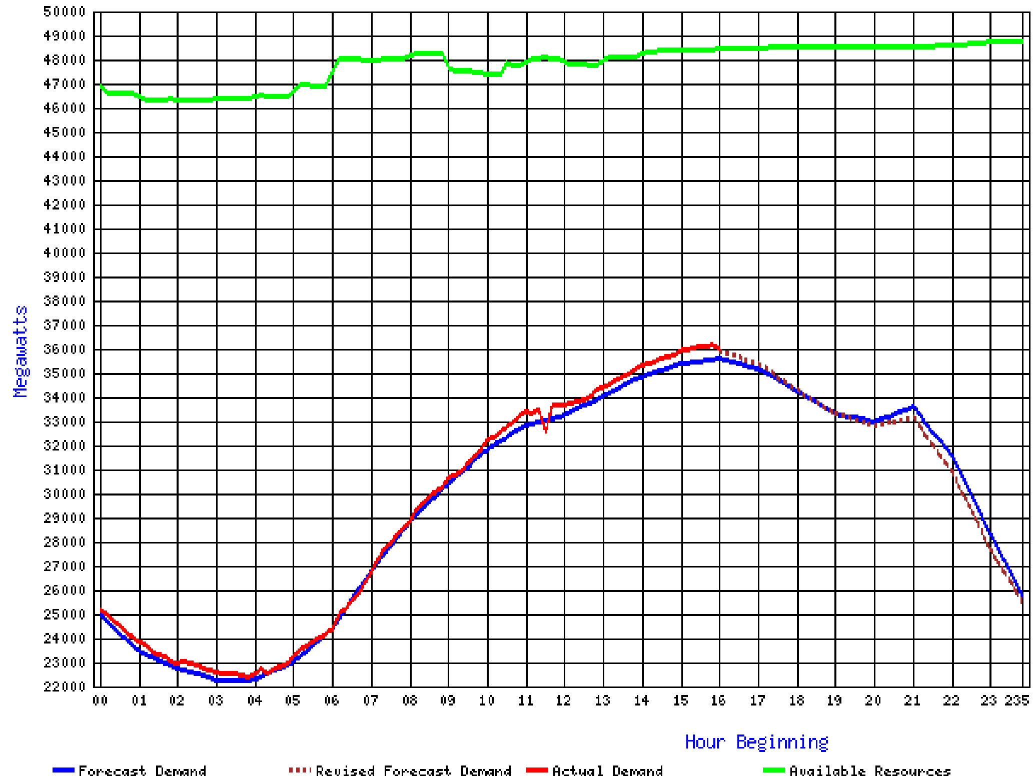
[10] US Transmission Capacity: Present Status and Future Prospects, by Eric Hirst, prepared for Edison Electric Institute and Office of Electric Transmission and Distribution, US Dept. of Energy, August 2004, p.34.

[11] BUGS 1 – Database of Public Back-Up Generators (BUGS) in California, Updated January 2004. California Energy Commission, http://www.energy.ca.gov/database/EDITED_PUBLIC_BUGS_INVENTORY.XLS

[12] The State of Demand Response in California, A. Faruqui, R. Hledik, Publication Number CEC-200-2007-003-F, California Energy Commission Division of Electricity and Demand Analysis, September 2007. Table 6, p. 16.

[13] On July 24, 2006 CAISO peak load reached 50,270 megawatts, with total California load at about 60,000 megawatts. Total resources available to the state are nearly 30,000 megawatts above the highest peak.

[14] July 2006 CAISO Actual System Daily Peak Demand, Generation and Imports at Time of Daily Peak,
CAL_ISO_08_29_2006.



IV. Avenal Energy would violate the Energy Commission and the CPUC's own policies and goals. The CPUC and CEC, in their 2008 update to Energy Action Plan Update, have stated that they are committed "to working together to evaluate the potential for making 33 percent of the power delivered in California renewable by 2020." The Energy Commission could back up this stated commitment by denying the application for the Avenal Energy project. As detailed in these comments, there is already excess capacity to meet California's energy needs. The same CPUC report concluded that the only way to arrive at a 33 percent RPS is to reduce generation from non-renewable resources by 11% in 2020. Such a result, according to the report, would require that nearly *all new procurement be renewable.* There is simply no need for the Avenal Energy project. We urge a denial of the application.

Yours,

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January 22, 2009

VIA ELECTRONIC MAIL AND HAND DELIVERY

Mr. Weyman Lee, P.E.
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San Francisco CA 94109
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Dear Mr. Lee:

The Sierra Club submits these comments to address the Bay Area Air Quality Management District's (the "District") BACT analysis in the re-noticed draft Statement of Basis ("SOB") and PSD permit[1] for the Russell City Energy Center ("RCEC").

The RCEC will generate up to 600 MW[2] net of electricity using two Westinghouse 501F combustion turbine generators, firing 2,038.7 MMBtu/hr of natural gas. The hot turbine exhaust gases are routed to two heat recovery steam generators ("HRSGs"). The HRSGs, or boilers that recover waste heat from the turbine exhaust, are each equipped with duct burners that burn 200 MMBtu/hr of natural gas. The HRSG and duct burners convert water into steam which drives a 235 MW steam turbine ("the Project").

This same project was proposed by the applicant, Calpine, and licensed by the California Energy Commission ("CEC") in 2002. The proposed facility location was

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[1] Statement of Basis for Draft Amended Federal "Prevention of Significant Deterioration" Permit, Russell City Energy Center, Bay Area Air Quality Management District Application Number 15487, December 8, 2008.

[2] We note that the Permit assumes 622 MW, presumably gross, while the CEC licensed a project rated at only 600 MW, presumably net. We assume that the difference is the auxiliary power load. See Russell City Energy Center, Amendment No. 1 (01-AFC-7C), Final Commission Decision, October 2007, p. 2. http://www.energy.ca.gov/2007publications/CEC-800-2007-003/CEC-800-2007-003-CMF.PDF.

subsequently moved 1,300 feet to the northwest of the approved location and thus required a modification to its CEC license and a new PSD permit.[3]

I. BACT for Carbon Dioxide (CO2)

The applicant asked the District to undertake a top-down BACT analysis for greenhouse gases.[4] The District conducted a BACT analysis and concluded that if BACT is required for CO2 emissions, an enforceable limit of 1,100 lb/MWh would suffice. Compliance would be demonstrated by an enforceable fuel throughput limit of 2,944.3 MMBtu/hr of heat input.[5]

We agree that the permit should include a BACT limit for CO_2. While the U.S. Environmental Protection Agency has wavered as to whether CO_2 is a "pollutant subject to regulation," within the meaning of the Clean Air Act's BACT definition, both the Clean Air Act and EPA's governing interpretations indicate that CO_2 falls within the pollutants demanding a BACT limit. *See* Ex. 1 **(In the Matter of: EPA Final Action Published at 73 Fed. Reg. 80300 (December 31, 2008), titled "Clean Air Act Prevention of Significant Deterioration (PSD) Construction Permit Program; Interpretation of Regulations That Determine pollutants Covered by the Federal PSD Permit Program," Petition for Reconsideration (January 6, 2009)**). However, the District's CO_2 limit and compliance provision as currently written do not satisfy BACT requirements, for the reasons below.

A. Failed To Consider More Efficient Options

The District acknowledges that an effective means to reduce CO2 emissions is to use the most efficient generating technology available; increased efficiency allows more of the fuel's energy content to be used to generate electricity, reducing emissions of CO_2 (and other pollutants). The District has not, however, conducted a full BACT analysis of efficient generating technologies. Instead, the District concludes (without supporting analysis) that the proposed "combined-cycle natural gas turbine technology" is "among the most efficient electrical generating technology created to date."[6]

BACT requires an emission limit based on the maximum degree of reduction that is achievable; limiting the District's review to a technology that is "among the most" effective fails to satisfy those "strong, normative terms." *Alaska Dep't of Envtl. Conservation* 540 U.S. 461, 485-86 (2004). As discussed in Section II, below,

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[3] Statement of Basis for Draft Amended Federal "Prevention of Significant Deterioration" Permit, Russell City Energy Center, Bay Area Air Quality Management District Application Number 15487, December 8, 2008.
[4] SOB, p. 58.
[5] SOB, p. 63.
[6] SOB, pp. 60-61.

the proposed generating technology is not the most efficient available. It is not sufficient to stop one's inquiry with the a broad classification of the thermodynamic cycle, combined-cycle, but rather, one must look deeper, at the components of the cycle – the gas turbine, HRSG, duct burners, and steam turbine.[7] There are many different turbines that could be used in the same combined-cycle configuration and more efficient ways to generate peaking power. The technology proposed by the applicant was selected eight years ago. BACT is determined as of the date of issue of the PSD permit. By failing to examine more efficient means to generate electricity, the District has failed to properly fulfill its duty, under the BACT requirements, to examine all methods and processes of pollution-reduction, including "innovative combustion processes." 42 U.S.C. § 7579(3).

B. Failure to Set Proper CO2 BACT Limit

After improperly concluding that the applicant had selected the most efficient power generation technology, the District next considered a range of CO2 emissions expressed in units of pounds per megawatt hour ("lb/MWh") of net (presumably) electric generation. The values considered were regulatory levels proposed by various states (675 lb/MWh in Oregon to 1,900 lb/MWh in Delaware)[8] and certain California test data (794 to 1,058 lb/MWh).[9]

From this data, the District concluded that CO2 BACT is 1,100 lb/MWh. The lower values were rejected without technical explanation, arguing that "a reasonable compliance margin" is required to assure the limit is met.[10] The selected limit is conveniently the minimum emission performance standard that certain gas fired power plants in California must meet. This limit is 39% higher than the lowest reported CO2 emission level identified by the District. No justification is provided for a "reasonable compliance margin" of 39% or for the concept that such a "compliance margin" applies to BACT.

Generally, when there is uncertainty as to what can be achieved, an optimization period is built in to a permit with a requirement to design the system to meet the goal and time to achieve the goal. The permit should require the system to be designed to meet a much lower CO2 level. The design basis should be submitted to the District to establish that the intent was met. The permit should also establish protocols that identify (a) test methods that will be used to measure CO2 and MWh net; (b) frequency of testing; (c) length of optimization period; (d) averaging period for limit; and (e) methods and criteria that will be used to

[7] David Gordon Wilson and Theodosios Korakianitis, The Design of High-Efficiency Turbomachinery and Gas Turbines, 2nd Ed., 1998; Kam W. Li and A. Paul Priddy, Power Plant System Design, 1985.
[8] SOB, p. 59, Table 20.
[9] SOB, pp. 62.
[10] SOB, p.63.

determine the lowest achievable CO2 limit. The permit should be drafted to require as BACT the lowest achievable limit, based on this testing demonstration.

The District tosses out all measured data, characterizing it as no more than a "snapshot" of turbine performance and not a continuous demonstration of compliance with an enforceable limit. The District also tosses out the lower end of the regulatory range and sets CO2 BACT at 1,100 lb/MWh,[11] based on California's interim performance standard for complying with a Senate Bill.

The 1,100 lb/MWh value was adopted by the California Public Utilities Commission under the Electricity Greenhouse Gas Emission Standards Act (SB 136812) as a performance standard for the state's investor owned utilities. It applies to new investments in existing plants, new or renewed contracts with plants outside of California, and new base load plants. Thus, it had to broadly apply across the existing gas-fired fleet that serves California.

The 1,100 lb/MWh value was not selected in a top-down BACT analysis, but rather through a political negotiation. It was a compromise between a value of 800 lb/MWh, which could then be achieved by the most efficient combined cycle plant, and 1,400 lb/MWh, which would envelop the majority of natural gas burning technologies (e.g., steam cycle boiler, simple cycle turbine).[12] Such a standard does not satisfy BACT, but (at most) serves as a floor for BACT.

Modern, efficient combined-cycle power plant in 2009 can cost-effectively achieve far lower emissions. The District failed to acknowledge that CO2 emissions from similar facilities have been continuously monitored for many years under the Acid Rain Program and publicly reported.[13] These data show that similar combined cycle power plants routinely meet CO2 emission levels of less than 800 lb/MWh.

Further, some of this data has been certified and reported to the California Climate Action Registry.[14] This data shows that Elk Hills, a similarly configured combined cycle project licensed by the CEC in 2000, reported CO2 emissions of 796 lb/MWh in 2006 and 794 lb/MWh in 2007. Calpine, the RCEC applicant who owns a number of similar gas-fired combined cycle projects in California, reported system-wide CO2 emissions from all fossil fuel generation of 891 lb/MWh in 2005 and 850 lb/MWh in 2006. This fleet includes many less efficient gas-fired facilities than proposed at RCEC.

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[11] SOB, pp. 62-63.
[12] Gary Collord, Implementation of SB 1368 Emission Performance Standard, Staff Issue Identification Paper, November 2006, p. 13.
[13]Clean Air Markets, Emissions Monitoring, http://www.epa.gov/airmarkets/emissions/.
[14] Climate Action Registry Reporting Online Tool, https://www.climateregistry.org/CARROT/public/Reports.aspx.

Similar facilities are also currently being licensed by the CEC with lower CO2 emissions. These include Avenal (500 lb/MWh);[15] Willow Pass Generating Station (933 lb/MWh);[16] and Lodi Energy Center (829 lb/MWh).[17] The State of Florida concluded that in 2007, new natural gas fired combined cycle plants could achieve 800 lb/MWh.[18] Based on this evidence, BACT should be an enforceable CO2 emission limit no higher than 800 lb/MWh.

C. Output-Based Limit Should Be Established

The District opted to determine compliance with the output-based CO2 emission limit, 1,200 lb/MWh, by setting an input-based fuel limit. In effect, this renders the limit input-based. Output-based measurements link the emissions from a power plant to the energy they produce. In 1998, the NSPS for utility and industrial boilers was changed from input to output based. Further, EPA has published an output-based guidance document under the NOx SIP Call as an option for states in the NOx Budget Trading Program.[19]

The use of an output-based CO2 limit is particularly critical here as the only currently feasible control option is more efficient energy production.[20] The District used a CO2 emission calculation to demonstrate that a heat input limit assures emissions remain below 1,100 lb/MWh. The Permit, however, does not cap electric output at 622 MW (a key assumption of the calculation). The calculations are, moreover, based on input rather than output, and utilize the wrong natural gas heat content (1050 instead of 1023 Btu/scf). The heat input method of determining compliance, for example, would not detect a decrease in efficiency due to aging of the equipment or due to changes in the equipment at a future time.

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[15] From Avenal Energy Application for Certification 08-AFC-01, February 2008, Vol. II, Appx. 6.2-1, Table 6.2-1.1. The highest values, calculated from CO2 in lb/hr divided by plant net output in MW. Table 6.2-41, the facility would emit 1.71 MT/yr of CO2, is 499.7 lb/MWh, based on case 12 (137,055 lb/hr/304.8 MW = **499.7 lb/MWh**). See: http://www.energy.ca.gov/sitingcases/avenal/documents/applicant/afc/

[16] From the Willow Pass AFC 08-AFC-6, Table 7.1-19, the facility would emit 987,970 MT/yr of CO2. From Figure 2.5-3, it would generate 266.5 MW net under worst-case conditions, 100% load and 94 F, 32% RH. This works out to: (987,970 MT/yr)(2204.6 lb/MT)/(266.7 MW)(8760 hr/yr) = 932.98 **lb/MW-hr** net and 905.8 lb/MWh gross. This is an air cooled plant so auxiliary power loads are higher than for a water cooled plant, such as RCEC. See: http://www.energy.ca.gov/sitingcases/willowpass/documents/applicant/afc/index.php.

[17] Lodi Energy Center Application for Certification 08-AFC-10, September 2008, Table 5.1-22. See: http://www.energy.ca.gov/sitingcases/lodi/documents/applicant/afc/.

[18] Florida Department of Environmental Protection, Electric Utility Greenhouse Gas Emissions Reductions, Initial Rule Development Workshop, August 22, 2007.

[19] Susan Freedman and Suzanne Watson, Output-Based Emission Standards, Northeast-Midwest Institute, 2003, http://www.nemw.org/output_emissions.pdf.

[20] SOB, pp. 60-61.

Net electrical output and CO_2 can both be monitored continuously using widely used, standard measurement technology. Thus, the Permit should be revised to set an explicit limit on CO_2 emissions in pounds per megawatt-hour.

D. Other Greenhouse Gases and Sources

The District only performed a BACT analysis for CO_2 emissions from the gas turbines and duct burners. Other sources emit greenhouse gases, including diesel generators and heaters. Further, other Greenhouse Gases are emitted by gas-fired power plants, including methane (CH_4) and nitrous oxide (N_2O) (from combustion sources) and sulfahexafluoride (SF_6) (which is used in circuit breakers). The BACT analysis should be revised to include these other gases and sources.

II. The BACT Analysis Did Not Consider More Efficient Processes

The BACT analysis for NOx, CO, and PM emissions from the gas turbine/HSRG equipment considered only two classes of control options – combustion controls and post combustion controls. However, the amount of pollution that is generated by combustion sources depends upon the efficiency of power generation. The more fuel that is burned to produce a megawatt of electricity, the more NOx, CO, and PM10 that is emitted. Similarly, the less fuel burned, the lower the emissions. The District did not consider the efficiency of the power generation cycle in making its BACT determination for NOx, CO, or PM (though it paid lip service to efficiency considerations in its BACT determination for CO_2).

Consideration of more efficient generating technologies is required under BACT, which requires a case-by-case, comprehensive assessment that includes "*production processes* and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or *innovative fuel combustion techniques* for control of each . . . pollutant" regulated under the PSD program. 42 U.S.C. § 7479(3) (emphases added). A BACT analysis should, accordingly, not be limited to a comparative assessment of combustion controls and add-on controls, but must consider "'inherently lower-polluting process[es]/practice[s]' that prevent[ ] emissions from being generated in the first instance." *In re Knauf Fiber Glass, BMBH,* 8 E.A.D. 121, 129 (EAB 1999) (citing NSR Manual at B.10, B.13). *See also In re CertainTeed Corp.*, 1 E.A.D. 743, 746 (EAB 1982) (Affirms BACT is an emission limitation achievable through application of "production processes and available methods, systems, and techniques" for control of pollutants, denying applicant review of permit based on argument that BACT does not include production and process requirements). Furthermore, the history of the Clean Air Act amendment adding the term "innovative fuel combustion techniques" shows that the amendment was intended to include all actions taken by the fuel user, such as selecting the combustion process. 123 Cong. Rec. S9421, S9434-35.[21]

Russell City will use two Westinghouse 501 FD combustion turbines with fired heat recovery steam generators to generate 600 MW net of electric power. This is not the most efficient combination to generate said power and thus does not satisfy BACT for at least three reasons.

First, the efficiency of the unfired system (without duct burners) is reported to be 55%.[22] While that may have been an efficient mark eight years ago, when the turbines were selected, there are far more efficient turbines on the market today. These include the Westinghouse 501G, a more advanced turbine by the same manufacturer and its successors. It has a combined cycle net efficiency of 58%.[23] This turbine is in widespread commercial operation, including at the Charlton Power Plant, MA (since 2001); Lakeland McIntosh Unit 5, FL (Ex. 12);[24] West County, FL; Lower Mount Bethel, PA; Ennis Power, TX; Wolf Hollow, TX; and Port Westward, OR, among others.[25]

Other more efficient turbines have entered the market since 2001, with efficiencies up to 60%.[26] If turbines with a net combined cycle efficiency of 60% were selected, RCEC would emit over 8% less NOx, CO, and PM than the selected turbines when operated in unfired mode. In fact, the same applicant, Calpine, is scheduled to complete construction of Inland Empire Unit 1 in January 2009 and Unit 2 in July 2009. These two turbines were licensed in 2003 at 56.5% lower heating value without duct firing[27] compared to only 55% for RCEC which is being

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[21] *"It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account* - be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, *gasification*, or liquefaction." (emphases added). 123 Cong. Rec. S9421, S9434-35.

[22] Russell City Energy Center Application for Certification, 01-AFC-7, May 2001 ("RCEC AFC"), p. 10-3, http://www.energy.ca.gov/sitingcases/russellcity/documents/applicant_files/afc/ and Russell City Energy Center, Application for Certification 01-AFC-7, Commission Decision, p. 74. http://www.energy.ca.gov/sitingcases/russellcity/documents/2002-09-12_COMMISSION_DECIS.PDF

[23] Gerard McQuiggan and others, Westinghouse's Advanced Turbine Systems Program.

[24] Gregory R. Gaul, Ihor S. Diakunchak, and Alfred M. Dodd, The W501G Testing and Validation in the Siemens Westinghouse Advanced Turbine Systems Program, Paper 2001-GT-399, International Gas Turbine & Aeroengine Congress & Exhibition, June 4-7, 2001.

[25] Universal Energy UEI LLC, Management Services for Power, Petrochemical, Offshore, and Industrial Facilities, Experience List, February 2006. http://www.univenergy.com/PDFs/Industrial%20Capabilities%20020306.pdf.

[26] Gas Turbine World 2007 -08 Handbook, Combined Cycle Ratings; GE Energy, News Release, GE's H System Achieves Technology Milestone: 8,000 Operating Hours at Baglan Bay; GE Power Systems, GE Combined-Cycle Line and Performance. http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger3574g.pdf.

[27] Inland Empire Application for Certification 01-AFC-17, Commission Decision, November 14, 2003, p. 74. http://www.energy.ca.gov/sitingcases/inlandempire/documents/2003-12-22_COM_DECISION.PDF.

permitted in 2009. Inland Empire will use the higher efficiency GE PG7252(FB) turbines.

Second, RCEC will use an inefficient method to generate peaking power. When the duct burners are not operating, the gas turbines will produce 184.3 MW each and the steam turbine 198.4 MW, for a net plant output of 552.6 MW. The heat rate, or amount of energy in BTUs per kilowatt hour of electricity produced, for this mode of operation is 6,177 BTU/kWh based on the lower heating value.[28] During periods of peak demand, the duct burners are turned on to generate more steam. The heat rate for this condition is not reported in documents we reviewed.

Duct burners are inefficient compared to gas turbines. The files we reviewed do not report the efficiency of incremental power generation by the duct burners, nor does it include a heat/mass balance diagram that could be used to estimate the impact of duct firing on fuel efficiency. However, such estimates have been made in other similar cases. Based on these, the incremental heat rate of peaking capacity could range from about 8,890 to 9,000 Btu/kWh, corresponding to an efficiency of about 40%.[29] The peaking heat rate is higher than can be achieved by some simple cycle gas turbines. (Ex. 18)[30] Thus, peaking power generation by simple cycle gas turbine should have been considered in the BACT analysis as an alternative to duct burners. Further, the inclusion of duct burners in a combined cycle plant reduces the overall efficiency of the combined cycle plant as the steam cycle has to be sized to provide base load plus peaking load. This adds a fuel efficiency penalty during baseload unfired operation.

Third, as cited in Knauf (8 E.A.D, 129), the NSR Manual explicitly recognizes that "[c]ombinations of inherently lower-polluting processes/practices (or a process made to be inherently less polluting) and add-on controls are likely to yield more effective means of emissions control than either approach alone...These combinations should be identified in Step 1 of the top down process for evaluation in subsequent steps." NSR Manual, p. B.14. The BACT analysis for NOx, CO, and PM did not identify any inherently lower-polluting processes or practices and thus failed to consider whether combinations of these and add-on controls could further reduce NOx, CO, and PM.

The EPA's RACT/BACT/LAER Clearinghouse indicates that lower emission limits have been permitted for other facilities, including 1.5 ppm NOx at IDC Bellingham and numerous facilities at less than 4 ppm CO. These lower CO limits include Kleen Energy Systems, CT (0.9 ppmvd); CPV Warren, VA (1.3 and 1.8 ppmvd); and 2 ppmvd at: Goldendale Energy, WA; Garnet Energy, ID, Wallula

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[28] RCEC AFC, Figure 2.2-3b.

[29] CPV Vaca Station Application for Certification 08-AFC-11, October 2008, p. 2-2; Presiding Members Decision for Inland Empire 01-AFC-17, November 14, 2003, p. 75.

[30] Gas Turbine World 2007-08 Handbook, Simple Cycle Ratings.

Generation, WA; Lawrence Energy, OH; Linden Generating Station, NJ; COB Energy Facility, OR; Vernon City Light & Power, CA; Magnolia Power Project, CA, and many others.

The BACT analysis should be revised to consider the efficiency of the energy production process and the draft SOB and Permit re-circulated for public review.

III. BACT for Carbon Monoxide (CO)

The District concluded that BACT for CO is an emission limit of 4 ppmvd at 15% oxygen based on a 1 hour average, achieved using an oxidation catalyst.[31] This is not BACT for several reasons.

A. The District Used an Illegal Process

The District argues that NOx and CO are inversely related, that is, when NOx is reduced, CO increases. Thus, the District prioritizes NOx and VOC reductions over CO reductions because the Bay Area is not in compliance with ozone standards but does comply with CO standards. The District requires applicants to minimize NOx to the greatest extent feasible, and then optimize CO and VOC emissions for that level of NOx control.[32]

This process is inconsistent with BACT, which requires that an emission limit be set for each pollutant based on the maximum degree of reduction for that pollutant. Further, even assuming this process were legal, it was improperly implemented. The emissions of both NOx and CO can be simultaneously reduced by using a higher efficiency power production system or more efficient post combustion controls. This flawed process resulted in picking a CO BACT level of 4 ppm based on a 1 hour average. As discussed below, CO BACT is lower than 4 ppmvd.

B. Power Production Cycle

As discussed in Comment I, a higher efficiency power production cycle coupled with the proposed controls would lower all emissions, including CO.

First, the applicant's emissions data show that with duct firing, an inefficient method to produce peaking power, uncontrolled CO emissions increase from 0.1 lb/MMBtu to 0.25 lb/MMBtu,[33] or by a factor of 2.5. Requiring a more efficient method of producing peaking power, such as a small aero-derivative turbine or more efficient duct burners, would allow a lower CO emission limit to be achieved.

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[31] SOB, p. 34.

[32] SOB, pp. 22, 31.

[33] Russell City Energy Center Application for Certifications (AFC) 01-AFC-7, Amendment No. 1, November 2006, Appendix 3.1A, Table 3.1A-2.

Second, the turbines chosen for this project, Westinghouse 501Fs generally emit more CO than comparable GE turbines. The Westinghouse 501F turbine outlet CO is about 10 ppm, compared to 9 ppm from a typical GE Frame F turbine. Further, the Westinghouse 501F is not as stable across loads and at low loads up to about 50-60% as GE Frame F turbines, requiring more catalyst to achieve the same CO outlet as for other turbines. Thus, the District should have considered alternative combustion processes to reduce CO emissions.

C. Maximum Degree of Removal

The District selected an oxidation catalyst as satisfying BACT, but fails to disclose the assumed CO control efficiency or the CO concentration at the inlet to the device, both required to complete the Step 3 top-down BACT ranking. Instead, the District jumps to a list of permitted exhaust gas CO concentrations. This leap of faith skips a critical step in the top-down process, the ranking of technologies according to their control effectiveness.[34]

The top technology can achieve over 98% CO control (Ex. 19)[35] and has been commonly specified at 90+% CO control on numerous projects in the past 5 years. (Ex. 20 [36] and 21[37]) Assuming an oxidation catalyst design basis of 0.25 lb/MMBtu during duct firing (112 ppm),[38] a 98% CO control efficiency would result in a CO concentration of 0.005 lb/MMBtu or 2.2 ppmvd at 15% oxygen. This is much lower than the proposed CO BACT limit of 4 ppmvd. The District should determine the design basis of the proposed oxidation catalyst, revisit its CO BACT determination, modify the SOB to disclose the design basis of the oxidation catalyst, and re-circulate it for public comment as meaningful review is not possible without this information.

D. Test Data

In selecting the 4.0 ppmvd limit, the SOB states that the District only reviewed CEMS data for a single facility, Metcalf. There are many other similarly controlled gas-fired Frame F turbines operating in combined cycle mode in California and elsewhere, including the Delta Energy Center and Sutter, similar Calpine projects.[39] In 2001, for example, there were 87 such units in California.[40] Stack

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[34] NSR Manual, pp. B.6, B.7

[35] BASF, Oxidation Catalyst - Power Generation.

[36] Engelhard Oxidation Catalyst Experience List, 2003 (Engelhard is now BASF).

[37] Mike Durilla, Fred Booth, Ken Burns, and William Hizny, Engelhard, The Use of Oxidation Catalysts for Controlling Emissions from Gas Turbines: A Historical Perspective with a View Towards the Future, Power-Gen International 2001.

[38] Russell City Energy Center Application for Certifications (AFC) 01-AFC-7, Amendment No. 1, November 2006, Appendix 3.1A, Table 3.1A-2.

[39] See California projects at: http://www.energy.ca.gov/sitingcases/all_projects.html and

tests for many of these facilities indicate that lower CO emissions are being routinely achieved. The Metcalf data alone should not determine BACT for RCEC. The District should be required to look more broadly.

The District misapplied the Metcalf data. The District concluded BACT is 4 ppmvd as the Metcalf CEMS data suggested it could only meet 2 ppm during some operations. During transient loads, CO emissions increased to 4 ppm.[41] Most of the exceedances of 2 ppmvd at Metcalf were in the first year of operation during optimization of the system and thus not relevant to what can be achieved during optimized operation.

Our review of the Metcalf CO data indicate that during the first year of operation, a CO concentration of 2 ppmvd was exceeded 54 times out of 730 measurements (2 turbines x 365 days) during the first year of operation (6/1/05 – 5/1/06), or about 8% of the time. However, during the next two plus years of operation (6/1/06 – 8/08), a CO concentration of 2 ppmvd was exceeded only 6 times out of 822 measurements, or only about 0.4% of the time. This small number of very small exceedances in the post-shakedown period could easily be accommodated by requiring a more efficient oxidation catalyst than the one installed on Metcalf.

This is excellent performance, given the Metcalf design basis and permit limit. Metcalf was permitted in 2000 with a CO limit of 6 ppmvd based on a 3-hour average, *without an oxidation catalyst.* According to the Permit, if stack tests and CEMS data indicated a lower CO limit could be achieved on a consistent basis, the District could reduce the limit to 4 ppmvd.[42] The District should only have considered the data collected after the optimization period.

Both Metcalf and RCEC are Calpine projects based on the same power generation system, a 2-on-1 combined cycle configuration using the same turbines and duct burners. Thus, the achievable CO limit, given the same pollution generation equipment, ultimately depends only upon the presence or absence of an oxidation catalyst and its CO control efficiency. The District disclosed neither. However, our research indicates that an oxidation catalyst was installed in the as-built Metcalf HSRG,[43] guaranteed to remove 76% of the CO. The District's analysis indicates that this facility has met its permit limit. However, this is not credible evidence that RCEC, eight years later, cannot do better.

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http://www.energy.ca.gov/sitingcases/alphabetical.html.
[40] Durilla et al. 2001
[41] SOB, p. 32.
[42] Final Determination of Compliance (FDOC), Metcalf Energy Center, August 24, 2000, Condition 20(d). http://www.baaqmd.gov/pmt/public_notices/1999_2001/27215/index.htm.
[43] The CEC ultimately required an oxidation catalyst to control VOCs. See: The Metcalf Energy Center, Application for Certification 99-AFC-3, Commission Decision, p. 166, Condition AQ-55.

Arguendo, if Metcalf could meet a CO limit of 6 ppmvd, 3 hour average uncontrolled in 2000, as reflected by the Metcalf permit and SOB, RCEC should be able to meet at a CO limit of less than 1 ppmvd with a 90% efficient oxidation catalyst today (0.1x6.0 = 0.6 ppmvd). Alternatively, assuming the 6 ppmvd could only be met with a 76% efficient oxidation catalyst, a 2 ppm limit could have been met with a 92% efficient catalyst.

Regardless, just because Metcalf meets a BACT limit established over eight years ago does not mean that in 2009, the RCEC cannot do better. BACT is determined as of the date of issue of the Permit. There is now a large amount of CO test data from which to make a more informed decision. The District should evaluate it, taking into consideration the installed controls, and make a new CO BACT determination. Further, there are at least three oxidation catalyst vendors in the market who are willing to guarantee 98%+ CO reduction from natural gas fired combustion turbine exhaust. There is simply no excuse for not requiring a CO BACT limit that is comparable to those in many permits that have been issued at 2 ppmvd or lower.

E. Lower Permitted Limits

The District compiled recent BACT determinations for CO from similar gas turbine projects. This tabulation included many BACT determinations that are lower than the 4 ppmvd 1 hour average required for RCEC. These include Turner Energy Center, BP Cherry Point, Wanapa, Morro Bay, Goldendale Energy, Sumas Energy, Bellingham, Magnolia, McDonough, and CPV Warren. Most of these were permitted at 2 ppmd.[44]

In spite of this impressive list of plants with lower CO limits, the District argues a limit in the 2-3 ppm range "may not be achievable for the proposed Russell City Energy Center."[45] The District advances several arguments in support of that limit, none of which have merit.

First, the District tosses out all lower CO limits that are permitted to emit NOx at higher levels on the theory that NOx and CO are inversely related and NOx is more important to reduce. As discussed above, higher NOx is not a valid reason to reject a lower CO limit. Further, once the pollution generating equipment has been selected, which is common to all subject facilities, the degree of CO reduction and NOx reduction are independent of the underlying combustion processes and depend only on the control efficiency of the SCR and oxidation catalyst. The control efficiency of these devices is not related. The lower NOx limit selected as BACT for RCEC does not in any way restrict the efficiency of the oxidation catalyst used to control CO. In fact, the District's tabulation proves the point. It includes one unit,

[44] SOB, pp. 32-33, Table 11.
[45] SOB, p. 34.

IDC Bellingham, that was permitted with both lower NOx (1.5 ppm, 1 hour average) and lower CO (2 ppm, 1 hour average).

Second, the District tosses out lower numeric limits that have longer averaging times. The RCEC limit is based on a 1 hour average, while some of the numerically lower limits are based on 3 hour averages. The District argues these longer averaging times are less stringent as emissions can be averaged over a longer period of time. However, the District fails to point out that a numerically higher limit, regardless of averaging time, represents more pollution than a lower limit. Thus, a 4 ppmvd limit based on a 1 hour average, as proposed for RCEC, will emit twice as much CO as a 2 ppmvd limit based on a 3-hour average. Regardless, averaging time is irrelevant for an oxidation catalyst, which achieves the same level of control on a continuous basis. Averaging time is not specified in an oxidation catalyst quote for this reason, the guarantee is assumed to be met continuously.

Third, the District argues that the majority of facilities with equivalent NOx limits (2 ppm, 1 hour average) have not been built and thus there is no operational data with which to evaluate performance.[46] However, this is not correct. The District shows that two units that have 2 ppm NOx limits and 2 ppm CO limits are operational – Goldendale Energy and Magnolia . The District did not analyze the CO data from these two facilities. Further, there are others that are operational with lower limits that the District did not consider. The District did not evaluate the CO CEMS data for these other facilities. Regardless, another agency's determination that a given CO level is achievable is by itself sufficient to conclude that it is feasible for RCEC, absent a clear demonstration that circumstances exist at RCEC which distinguish it from the other sources with lower limits.[47]

The District argues that operational data is required to make a CO BACT determination. If operational data were required, BACT would present a chicken and egg problem. BACT is intended to be technology forcing, and thus requires the exercise of engineering judgment as to the applicability of transferable or new methods of pollution control. The large number of CO BACT determinations made by many other agencies indicates that a much lower CO limit is achievable, and the District is required to assess the achievability of such lower limits.

Finally, the District's list of recent BACT determinations is incomplete. It omits Kleen Energy Systems, CT (0.9 - 1.7 ppmvd); CPV Warren, VA (1.3 and 1.8 ppmvd); Malburg Generating Station, CA (2.0 ppm), and several Massachusetts plants that were permitted and are operating with a NOx limit of 2 ppm, based on a 1 hour average, and a CO limit of 2 ppm, based on a 1-hour average, including Sithe Mystic

[46] SOB, p. 34.
[47] See, e.g. NSR Manual, p. B.29

(Ex. 26[48]) and Sithe Fore River (Ex. 27[49]). These similar operating facilities with lower CO limits and identical NOx limits establish CO BACT for RCEC.

If you have any questions or concerns, please do not hesitate to contact me at (415) 977-5769 or sanjay.narayan@sierraclub.org. Thank you for your time and attention.

Sincerely,

Sanjay Narayan /SB

Sanjay Narayan

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[48] SCAQMD, Section II: Non-AQMD LAER/BACT Determinations, Application No. MBR-99-COM-012, Sithe Mystic Development LLC. http://www.aqmd.gov/bact/MBR-99-COM-012-Mystic2.doc.

[49] Massachusetts Department of Environmental Protection, PSD Permit, Sithe Four River Station, March 10, 2000.

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APPLICATION FOR CERTIFICATION *For the AVENAL ENERGY PROJECT*	Docket No. 08-AFC-1 PROOF OF SERVICE *(Revised 6/11/2009)*

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DECLARATION OF SERVICE

I, Rob Simpson, declare that , June 6, 2009, I served and filed copies of the attached dated June 6, 2009. The original document, filed with the Docket Unit, is accompanied by a copy of the most recent Proof of Service list, located on the web page for this project at:
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I declare under penalty of perjury that the foregoing is true and correct.

Rob Simpson