Final Staff Assessment
(Part 3 of 3)

ELK HILLS POWER PROJECT

Application For Certification (99-AFC-1)
Kern County, California

CALIFORNIA ENERGY COMMISSION

STAFF REPORT

APRIL 2000
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Gray Davis, *Governor*

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SITING OFFICE

Marc Pryor
Energy Commission Project Manger

Robert Haussler,
Manager

ENERGY FACILITIES SITING & ENVIRONMENTAL PROTECTION DIVISION

Robert L. Therkelsen
Deputy Director

INTRODUCTION AND RECOMMENDATION

INTRODUCTION

This Final Staff Assessment (FSA) Part III contains the California Energy Commission (Energy Commission) staff's evaluation of the Elk Hills Power, LLC (EHP) Application for Certification (99-AFC-1) for the Elk Hills Power Project (EHPP) for the technical areas of Air Quality and Alternatives. Please see Part I of the FSA for the background of the project, a description of the project, a description of staff's assessment, and a more complete introduction to the project.

Part I of the FSA was filed on January 5, 2000, and contained the following technical areas: Need Conformance, Public Health, Worker Safety and Fire Protection, Transmission Line Safety and Nuisance, Hazardous Materials Management, Waste Management, Land Use, Traffic and Transportation, Noise, Visual Resources, Cultural Resources, Socioeconomics, Geology/Paleontology, Facility Design, Reliability, Efficiency, Transmission System Engineering, and General Conditions (includes Compliance Monitoring and general Facility Closure). Part II was filed on February 18, 2000, and contained the Biological Resources, and Soil and Water Resources technical areas.

The Energy Commission's EHPP Committee held hearings on FSA Part I in January and February, 2000, and on Part II in March 2000. On May 2, 2000, the Committee will be hearing additional testimony on Soil and Water Resources that pertain to dry cooling, and the State Water Resources Control Board's Policy 75-58. The latter addresses the use of inland fresh water for power plant cooling.

STAFF'S RECOMMENDATION

With the filing of FSA Part III, staff testimony is complete, and recommends that the project be certified if all Conditions of Certification are included in the decision.

ALTERNATIVES

Testimony of Marc S. Pryor

INTRODUCTION

Staff is required to examine the “feasibility of available site and facility alternatives to the applicant’s proposal that substantially lessen the significant adverse impacts of the proposal on the environment”. The purpose of staff’s alternatives analysis is to provide the Energy Commission with an analysis of a reasonable range of feasible alternative sites which could substantially reduce or avoid any potentially significant adverse impacts of the proposed project. (Cal. Code Regs., tit. 14, §15126(d); Cal. Code Regs., tit. 20, § 1765.) This analysis identifies the potential significant impacts of the proposed project, technology alternatives and alternative sites that are capable of reducing or avoiding significant impacts.

ALTERNATIVE ANALYSIS CRITERIA

The “Guidelines for Implementation of the California Environmental Quality Act” (CEQA), Title 14, California Code of Regulations Section 15126(d), provide direction by requiring an evaluation of the comparative merits of “a range of reasonable alternatives to the project, or to the location of the project, which would feasibly attain most of the project objectives...” In addition, the analysis must address the “no project” alternative. (Cal. Code Regs., tit. 14, §15126(d).)

The range of alternatives is governed by the “rule of reason” which requires consideration only of those alternatives necessary to permit informed decision-making and public participation. CEQA states that an environmental document does not have to consider an alternative of which the effect cannot be reasonably ascertained and of which the implementation is remote and speculative. (Cal. Code Regs., tit. 14, §15125(d)(5).) However, if the range of alternatives is defined too narrowly, the analysis may be inadequate. (City of Santee v. County of San Diego (4th Dist. 1989) 214 Cal.App. 3d 1438.)

To prepare this alternatives analysis, staff used the methodology summarized below:

- Identify the basic objectives of the project.
- Identify and evaluate alternatives to the project. The principle project alternatives examined that do not require the construction of a natural gas-fired facility are increased energy efficiency (or demand side management) and construction of alternative technologies (e.g., geothermal, wind or solar).
- Identify and evaluate alternative locations or sites.
- Evaluate the impacts of not constructing the project (the “no project” alternative).

DETERMINING THE SCOPE OF THE ALTERNATIVES ANALYSIS

The purpose of staff's alternatives analysis is to provide the Energy Commission with a reasonable range of feasible alternatives which could substantially reduce or avoid any potentially significant adverse impacts of the proposed project. To accomplish this, staff must determine the appropriate scope of analysis. Consequently, it is necessary to identify and determine the potential significant impacts of the proposed project and then focus on alternatives that are capable of reducing or avoiding significant impacts.

This section presents staff's analysis of generation and siting alternatives, and the "no project" alternative [CEQA Guidelines, section 15112(d)(2)]. In addition, alternative routes for the proposed project's linear facilities are addressed. Alternatives were developed in response to comments and information provided by Energy Commission staff and staffs of other agencies.

In considering location alternatives, the staff determined a reasonable geographical area. Since alternatives must consider the underlying objectives of the proposed project, staff confined the geographic area for location alternatives to the Elk Hills Oil and Gas Field. The locations chosen are consistent with the EHPP's objectives and the applicant's siting criteria of use of previously disturbed areas; existence of a restricted access land buffer, close proximity to and availability of suitable transmission line interconnections, process water and natural gas supplies; compatibility with oil field activities, proximity to another power plant facility (35R); and other environmental considerations such as visual resources and air quality (EHPP 1999a, p. 3-79).

BASIC OBJECTIVES OF THE PROJECT

After studying the applicant's Application for Certification (AFC), Energy Commission staff has determined the project's objectives to be:

- The construction and operation of a merchant power plant in the region that supplies economic, reliable, and environmentally sound electrical energy and capacity in the newly deregulated power market.
- To locate near key infrastructure, such as transmission line interconnections, and supplies of process water and natural gas.

PROJECT DESCRIPTION AND SETTING

A more complete description of the project and its setting is in the Project Description section of this Final Staff Assessment (FSA).

POWER PLANT

Located in the arid western Kern County region, the Elk Hills region has been heavily exploited for oil and natural gas production since the early 20th Century. Although zoned primarily as agricultural land, the Elk Hills have seen little, if any, typical agricultural activities, such as the raising of crops and cattle grazing. Narrow and deep ravines and equally narrow and steep ridges characterize much of the terrain. Scattered throughout the field are well sites that have been leveled to accommodate drilling, access roads and many pipelines of assorted uses.

The proposed EHPP would be a nominal 500-megawatt, combined-cycle, natural gas-fired power plant with two combustion turbine generators/heat recovery steam generator (HRSG) combinations. Steam generated in the two HRSGs would be combined and used to run one steam turbine generator. The power plant would be located on 12 acres in the middle of the former Elk Hills Naval Petroleum Reserve Number 1, which was operated by the Government of the United States from the early 1900's until its purchase by Occidental of Elk Hills, Inc. (OEHI) in February 1998. The former Reserve is now referred to as the Elk Hills Oil and Gas Field and comprises 75 square miles (47,000 acres). (EHPP 1999a, Sections 1 and 3.) See **ALTERNATIVES Figure 1** for a map of the location of the proposed project site and related facilities.

The EHPP would be the second power plant located in the middle of the Elk Hills Oil and Gas Field. Nearby the proposed site is a 45-megawatt cogeneration power plant, known as 35R, that was constructed by the U.S. Government in 1994 to supply electrical power and heat to the Elk Hills Reserve (EHPP 1999a, p. 3-75).

RELATED FACILITIES

TRANSMISSION LINE

Electricity generated by the EHPP would be transmitted to Pacific Gas & Electric's (PG&E) Midway Substation at the unincorporated community of Buttonwillow, approximately nine miles north of the power plant site. The applicant has proposed two alternative transmission line routings, 1A and 1B, and a variation of 1B. It is the applicant's intention that all three routes be approved. (See Siting and Related Facilities Alternatives below.)

RAW WATER SUPPLY PIPELINE

Water for the EHPP would be supplied by the West Kern Water District (WKWD) via a new 9.8-mile long, 16-inch steel pipeline extending from WKWD's existing facilities east of the proposed power plant site and adjacent to State Highway 119. The first 4.1 miles of the raw water supply pipeline would be placed underground alongside existing underground pipelines. Of this 4.1 miles, 0.7 mile of pipeline crosses the Coles Levee Ecosystem Preserve and 0.5 mile crosses Bureau of Land Management land. The remainder of the pipeline is on Elk Hills Oil and Gas Field property and features above ground mounting on pipe supports for the last 5.7 miles.

ALTERNATIVES Figure 1
Location of the Proposed Site and Related Facilities

WASTEWATER DISPOSAL PIPELINE

A new 4.4-mile long, 8-inch wastewater pipeline is proposed to convey wastewater from the plant site south to two new injection wells, both on Elk Hills Oil and Gas Field property. These injection wells would be located near existing disposal wells used to dispose of produced water from OEHI's oil and gas field operations. Except for a portion of the pipeline that would go under Elk Hills Road, the pipeline would be mounted above ground on pipe supports.

NATURAL GAS SUPPLY PIPELINE

OEHI's locally produced natural gas would be supplied to the power plant via a new 2,500-foot long, 10-inch supply pipeline. This pipeline would be mounted above ground on pipe supports as well.

POTENTIAL SIGNIFICANT ENVIRONMENTAL IMPACTS

At this time there are only two technical areas that have identified potential significant environmental impacts: air quality and biological resources. It is staff's opinion that the mitigation measures the applicant has proposed will reduce any potential significant environmental impacts to less than significant levels.

ALTERNATIVES TO THE PROJECT

GENERATION TECHNOLOGY ALTERNATIVES

Public Resources Code, section 25305(c) limits the scope of alternatives analyses during a siting case under specific conditions. This section states that conservation, load management, or other demand reducing measures reasonably expected to occur shall be explicitly examined in the Energy Commission's Electricity Report and shall not be considered as alternatives to a proposed facility during the siting process. Thus, such alternatives are not included in this FSA.

Staff compared various alternative technologies with the proposed project, scaled to meet the project's objectives. Technologies examined were those principal electricity generation technologies which do not burn fossil fuels such as natural gas, solar and wind. Each of these technologies could be attractive from an environmental perspective because of the absence or reduced level of air pollutant emissions.

Solar and wind resources require large land areas in order to generate 500 megawatts of electricity. Specifically, central receiver solar thermal projects require approximately 9 to 10 acres per megawatt; 500 megawatts would require approximately 4,500 to 5,000 acres, or about 400 times the amount of space taken by the proposed plant site and linear facilities. Parabolic trough solar thermal technology requires similar acreage per megawatt. Wind generation "farms" generally require about 17 acres per megawatt, with 500 megawatts requiring 8,500 acres, more than 700 times the amount of space taken by the proposed plant site and linear facilities. (CEC 1996, pp. B.15.2 & B.15.3)

The alternative technologies discussed above have the potential for significant land use, biological and visual impacts. This is true in the western San Joaquin Valley, which has a number of sensitive species and related habitat areas, and many broad views of the Coast Range from Interstate 5. Looking outside the San Joaquin Valley, the development uncertainties and the potential for impacts at remote resource areas are significant constraints. Consequently, staff does not believe that solar and wind technologies present any feasible alternatives to the proposed project.

SITING AND RELATED FACILITIES ALTERNATIVES

COMMENTS ON THE PRELIMINARY STAFF ASSESSMENT

California Unions for Reliable Energy (CURE) provided comments on the Cultural Resources and Alternatives analysis in staff's Preliminary Staff Assessment (CURE 1999c, p. 21). CURE commented that due to the large number of cultural resources sites that could be affected by the project, staff should have evaluated project alternatives, including configurations, that would avoid or lessen the project's impacts. Cultural Resources staff has testified that for the proposed power plant site and all the proposed linear facilities, any significant potential impacts on cultural resources can be mitigated to less than significant levels. Therefore, staff believes that evaluation of the proposed power plant site and linear facilities is sufficient. Staff provides, in the discussion and in its conclusion below, its preference for the alternative transmission line route 1B Variation over the other two. This preferred route would have the least impact on both Cultural Resources and Visual Resources.

POWER PLANT SITING ALTERNATIVES

Staff believes that due to the oil and gas field's large geographic extent, the proposed project's separation from other activities, such as farming and residential, the long history of extensive oil and gas field disturbances, availability and proximity to a natural gas supply, and the physical security maintained by OEHI (controlled access roads and fencing), the consideration of site alternatives outside the Elk Hills Oil and Gas Field are unnecessary.

Staff examined the three siting alternatives proposed by the applicant, Alternative Sites A, B and C (EHPP 1999a, pp. 3-75 through 3-79). All are located within the Elk Hills Oil and Gas Field and share the common attributes mentioned above. The basic characteristics of each site that differentiates it from the others, including the preferred site, are presented below. Please see **ALTERNATIVES Figure 2**.

ALTERNATIVE SITE A

Alternative Site A is a vacant, 12-acre unused portion of the property that is in a partially disturbed condition. The topography of the site is the roughest of all the sites and is of low quality as biological habitat. Situated about 3,500 feet west of the preferred site, Alternative Site A is both farther away and not visible from Elk Hills Road. However, access from Elk Hills Road is not as direct and improved as the other sites. Work to effect road improvements could impact more biological, cultural and paleontological resources than the applicant's preferred site due to the greater access distance involved.

ALTERNATIVE SITE B

Alternative Site B is about 1,500 feet south of Alternative Site A and is currently a large, graveled area used for the storage of oil and gas field equipment. This site is also about 3,500 feet from Elk Hills Road, but access is more direct and utilizes better roadways. Alternative Site B is also not visible from Elk Hills Road. Use of this site would displace the current storage use to a different, and as yet unknown, location. This could impact biological, cultural and paleontological resources at the replacement location.

ALTERNATIVE SITE C

Located about four miles south of the preferred site and situated on the southwestern slope of the Elk Hills, Alternative Site C is currently occupied by out of service tanks. This site is in the same general location as the proposed wastewater injection wells, and is adjacent to Elk Hills Road. The site is quite visible from both Elk Hills Road and the nearest community, Valley Acres, three miles away. Vehicular access to the site is similar to the preferred site's access characteristics. The lengths of the transmission line and raw water supply pipeline would each be about four miles longer than those associated with the other sites. In addition, Alternative Site C is lower in elevation than the other sites (600 feet above mean sea level, as opposed to 1,300 feet) which may pose greater air quality impact concerns than the others pose.

RELATED FACILITIES ALTERNATIVES

During the 20th Century, the Elk Hills were the scene of intensive activities that changed the complexion of the area by disturbing the former natural and cultural environments. Staff believes that the proposed related facilities for the raw water supply, wastewater, and natural gas supply pipelines would create fewer potential impacts because they tend to follow well established, disturbed routes. Other potential routes may create more impacts because they would either cross less-disturbed areas, require longer routing distances, or both. However, as mentioned above, staff has a preference for one of the three proposed transmission line options. The following related facilities pertain only to those associated with the applicant's preferred power plant site.

TRANSMISSION LINES

GUIDANCE PERTAINING TO TRANSMISSION LINE SITING

Senate Bill 2431 (Garamendi, 1988) specifies that planning and siting of new transmission facilities be pursued in the following order (CEC 1992):

ALTERNATIVES Figure 2
Location of Alternative Sites

1. The use of existing right-of-way should be encouraged by upgrading existing transmission facilities where technically and economically feasible.
2. Expansion of existing right-of-way should be encouraged whenever construction of new transmission lines is required.
3. New right-of-way should be created when justified by environmental, technical, or economic reasons, as determined by the appropriate licensing agency.
4. Agreement among all interested utilities should be sought on efficient use of new transmission capacity whenever there is a need to construct such capacity.

Staff applies the SB 2431 priority listing in the following discussions to each of the three transmission line alternatives.

ALTERNATIVE 1A

Route 1A is a transmission line mounted on steel poles that originates at the power plant site and trends north for about two miles. For most of the two miles, the transmission line route would parallel the existing 115 kV Midway-Taft transmission line that runs north-south between the Midway Substation and the city of Taft, which is about ten miles south of the plant site. (The Midway- Taft transmission line is mounted on steel latticework towers in the Elk Hills area and on concrete poles north of the California Aqueduct. This transmission line is associated to some degree with all three of Elk Hills Power's proposed transmission line route alternatives/variation.)

At the two-mile distance, Route 1A turns east and extends about seven miles to a proposed new substation near the unincorporated community of Tupman. The substation would be located near and to the west of the California Aqueduct, and would connect with the existing Midway-Wheeler Ridge transmission line. Because the Midway-Wheeler Ridge transmission line is east of the aqueduct, the connection with the proposed substation would have to the cross the aqueduct twice. These crossings would require agreement between PG&E and the California Department of Water Resources which share ownership of the Midway-Wheeler Ridge line.

According to the Cultural Resources FSA section, Alternative 1A will potentially impact two sites listed on the National Register of Historic Places (NRHP) (Torres 2000). A third NRHP site is identified as within 0.25 mile of EHPP facilities, but outside the Area of Potential Effect (APE) and not likely to be impacted. The **Visual Resources** FSA section demonstrates that Alternative 1A would, of the three options, create the most visual impacts (CEC 2000, p. 166). Neither of these sections found that Alternative 1A created significant environmental impacts that cannot be mitigated to less than significant levels. However, because Alternative 1A requires new right of way, it would be third in priority according to the SB 2431 listing.

ALTERNATIVE 1B

The first two miles of Route 1B are the same as 1A and is also a transmission line mounted on steel poles. From this point the route proceeds almost directly to the Midway Substation, crossing the California Aqueduct at about milepost 4.3, and following the east side of Wasco Way. Route 1B would parallel the aforementioned Midway-Taft transmission line which, along Wasco Way, is mounted on concrete poles that are located west of the roadway. Wasco Way is in a cotton-growing agricultural area. The transmission line would interconnect with PG&E's system at the Midway substation, which is about 8.6 miles north of the preferred power plant site.

There is one Cultural Resources National Register of Historical Places (NRHP) site identified within 0.25 mile of EHPP facilities, but outside the APE in the vicinity of Route 1B, but there are no anticipated impacts to this site (Torres 2000). The Visual Resources FSA section demonstrates that Alternative 1B would create fewer visual impacts than 1A, but more than the 1B Variation (CEC 2000, p. 166). Again, neither of these sections found that Alternative 1B created significant environmental impacts that cannot be mitigated to less than significant levels. Alternative 1B would require expansion of an existing right of way. Alternative 1B would be second in priority according to SB 2431 listing.

ALTERNATIVE 1B VARIATION

The Route 1B variation would combine the Midway-Taft transmission line with the proposed Route 1B, thus replacing the existing lattice tower and concrete poles of the Midway-Taft transmission line with steel poles. The routing would follow the existing Midway-

Taft transmission line's route which, along Wasco Way, is located on the west side of the roadway. This route would also interconnect at the Midway substation. The route 1B Variation will have the least environmental and visual impacts due to the fact that two transmission lines will use a single set of poles. (CEC 2000, p. 166). Alternative 1B Variatioin would have the same potential Cultural Resources impacts as Alternative 1B. Also, as with route 1B the visual impacts would be most noticeable in the agricultural area along Wasco Way. Alternative 1B Variation satisfies the first priority under SB 2431 because it upgrades (by combining) an existing transmission facility.

RAW WATER SUPPLY

A detailed analysis of raw water supply alternatives was presented in the **Soil and Water Resources** section of FSA, Part II (February 17, 2000), a Supplement to the Soil and Water Resources section (March 2, 2000), and in an analysis of dry cooling and State Water Resources Control Board Policy 75-58 (April 4, 2000). Staff conluded that use of the proposed raw water supply, and the construction, use and maintenance of the proposed raw water supply pipeline would not create significant environmental impacts that cannot be mitigated to less than significant levels.

WASTEWATER PIPELINE

The 4-mile long wastewater pipeline follows established roads to a heavily disturbed area. Staff has concluded that the site of the injection wells is suitable for such use (White 2000). Therefore, staff concludes that other routing alternatives need not be examined.

NATURAL GAS SUPPLY PIPELINE

The ½-mile long pipeline route crosses an area with minimal environmental resources and is the most direct route. Therefore, staff concluded that route alternatives need not be examined.

COMPARATIVE CUMULATIVE LENGTHS OF RELATED FACILITIES BY SITE

ALTERNATIVES Table 1 shows lengths of related facilities associated with the preferred site and the three alternative sites. The overall length for the related facilities is 23.7 miles. The alternatives all have greater overall lengths associated with them, ranging from 24.6 miles for Site A to 31.7 miles for Site C. This equates to percentage increases from 4% to 34%. The preferred site, with either transmission line Route 1B or the Route 1B Variation, would decrease the total length to 23.3 miles or about 2% less.

ALTERNATIVES Table 1
Lengths of Linear Facilities (miles)

	Preferred Site			Alternative Sites								
				Site A			Site B			Site C		
Linear Facilities[1]												
Raw Water Pipeline	9.8			10.1			10.5			13.8		
Wastewater Pipeline	4.4			5.0			5.5			0.4		
Natural Gas Pipeline	0.5			0.5[2]			0.5[2]			4.5[2]		
Transmission Line	1A	1B	1B Var	1A	1B	1B Var	1A	1B	1B Var	1A	1B	1B Var
	9.0	8.6	8.6	9.0	8.6	8.6[2]	9.4	9.0	9.0	13.0	12.6	12.6
Total (maximum) & [%} Increase	23.7			24.6 [4%]			25.9 [9%]			31.7 [34%]		

[1] Source: EHPP 1999a, Table 3.11-1, p. 3-81
[2] Source: Champion 1999, personal communication

THE "NO PROJECT" ALTERNATIVE

CEQA Guidelines and Energy Commission regulations require consideration of the "no project" alternative. This alternative assumes that the project is not constructed, and is compared to the proposed project. A determination is made whether the "no project" alternative is superior, equivalent, or inferior to the proposed project.

In the AFC, the applicant presented the "no project" alternative as not feasible and provided four supporting arguments for their conclusion (EHPP 1999a, p. 3-73 and 3-74):

1. the proposed project would serve to fill part of California's need for "… a substantial amount of additional generation capacity …;
2. the proposed project will "… help to replace nuclear and fossil fuel generation resources retired due to age or cost of producing power";
3. "… existing power plants operating in place of the EHPP would most likely consume more fuel and emit more air pollutants per kilowatt-hour generated"; and
4. the project would insulate ratepayers or taxpayers from risk, and would assist ratepayers by increasing competition and therefore decrease electricity rates.

If this project is not built, the same market conditions that encouraged it to be proposed will encourage others. Therefore, the "no project" alternative is feasible. It is quite feasible that a substantial amount of additional generating capcity will be proposed even in the absence of this project. Staff can reasonably expect California's need for new plants to be filled with or without the proposed project. There is no reason to assume that the total amount of capacity actually built would differ, with or without this project.

It follows then, that the extent to which retired, nuclear and fossil generation resources will be replaced by new resources can be expected to be the same with or without this project. The extent to which generation from existing power plants would consume fuel and emit pollutants would be the same with or without this project. And whatever effect new plants might have insulating ratepayers and taxpayers from risk will occur whether or not the proposed plant is included among the new plants actually built.

The “no project” alternative would eliminate the expected economic benefits which the proposed project would bring to Kern County. These include minimum property tax revenues of approximately $20 million over the first ten years of operation. Local construction supply and materials purchases are estimated to be $25 million, with sales tax revenues accrued during construction from these sales estimated to be approximately $1.8 million. During operations, the project owner is estimated to spend approximately $3 million per year locally, resulting in an estimated sales tax revenue of about $217,000 (EHPP 1999a, pp. 5.8-21 and 5.8-22).

Staff has determined that the “no project” alternative is environmentally superior to the proposed project in an unmitigated condition. This is because the EHPP would, in an unmitigated condition, have significant environmental impacts on air quality, water and biological resources. Not constructing and operating an (unmitigated) power plant would avoid these impacts. However, as stated above, staff believes mitigation measures proposed by the applicant will reduce any impacts to less than significant levels. In addition, staff recognizes potential economic benefits will be derived from the project. Therefore, staff believes that, overall, the “no project” alternative is not superior to the proposed project.

CONCLUSIONS AND RECOMMENDATION

Staff has determined the proposed power plant site is the best option among those considered because it: 1) provides the closest and most direct access, 2) would present fewer impacts to biological, cultural and paleontological resources, 3) does not present as great a visual impact and air quality impacts as Alternative Site C, and 4) would not require longer water, natural gas supply and wastewater pipelines. Staff does not believe that energy efficiency measures and alternative technologies (geothermal, solar, wind, and hydroelectric) present any feasible alternatives to the proposed project.

With regard to the transmission line route options, staff believes any of the three are suitable because the environmental impacts associated with each can be reduced to less than significant levels. However, staff strongly prefers the Route 1B Variation because it would 1) reduce environmental and visual impacts compared to the other alternatives, and 2) it complies with SB 2431 by combining the new transmission line with an existing line. Staff recognizes that the EHP may be unable to accomplish Alternative 1B Variation due to economic considerations, which would relieve EHPP from conforming to the first priority of SB 2431.

If so, Alternative 1B route would be staff’s second preference, and Alternative 1A, its third.

Notwithstanding its transmission line route preference, staff recommends that the Energy Commission certify the Elk Hills Power Project as proposed, including the three options for transmission line routings.

REFERENCES

CEC (1992). Transmission System and Right of Way Planning for the 1990's and Beyond, Executive Summary, March 1992.

CEC (2000). Final Staff Assessment (FSA), Part 1 of 3, Elk Hills Power Project. Issued January 5, 2000.

Champion, Dennis. Personal communication with Marc S. Pryor, November 11, 1999.

Elk Hills Power, L.L.C. 1999a. Application For Certification for the Elk Hills Power Project.

Torres (2000). Personal communication with Dorothy Torres, CEC staff, regarding Cultural Resources impacts posed by transmission line alternative routes.

White (2000). Report of Conversation regarding the Feb. 18, 2000 site visit. New Wastewater Injection Well Locations and Geologic Lineations.

AIR QUALITY

Joseph M. Loyer

INTRODUCTION

This analysis evaluates the expected air quality impacts of the emissions of criteria air pollutants due to the construction and operation of the proposed Elk Hills Power Project (EHPP). Criteria air pollutants are defined as those for which a state or federal ambient air quality standard has been established to protect public health. They include nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), ozone (O3), volatile organic compounds (VOC) and particulate matter less than 10 microns in diameter (PM10).

In carrying out this analysis, the California Energy Commission staff evaluated the following major points:

- whether the EHPP is likely to conform with applicable Federal, State and San Joaquin Valley Unified Air Pollution Control District air quality laws, ordinances, regulations and standards, as required by Title 20, California Code of Regulations, section 1742.5 (b);
- whether the EHPP is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contributions to existing violations of those standards, as required by Title 20, California Code of Regulations, section 1742 (b); and
- whether the mitigation proposed for the EHPP is adequate to lessen the potential impacts to a level of insignificance, as required by Title 20, California Code of Regulations, section 1744 (b).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS (LORS)

FEDERAL

Under the Federal Clean Air Act (40 CFR 52.21), there are two major components of air pollution law, New Source Review (NSR) and Prevention of Significant Deterioration (PSD). NSR is a regulatory process for evaluation of those pollutants that violate federal ambient air quality standards. Conversely, PSD is a regulatory process for evaluation of those pollutants that do not violate federal ambient air quality standards. The NSR analysis has been delegated by the US Environmental Protection Agency (EPA) to the San Joaquin Valley Unified Air Pollution Control District (District). The EPA determines the conformance with the PSD regulations. The PSD requirements apply only to those projects (known as major sources) that exceed 100 tons per year for any pollutant.

STATE

The California State Health and Safety Code, section 41700, requires that “no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerate number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property."

LOCAL

The proposed project is subject to the following San Joaquin Valley Unified Air Pollution Control District rules and regulations:

RULE 2201 - NEW AND MODIFIED STATIONARY SOURCE REVIEW RULE

The main functions of the District's New Source Review Rule are to allow for the issuance of Authorities to Construct, Permits to Operate, the application of Best Available Control Technology (BACT) to new permit sources and to require the new permit source to secure emission offsets.

SECTION 4.1 - BEST AVAILABLE CONTROL TECHNOLOGY

Best Available Control Technology is defined as: a) has been contained in any State Implementation Plan and approved by EPA; b) the most stringent emission limitation or control technique that has been achieved in practice for a class of source, or c) any other emission limitation or control technique which the District's Air Pollution Control Officer (APCO) finds is technologically feasible and is cost effective. BACT will apply to any air pollutant that results in an emissions increase of 2 pounds per day. In the case of the EHPP, BACT will apply for NOx, SO2, PM10, VOC and CO emissions from all point sources of the project.

SECTION 4.2 - OFFSETS

Emissions offsets for new sources are required when those sources exceed the following emissions levels:

- Sulfur oxides - 150 lbs/day
- PM10 - 80 lbs/day
- Oxides of nitrogen - 10 tons/year
- Volatile organic compounds - 10 tons/year

The EHPP exceeds all of the above emission levels; therefore offsets are required for all four of these pollutants. The emission offsets provided shall be adjusted according to the distance of the offsets from the EHPP. The ratios are:

- Within 15 miles of the same source - 1.2 to 1
- 15 miles or more from the source - 1.5 to 1

Section 4.2.5.3 allows for the use of interpollutant offsets (including PM10 and precursors for PM10) on a case-by-case basis, provided that the applicant demonstrates that the emissions increase will not cause a violation of any ambient air quality standard.

The ratio for interpollutant trading shall be based on an air quality analysis and shall be equal to or greater than the minimum offsetting requirements (the distance ratios) of this rule.

SECTION 4.3 - ADDITIONAL SOURCE REQUIREMENTS

Rule 4.3.2.1 requires that a new source not cause, or make worse, the violation of an ambient air quality standard as demonstrated through analysis with air dispersion models.

RULE 2520 – FEDERALLY MANDATED OPERATING PERMITS

Requires that a project owner file a Title V Operating Permit with the District within 12 months of commencing operation. A project is subject to this requirement if any of the following apply: the project is a major stationary source (under PSD definitions), it has the potential to emit greater than 100 tons per year of a criteria pollutant, that any equipment is subject to New Source Performance Standards, the project is subject to Title IV Acid Rain program, or the applicant is required to obtain a PSD permit from EPA. The Title V permit application requires that the owner submit information on the operation of the air polluting equipment, the emission controls, the quantities of emissions, the monitoring of the equipment as well as other information requirements.

RULE 2540 – ACID RAIN PROGRAM

A project greater than 25 MW and installed after November 15, 1990, must submit an acid rain program permit application to the District. The acid rain requirements will become part of the Title V Operating Program (Rule 2520). The specific requirements for the EHPP will be discussed in the section, “Compliance with LORS – Local” later in this analysis.

RULE 4001 - NEW SOURCE PERFORMANCE STANDARDS

Rule 4001 specifies that a project must meet the requirements of the Federal New Source Performance Standards (NSPS) specified in Title 40, Code of Federal Regulations (CFR), Part 60, Chapter 1. Subpart GG, which pertains to Stationary Gas Turbines, requires that NOx concentrations are a function of the heat rate of the combustion, which in this case would be approximately 116 ppmv at 15% O2. In addition, the SO2 concentration shall be less than 150 ppmv and the sulfur content of the fuel shall be no greater than 0.8 percent by weight.

RULE 4101 - VISIBLE EMISSIONS

Rule 4101 prohibits air emissions, other than water vapor, of more than Ringelmann No. 1 (20 percent opacity) for more than 3 minutes in any one hour.

RULE 4201 - PARTICULATE MATTER CONCENTRATION

Rule 4201 limits particulate emissions from sources such as the gas turbines, cooling towers and emergency fire water pumps to less than 0.1 grain per cubic foot of exhaust gas at dry conditions.

Rule 4202 – Particulate Matter Emission Rate

Rule 4202 limits hourly particulate emissions based on the process rate of the process. Combustion of gaseous and liquid fuels are excluded from this rule, however, the particulate emissions associated with the cooling tower are subject to the emission limits of this rule.

Rule 4703 - Stationary Gas Turbines

Rule 4703 limits NOx concentrations to 12.2 ppm for the SCR controlled turbines and 21 ppm for the SCONOx controlled turbine. In addition there is a limit in CO concentrations of less than 200 ppm.

Rule 4801 - SO2 Concentration

Rule 4801 limits the SO2 concentration emitted into the atmosphere to no greater than 0.2 percent by volume.

Rule 8010 - Fugitive Dust Administrative Requirements for Control of Fine Particulate Matter (PM10)

Rule 8010 specifies the types of chemical stabilizing agents and dust suppressant materials that can (and cannot) be used to minimize fugitive dust.

Rule 8020 - Fugitive Dust Requirements for Control of Fine Particulate Matter (PM10) from Construction, Demolition, Excavation, and Extraction Activities

Rule 8020 requires that fugitive dust emissions during construction activities be limited to no greater than 40 percent opacity by means of water application or chemical dust suppressants. The rule also encourages the use of paved access aprons, gravel strips, wheel washers or other measures to limit mud or dirt carry-out onto paved public roads.

Rule 8030 - Control of PM10 from Handling and Storage of Bulk Materials

Rule 8030 limits the fugitive dust emissions from the handling and storage of materials. It specifies that bulk materials be transported using wetting agents, allow appropriate freeboard space in the vehicles, or be covered. It also requires that stored materials be covered or stabilized.

Rule 8060 - Control of PM10 from Paved and Unpaved Roads

Rule 8060 specifies the width of paved shoulders on paved roads or the use of chemical dust suppressants on unpaved roadways, shoulders and medians.

RULE 8070 - CONTROL OF PM10 FROM VEHICLE/EQUIPMENT PARKING, SHIPPING, RECEIVING, TRANSFER, FUELING AND SERVICE AREAS

This rule is intended to limit fugitive dust from unpaved parking areas by means of using water or chemical dust suppressants or the use of gravel. It also requires that the affected owners/operators shall remove tracked out mud and dirt onto public roadways once a day.

ENVIRONMENTAL SETTING

METEOROLOGICAL CONDITIONS

The climate of the southern San Joaquin Valley is typically dominated by hot dry summers and mild winters with relatively small amounts of precipitation. The semi-permanent Pacific High pressure ridge over the eastern Pacific Ocean dominates the weather during the summer months, blocking low pressure systems from passing through the area. The Pacific High, along with the Temblor Range to the west that blocks the marine air influence from the Pacific Ocean, results in summers that are usually quite warm, with average daily maximum temperatures during July of over 98^{o}F.

During the winter months, the Pacific High weakens and migrates to the south allowing Pacific storms into California. The annual rainfall in the Bakersfield area is only 5.7 inches. In between storms, high pressure from the Great Basin High can block storms and result in persistent tule fog caused by temperature inversions. Daily maximums during the December-January months are a relatively mild 57^{o}F, with lows averaging 38^{o}F. At the Maricopa weather station, a record high of 115^{o}F and record low of 15^{o}F was measured. These temperatures are used in determining the maximum possible emissions from the EHPP and the maximum emission impacts in the air dispersion modeling analysis.

Winds in the area are strongly influenced by the Temblor Range to the west and the marine air that enters the Central Valley through the Carquinez Strait and Altamont Pass in the Bay Area to the north. During the summer, marine air entering the Central Valley results in northeasterly winds in the daytime hours. In the nighttime hours downslope drainage of air from the hills and mountains to the south and west results in winds from the southwest. This windflow pattern is fairly consistent throughout the year, although there is more variability to wind directions during the winter with the passage of storms through the area. Winds are usually of higher speeds during the summer because during the winter, calm and stagnant atmospheric conditions can occur between storms and the influence of the marine air from the coast is significantly diminished.

Along with the winds, another climatic factor is atmospheric stability and mixing height. Atmospheric stability is an indicator of the air turbulence and mixing. During the daylight hours of the summer when the earth is heated and air rises, there is more turbulence, more mixing and thus less stability. During these conditions there is more air pollutant dispersion and, therefore, usually fewer air quality impacts from a single air pollution source like the EHPP. During the winter months between storms, very stable atmospheric conditions occur, resulting in very little mixing. Under these conditions, little air pollutant dispersion occurs, and consequently higher air quality impacts result from stationary source emissions. Mixing heights are generally lower during the winter, along with lower mean wind speeds and less vertical mixing.

EXISTING AIR QUALITY

The Federal Clean Air Act and the California Air Resources Board (CARB) both required the establishment of allowable maximum ambient concentrations of air pollutants, called ambient air quality standards (AAQS). The state AAQS, established by CARB, are typically lower (more protective) than the federal AAQS, which are established by the EPA. The state and federal air quality standards are listed in **AIR QUALITY Table 1**. As indicated in **AIR QUALITY Table 1**, the averaging times for the various air quality standards (the duration over which they are measured) range from one-hour to an annual average. The standards are read as a concentration, in parts per million (ppm), or as a weighted mass of material per a volume of air, in milligrams or micrograms of pollutant in a cubic meter of air (mg/m^3 and $\mu g/m^3$).

In July 1997, the EPA promulgated new ozone and PM2.5 (particulate matter less than 2.5 microns in diameter) ambient air quality standards, which are shown in **AIR QUALITY Table 1**. The new 8-hour ozone standard will replace the existing 1-hour standard. The PM2.5 standards will be in addition to the existing PM10 standards. Although the standards may be set, the EPA will first have to designate areas which violate these new standards, and then air districts that violate these standards will have to prepare implementation plans to reach attainment of those standards.

In general, an area is designated as attainment for a specific pollutant if the concentrations of that air contaminant do not exceed the standard. Likewise, an area is designated as non-attainment for an air contaminant if that standard is violated. Where not enough ambient data is available to support designation as either attainment or non-attainment, the area can be designated as unclassified.

Unclassified areas are normally treated the same as attainment areas for regulatory purposes. An area can be attainment for one air contaminant while non-attainment for another, or attainment for the federal standard and non-attainment for the state standard for the same contaminant. The entire area within the boundaries of a district is usually evaluated to determine the district's attainment status.

The EHPP is located in the Kern County portion of the San Joaquin Valley Air Basin and, as stated above, is under the jurisdiction of the San Joaquin Valley Unified Air Pollution Control District (District). This area is designated as non-attainment for both the state and the federal ozone and PM10 standards, attainment for the state's CO, NO2, SO2, SO4 and Lead standards, attainment for the federal SO2 standard, and unclassified/attainment for the federal CO and NO2 standards (CARB 1998).

AIR QUALITY Table 1

Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	1 Hour	0.12 ppm (235 $\mu g/m^3$)	0.09 ppm (180 $\mu g/m^3$)
	8 Hour	0.08 ppm (157 $\mu g/m^3$)	---
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide (NO_2)	Annual Average	0.053 ppm (100 $\mu g/m^3$)	---
	1 Hour	---	0.25 ppm (470 $\mu g/m^3$)
Sulfur Dioxide (SO_2)	Annual Average	80 $\mu g/m^3$ (0.03 ppm)	---
	24 Hour	365 $\mu g/m^3$ (0.14 ppm)	0.04 ppm (105 $\mu g/m^3$)
	3 Hour	1300 $\mu g/m^3$ (0.5 ppm)	---
	1 Hour	---	0.25 ppm (655 $\mu g/m^3$)
Respirable Particulate Matter (PM10)	Annual Geometric Mean	---	30 $\mu g/m^3$
	24 Hour	150 $\mu g/m^3$	50 $\mu g/m^3$
	Annual Arithmetic Mean	50 $\mu g/m^3$	---
Fine Particulate Matter (PM2.5)	24 Hour	65 $\mu g/m^3$	---
	Annual Arithmetic Mean	15 $\mu g/m^3$	---
Sulfates (SO_4)	24 Hour	---	25 $\mu g/m^3$
Lead	30 Day Average	---	1.5 $\mu g/m^3$
	Calendar Quarter	1.5 $\mu g/m^3$	---
Hydrogen Sulfide (H_2S)	1 Hour	---	0.03 ppm (42$\mu g/m^3$)
Vinyl Chloride (chloroethene)	24 Hour	---	0.010 ppm (26 $\mu g/m^3$)
Visibility Reducing Particulates	1 Observation	---	In sufficient amount to produce an extinction co-efficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent.

Ambient air quality data has been collected by the oil companies, known as the Westside Operators, in western Kern County for a number of years. Ambient air quality data was collected between 1993 and 1995 at three Westside Operators sites: Fellows, located approximately 8 miles south-southwest of the project site; Maricopa, located approximately 16 south of the project site; and McKittrick, which is located approximately 6 miles west-northwest of the project site, is presented in **AIR QUALITY Table 2**. That data shows there have been no violations during that period of the NO2, SO2 or CO ambient air quality standards.

Additional ambient air quality data from the Air Resources Board's ozone monitor in Maricopa and Taft College PM10 monitor (9 miles to the south of the project site) are shown in **AIR QUALITY Table 3**. This data shows that frequent violations of the state 1-hour ozone and 24-hour PM10 standard have occurred between 1993 and 1997. There appears to be no clear trend of significant improvement in the ambient concentrations of these two pollutants.

Ozone is not directly emitted from stationary or mobile sources, but is formed as the result of chemical reactions in the atmosphere between directly emitted air pollutants. Nitrogen oxides (NOx) and hydrocarbons (Volatile Organic Compounds [VOCs]) interact in the presence of sunlight to form ozone. The collected air quality data indicate that the ozone violations occurred primarily during the period of May through October.

In the most recent CARB report on the contribution of various districts to ozone violations in other districts (CARB 1996), the San Joaquin Valley Air Basin contributes measurably to ambient ozone levels in other districts, as well as other districts contributing measurably to the San Joaquin Valley's ozone problems. The report concludes that sources within the San Joaquin Valley Air Basin contribute to ozone levels in Mountain County districts to the northeast, the South Central and North Central Air Basins to the south, to the Mojave Desert to the east, the Sacramento area to the north, the Great Basin Valleys to the east, and to the North Central Coast Air Basin to the west. Conversely, emissions from districts such as the San Francisco Bay Area and the Sacramento area contribute to San Joaquin Valley's ozone problems. This widespread contribution from one geographic area to another demonstrates the regional nature of the ozone problem and ozone formation.

AIR QUALITY Table 2
Maximum PM10, NO2, CO and SO2 Readings
Collected at Fellows and Maricopa

Pollutant	Averaging Time	1995	1994	1993	Most Restrictive Ambient Air Quality Standard	Air Monitoring Station
PM10	24 hours	80	85	109	50	Fellows
	Annual	24.6	25.9	31.0	30	Fellows
NO2	1 hour	97	81	81	470	Maricopa
	Annual	13.6	16.3	15.6	100	Maricopa
CO	1 hour	2440	2303	2941	23,000	Fellows
	8 hour	1869	1985	2222	10,000	Fellows
SO2	1 hour	65	94	36	655	Fellows
	3 hours	36	57	27	1300	Fellows
	24 hours	13	20	14	130	Fellows
	Annual	1.5	1.8	1.8	80	Fellows

AIR QUALITY Table 3
Ozone and PM10 Ambient Air Quality Data

Pollutant & Location		1997	1996	1995	1994	1993
Ozone Maricopa	Maximum concentration (ppm)	.12	.12	.13	.13	.13
	# days exceed standard	24	63	85	78	85
PM10 Taft College	Maximum concentration ($\mu g/m^3$)	78	94	93	64	118
	# days exceed standard	6	12	15	6	13
	% of samples above 24-hour standard	10%	20%	25%	11%	23%
California Ozone Ambient Air Quality Standard: 0.09 ppm (1-hour average) National Ozone Ambient Air Quality Standard: 0.12 ppm (1-hour average) California PM10 Ambient Air Quality Standard: 50 $\mu g/m^3$ (24-hour average)						

AMBIENT PM10

As **AIR QUALITY Table 3** indicates, the project area also annually experiences a number of violations of the state 24-hour PM10 standard, although violations of the federal 24-hour standard are not occurring. The violations of the state 24-hour standard occur predominately between the months of August and February, with the highest number of violations occurring from September through November.

PM10 can be emitted directly or it can be formed many miles downwind from emission sources when various precursor pollutants interact in the atmosphere. Gaseous emissions of pollutants like NOx, SOx and VOC from turbines, and ammonia from NOx control equipment can, given the right meteorological conditions, form particulate matter known as nitrates (NO3), sulfates (SO4), and organics. These pollutants are known as secondary particulates, because they are not directly emitted but are formed through complex chemical reactions in the atmosphere.

A number of studies have been undertaken to understand the particulate phenomenon, both PM10 and the smaller PM2.5, in the San Joaquin Valley. The EHPP has undertaken an extensive review of the literature to specifically address the role of nitrogen oxides emissions in the formation of particulate matter (Sylte 1999). Major sources of information on the subject are available from the District and CARB. The District, CARB, EPA and the Energy Commission staff agree on the following conclusions about the NOx/PM10 relationship:

- NOx emissions contribute significantly to the formation of particulate nitrate in the region where the EHPP is located; and
- ammonium nitrate is the largest contributor to PM10 levels during the winter when ambient PM10 levels are at their highest.

Energy Commission staff's assessment of the NOx contribution to particulate nitrate formation (CARB 1993-1997, Chow et al. 1993) corroborates the conclusion that emissions of gaseous NOx emissions can contribute a substantial portion of the ambient particulate nitrate in the southern San Joaquin Valley, especially during the winter season when the PM10 levels are the highest.

PROJECT DESCRIPTION AND EMISSIONS

CONSTRUCTION

The EHPP will include not only the power plant, but the following ancillary facilities as well:

- a water pumping station located near Western Kern Water District (WKWD) facilities;
- a 9.8 mile long, 16-inch diameter water supply line from the pumping station to the project site;
- a 1,000,000 gallon water storage tank along the water supply line at the project site;
- a 4.4 mile long, 6-inch pipeline to existing waste water injection well field located in the Occidental Elk Hills Inc. (OEHI), oil and gas field;
- a 2,500 foot long, 10-inch diameter natural gas supply line from the existing 20-inch supply line from the nearby gas processing facilities operated by OEHI; and
- a double circuit 230 kV transmission line approximately 9.0 miles long from the project site to either a new substation at the

Midway-Wheeler Ridge transmission corridor to the northeast near Tupman or to the north at the Midway substation at Buttonwillow.

The construction of facilities will generate air emissions, primarily fugitive dust from earth moving activities and combustion emissions generated from the construction equipment and vehicles. The projected highest daily emissions, based on the highest monthly emissions over the 15-month construction activity are shown in **AIR QUALITY Table 4**. The emissions for the linear facilities are aggregated in **AIR QUALITY Table 4**, and represent all the linear facilities previously identified. These peak emissions will not occur over the entire construction period of the project, however it is likely that the peak emissions for the project site will coincide with the peak emissions of the linear facilities

AIR QUALITY Table 4
Maximum Daily Construction Emissions (lbs/day)

	NOx	VOC	CO	SOx	PM10	Fugitive PM10
Project Site [a]	609.5	532.5	387.6	56.6	66.1	144.1[c]
All Linear Facilities [b]	103.3	151.3	47.6	9.7	11.4	408.2[d]
Total	712.8	683.8	435.2	66.3	77.5	552.3

Notes: All activities based on an 8 hour workday, 20 days per month.
[a] Includes the combustion turbines, cooling towers, 230kV Substation, water storage tank , associated buildings and services, and employee vehicle emissions.
[b] Includes the water supply pipeline & pumping station, waste water pipeline, natural gas pipeline and 230 kV transmission line.
[c] Assumes the disturbed earth is 12 acres and 1.2 ton PM/month/acre, 60% of which is PM10, 50% of which will be controlled by watering, averaged over a 3 month peak period.
[d] Assumes the total disturbed earth is 113.4 acres for all linear facilities and 1.2 ton PM/month/acre, 60% of which is PM10, 50% of which will be controlled by watering, averaged over a 10 month period.
(EHPP 1999a, EHPP 1999b)

PROJECT SITE

This construction will include the combustion turbines, the cooling towers, the water storage tank, the 230kV substation and all other associated services (such as pumps, valves, pressure vessels and buildings). The emissions in **AIR QUALITY Table 4** for the project site also include the vehicle emissions of the construction employees.

The power plant itself will take approximately 15 months to construct. The power plant project construction consists of three major areas of activity: 1) the civil/structural construction, 2) the mechanical construction, and 3) the electrical construction. The largest emissions are generated during the civil/structural activity, where work such as grading, site preparation, foundations, underground utility installation and building erection occur. These types of activities require the use of large earth moving equipment, which generate considerable combustion emissions themselves, along with creating fugitive dust emissions. The mechanical construction includes the installation of the heavy equipment, such as the combustion and steam turbines, the heat recovery steam generators, condenser, pumps, piping and valves. Although not a large fugitive dust generation activity, the use of large cranes to install such equipment generates significantly more emissions than other construction equipment on site. Finally, the electrical equipment installation occurs involving such items as transformers, switching gear, instrumentation and wiring. This is a relatively small emissions generating activity in comparison to the early construction activities.

Not surprisingly, the largest level of construction emissions for the project will occur from the project site activity, most of it due to earth moving and grading activities and large crane operations. The maximum fugitive dust emissions are expected to occur during the first three months of construction. During this time Elk Hills estimates that they will be disturbing approximately 12 acres of earth (an average of 4 acres per month). Elk Hills assumed that 1.2 tons of fugitive dust is generated for each acre of earth disturbed per month (EPA 1995a, Section 13.2.3.3), that 60% of that dust is PM10, and that 50% of that PM10 is controlled through watering the construction site. From these assumptions, the estimated maximum expected PM10 emissions from fugitive dust at the project site would be 144 lbs/day over a 3-month period. For a more detailed review of the construction emission estimated see Appendix B.

LINEAR FACILITIES

In a supplemental filing (EHPP 1999b), Elk Hills clarified their estimate of emissions associated with the construction of the linear facilities. These facilities include the two alternative transmission lines, the natural gas pipeline, the wastewater pipeline, the water pipeline and the associated pumping stations. The supplemental filing aggregated the construction emissions associated with the linear facilities into one set of emission values.

Elk Hills estimated the construction time for the linear facilities to be approximately 10 months, beginning in the fourth month of construction of the facility site and ending in the thirteenth month. During that time the construction activity stays fairly constant, peaking around months 7 and 8. Using the emissions for months 7 and 8, staff made a conservative estimate of the daily emissions of the construction of the linear facilities. Staff took the emission values for months 7 and 8 (they are identical for both months) and averaged them over a 20 workday month (which is consistent with the assumptions of Elk Hills). It is staff's position that these daily emissions can be conservatively assumed for the entire construction time (10 months).

The supplemental filing by Elk Hills did not include an estimate of fugitive PM10 emissions from construction activities associated with the linear facilities. To estimate these emissions, staff used the estimated land disturbance Elk Hills provided in Table 3.8-2 (EHPP 1999a, page 3-69). The estimated land disturbance for all the linear facilities together is 113.4 acres. Individually they are as follows: the transmission line (route 1A) is 41 acres, the water pipeline is 48 acres, the water pumping station is 1 acre, the wastewater pipeline is 21 acres and the natural gas pipeline is 2.4 acres. Staff made the previously stated assumptions for estimating fugitive PM10 emissions: the EPA emission rate of 1.2 lbs PM/acre/month, that 60% of this PM is PM10, and that 50% of the PM10 will be controlled through watering down the construction sites. Staff estimated the fugitive PM10 emissions from construction of the linear facilities to be 408.2 pounds per day over the entire 10-month construction period. For a more detailed review of the construction emission estimated see Appendix B.

OPERATIONAL PHASE

EQUIPMENT DESCRIPTION

The major components of the EHPP consist of the following: two combustion turbine generators (CTG), using the General Electric Power Systems PG7241FA, nominally rated at 171 MW. Each of the CTGs would be equipped with evaporative inlet air coolers;

- two natural gas fired heat recovery steam generators (HRSG) and ancillary equipment;
- one steam turbine, rated at 171 MW;
- one six-cell cooling tower; and
- one redundant diesel fuel fired water pump.

EQUIPMENT OPERATION

The CTGs will burn only natural gas, and there are no provisions for an alternative back-up fuel.

Elk Hills is requesting that the project be analyzed with the assumption of 200 start-ups per turbine each year. However, there are three different start-up scenarios for the CTGs, depending on length of time that the turbine has been shutdown and the temperatures and pressures on the steam turbine side of the power generation block. The usual practice is to define start-ups as either a hot start, a warm start or a cold start, with the start-up period being defined as the length of time until the gas turbine is fully loaded, that is, producing base load electrical power. A hot start would occur after an overnight turbine shutdown. The duration of a hot start is relatively short, approximately half an hour. A warm start-up is approximately 30 to 120 minutes in duration to allow the steam turbine to be ramped up. A warm start-up would occur after a typical weekend shutdown (approximately 60 to 72 hours). A cold start takes considerably longer, on the order of four hours. However, this type of start-up would be very rare, occurring only after the turbines have been under extended shutdown, such as a annual maintenance inspection that the manufacturer may require.   Because of the thermal efficiency of the project, it is highly likely that the EHPP will operate extensively, therefore extended shutdowns are likely to be rare.

Elk Hills has requested the project be analyzed assuming that of the 200 start-ups per turbine, 12 start-ups are defined as cold start (4-hours) and 188 are defined as warm or hot start-ups (2-hours). Barring major mechanical malfunction of the equipment itself, cold start-ups may occur once or twice a year, most likely during the annual maintenance and inspection. Additional cold start-ups may result from economic shutdowns that continue for longer than a weekend. Other start-ups that last longer that 2 hours may result from delays to correct minor equipment malfunctions encountered during the start-up process. Staff would expect that the vast majority of start-ups would be hot or warm starts, thus minimizing start-up time.

The EHPP will have several different operating modes to respond to the changing power market; start-up, shutdown, base load, turndown (or part load) and peaking (or power augmented). Peak load operation is the use of steam injection into the compressor ahead of the turbine intake. This has the effect of increasing the power output of the turbine (up to 106% of rated capacity). It will also cause an increase in the NOx and CO emissions from the combustion turbines. However, these pollutants will be controlled by post combustion equipment (SCR and catalyst). Elk Hills has determined that they will be operating at peak load 976 hours and at base load 7,360 hours per year per turbine (the balance of time being start-up). Elk Hills further assumes that, based on data from GE Power Systems submitted in response to staff Data Request #1, EHPP can meet the air emission limits for base load while operating at part load, even for CO and VOC emissions. Therefore, emission limits for part load are not necessary and will not be analyzed. The HRSGs have natural gas fired duct burners that will also be controlled through the post combustion equipment. Elk Hills identified the operational scenario in which the highest emissions occur as being at peak load, duct fire on, and 63.9^{o}F ambient temperature.

The redundant diesel-fired emergency fire water pump will only operate if the two electric motor pumps fail to start or the pressure in the fire water distribution header drops below a certain set point. Elk Hills will test the diesel pump once a month.

EMISSION CONTROLS

The exclusive use of an inherently clean fuel, natural gas, will limit the formation of SO2 and PM10 emissions. Natural gas contains very small amounts of a sulfur compound known as mercaptan, which when combusted, results in sulfur dioxide emissions in the flue gas. However, in comparison to other fuels used in power plants, such as fuel oil or coal, the sulfur dioxide emissions from the combustion of natural gas are very low.

Like SO2, the emissions of PM10 from natural gas combustion are very low compared to the combustion of fuel oil or coal. Natural gas contains very little noncombustible gas or solid residue; therefore, it is a relatively clean-burning fuel.

A sulfur content of 0.75 grains of sulfur per 100 standard cubic feet of natural gas was assumed for the SO2 emission calculations.

To minimize NOx, CO and VOC emissions during the combustion process, the CTG is equipped with the latest dry low-NOx combustor design developed by GE. A more detailed discussion of this combustion technology is presented in the **Mitigation** section of this analysis.

After combustion, the flue gases pass through the natural gas fired heat recovery steam generator (HRSG), where catalyst systems are placed to further reduce NOx, CO and VOC emissions. Elk Hills is proposing to use a Selective Catalytic Reduction (SCR) system to reduce NOx emissions. Another catalyst, an oxidizing catalyst, will also be installed in the HRSG to reduce CO and VOC emissions. A more complete discussion of these catalyst technologies is included in the **Mitigation** section.

PROJECT OPERATING EMISSIONS

The proposed project's criteria air pollutant emissions during short periods of time, one hour or less, are shown in **AIR QUALITY Table 5**. As this table shows, the highest emissions are from the combustion turbine, with the emissions during startup being significantly higher than during steady state, full load operation. Most notably, emissions of NOx, VOC and CO are significantly higher during startup and shutdown. These higher emissions occur because the turbine combustor technology is designed for maximum efficiency during full load steady state operation.

AIR QUALITY Table 5
Project (Per CTG) Hourly Emissions

Operational Profile	NOx	SO2	PM10	VOC	CO

CTG Cold Start-up (4 hours) (lbs/event)	152[A]	8.8	72.0	10.4	76.0
CTG Warm Start-up (2 hours) (lbs/event)	76[A]	4.4	36.0	5.2	38.0
CTG Steady State at peak load + duct firing at 63.9°F (lbs/hr)	15.8	3.6	18.0	4.0	12.5
Cooling Tower (lbs/hr)	--	--	0.39	--	--
Emergency Fire-water Pump (lbs/hr)	0.98	0.07	0.04	0.17	0.30
2 CTGs at peak load + duct firing at 63.9°F & Cooling Tower + Emergency Fire-water Pump (lbs/hr)	32.6	7.27	36.7	8.2	25.4
Maximum Expected Facility Emissions	77.0[B]	7.3[C]	36.4[C]	8.2[C]	38.3[B]

A NOx startup emissions assume a maximum emission rate of 38 lbs/hr for 2 and 4-hour start-ups.
B Maximum expected facility NOx emissions assume that both turbines are in start-up mode (38 lbs/hr), the cooling tower is operating, and that the emergency fire-water pump is being tested.
C Maximum expected facility SO2, PM10 and VOC emissions assume that both turbines are in peak load operation, the cooling tower is operating and that the emergency fire-water pump is being tested.
For more information on the project emissions see Appendix B.

For the NOx start up emissions in **AIR QUALITY Table 5**, staff assumes that the turbine emissions will not exceed 38 lbs/hour as stated in the Final Determination of Compliance (FDOC) for the EHPP. This emission rate is considered the maximum hourly potential to emit during this mode of operation. However, for the daily and annual potential to emit, the District assumes an emission rate of 25.5 lbs/hour. The daily and annual potentials to emit, as calculated according to District Rule 2201, indicate the amount of mitigation that an applicant must provide. EHPP will be required to mitigate startup emissions at 25.5 lbs/hour, but allowed to emit at 38 lbs/hour (District Condition 13 in the FDOC). This is consistent with past District interpretation of their rules and regulations and staff finds no fault with this interpretation. To be equally consistent with recent siting cases, staff will use the higher emission rate of 38 lbs/hour to assess the project potential impacts and required mitigation.

During start-up, combustion temperatures and pressures are rapidly changing, which results in less efficient combustion and higher emissions. Also, the flue gas controls, the catalysts discussed above, operate most efficiently when the turbine operates near or at full load. Those flue gas controls are not as effective during the transitory temperature changes that occur during startup. The start-up emissions data reflect information provided by Elk Hills (EHPP 1999d). See Appendix B for more information about how the hourly emission rates were calculated.

The daily emissions from the project are shown in **AIR QUALITY Table 6**. The table shows different operating scenarios, and the resultant emissions, including CTG start-up, steady state operation and the operation of the cooling tower. The table also includes the test firing of the backup diesel generator for the fire-water pump. This type of testing should typically take no more than an hour. The typical daily emissions level scenario (2 turbines operating at full load with no start-ups) is presented in the last row of the table. See Appendix B for more information about how the hourly emission rates were calculated.

AIR QUALITY Table 6
Project Daily Emissions
(pounds per day [lbs/day])

Operational Profile	NOx	SO2	PM10	VOC	CO
1 turbine cold-start (4-hours) and steady state operation (20-hours)	468	80.8	432.0	90.4	326.0
1 turbine warm start (2-hours) and steady state operation (22-hours)	423.6	77.0	432.0	86.6	313.0
Cooling towers operating 24-hr	--	--	9.29	--	--
Maximum Expected Facility Emissions	937.0[A]	172.9[B]	873.3 [B]	192.2 [B]	652.3 [B]
Typical Expected Facility Emissions[C]	759.4	158.5	873.3	177.8	600.3

A Assumes that both turbines cold start-up and operate at peak load for the remainder of the day, plus 24-hours of cooling tower emissions and 1-hour of diesel generator operation.
B Assumes both turbine operate at peak load for 24-hours, plus 24-hours of cooling tower emissions and 1-hour of diesel generator operation.
C Assumes that both turbines operate at normal load for 24-hours, plus 24-hours of cooling tower emissions and 1-hour of diesel generator operation.
For more information on the project emissions see Appendix B.

Annual emissions are summarized in the **AIR QUALITY Table 7**. Elk Hills has requested that the project be analyzed assuming 12 cold start-ups per turbine per year, 188 warm or hot start-ups per turbine per year, and 976 hours of operation peak load per turbine per year. The balance of the year's operation (7,360 hours) assumes full load operation of the CTGs. This type of operational scenario is actually not possible, since by definition, the start-ups must be preceded with no turbine operation and thus no emissions. In this case, the turbines would have to be down for many days before a cold start would be initiated. Therefore, the assumption of 7,360 hours of steady state operation could not happen, however, Elk Hills presented this assumption as a conservative estimate for annual emissions.

AIR QUALITY Table 7
Project Annual Emissions
(tons per year [ton/yr])

Operational Profile	**NOx**	**SO2**	**PM10**	**VOC**	**CO**
12 4-hour Turbine Startups	0.912	0.053	0.432	0.062	0.456
188 2-hour Turbine Startups	7.144	0.414	2.284	0.489	3.572
976-hours of Peak Load Operation	7.710	1.757	8.784	1.952	6.100
7360-hours of Normal Load Operation	58.144	12.144	66.240	13.616	46.000
7784-hours of Normal Load Operation	61.494	12.844	70.056	14.400	46.650
8760-hours of Cooling Tower Operation	0.0	0.0	1.696	0.0	0.0
200-hours of Diesel Engine Operation	0.098	0.007	0.004	0.017	0.030
Maximum Expected Facility Emissions	147.9[A]	29.2[B]	159.4[B]	32.7[B]	112.3[A]

Notes:
A Assumes 12 4-hr cold start/turbine, 188 2-hr warm start/turbine, 976 hr peak load/turbine, 7,360 hr steady state/turbine, 8,760 hours cooling towers operation, and 200 hr of diesel fired generator testing.
B Assumes 976 hr peak load/turbine, 7,784 hr steady state/turbine, 8,760 hours cooling towers operation and 200 hr of diesel fired generator testing.

For comparison, staff added in the diesel generator emissions to the above operational scenario. Staff followed the assumption of the District, that the diesel generator is test fired no more than 200 hours per year. This number of hours is unlikely, because typically the diesel generator testing will last no more than 1-hour. Additionally, the applicant does not expect to test the diesel generator more than once a month. Two hundred hours a year would allow a monthly test period to last more than 16 hours on average. The difference between adding in the diesel generator emissions can only be seen on the NOx emissions, which increased by 0.1 tons/yr. See Appendix B for more information about how the hourly emission rates were calculated.

Staff also presented the scenario of both turbines operating non-stop throughout the year. The highest annual emissions of SO2, PM10 and VOC would occur with this scenario, since these emissions are a function of the quantity of fuel burned. The annual emissions of NOx and CO would be higher with the inclusion of the start-up emissions. The PM10 emissions are identical in both cases because of Elk Hills' choice to make the conservative assumption that PM10 emissions during start-up are the same as those during normal operation. In fact, PM10 is dependent on the amount of fuel burned, as is SO2. Since VOC is being controlled through a post-combustion catalyst, the emissions are fairly similar in both startup and normal operating scenarios. See Appendix B for more information about how the emissions were calculated.

AMMONIA EMISSIONS

Due to the large combustion turbines used in this project, and the need to control NOx emissions, significant amounts of ammonia will be injected into the flue gas stream as part of the SCR system. Not all of this ammonia mixes in the flue gases to reduce NOx; a portion of the ammonia passes through the SCR and is emitted unaltered, out the stacks. These ammonia emissions are known as “ammonia slip.” Elk Hills has committed to an ammonia slip no greater than 10 ppm, which is the current lowest ammonia slip level being achieved and permitted throughout California. On a daily basis, an ammonia slip of 10 ppm is equivalent to approximately 583 lbs per day of ammonia emitted into the atmosphere per turbine.

It should be noted that an ammonia slip of 10 ppm is usually associated with the degradation of the SCR catalyst, usually in a time frame of five years or more after initial operation. At that point, the SCR catalysts are removed and replaced with new catalysts. Through most of the operation of the SCR system, ammonia slip emissions are usually in the range of 1 to 2 ppm, corresponding to a mass emissions in the EHPP case to approximately 50 to 125 pounds per day per turbine. The implications of these ammonia emissions are discussed later in this analysis.

FACILITY CLOSURE

Eventually the EHPP will close, either as a result of the end of its useful life, or through some unexpected situation such as a natural disaster or catastrophic facility breakdown. When the facility closes, then all sources of air emissions would cease and thus all impacts associated with those emissions would no longer occur.

The Permit to Operate, issued by the District under Rule 2010, is required for the operation of the facility and is usually renewed on a five year schedule. However, during those five years, the applicant must still pay permit fees annually. If the applicant chooses to close the facility and not pay the permit fees, then the Permit to Operate would be cancelled. In that event, the project could not restart and operate unless the applicant pays the fees to renew the Permit to Operate.

If Elk Hills were to decide to dismantle the project, there would likely be fugitive dust emissions associated with this dismantling effort. District Rule 8020 requires that during demolition fugitive dust emissions be limited to no greater than 40% opacity by means of water application or chemical suppressants. The Facility Closure Plan to be submitted to the Energy Commission Compliance Project Manager (CPM) should include the specific details regarding how Elk Hills plans to demonstrate compliance with the District Rule 8020.

PROJECT INCREMENTAL IMPACTS

MODELING APPROACH

An air dispersion modeling analysis usually starts with a conservative screening level analysis. Screening models use very conservative assumptions, such as the meteorological conditions, which may or may not actually occur in the area. The impacts calculated by screening models, therefore, can be double or more than the actual or expected impacts. If the screening level impacts are significant, refined modeling analysis is performed. A major difference in the refined modeling is that hour-by-hour meteorological data collected in the vicinity of the project site is used. The Industrial Source Complex Short-Term model, Version 3, known as the ISCST3 model, was used for the refined modeling.

CONSTRUCTION IMPACTS

Elk Hills performed air dispersion modeling analyses of the potential construction impacts at the project site. The analyses included fugitive dust generated from the construction activity (modeled as an area source) and combustion emissions from the equipment (modeled as a volume source). The emissions used in the analysis were the highest emissions of a particular pollutant during a one month period, converted to a gram per second emission rate for the model. Most of the highest emissions occurred during the 11^{th} month of the 15-month construction period.

The results of this modeling effort are shown in **AIR QUALITY Table 8**. They show that the construction activities would cause a violation of the state 1-hour average NO2 standard and further exacerbate existing violations of the state 24-hour average PM10 standard. In reviewing the modeling output files, the project's construction impacts are not occasional or isolated events, but are over an area within a few hundred meters of the project site.

AIR QUALITY Table 8
Maximum Construction Impacts

Pollutant	Averaging Time	Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO2	1-hour	593.4	97	690.4	470	147
CO	1-hour	1552.2	2941	4493.0	23,000	20
	8-hour	.9	2222	2750.9	10,000	28
SO2	1-hour	235.4	104	339.4	655	52
	3-hour	162.0	53	215.0	1,300	17
	24-hour	26.7	17	43.7	130	34
PM10	24-hour	206.3	109	315.3	50	631

Although construction of the EHPP will result in unavoidable short-term impacts, it is doubtful that the general public would be exposed to the construction impacts associated with the project. This is because of the project's rather isolated location away from any population centers in a heavily industrial area (the surrounding oilfields), where the impacts would actually occur. Nevertheless, staff believes that the impact from the construction of the project could have a significant and unavoidable impact on the NO2 and PM10 ambient air quality standards, and should be mitigated, to the extent feasible.

PROJECT OPERATION IMPACTS

The air quality impacts of project operation are shown in the following sections for fumigation meteorological conditions, and during combustion turbine start-up and steady-state operations.

The California Unions for Reliable Energy (CURE) contends that the receptor grid used in the emission impact modeling underestimates the impacts. For the screening level modeling, receptors were modeled along the Elk Hills Road at 100 meters spacing, along the Elk Hills Oil and Gas Field Property boundary at 500 meters spacing, within the oil field at 500 meters spacing and 500 meters outside of the oil field at 500 meters spacing. For refined modeling, receptors were modeled at 100 meter spacing around the highest points of impact identified in the screening level modeling. Receptors were not modeled along the fence line of the power plant site itself. CURE contends that the power plant emission impacts are most significant along the power plant fence line. Commission staff has had a significant amount of experience regarding power plant modeling and maximum impact locations. Staff contends that in evaluating many air dispersion modeling analyses, it has been our experience that the maximum impacts virtually never occur at the power plant fence line, rather they occur several hundred meters away from it. It is staff's opinion that the receptor grid used by Elk Hills adequately predicts the location and magnitude of the maximum impacts from the EHPP.

FUMIGATION IMPACTS

During the early morning hours before sunrise, the air is usually very stable. During such stable meteorological conditions, emissions from elevated stacks rise through this stable layer and are dispersed. When the sun first rises, the air at ground level is heated, resulting in a vertical (both rising and sinking air) mixing of air for a few hundred feet or so. Emissions from a stack that enter this vertically mixed layer of air will also be vertically mixed, bringing some of those emissions down to ground level. Later in the day, as the sun continues to heat the ground, this vertical mixing layer becomes higher and higher, and the emissions plume becomes better dispersed. The early morning air pollution event, called fumigation, usually lasts approximately 30 to 90 minutes.

The applicant used the SCREEN3 model, which is an EPA approved model, for the calculation of fumigation impacts. **AIR QUALITY Table 9** shows the modeled fumigation results and impacts on the 1-hour NO2, CO and SO2 standards. Since fumigation impacts will not typically occur much beyond a 1-hour period, only impacts on these 1-hour standards were addressed. The results of the modeling analysis show that fumigation impacts at full load will not violate the NO2, CO or SO2 1-hour standards.

AIR QUALITY Table 9
CTG Fumigation Modeling Maximum 1-Hour Impacts

Pollutant	Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO2	28.3	97	125.3	470	27
CO	21.0	2941	2962	23,000	13
SO2	2.5	104	107	655	16
Notes: Impacts reflect the highest results, turbine at 50% load, 63.9^{o}F, no duct burners, no steam injection winds at 1 m/s.					

(EHPP 1999a)

OPERATIONAL MODELING ANALYSIS

COMBUSTION TURBINE AND COOLING TOWER EMISSION IMPACTS

The original modeling performed by Elk Hills utilized meteorological data that was later found to have errors. These errors involved wind directions and stability classes identified in the meteorological files. Elk Hills corrected these errors to the satisfaction of the District and Commission Staff. The project operation emissions were then re-evaluated using the corrected meteorological files. The resulting new modeling outputs were not significantly different from the original modeling effort, except that they include the IC diesel engine. The results of this modeling analysis are shown in **AIR QUALITY Table 10**. This table shows that during normal operation of the combustion turbines, the air pollution impacts would not cause a violation of any NO2, CO or SO2 ambient air quality standards.

The project's PM10 impacts could contribute to existing violations of the state 24-hour and annual average PM10 standards. However, it should be noted that the modeling outputs show that the vast majority of 24-hour impacts are on the level of 2 $\mu g/m^3$ or less. Because of the conservatism of the air dispersion model itself, staff believes that the actual impacts from the project would be significantly less than the projected modeled impacts shown in **AIR QUALITY Table 10**.

The start-up circumstances of the project are such that the combustion turbines will be started sequentially; that is, there will be no simultaneous start-up of both turbines. A start-up sequence of one turbine will only occur when the other turbine is operating at steady state or is not operating at all. However, Elk Hills has chosen to conservatively characterize their modeling of start-up emissions as though the turbines were started at the same time.

Start-up circumstances can be troublesome for significant air quality impacts for the following reasons. First, emissions (particularly of NOx and CO) can be high and often uncontrolled, because emission control equipment is not operating at optimum temperature ranges. Second, low volumetric flow rates and exhaust gas temperatures can result in low exhaust plume rise and consequently higher ground level impacts.

For determining the maximum 1-hour impacts, Elk Hills assumed that there would be two cold start-ups, each of 4 hours, and to be conservative, they assumed they were simultaneous, not sequential. NOx controls were assumed to be at 33% efficiency and CO controls were assumed to be inactive.

The modeling results show that the highest short-term impacts on ambient NO2 and CO levels do indeed occur during start-up circumstances. The highest SO2 and PM10 impacts, both short-term and long term, occur during full load steady state operation. Start-up impacts on these pollutants are usually less because emissions of SO2 and PM10 are primarily a function of volume of fuel burned, and thus during start-up, much less fuel is burned than at full load, hence lower impacts.

AIR QUALITY Table 10
Combustion Turbine Modeling Maximum Impacts

Pollutant	Operation	Averaging Time	Impact ($\mu g/m^3$)	Back-Ground ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Perc o Stan
NO2	A	1-hour	136.3	97	233.3	470	5

	E	Annual	0.53	16.6	17.1	100	17
CO	A	1-hour	68.1	2941	3,009.1	23,000	13
	C	8-hour	20.1	2222	2,242.1	10,000	22
SO2	A	1-hour	12.9	104	116.9	655	18
	B	3-hour	19.5	53	72.5	1300	6
	D	24-hour	6.6	17	23.6	130	18
	E	Annual	0.12	1.8	1.92	80	2
PM10	D	24-hour	6.44	118	124.4	50	249
	E	Annual	1.03	39.8	40.83	30	136

A Both turbines start-ups NOx emission controls at 33% average efficiency, CO emission controls at 0%, employs ozone limiting method.
B Since start-up requires 4-hours for a cold start, maximum emission are identical to operation scenario A.
C Both turbines start-up (4-hours) and operate at 100% load (4-hours).
D Both turbines start-up (4-hours) and operate at 100% load (20-hours), plus 24 hours cooling tower.
E Both turbines 12 cold starts, 188 warm starts, 976 hours peak load and 7,384 hours base load, 8760-hour cooling tower.

The modeling analysis above indicates that during a project start-up scenario, the impacts from that start-up, plus background NO2 ambient levels would result in the highest impact of the project on the 1-hour state NO2 standard. This modeling analysis reflected the use of the Ozone Limiting Method (OLM) to provide a more refined estimate of NO2 impacts.

IC Engine Emission Impacts

Elk Hills has modeled the diesel powered IC engine emission impacts separately and in conjunction with the combustion turbines. In general the emission impacts from the IC engine are much higher than the emission impacts from just the combustion turbine. This is due to the fact that the combustion turbine stack height allow the emissions to dilute to a much higher degree than the IC engine. **AIR QUALITY Table 11** Shows the results of the modeling effort made by Elk Hills for the diesel powered IC engine. The results show that there will be no significant impacts from the IC engine by itself on the National or State Ambient Air Quality Standards.

AIR QUALITY Table 11
Diesel Powered IC Engine Modeling Maximum Impacts

Pollutant	Averaging Time	Impact ($\mu g/m^3$)	Back-Ground ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO2	1-hour[A]	63.42	275	338.4	470	72
	Annual	0.38	16.6	17.0	100	17
CO	1-hour	195.98	2941	3,137	23,000	14
	8-hour	50.96	2222	2,273	10,000	23
SO2	1-hour	23.15	104	127.2	655	19
	3-hour	11.94	53	64.9	1300	5
	24-hour	3.22	17	20.2	130	19
	Annual	0.00	1.8	1.4	80	2
PM10	24-hour	3.47	118	112.5	50	75
	Annual	0.01	39.8	39.8	30	80

A Uses ozone limiting method, highest O_3 level with highest NOx level is 254 and 21 ug/m^3 respectively (background is 275). Impact assumes 10% of NOx emissions are NO2.

Elk Hills also modeled the emission impact of the diesel fired IC engine with the emissions from the combustion turbines. The IC engine is a back up engine, and its normal operation should be only periodic test firing. Therefore, Elk Hills was directed by staff to model against only the 1-hour standards when modeling the combustion turbines and IC engine together. Furthermore, the combustion turbines were modeled at their worst possible emission level, startup mode. In reality it is extremely unlikely that any power plant operator would test the back IC engine during the combustion turbine startup. Elk Hills agreed to this characterization to be as conservative as possible. **AIR QUALITY Table 12** shows the results of this modeling effort. The results of modeling both the IC diesel engine and the combustion turbine at the same time show that there will be no significant impacts on the National or State 1-hour Ambient Air Quality Standards.

AIR QUALITY Table 12
Diesel Powered IC Engine Modeling Maximum Impacts

Pollutant	Averaging Time	Impact ($\mu g/m^3$)	Back-Ground ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	Limiting Standard ($\mu g/m^3$)	Percent of Standard
NO2	1-hour[A]	64.14	275	339.1	470	72
CO	1-hour	198.52	2,941	3,140	23,000	14

SO2	1-hour	30.54	104	134.5	655	21
A Uses ozone limiting method, highest O_3 level with highest NOx level is 254 and 21 ug/m^3 respectively (background is 275). Impact assumes 10% of NOx emissions are NO2.						

VISIBILITY IMPACTS

A visibility analysis of the project's gaseous emissions is required under the Federal Prevention of Significant Deterioration (PSD) permitting program. The analysis addresses the contributions of gaseous emissions (primarily NOx) and particulate (PM10) emissions to visibility impairment on the nearest Class 1 PSD areas, which are national parks and national wildlife refuges. The nearest Class 1 areas to the Elk Hills Project are the Domeland Wilderness Area, 90 miles to the northeast, and the San Rafael Wilderness Area, 35 miles to the south. Elk Hills used the EPA approved model VISCREEN to assess the project's visibility impacts. The results from the VISCREEN modeling analysis indicated that the project's visibility impacts would be below the significance criteria for contrast and perception. Therefore, the project's visibility impacts on these Class 1 areas are considered insignificant.

CUMULATIVE IMPACTS

KERN COUNTY POWER PLANT PROJECTS

To evaluate reasonably foreseeable future projects as part of a cumulative impacts analysis, staff needs specific information. The time in which a probable future project is well enough defined to have the information necessary to perform a modeling analysis is usually when the project applicant has submitted an application to the District for a permit. Air dispersion modeling required by the District would necessitate that the applicant develop the necessary modeling input parameters to perform a modeling analysis. Therefore, we evaluate those probable future projects in our cumulative impacts analysis that are currently under construction, or are currently under District review. Projects located up to six miles from the proposed facility site usually need to be included in the analysis.

At the time of the filing of the AFC (February 1999), Elk Hills stated that there were two other projects that required a District permit within a six mile radius of the project site that were either under construction or undergoing permit review. They are the Sunrise Cogeneration and Power Project that filed an AFC with the Energy Commission in December 1998 and the La Paloma Generation Project that was certified on October 6, 1999. Staff has performed a cumulative modeling assessment of the three projects, Elk Hills, Sunrise Cogeneration and the La Paloma Generation Project, with each project located approximately six miles from each other. The Western Midway-Sunset Cogeneration Project (WMSCP) Application for Certification was filed with the Commission on December 23, 1999, but was not included based on the distances involved; Elk Hills is well over 6 miles away from WMSCP and thus we would not expect any plume overlap between the two projects.

The Midway-Sunset Cogeneration Company (Midway) has been requested by staff to submit a cumulative analysis which includes La Paloma, Sunrise, Western Midway-Sunset and Elk Hills. Staff expects that EHPP will not contribute significantly to any modeled impacts in the WMSCP cumulative analysis. In fact, in its request staff notes that… " Elk Hills is located a significant distance to the east from these three towns (Derby Acres, McKittrick and Fellows), making it unlikely that emissions from Elk Hills would ever impact them." Even though the WMSCP is greater than six miles from the EHPP, Midway has agreed to the cumulative modeling that staff requested, although it is staff's opinion that the WMSCP does not need to be included in the cumulative analysis for the EHPP.

Staff used the ISCST3 air dispersion model along with the 1993 meteorological file provided by Elk Hills. The results of this modeling analysis are shown in **AIR QUALITY Table 13**.

AIR QUALITY Table 13
Maximum Cumulative Impacts

Pollutant	Averaging Time	Impact (µg/m^3)	Background (µg/m^3)	Total Impact (µg/m^3)	Limiting Standard (µg/m^3)	Percent of Standard
NO2	1-hour	25.31	94	119.3	470	25
	Annual	0.34	16.6	16.9	100	17
CO	1-hour	30.46	2941	2971.5	23,000	13
	8-hour	7.72	2222	2229.7	10,000	22
SO2	24-hour	0.12	20	20.1	130	15
	Annual	0.02	1.8	1.8	80	2
PM10	24-hour	1.12	118	119.1	50	238
	Annual	0.17	31.7	31.9	30	106

As **AIR QUAITY Table 13** shows, the cumulative air quality effects of the three projects do not cause a new violation of any NO2, CO or SO2 ambient air quality standards. The three projects would contribute to already existing violations of the state PM10 ambient air quality standards. However, all three of these projects will be required to provide PM10 emission offsets to mitigate their PM10 impacts.

Staff also performed an assessment of the possible secondary PM10 formation of nitrates and sulfates from the three projects' NOx and SO2 emissions. For NOx to nitrate formation, a conversion of 33% over a time span of 18 to 24 hours was used. For oxides of sulfur to sulfate formation, the conversion of 50% over 8 hours was used. These conversion rates can be input into the ISCST3 model to predict possible nitrate and sulfate PM10 impacts. The combined three-project nitrate impact was predicted to be approximately 1$\mu g/m^3$, located about 50 miles to the northeast of the projects' sites. The combined sulfate impacts would be approximately 0.1$\mu g/m^3$, located about 30 miles to the northeast. As with PM10, the emissions of NOx and SO2 will be fully offset. Because these secondary PM10 pollutants are mitigated and the magnitude of their impacts are very small, staff concludes that these secondary PM10 impacts are insignificant. For a more complete discussion of the cumulative modeling analysis, please refer to Appendix A.

SECONDARY POLLUTANT IMPACTS

The project's emissions of gaseous emissions, primarily NOx, SO2 and VOC, can contribute to the formation of secondary pollutants, namely ozone and PM10, particularly ammonium nitrate PM10 and sulfate.

OZONE

There are air dispersion models that can be used to quantify ozone impacts, but they are used for regional planning efforts where hundreds or even thousands of sources are input into the model to determine ozone impacts. There are no regulatory agency models approved for assessing single source ozone impacts. However, because of the known relationship of NOx and VOC emissions to ozone formation, it can be said that the emissions of NOx and VOC from the EHPP do have the potential (if left unmitigated) to contribute to higher ozone levels in the region which are cumulatively considerable.

Emissions from the San Joaquin Valley Air Basin are considered a significant contributor to the ozone exceedences in the South Central Coast Air Basin[1] (SCCAB) and the North Central Coast Air Basin (NCCAB, CARB 1996). That is, air pollution from the San Joaquin Valley in combination with emissions from within the SCCAB and NCCAB, do cause violations of ozone ambient air quality standards within the SCCCB. However, CARB has found that San Joaquin Valley emissions alone do not cause violations of ozone standards within the SCCAB and NCCAB. To reduce ozone precursor (NO_x and VOC) emissions within their own District as well as reducing the impact to neighboring air basins, the San Joaquin Valley Unified Air Pollution Control District has adopted best available retrofit control technology (BARCT, CARB 1996) to a number of categories of stationary sources. The EHPP's operational emissions will be offset and thus, there will be no net emissions increase. Therefore, staff believes that there will be no significant impact, either within the San Joaquin Valley Air Basin or in the neighboring SCCAB. The construction impacts are very short term and are not likely to contribute to significant ozone formation in the SCCAB. Therefore, it is staff's opinion that there will be no significant impacts from the EHPP's emissions on the formation of ozone in the South Central Coast Air Basin.

CURE contends that the emission reduction credits (ERCs) that have been purchased by EHPP are not contemporaneous with the project emission increases and thus, do not mitigate the potential project ozone impacts in the SCCAB or NCCAB. The basis of this contention is that the ERCs have been "retired historically", meaning that they were credited to the District ERC bank some time ago. ERC banking has been well established in California for a number of years and is accepted by CARB and EPA as meeting the requirements of the Federal and State Clean Air Acts. Neither CARB nor EPA are currently suggesting that ERC banking is any less an effective means of mitigation for emission increases within the District as well as in the downwind districts. Therefore, staff believes the contention by CURE is without foundation.

CURE further contends CO is an ozone precursor and that the CO emissions from EHPP, being unmitigated, contribute to ozone formation within the District and in downwind air basins. The contribution of CO to ozone formation is very small and not well understood. Currently no air districts within California recognize CO as an ozone precursor and neither EPA nor CARB recognize CO as an ozone precursor. Consequently, the CEC staff does not recognize CO as an ozone precursor. The general consensus is that NOx and VOC emissions are overwhelmingly ozone precursors and by controlling them ozone formation will be reduced far more efficiently than controlling CO emissions.

SECONDARY PM10

Concerning secondary PM10 (primarily ammonium nitrate) formation, the applicant for the La Paloma Generation Plant (LPGP 1999a) submitted a conclusion from a study by Sonoma Technology, Inc. which states that the San Joaquin Valley is generally ammonia rich during the winter season when ambient PM10 levels are highest. This means that under such conditions, adding more ammonia to the ambient air will not automatically result in more ammonium nitrate formation. CURE contends that these results demonstrate that the area is ammonia-limited. However, the opposite of CURE's contention is demonstrated by these results; the area is NOx/SOx limited. In other words, there is currently sufficient ambient ammonia to react with the EHPP NOx/SOx emissions to form particulate.

In the case of EHPP, Elk Hills quantified the highest ammonia emissions at approximately 583 pounds per day per turbine based on a permitted 10 ppm ammonia slip. However, staff believes that these mass emissions will be more on the order of 50 to 125 pounds per day per turbine based on a normal 1 to 2 ppm ammonia slip. CURE contends that the ammonia slip limit of 10 ppm is too high and that additional collateral impacts will occur as a result of this limit, because CURE further contends that the area is ammonia limited (stated above). CURE contends that the assumption of a normal ammonia slip level of 1-2 ppm is incorrect and that an average lifetime slip level for the catalyst should be approximately 5 ppm. In general, CURE is basing these comments on a CARB guidance document, which CURE reports as stating that slip levels as low as 2 ppm can be achieved and a lifetime average slip level of 5 ppm is recommended. Staff suggests that a subtle interpretation of definitions has been ignored by CURE. The difference is between "normal operational slip levels" and "lifetime average slip levels". Staff contends that normal operational slip levels will be on the order of 1-2 ppm. A lifetime average of 5 ppm, as recommended by CARB, means that the slip level will sometimes be below 5 ppm and will sometimes be above 5 ppm over the life of the catalyst (approximately 6 years). This is consistent with staff experience. The 10 ppm ammonia slip limit is not a lifetime average limit, but a 24-hour rolling limit.

It should be remembered that the CARB Guidance Document contains recommendations for air districts to consider when issuing permits. The SJVUAPCD has decided that at 10 ppm ammonia slip is appropriate for this applications. Because CEC staff finds that there are no significant impacts at the 10 ppm level, staff can see no reason to require a stricter level of ammonia slip than the District requires.

Given the ammonia rich ambient environment and the ammonia slip emission levels associated with normal operations, staff finds it reasonable to expect that there will be no significant air quality impact from the EHPP ammonia slip emission limit. Nevertheless, the NOx/SOx emissions from the EHPP could add to PM10 formation, since there is more than sufficient ambient ammonia available for the NOx/SOx to react with to form PM10.

The process of gas-to-particulate conversion is complex and depends on many factors, including local humidity and the presence of other compounds. Currently, there are no agency (EPA or CARB) recommended models or procedures for estimating nitrate or sulfate formation. Nevertheless, studies during the past two decades have provided data on the oxidation rates of SO2 and NOx. The data from these studies can be used to approximate the conversion of SO2 and NOx to particulate. This can be done by using an aggregate conversion factor (typically about 0.01 to 1 percent per hour) with Gaussian dispersion models such as ISCST3. The model is run with and without chemical conversion (decay factor) and the difference corresponds to the amount of SO2 and NO2 that is converted to particulate. This approach is an over simplification of a complex process; nevertheless, given the stringency of the PM10 and the new PM2.5 standards, and the need to address interpollutant conversion rates in setting offset ratios, for interpollutant trading, staff believes this issue needs to be addressed.

Staff, as part of their cumulative modeling analysis quantified, through air dispersion modeling and assumed NOx and SO2 conversion rates to PM10, the potential secondary PM10 impacts from the two power projects in the area currently before the Commission for licensing: Elk Hills and Sunrise Cogeneration and the recently licensed La Paloma. Staff believes that the emissions of NOx and SOx from EHPP do have the potential (if left unmitigated) to contribute, to higher secondary PM10 levels in the region.

MITIGATION

APPLICANT'S PROPOSED MITIGATION

CONSTRUCTION MITIGATION

As discussed earlier in the applicable LORS section, there are a series of District rules under Regulation 8 that limit fugitive dust during the construction phase of a project. Those rules require the use of chemical stabilizing agents and dust suppressants or gravel areas on site, and the wetting or covering of stored earth materials on site. They also encourage, although do not require, the use of paved access aprons, gravel strips, wheel washing or other means to limit mud or dirt carry-out onto paved public roads. Because they are required by District rules, Elk Hills will employ appropriate fugitive dust mitigation measures to limit their construction related PM10 emissions. At this time Elk Hills is proposing to use watering techniques approved by the District. These techniques are assumed to reduce the fugitive PM10 emissions by 50%.

OPERATIONS MITIGATION

The EHPP's air pollutant emissions impacts will be reduced by using emission control equipment on the project and by providing emission offsets. To reduce NOx emissions, Elk Hills proposes to use dry-low NOx combustors in the CTGs. In addition, an ammonia injection grid will be used in conjunction with a Selective Catalytic Reduction system.

To reduce CO and VOC emissions, Elk Hills proposes to use a combination of good combustion and maintenance practices, along with an oxidizing catalyst located in the HRSG. PM10 emissions will be limited by the use of a clean burning fuel (natural gas) and the efficient combustion process of the CTGs. The use of natural gas as the only fuel will limit SO2 emissions.

COMBUSTION TURBINE

BACT Determination

SCONOx BACT Analysis

The Committee for the Elk Hills Power Project has ordered staff and other parties to address a rigorous analysis of SCONOx BACT as it applies to this project (Committee Order 99-AFC-1, March 2, 2000). Specifically, staff is ordered to compare the SCONOx technology to Dry low-NOx and Selective Catalytic Reduction (DLN-SCR) technology and state a preference for the Elk Hills Project. In the following analysis, staff discusses BACT issues for the Elk Hills Power Project, as well as XONON, SCONOx and DLN-SCR technologies.

Best Available Control Technology or BACT is a structured program to ensure that new pollution emitting sources have the lowest emissions feasible. BACT was instituted by the United States Environmental Protection Agency (EPA) and implemented by EPA and the California Air Resources Board (CARB) via the local air districts in California. Local air districts have BACT determination requirements written into their rules and regulations. The BACT determination is subject to review and comments by the EPA, CARB and, in the case of power plants over 50 MW in capacity, the California Energy Commission. It is important to recognize that BACT is a level based on the demonstrated availability of a technology to achieve a level of control. BACT is a control level requirement; it does not require a specific technology to be installed. EPA and the San Joaquin Valley Unified Air District (District) have determined and agreed on the BACT level for NO_2 and CO for the Elk Hill Power Project. These levels are identified in **AIR QUALITY Table 14**.

AIR QUALITY Table 14
BACT Emission Levels for the Elk Hills Power Project

	BACT Level	Averaging Period
NO_2	2.5 ppm @ 15% O2	1 hour
CO	4.0 ppm @ 15% O2	3 hour

(EPA 2000a)

BACT determinations have several components to them, starting with the “Top Down” requirement. Top down refers to the necessity to start with the most stringent technology available. For the Elk Hills Power Project, this essentially includes XONON, SCONOx and DLN-SCR. The manufacturers of these three technologies suggest that they can all achieve the emission levels stated in **AIR QUALITY Table 14**.

Technical Availability

The first test that might eliminate a control technology in a BACT determination is the technical feasibility of the technology as applied to the proposed project. A technology may be available by demonstration or guarantee, but it might not be applicable to the proposed project. There may be constraining requirements for the application of the technology that render it unusable for a particular project. This is typically addressed on a case by case basis.

DLN-SCR

There is no dispute that DLN-SCR is technically feasible. It has been successfully tested and demonstrated for achieving the BACT limit (**AIR QUALITY Table 12**) or better in similar sized power plants. The DLN portion of this technology controls NOx formation by premixing the fuel and air prior to firing, thereby lowering the flame temperature and lowering NOx while increasing CO slightly (for further information see the Dry Low-NOx Combustors section below). It is common to employ an oxidizing catalyst with the DLN-SCR to control CO emissions, and Elk Hills is proposing to do so. The SCR portion requires the use of ammonia, which must be stored on site. Ammonia is injected into the flue gas upstream of the catalyst bed. The catalyst reacts with ammonia and NOx to form elemental nitrogen and water. The useful life of the catalyst is typically stated to be 2-3 years by the manufacturer, but in natural gas only facilities the catalyst life may be as high as 6-8 years. Elk Hills is proposing to fire only natural gas. Staff concurs with the EPA and District in finding that the DLN-SCR technology is technically feasible for the Elk Hills Power Project.

SCONOx

There is some debate over whether SCONOx is technically feasible when applied to a combustion turbine as large as the GE Frame 7F. ABB Environmental has issued a press release stating that the SCONOx technology is commercially ready for any size turbine. However, the largest turbine that SCONOx has been applied to is a GE LM2500, approximately 32 MW in capacity or about 1/15th the size of the proposed Elk Hills Power Project. This facility uses 4 SCONOx modules to control NOx and CO emission to or below the BACT levels identified in **AIR QUALITY Table 12**. The Otay Masa Power Project (which will use size F turbines) has issued a press release stating that they intend to use the SCONOx technology as their primary NOx and CO control method. The recently (March 8, 2000) filed AFC for the Nueva Azalea Project also proposed to use the SCONOx technology. SCONOx would not require an oxidizing catalyst or the use of ammonia to control NOx and CO emissions. SCONOx technology employs a reactive catalyst that must be regenerated on a regular basis. The catalyst reacts with CO and NO to form CO2, which is emitted, and NO2, which is absorbed on the surface of the catalyst until it is saturated. Prior to saturation, the catalyst is regenerated. This is done by sealing off the catalyst from the exhaust stream by of a pair of mechanical louver doors and subjecting it to a mixture of natural gas and steam to create an oxygen free atmosphere. This produces elemental nitrogen and CO2, which are emitted through the stack.

ABB Environmental requires that the catalyst in each module be removed and put through a regenerative bathing process once a year. There is some concern that this bathing process may result in an additional hazardous waste stream. The time required for this process is not clearly known, but it is likely to be approximately 1-2 weeks. Also, there may be a requirement that liquefied natural gas be stored on site to be used during the regular regeneration process of the catalyst throughout the year. This is primarily to avoid natural gas curtailment, however the Elk Hill Power Project has a natural gas processing facility nearby. Therefore, it is unclear if liquefied natural gas would have to be stored at the Elk Hills Power Plant.

ABB Environmental estimates that it would take 15 or more SCONOx modules (as compared to 4 for the LM2500) to control NOx and CO to the BACT levels identified (see **AIR QUALITY Table 12**) for a GE Frame 7F size power plant (Beck 2000). ABB Environmental has tested the louver doors used by each module under both static and dynamic thermal conditions similar to those found in the Frame 7F exhaust stream (Beck 2000). However, the testing did not include realistic flow or emission conditions that can be expected in an actual installation on an F size turbine (Beck 2000). Control algorithms have not yet been developed, nor tested for the 15 or more SCONOx modules (Beck 2000). Due to the lack of appropriate testing and information, some HRSG manufacturers have expressed reluctance to issue guarantees for their equipment if SCONOx is installed (Beck 2000).

On December 1, 1999, ABB Environmental issued a press release indicating that the SCONOx technology is commercially available for all size turbines. EPA issued a letter on December 20, 1999 indicating that SCONOx is a technically feasible and commercially available technology and must be included as part of the BACT analysis for all large turbines. Furthermore, EPA specifically requested that the San Joaquin Valley Unified Air Pollution Control District revise the SCONOx BACT analysis for the Elk Hills Power Project. Based on the EPA directive, staff considers SCONOx technically and commercially available.

XONON

The Elk Hills Power Project is proposing to use duct-fired heat recovery steam generators (HRSG). This means that XONON, which is being considered for the Pastoria Project before the Commission, is not applicable to this project. XONON is a catalyst that is installed in the combustors for the turbine. This technology controls emissions from the turbine only, not the HRSG. The emissions from the turbine might be very low (2.5 ppm or less), but because the duct burners in the HRSG also burns natural gas the project would still be required to install an SCR or SCONOx downstream or the HRSG. Thus, XONON does not offer any advantage over DLN-SCR or SCONOx technology for this application. Furthermore, XONON is just now being tested on an E size turbine. Pending the results of that testing, Pastoria Energy is proposing to install the XONON technology as their primary emission control for their F size turbines. The manufacturer of XONON has not declared it commercially available at this time. Therefore, it is staff's opinion that this technology should not be considered any further for this application.

Economic Feasibility

AIR QUALITY Table 15 summarizes the economic impacts for the project proponent of both the DLN-SCR (plus oxidizing catalyst) and SCONOx. This information was taken from a BACT analysis for the Towantic Energy Project in Connecticut, Mass (BECK 2000, Appendix C). That project consists of two GE Frame 7FA combustion turbines, two HRSG (unfired) and a steam turbine. This is a very similar arrangement to the Elk Hills power project. One important aspect of this economic analyses is that both the SCR and SCONOx options assume that the DLN is installed. Therefore, this economic analysis more correctly compares SCR-Oxidation Catalyst to SCONOx, not DLN-SCR to SCONOx. The economic analysis incorporates the different life spans of the various equipment, 3 years for SCR, 8 years for the oxidation catalyst and 7 years for the SCONOx. The capital recovery rate is assumed to be 12% and the emission reduction calculations are based on the maximum expected operation of the facility. The BACT analysis indicated that 28 tons/yr of particulate would be formed due to the SCR and oxidation catalyst combination, therefore staff has included this emission as an increase in **AIR QUALITY Table 15**. The results show that SCONOx is approximately 3 times the cost per ton as compared to SCR-oxidation catalyst.

Staff also reviewed the BACT analysis provided by Elk Hills as a response to an EPA request for additional information (Appendix D). The Elk Hills BACT analysis is very similar to the Beck analysis and comes to the same basic conclusion regarding economics, SCONOx is approximately 3 times the cost per tone as compared to SCR-oxidation catalyst.

AIR QUALITY Table 15
Economics of Emission Controls for two GE F7A Turbines

	SCR-Catalyst	SCONOx
Installed Capital Cost	**6,500,000**	**31,000,000**
Direct Annual Costs		
Labor	46,600	333,300
Maintenance	46,600	333,300
Energy	1,085,900	2,030,500
Parts and Materials	1,884,000[1]	5,434,000[5]
Waste Disposal	-	-
Misc.	-	-
Subtotal	**3,066,100**	**8,131,100**
Indirect Annual Costs		
Overhead	56,000	400,000
Administrative, Tax & Insurance	260,000	1,240,000
Capital Recovery[2]	870,000	4,150,000
Tax Credit	-	-
Subtotal	**1,186,000**	**5,790,000**
Total Annual Cost	**4,249,100**	**13,921,100**
Total Pollutant Removed (tons/yr)		
NO2[3]	410	410
CO[4]	46	46
Particulate	-28	
Total	428	456
Cost Effectiveness ($/ton)	**9,928**	**30,529**
Basis of Costs		
Energy Use (MWh/yr)	11,500	37,100
Energy Cost ($/MWh)	35.00	35
Natural Gas Use (MCF/yr)	135,800	244,000
Natural Gas Cost ($/MMBtu)	3.00	3.00
Ammonia Use (lbs/hr)	85	0
Ammonia Cost ($/ton)	300	-

1. SCR Catalyst replacement based on replacement of 100% catalyst every 3 years, catalyst cost at 80% of initial equipment cost. CO catalyst replacements based on replacement of 100% of catalyst every 8 years, catalyst cost at 80% of initial equipment cost.
2. Capital Recovery based on 12%.
3. NOx reduction based on gas-fired operation for 8760 hours per year at 90% capacity factor.
4. CO reduction represents two units operating on natural gas for 8760 hours per year and includes additional emissions due to start-up, shutdown and testing.
5. ABB Environmental could not provide cost for catalyst replacement. Cost estimate based on replacing 100% of catalyst at 7 year intervals with catalyst cost at 80% of initial equipment cost.

(Beck 2000)

Environmental Impacts

Since DLN-SCR uses ammonia to control NOx emissions, the transportation, storage and use of ammonia must be considered in any environmental assessment. At a minimum, the analysis should include an EPA Risk Management Program style of off-site consequence analysis of the storage facility. However, to be complete the transportation corridor should be evaluated as well as potential mitigating factors for storage and use. Staff has completed their assessment for the Elk Hills Power Project for Hazardous Materials Management and Transportation, concluding that there will be no significant impact from the transportation, storage or use of anhydrous ammonia at the Elk Hills Power Project site. Other environmental impacts include solid waste. The SCR and oxidation catalysts ultimately result in a solid waste stream, the catalysts themselves. These catalysts are typically returned to the manufacturer for reclamation, recycling and/or disposal. They have the potential to be considered hazardous waste depending on how they are handled.

Since the ABB version of SCONOx has not been installed yet, it is difficult to assess potential environmental impacts. Air emissions may include leakage of regeneration gases, however these gases are primarily natural gas and hydrogen. Therefore they may have a minor greenhouse gas effect (in the case of natural gas), but would not be considered VOC emissions. ABB Environmental estimated that the annual catalyst bath would produce approximately 720,000 gallons of wastewater (Beck 2000). Additionally, 92,000 gallons of water would be used throughout the year for the continuous regeneration process (Beck 2000). ABB Environmental is unsure if the catalyst can be recycled after its useful life is completed. ABB is also unsure if the spent catalyst would be considered hazardous waste. The accidental release of hazardous materials could be significant. If the modules leak, they will be releasing uncombusted natural gas and hydrogen, which are explosive in air. Additionally, ABB may require (or strongly advise) the project operators to store and use liquefied natural gas on site for the continuous regeneration process. In that case, that would represent a potentially significant hazard to workers, and possibly the public due to accidental detonation. However, in the case of Elk Hills, this is likely to be unnecessary due to the close proximity of a natural gas plant. Finally, the complexity of the mechanical control and the probable control algorithms (which have not been developed yet) are such that emission control problems may be encountered. However, this last item can be overcome with appropriate field testing on a large size turbine.

Energy Analysis

Staff finds no compelling information to suggest that the DLN-SCR and SCONOx technologies cause significantly different energy penalties. Both require annual maintenance, both require periodic shutdown, both have operational constraints and both can cause a significant amount of back-pressure. Therefore, staff suggests that there is no compelling argument for a significant difference in energy production and use.

Conclusions regarding the SCONOx BACT analysis

BACT requirements are primarily a level of emission, with consideration to other environmental impacts. Based on the above analysis, staff concludes that either DLN-SCR or SCONOx has the potential to meet the BACT requirements stated in **AIR QUALITY Table 14**. Staff notes that there are many unknowns about SCONOx which affect its reliability. These unknowns will very likely be resolved in the future, but currently, remain unresolved. Staff further notes that the water usage requirements of SCONOx may be more than a local water district is willing or able to allocate when added to the water usage of the rest of the facility. Again, however, this can be overcome by reducing the facility water usage (such as, using dry cooling when possible). Finally, staff concludes that there is likely to be no significant environmental impact from either DLN-SCR or SCONOx. Provided Elk Hills is willing to work out any reliability issues with ABB Environmental on the SCONOx technology, staff's opinion is to allow the applicant to choose either emission control technology.

BACT Determinations for NOx, CO and Startup

CURE has raised several issues regarding the BACT determinations for various air emissions associated with the EHPP. For NOx emissions during normal and peak load operations, CURE contends that the BACT limit should be 2.5 ppm @ 15% O_2 averaged over 1-hour. This is in fact the established BACT limit for NOx emission from the EHPP during normal and peak load operations. CURE further insists that the BACT limit for NOx should be lowered to 1 ppm based on achieved emission levels in two other power plants. However, these power plant are much smaller than the proposed EHPP, and thus do not represent an achievement in practice indicating reasonable reliability. CURE further insists that SCONOx be forced on Elk Hills as BACT. Staff respectfully reminds CURE that BACT is a level of emission, not a specific technology.

The determined BACT level for CO is 4 ppm @ 15% O_2 averaged over 4 hours using any technology available. CURE contends that the BACT level for CO is 1 ppm @ 15% O_2 averaged over 1 hour based on the achievements of smaller turbines using SCONOx. This power plant is much smaller than the proposed EHPP, and thus does not represent an achievement in practice indicating reasonable reliability.

CURE suggests that the CO emissions during startup are too high and that an auxiliary boiler warming the catalysts should be forced on Elk Hills to reduce CO start-up emissions. Staff notes that the CO emissions during startup were modeled and shown not to cause a significant impact to the national and state ambient air quality standards. Therefore, staff finds no compelling reason to introduce an additional emission source, which would include NOx, SOx, CO, VOC and PM10 emissions, as well as complex startup procedures, to reduce a proposed emission source that has no associate air quality impact.

CURE contends that the NOx and CO emissions are underestimated for startup and shutdown modes of operations. This seems to contradict their comment above, that the CO emissions during startup are too high. The emission limits for NOx and CO during startup are restricted to 51 lbs and 38 lbs in any one hour and are verified by the continuous emission monitoring system (CEM). It is staff's opinion that these emission limits are achievable and verifiable. Therefore, since Elk Hills is willing to operate under these lower emission limits, staff finds there to be no compelling reason to raise them.

Dry Low-NOx Combustors

Over the last 20 years, combustion turbine manufacturers have focused their attention on limiting the NOx formed during combustion. Because of the expense and efficiency losses due to steam or water injection in the combustor cans to reduce combustion temperatures and the formation of NOx, CTG manufacturers are presently choosing to limit

NOx formation through the use of dry low-NOx technologies. The GE version of the dry low-NOx combustor is a four-stage ignition system. Initially the fuel/air mixture is ignited in two independent combustors (0% to 35% load). Then the startup sequence moves to a lean-lean operation (35% to 70% load) where the center burner is engaged as well. Then second stage burning is begun and all the fuel is directed to the center burner. The second stage burning is a transient event while proceeding to the premixed phase. Premixed operation (70% and 100% load) has fuel being pumped to all burners, but ignition only in the center burner.

In this process, firing temperatures remain somewhat low, thus minimizing NOx formation, while thermal efficiencies remain high. At steady state CTG loads greater than 40 percent load, NOx concentrations entering the HRSG are 25 ppm corrected to 15 percent O2. CO concentrations are more variable, with concentrations greater than 100 ppm at 50 percent load, dropping to 5 ppm at 100 percent load.

FLUE GAS CONTROLS

To further reduce the emissions from the combustion turbines before they are exhausted into the atmosphere, flue gas controls, primarily catalyst systems, will be installed in the HRSGs. Elk Hills is proposing two catalyst systems, a selective catalytic reduction system to reduce NOx, and an oxidizing system to reduce CO.

Selective Catalytic Reduction (SCR)

Selective catalytic reduction refers to a process that chemically reduces NOx by injecting ammonia into the flue gas stream over a catalyst in the presence of oxygen. The process is termed selective because the ammonia reducing agent preferentially reacts with NOx rather than oxygen, producing inert nitrogen and water vapor. The performance and effectiveness of SCR systems are related to operating temperatures, which may vary with catalyst designs. Flue gas temperatures from a combustion turbine typically range from 950 to 1100^{o}F.

Catalysts generally operate between 600 to 750°F (CARB 1992), and are normally placed inside the HRSG where the flue gas temperature has cooled. At temperatures lower than 600°F, the ammonia reaction rate may start to decline, resulting in increasing ammonia emissions, called ammonia slip. At temperatures above about 800°F, depending on the type of material used in the catalyst, damage to some catalysts can occur. The catalyst material most commonly used is titanium dioxide, but materials such as vanadium pentoxide, zeolite, or a noble metal are also used. These newer catalysts (versus the older alumina-based catalysts) are resistant to fuel sulfur fouling at temperatures below 770°F (EPRI 1990).

Regardless of the type of catalyst used, efficient conversion of NOx to nitrogen and water vapor requires uniform mixing of ammonia into the exhaust gas stream. Also, the catalyst surface has to be large enough to ensure sufficient time for the reaction to take place.

Elk Hills proposes to use a combination of the dry low-NOx combustors and SCR system to produce a NOx concentration exiting the HRSG stack of 2.5 ppm, corrected to 15 percent excess oxygen averaged over a 1-hour period.

Oxidizing Catalyst

To reduce the turbine carbon monoxide (CO) emissions, Elk Hills proposes to install an oxidizing catalyst, which is similar in concept to catalytic converters used in automobiles. The catalyst is usually coated with a noble metal, such as platinum, which will oxidize unburned hydrocarbons and CO to water vapor and carbon dioxide (CO2). The CO catalyst is proposed to limit the CO concentrations exiting the HRSG stack to 4 ppm, corrected to 15 percent excess oxygen and averaged over 3 hours.

COOLING TOWER

Cooling tower drift consists of small water droplets, which contain particulate matter that originate from the total dissolved solids in the circulating water. To limit these particulate emissions, drift eliminators are installed in the cooling tower to capture these water droplets. Elk Hills intends to use drift eliminators on the cooling tower, with a design efficiency of 0.0006 percent. This is a very high level of efficiency for cooling tower drift eliminators. Similar cooling tower designs have been used successfully by a number of other projects licensed by the Energy Commission in recent years.

EMISSION OFFSETS

District Rule 2102, Section 4.2, requires that Elk Hills provide emission offsets, in the form of banked Emission Reduction Credits (ERC), for the project's emissions increases of NOx, SO2, VOC and PM10. Elk Hills has secured a number of offsets through option agreements. Offsets for the project's CO emissions are not required since the project will not cause any violations of any CO standard and the area currently does not experience any violations of any CO standard. A summary of the offset liability is shown in **AIR QUALITY Table 16**.

Elk Hills is proposing inter-pollutant trading for their PM10 liability (i.e., trading of NOx for PM10). The ratio of 2.22 pounds of NOx for every one pound of PM10 was determined by the District as the appropriate interpollutant trading ratio. The District rules allow for such inter-pollutant trading (Rule 4.2.5.3). Staff agrees that based on the relationship of NOx contributing to secondary PM10 formation of ammonium nitrate, especially during the high ambient PM10 winter season, that NOx reductions for PM10 increases is an appropriate mitigation measure.

AIR QUALITY Table 16
Emissions Offsets Balance

	Offsets Required	Offsets Required[A] (with Distance Ratio)	Offsets Provided	Additional Offsets Needed	Average daily Offsets provided[B]	Average daily project emissions[C]
	Tons/year				Lbs/day	
PM10	159.4	353.8	385.7	-31.9	2,113	873.3
NOx	147.9	147.9	159.0	-11.1	871	759.4
SO2	29.2	29.2	34.5	-5.3	189	158.5
VOC	32.7	32.7	26.7	6.0	146	177.8

A For CEQA purposes, the distance ratio for all pollutants is 1:1, the inter-pollutant trading ratio for NOx for PM10 is 2.22:1.
B The annual offsets provided divided by 365 days/year and multiplied by 2,000 lbs/ton.
C Reflect Typical Expected Facility Emissions as reported in Air Quality Table 6.

AIR QUALITY Table 16 shows that Elk Hills is short 6.0 tons per year of VOC emission offsets. However, there is a total excess of 43.0 tons per year of NOx emission ERC. That is 31.9 tons from the PM10 ERCs (which is using inter-pollutant trading NOx for PM10) and 11.1 tons from the NOx ERCs. That is more than 7 times the shortfall in VOC offsets. Since NOx and VOC are established ozone precursors, it is staff's opinion that the excess NOx ERCs more than offset the VOC shortfall. Similarly, the average daily offsets show a shortfall in VOC and an excess in NOx.

ADEQUACY OF PROPOSED MITIGATION

CONSTRUCTION MITIGATION

Elk Hills is required to comply with the District Regulation 8 for limiting fugitive dust emissions during construction. Staff believes that additional measures are necessary to mitigate potential construction impacts (refer to staff proposed mitigation below).

OPERATIONS MITIGATION

EMISSION CONTROLS

Elk Hills has proposed, in their opinion, all practical and technically feasible mitigation measures to limit NOx emissions from the combustion turbines to 2.5 ppm over a 1-hour average. In addition, they propose to use an oxidizing catalyst to limit CO emissions to 4 ppm over a 3-hour period, which will also limit VOC emissions to 2 ppm over a 3-hour period.

Elk Hill's use of drift eliminators with an efficiency of 0.0006 percent represent the state-of-the-art of drift eliminator design. To our knowledge, commercially available drift eliminators with even higher efficiency, which could further reduce the cooling tower's PM10 emissions, are not available.

OFFSETS

The emission reduction credits for the EHPP originate from four sources. Two of the ERC certificates (VOC credits and NOx credits) originate from the same emission reduction act. This was the retrofit of existing diesel fired IC engines with pre-combustion chambers, located in the natural gas plant owned by Occidental of Elk Hills on March 20, 1989. The ERC certificate used to offset the EHPP PM10 emissions (inter-pollutant offset trading, NOx for PM10) originated from the retrofit of 31 existing diesel IC engines with pre-combustion chambers. These were also located in the natural gas plant owned by Occidental of Elk Hills on December 5, 1990. The ERC certificate used to offset the EHPP SOx emissions originated from a shutdown of four boilers at the Rio Bravo Pump Station, which is located near the EHPP site, owned by Chevron Pipeline-Midway, on September 1, 1992. Neither EPA nor CARB have raised any questions regarding the validity of the ERCs provided. Staff therefore finds that these ERCs are valid to offset the EHPP emission impacts.

STAFF PROPOSED MITIGATION

CONSTRUCTION MITIGATION

As stated above, there are a number of rules in the District's Regulation 8 that will minimize fugitive dust emissions. Those rules allow for some latitude and flexibility as to how they will demonstrate compliance. Elk Hills stated in their AFC that they intend to use watering as their main control mechanism for fugitive PM10.

The modeling assessment discussed earlier shows that the combustion sources used for heavy construction have the potential for causing significant air quality impacts. Elk Hills is not proposing to minimize combustion emissions such as NOx, SO2, CO, VOC and PM10. Control of combustion emissions associated with construction is not required by District rules. Elk Hills has agreed to using an oxidizing soot filter where applicable. The oxidizing soot filter is a device that replaces the muffler of the construction equipment. It reduces CO and hydrocarbon (VOC) emissions by approximately 80-90% and PM10 emissions by approximately 90-99%. This technology has several operational constraints and the Conditions of Certification will be written to give the on-site engineer the latitude to remove the oxidizing soot filters when it is determined that they are not appropriate for the specific application.

OPERATIONS MITIGATION

Neither EPA nor CARB have raised any questions regarding the validity of the ERCs provided. Staff, therefore, finds that these ERCs are valid to offset the EHPP emission impacts. Staff finds that with the proposed emission controls and ERCs provided, there is no further mitigation necessary for the EHPP emission impacts.

COMPLIANCE WITH LORS

FEDERAL

The EHPP is currently under review by EPA on the Prevention of Significant Deterioration (PSD) permit. EPA has not yet issued a draft PSD analysis for the EHPP.

STATE

The project, with the anticipated full mitigation (offsets) that will be necessary for the project to secure a Determination of Compliance from the SJVUAPCD, will comply with Section 41700 of the California State Health and Safety Code. The project will be fully mitigated and therefore would not cause any injury, detriment, nuisance or annoyance to the public.

LOCAL

Compliance with specific SJVUAPCD rules and regulations are discussed below. For a more detailed discussion of the compliance of the EHPP, please refer to the Determination of Compliance (SJVUAPCD 2000a).

RULE 2201 - NEW AND MODIFIED STATIONARY SOURCE REVIEW RULE

SECTION 4.1 - BEST AVAILABLE CONTROL TECHNOLOGY

The SJVUAPCD has determined the Best Available Control Technology for the emission generating equipment and is summarized in the following **AIR QUALITY Table 17**.

AIR QUALITY Table 17
BACT Determinations

Pollutant	Gas Turbine Engines
PM10	Air inlet filters, lube oil vent coalescer and opacity <5%, natural gas fuel
SO_2	Utility quality natural gas
NO_x	2.5 ppm @ 15% O_2, 1-hr average
VOC	1.2 ppm @ 15% O_2 3-hr average
CO	6 ppm @ 15% O_2 3-hr average

SECTION 4.2 - OFFSETS

EHPP demonstrated through air dispersion modeling that their project would not cause a violation of any CO ambient air quality standard, therefore, CO emission offsets are not required for the combustion turbine CO emissions. All other project emissions are subject to emissions offsets, which are discussed in the Mitigation section of this analysis, and in the DOC. Staff notes that a slight inconsistency has occurred in the District's final Determination of Compliance. In section VII of the DOC, the District calculates both the EHPP daily and annual potential to emit. These are both the basis for determining the appropriate offsets that will be required for the project, as well as the basis for the daily and annual emission limits. Page 8 of the DOC shows the startup emission factors for the EHPP to an accuracy of one decimal place. Page 9 shows the emission factors for base load and peak load operations, also to one decimal place. On page 11 of the DOC, the District shows the calculated daily and annual Potential to Emit (PTE). The Annual PTE are based on the emission factors reported on pages 8 and 9. However, the daily PTE are based on a more accurate emission factor. **AIR QUALITY Table 18** shows the difference between these two sets of emission factors.

AIR QUALITY Table 18
Emission Factors used for EHPP Combustion Turbine

Pollutant	Daily PTE Emission Factors (lbs/hr)	Annual PTE Emission Factors (lbs/hr)	Amount Annual PTE Underestimates Emissions (lbs/hr)
Startup			
PM10	18.0000	18.0	0.0
SOx	2.2454	2.2	0.0454
NOx	25.4500	25.5	-0.05
VOC	2.5714	2.6	-0.0286
CO	19.0000	19.0	0.0
Normal Operation			
PM10	18.0000	18.0	0.0
SOx	3.2705	3.3	-0.0295
NOx	15.8333	15.8	0.0333
VOC	3.7143	3.7	0.0143
CO	12.4444	12.4	0.0444
Peak Load Operation			
PM10	18.0000	18.0	0.0
SOx	3.6088	3.6	-0.0088
NOx	15.8333	15.8	0.0333
VOC	4.0000	4.0	0.0

CO	12.5333	12.5	0.0333

The most significant result of the annual PTE underestimating the emission factors is for NOx, which might resulted in approximately 650 lbs per year being unmitigated. However, since Elk Hills is willing to accept the lower emission factors used in the annual PTE, the EHPP will be fully offset and restricted to those emission levels.

AIR QUALITY Table 19 shows the daily and annual emission limits for the EHPP based on the Districts assumptions in the DOC. According to the District rules (2201 section 4.2.1.2) the diesel IC engine is exempted from offset requirements, however staff includes these emissions in the daily and annual totals.

AIR QUALITY Table 19
Daily and Annual Emission Limits for the EHPP

Permitted Unit	PM10	SOx	NOx	VOC	CO
Daily (lbs/day)					
Turbine 1	432	86.4	418.5	96.0	326.7
Turbine 2	432	86.4	418.5	96.0	326.7
Cooling Tower	9.3	0	0	0	0
Diesel Engine	0.9	1.6	23.5	4.0	7.3
Total (lbs/day)	874.2	174.4	860.5	196.0	660.7
Annual (lbs/year)					
Turbine 1	315,360	57,468	285,042	64,478	223,040
Turbine 2	315,360	57,468	285,042	64,478	223,040
Cooling Tower	3,392	0	0	0	0
Diesel Engine	8	14	196	34	60
Total (lbs/year)	318,760	57,482	285,238	64,512	223,100
Total (tons/year)	159.4	28.7	142.6	32.3	111.6

SECTION 4.3 - ADDITIONAL SOURCE REQUIREMENTS

Rule 4.3.2.1 requires that a new source not cause, or make worse, the violation of an ambient air quality standard as demonstrated through analysis with air dispersion models. Because the project demonstrates that it does not cause a violation of any CO ambient air quality standard, and that the project is fully offset for its other emissions, the District has determined that the EHPP will not make the ambient air quality worse.

Rule 2520 – Federally Mandated Operating Permits

EHPP is required to file a Title V Operating permit with the District within 12 months of commencing operation. Presently, no action is required.

Rule 2540 – Acid Rain Program

An acid rain application must be submitted at least 24 months prior to the project generating electricity. The requirements will include that NO_x and SO_x emissions will have to be monitored and a small quantity of SO_x allowance will have to be provided from a national SO_x allowance bank. Compliance will be determined at a later date.

Rule 4001 - New Source Performance Standards

Based on the heat rate of the GE Frame 7FA turbine, a NSPS NO_x limit is calculated at 109 ppmv at 15% O_2. The EHPP will be permitted at 2.5 ppmv at 15% O_2. The SO_x emission concentration will be 0.38 ppmv at 15% O_2 which is less than the NSPS requirement of 150 ppmv. The sulfur content of the natural gas fuel is equivalent to 0.003% which is less than the NSPS requirement of 0.8%. Compliance with Rule 4001 is therefore demonstrated.

Rule 4101 - Visible Emissions

All equipment will be limited to a 5 percent opacity limit by permit condition, which is less than the rule requirement of 20 percent opacity.

Rule 4201 - Particulate Matter Concentration

The District determined that the particulate emissions from the GE Turbines at 45% load, 115^{o}F ambient air temperature is 0.0089 gr/dscf. This emission rate is below the rule limit of 0.1 gr/dscf, therefore compliance is demonstrated.

The District determined that the particulate emissions from the diesel IC engine is 0.024 gr/dscf. This emission rate is below the rule limit of 0.1 gr/dscf, therefore compliance is demonstrated.

Rule 4703 - Stationary Gas Turbines

The permitted NO_x limit of 2.5 ppm is below the rule mandated limits of 12.2 ppm for SCR controlled turbines. The permitted CO limit of 4 ppm is well below the rule requirement of 25 ppm.

Rule 4801 - SO_2 Concentration

The fuel sulfur content of the natural gas to be used at the EHPP will result in a SO_2 emission concentration of 0.38 ppm @ 15% O_2 and is not expected to exceed the 2,000 ppm limit imposed by this rule.

Rule 8010 - Fugitive Dust Administrative Requirements for Control of Fine Particulate Matter (PM-10)

EHPP will provide a Construction Fugitive Dust Mitigation Plan that will discuss the types of chemical stabilizing agents and dust suppressant materials they intend to use.

Rule 8020 - Fugitive Dust Requirements for Control of Fine Particulate Matter (PM-10) from Construction, Demolition, Excavation, and Extraction Activities

The Construction Fugitive Dust Mitigation Plan will specify the specific measures that EHPP will employ to limit fugitive dust and thus comply with this rule.

Rule 8030 - Control of PM10 from Handling and Storage of Bulk Materials

The Construction Fugitive Dust Mitigation Plan will specify the specific measures that EHPP will employ to limit fugitive dust during the handling and transport of any borrow soil if needed and thus comply with this rule.

Rule 8060 - Control of PM10 from Paved and Unpaved Roads

The Construction Fugitive Dust Mitigation Plan will specify the use of chemical dust suppressant and/or the use of paved shoulders on paved roadways that will demonstrate compliance with this rule.

Rule 8070 - Control of PM10 from Vehicle/Equipment Parking, Shipping, Receiving, Transfer, Fueling and Service Areas

The Construction Fugitive Dust Mitigation Plan will include measures to limit fugitive dust from unpaved parking areas and the tracking out of mud and dirt onto public roadways, and thus demonstrate compliance with this rule.

CONCLUSIONS AND RECOMMENDATIONS

The Elk Hills Power Project's emissions of NOx, SO2 and CO will not cause a violation of any NO2, SO2 or CO ambient air quality standards, and therefore, their impacts are not significant. The project's air quality impacts from directly emitted PM10 and of the ozone precursor emissions of NOx and VOC and PM10 precursors of NOx and SO2 could be significant if left unmitigated. EHPP will reduce emission to the extent feasible and provide emission offsets for their NOx, VOC, SO2 and PM10 emissions, and thus these mitigation measures reduce the potential for directly emitted PM10, as well as ozone and secondary PM10 formation to a level of insignificance.

The District has submitted a Final Determination of Compliance that concludes that the Elk Hills Power Project will comply with all applicable District rules and regulations and therefore has proposed a set of conditions which are presented here as Conditions of Certification AQ-1 through AQ-62.

CEC staff recommends the inclusion of two additional Conditions of Certification (AQ-C1 and AQ-C2) that address the construction related impacts. Staff therefore recommends the certification of the Elk Hills Power Project with the following proposed Conditions of Certification.

CONDITIONS OF CERTIFICATION

AQ-C1 Prior to breaking ground at the project site, the project owner shall prepare a Construction Fugitive Dust Mitigation Plan that will specifically identify fugitive dust mitigation measures that will be employed for the construction of the Elk Hills Power Project and related facilities.

<u>Protocol:</u> The Construction Fugitive Dust Mitigation Plan shall specifically identify measures to limit fugitive dust emissions from construction of the project site and linear facilities. Measures that should be addressed include the following:

- the identification of the employee parking area(s) and surface of the parking area(s);
- the frequency of watering of unpaved roads and disturbed areas;
- the application of chemical dust suppressants;
- the use of gravel in high traffic areas;
- the use of paved access aprons;
- the use of posted speed limit signs;
- the use of wheel washing areas prior to large trucks leaving the project site; and,
- the methods that will be used to clean tracked-out mud and dirt from the project site onto public roads.

<u>**Verification:**</u> At least sixty (60) days prior to breaking ground at the project site, the project owner shall provide the CPM with a copy of the Construction Fugitive Dust Mitigation Plan for approval.

AQ-C2 The project owner shall ensure that all heavy earthmoving equipment including, but not limited to, bulldozers, backhoes, compactors, loaders, motor graders and trenchers, and cranes, dump trucks and other heavy duty construction related trucks, have been properly maintained and the engines tuned to the engine manufacturer's specifications. The project owner shall also install oxidizing soot filters on all suitable construction equipment used either on the power plant construction site or associated linear construction sites. Suitability is to be determined by an independent California Licensed Mechanical Engineer who will stamp and submit for approval an initial and all subsequent Suitability Reports as necessary containing at a minimum the following:

Initial Suitability Report:

- The initial suitability report shall be submitted to the CPM for approval 60 days prior to breaking ground on the project site.
- A list of all fuel burning, construction related equipment used,
- a determination of the suitability of each piece of equipment to work appropriately with an oxidizing soot filter,

• if a piece of equipment is determined to be suitable, a statement by the independent California Licensed Mechanical Engineer that the oxidizing soot filter has been installed and is functioning properly, and

• if a piece of equipment is determined to be unsuitable, an explanation by the independent California Licensed Mechanical Engineer as to the cause of this determination.

Subsequent Suitability Reports

• If a piece of construction related equipment is subsequently determined to be unsuitable for an oxidizing soot filter after such installation has occurred, the filter may be removed immediately. However notification must be sent to the CPM for approval containing an explanation for the change in suitability within 10 days.

• Changes in suitability are restricted to three explanations which must be identified in any subsequent suitability report.

1. The oxidizing soot filter is reducing normal availability of the construction equipment due to increased downtime, and/or power output due to increased back pressure by 20% or more.
2. The oxidizing soot filter is causing or reasonably expected to cause significant damage to the construction equipment engine.
3. The oxidizing soot filter is causing or reasonably expected to cause a significant risk to nearby workers or the public.

Verification: The project owner shall submit to the CPM, via the Monthly Compliance Report, documentation, which demonstrates that the contractor's heavy earthmoving equipment is properly maintained and the engines are tuned to the manufacturer's specifications. The project owner shall maintain all records on the site for six months following the start of commercial operation. The project owner will submit to the CPM for approval, the initial suitability report stamped by an independent California Licensed Mechanical Engineer, 60 days prior to breaking ground on the project site. The project owner will submit to the CPM for approval, subsequent suitability reports as required, stamped by an independent California Licensed Mechanical Engineer no later than 10 working day following a change in the suitability status of any construction equipment.

Conditions of Certification AQ-1 through AQ-44 apply to the following equipment:

SJVUAPCD Permit No. S-3523-1-0 - GE FRAME 7 MODEL PG7241FA NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #1 WITH DRY LOW NOX COMBUSTORS, SELECTIVE CATALYTIC REDUCTION, OXIDIATION CATALYST, AND STEAM TURBINE S-3532-2 (503 MW TOTAL NOMINAL RATING),

SJVUAPCD Permit No. S-3523-2-0 - GE FRAME 7 MODEL PG7241FA NATURAL GAS FIRED COMBINED CYCLE GAS TURBINE ENGINE/ELECTRICAL GENERATOR #1 WITH DRY LOW NOX

COMBUSTORS, SELECTIVE CATALYTIC REDUCTION, OXIDIATION CATALYST, AND STEAM TURBINE S-3532-2 (503 MW TOTAL NOMINAL RATING),

AQ-1 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

Verification: The project owner shall make the site available for inspection by representatives of the District, California Air Resources Board (CARB) and the Commission.

AQ-2 The project owner shall submit selective catalytic reduction, oxidation catalyst, and continuous emission monitor design details to the District at least 30 days prior to the construction of permanent foundations. [District Rule 2201]

Verification: The project owner shall provide copies of the drawings of the catalyst system chosen and the continuous emission monitor design detail to the CPM and the District at least 30 days prior to the construction of permanent foundations.

AQ-3 Combustion turbine generator (CTG) and electric generator lube oil vents shall be equipped with mist eliminators to maintain visible emissions from lube oil vents shall no greater than 5% opacity, except for three minutes in any hour. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-4 The CTG shall be equipped with continuously recording fuel gas flowmeter. [District Rule 2201]

Verification: The information above shall be included in the quarterly reports of Condition **AQ-35.**

AQ-5 CTG exhaust shall be equipped with continuously recording emissions monitor for NOx (before and after the SCR unit), CO, and O2 dedicated to this unit. Continuous emission monitors shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as normal operating conditions. If relative accuracy of CEM(s) cannot be certified during startup conditions, CEM results during startup and shutdown events shall be replaced with startup emission rates obtained during source testing to determine compliance with emission limits in **Conditions AQ-13, 16, 17 and 18**. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-6 Ammonia injection grid shall be equipped with operational ammonia flowmeter and injection pressure indicator. [District Rule 2201]

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-7 Exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods. [District Rule 1081]

Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-8 Heat recovery steam generator design shall provide space for additional selective catalytic reduction catalyst and oxidizing catalyst if required to meet NOx and CO emission limits. [District Rule 2201]

Verification: Please refer to **Condition AQ-2**.

AQ-9 The project owner shall monitor and record exhaust gas temperature at the selective catalytic reduction and oxidation catalyst inlets. [District Rule 2201]

Verification: The project owner shall record the exhaust gas and selective catalytic reduction temperatures in the daily logs.

AQ-10 CTG shall be fired on natural gas, consisting primarily of methane and ethane, with a sulfur content no greater than 0.75 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

Verification: The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-34.**

AQ-11 Startup is defined as the period beginning with initial turbine firing until the unit meets the lb/hr and ppmv emission limits in Condition AQ-15. Shutdown is defined as the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup and shutdown durations shall not exceed two hours for a regular startup, four hours for an extended startup, and one hour for a shutdown, per occurance. [District Rule 2201 and 4001]

Verification: The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-12 Ammonia shall be injected when the selective catalytic reduction system catalyst temperature exceeds 500 degrees F. The project owner shall monitor and record catalyst temperature during periods of startup. [District Rules 2201]

Verification: The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-13 During startup or shutdown of any gas turbine engine(s), combined emissions from both gas turbine engines (s-3523-1-0 and –2-0) heat recovery steam generator exhausts shall not exceed any of the following limits in any one hour:

NOx (as NO2)	76 lbs
CO	38 lbs

[CEQA]

<u>Verification:</u> The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-14 By two hours after initial turbine firing, CTG exhaust emissions shall not exceed any of the following: NOx (as NO2) 12.2 ppmv @ 15% O^2 and CO 25 ppmv @ 15% O^2. [District Rule 4703]

<u>Verification:</u> The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-15 Emission rates from each CTG, except during startup or shutdown, shall not exceed any of the following emission limits:

PM10	18 lbs/hr
SO2	3.6 lbs/hr
NO2	15.8 lbs/hr and 2.5 ppmvd @ 15% O^2 averaged over 1-hr
VOC	4.0 lbs/hr and 2.0 ppmvd @ 15% O^2 averaged over 3-hr
CO	12.5 lbs/hr and 4 ppmvd @ 15% O^2 averaged over 3-hr
Ammonia	10 ppmvd @ 15% O^2 averaged over 24-hr

[District Rule 2201, 4001 and 4703]

<u>Verification:</u> The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-16 Emission rates from each CTG, on days when a startup or shutdown occurs, shall not exceed any of the following:

PM10	432 lbs/day
SO2	86.4 lbs/day
NO2	418.5 lbs/day
VOC	96.0 lbs/day
CO	326.7 lbs/day

[District Rule 2201]

<u>Verification:</u> The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-17 Emission rates from both CTGs (S-3523-1 and -2), on days when a startup or shutdown occurs for either or both turbines, shall not exceed any of the following:

PM10	864.0 lb/day
SO2	172.8 lb/day
NO2	817.8 lb/day
VOC	192.0 lb/day
CO	640.4 lb/day.

[District Rule 2201]

Verification: The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-18 Annual emissions from both CTGs calculated on a twelve consecutive month rolling basis shall not exceed any of the following: PM10 - 315,360 lb/year , SOx (as SO2) - 57,468 lb/year, NOx (as NO2) - 285,042 lb/year, VOC - 64,478 lb/year, and CO - 223,040 lb/year. [District Rule 2201]

Verification: The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-19. Each one-hour period in a one-hour rolling average will commence on the hour. Each one-hour period in a three-hour rolling average will commence on the hour. The three-hour average will be compiled from the three most recent one-hour periods. Each one-hour period in a twenty-four-hour average for ammonia slip will commence on the hour. The twenty-four-hour average will be calculated starting and ending at twelve-midnight. [District Rule 2201]

Verification: The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-20 Daily emissions will be compiled for a twenty-four period starting and ending at twelve-midnight. Each calendar month in a twelve-consecutive-month rolling emissions will commence at the beginning of the first day of the month. The twelve-consecutive-month rolling emissions total to determine compliance with annual emissions will be compiled from the twelve most recent calendar months. [District Rule 2201]

Verification: The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-21 Prior to or upon startup of S-3523-1-0, -2-0, & 3-0, emission offsets shall be surrendered for all calendar quarters in the following amounts, at the offset ratio specified in Rule 2201 (6/15/95 version) Table 1, PM10 - Q1: 78,596 lb, Q2: 79,470 lb, Q3: 80,343 lb, and Q4: 80,343 lb; SOx (as SO2) - Q1: 14,170 lb, Q2: 14,328 lb , Q3: 14,485 lb, and Q4: 14,485 lb; NOx (as NO2) - Q1: 65,353 lb, Q2: 66,079 lb, Q3: 66,805 lb, and Q4: 66,805 lb; and VOC - Q1: 10,967 lb, Q2: 11,089 lb, Q3: 11,211 lb, and Q4: 11,211 lb.
[District Rule 2201]

Verification: The owner/operator shall submit copies of ERC surrendered to the SJVUAPCD in the totals shown to the CPM prior to or upon startup of the CTGs or cooling tower.

AQ-22 NOx and VOC emission reductions that occurred from April through November may be used to offset increases in NOx and VOC respectively during any period of the year. [District Rule 2201]

Verification: The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-21.**

AQ-23 NOx ERCs may be used to offset PM10 emission increases at a ratio of 2.42 lb NOx : 1 lb PM10 for reductions occurring within 15 miles of this facility, and at 2.72 lb NOx : 1 lb PM10 for reductions occurring greater than 15 miles from this facility. [District Rule 2201]

Verification: The project owner shall provide records of the ERCs as part of **Condition AQ-21.**

AQ-24 At least 30 days prior to the construction of permanent foundations, the project owner shall provide the District with written documentation that all necessary offsets have been acquired or that binding contracts to secure such offsets have been entered into. [District Rule 2201]

Verification: The project owner shall provide records of the ERCs as part of **Condition AQ-21.**

AQ-25 Compliance with ammonia slip limit shall be demonstrated by using the following calculation procedure: ammonia slip ppmv @ 15% O2 = ((a-(bxc/1,000,000)) x 1,000,000 / b) x d, where a = ammonia injection rate(lb/hr)/17(lb/lb. mol), b = dry exhaust gas flow rate (lb/hr)/(29(lb/lb. mol), c = change in measured NOx concentration ppmv at 15% O2 across catalyst, and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. Alternatively, the project owner may utilize a continuous in-stack ammonia monitor, acceptable to the District, to monitor compliance. At least 60 days prior to using a NH3 CEM, the project owner must submit a monitoring plan for District review and approval [District Rule 4102]

Verification: The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-26. Compliance with the short term emission limits (lb/hr and ppmv @ 15% O2) shall be demonstrated within 60 days of initial operation of each gas turbine engine and annually thereafter by District witnessed in situ sampling of exhaust gasses by a qualified independent source test firm at full load conditions as follows - NOx: ppmvd @ 15% O2 and lb/hr, CO: ppmvd @ 15% O2 and lb/hr, VOC: ppmvd @ 15% O2 and lb/hr, PM10:

lb/hr, and ammonia: ppmvd @ 15% O2. Sample collection to demonstrate compliance with ammonia emission limit shall be based on three consecutive test runs of thirty minutes each. [District Rule 1081]

Verification: The project owner shall provide records of compliance as part of **Condition AQ-29.**

AQ-27. Compliance with the startup NOx, CO, and VOC mass emission limits shall be demonstrated for one of the CTGs (S-3523-1, or -2) upon initial operation and at least every seven years thereafter by District witnessed in situ sampling of exhaust gases by a qualified independent source test firm. [District Rule 1081]
Verification: The project owner shall provide records of compliance as part of **Condition AQ-29.**

AQ-28 Compliance with natural gas sulfur content limit shall be demonstrated within 60 days of operation of each gas turbine engine and periodically as required by 40 CFR 60 Subpart GG and 40 CFR 75. [District Rules 1081, 2540, and 4001]
Verification: The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-29 The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. Official test results and field data collected by source tests required by conditions on this permit shall be submitted to the District within 60 days of testing. [District Rule 1081]
Verification: The project owner shall notify the CPM and the District 30 days prior to any compliance source test. The project owner shall provide a source test plan to the CPM and District for the CPM and District approval 15 days prior to testing. The results and field data collected by the source tests shall be submitted to the CPM and the District within 60 days of testing.

AQ-30 Source test plans for initial and seven-year source tests shall include a method for measuring the VOC/CO surrogate relationship that will be used to demonstrate compliance with VOC lb/hr, lb/day, and lb/twelve month rolling emission limits. [District Rule 2201]
Verification: The project owner shall provide a source test plan to the CPM and District for the CPM and District approval 15 days prior to testing. The results and field data collected by the source tests shall be submitted to the CPM and the District within 60 days of testing.

AQ-31 The following test methods shall be used PM10: EPA method 5 (front half and back half), NOx: EPA Method 7E or 20, CO: EPA method 10 or 10B, O2: EPA Method 3, 3A, or 20, VOC: EPA method 18 or 25, ammonia: BAAQMD ST-1B, and fuel gas sulfur content: ASTM D3246. EPA approved alternative test methods as approved by the District may

also be used to address the source testing requirements of this permit. [District Rules 1081, 4001, and 4703]
Verification: The project owner shall provide records of compliance as part of **Condition AQ-29.**

AQ-32 The project owner shall notify District of date of initiation of construction no later than 30 days after such the date, date of anticipated startup not more than 60 days nor less than 30 days prior to such date, and date of actual startup within 15 days after such date. [District Rule 4001]
Verification: The project owner shall notify the CPM and the District of the date of initiation of construction no later than 30 days after such date. The project owner shall notify the CPM and the District of the date of anticipated startup not more than 60 days nor less than 30 days prior to such date, and the date of actual startup within 15 days after such date.

AQ-33 The project owner shall maintain hourly records of NOx, CO, and ammonia emission concentrations (ppmv @ 15% O2), and hourly, daily, and twelve month rolling average records of NOx and CO emissions. Compliance with the hourly, daily, and twelve month rolling average VOC emission limits shall be demonstrated by the CO CEM data and the VOC/CO relationship determined by annual CO and VOC source tests. [District Rule 2201]
Verification: The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-34 The project owner shall maintain records of SOx lb/hr, lb/day, and lb/twelve month rolling average emission. SOx emissions shall be based on fuel use records, natural gas sulfur content, and mass balance calculations. [District Rule 2201]
Verification: The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-35 The project owner shall maintain the following records for the CTG: occurrence, duration, and type of any startup, shutdown, or malfunction; emission measurements; total daily and annual hours of operation; and hourly quantity of fuel used. [District Rules 2201 & 4703]
Verification: The project owner shall compile required data and submit the information to the CPM in quarterly reports submitted no later than 60 days after the end of each calendar quarter.

AQ-36 The project owner shall maintain the following records for the continuous emissions monitoring system (CEMS): performance testing, evaluations, calibrations, checks, maintenance, adjustments, and any period of non-operation of any continuous emissions monitor. [District Rules 2201 & 4703]
Verification: The project owner shall provide records of compliance as part of the quarterly reports of **Condition AQ-35.**

AQ-37 All records required to be maintained by this permit shall be maintained for a period of five years and shall be made readily available for District inspection upon request. [District Rule 2201]
Verification: The project owner shall make records available for inspection by representatives of the District, CARB and the Commission upon request.

AQ-38 Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3. 3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]
Verification: The project owner shall compile the required data in the formats discussed above and submit the results to the CPM quarterly.

AQ-39 The project owner shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the Districts satisfaction that the longer reporting period was necessary. [District Rule 1100]
Verification: The project owner shall comply with the notification requirements of the District and submit written copies of these notification reports to the CPM as part of the quarterly reports of **Condition AQ-35**.

AQ-40 The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100]
Verification: The project owner shall comply with the notification requirements of the District and submit written copies of these notification reports to the CPM as part of the quarterly reports of **Condition AQ-35**.

AQ-41 Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]
Verification: The project owner shall submit the continuous emission monitor audit results with the quarterly reports required of **Condition AQ-43**.

AQ-42 The project owner shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F . [District Rule 1080]

Verification: The project owner shall submit the continuous emission monitor results with the quarterly reports of **Condition AQ-43**.

AQ-43 The project owner shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred . [District Rule 1080]
Verification: The project owner shall compile the required data and submit the quarterly reports to the CPM and the APCO within 30 days of the end of the quarter.

AQ-44 The project owner shall submit an application to comply with Rule 2540 - Acid Rain Program 24 months before the unit commences operation. [District Rule 2540]
Verification: The project owner shall file their application with the District at least 24 months prior to the commencement of operation of any of the combustion turbine generators.

Conditions of Certification AQ-45 through AQ-52 apply to the following equipment:

FORCED DRAFT COOLING TOWER WITH 6 CELLS AND HIGH EFFICIENCY DRIFT ELIMINATOR S-3523-3-0:

AQ-45 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-46 The project owner shall submit drift eliminator design details and vendor specific emission justification for the correction factor to be used to correlate blowdown TDS to drift TDS and the amount of drift that stays suspended in the atmosphere in the equation in **Condition AQ-51** to the District at least 30 days prior to commencement of construction. [District Rule 2201]
Verification: 30 days prior to commencement of construction of the cooling towers, the project owner shall submit the information required above to the District and the CPM.

AQ-47 The project owner shall submit cooling tower design details including the cooling tower type and materials of construction to the District at least 30 days prior to commencement of construction, and at least 90 days before the tower is operated. [District Rule 7012]

Verification: 30 days prior to commencement of construction of the cooling towers, the project owner shall submit the information required above to the District and the CPM.

AQ-48 No hexavalent chromium containing compounds shall be added to cooling tower circulating water. [District Rule 7012]
Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-49 Drift eliminator drift rate shall not exceed 0.0006%. [District Rule 2201]
Verification: The project owner shall submit documentation from the selected cooling tower vendor that verifies the drift efficiency to the CPM 30 days prior to commencement of construction of the cooling towers.

AQ-50 PM10 emission rate shall not exceed 9.3 lb/day. [District Rule 2201]
Verification: Please refer to **Condition AQ-51**.

AQ-51 Compliance with the PM10 daily emission limit shall demonstrated as follows: PM10 lb/day = circulating water recirculation rate * total dissolved solids concentration in the blowdown water * design drift rate * correction factor. [District Rule 2201]
Verification: The project owner shall compile the required daily PM10 emissions data and maintain the data for a period of five years. The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-52 Compliance with PM10 emission limit shall be determined by circulating water sample analysis by independent laboratory within 90 days of initial operation and weekly thereafter. [District Rule 1081]
Verification: The project owner shall compile the required daily PM10 emissions data and maintain the data for a period of five years. The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

Conditions of Certification AQ-53 through AQ-62 apply to the following equipment:

SAMPLE EQUIPMENT DESCRIPTION: 125 HP PERKINS/DETROIT DIESEL MODEL PDFP-06YR DIESEL-FIRED IC ENGINE DRIVING EMERGENCY FIRE WATER PUMP S-3523-4-0:

AQ-53 No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
Verification: The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-54 No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
<u>**Verification:**</u> The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-55 Engine shall be equipped with a turbocharger and intercooler/aftercooler. [District Rule 2201]
<u>**Verification:**</u> The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-56 Engine shall be equipped with an operational non-resettable hour meter. [District Rule 2201]
<u>**Verification:**</u> The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-57 The engine shall be equipped with a positive crankcase ventilation (PCV) system or a crankcase emissions control device of at least 90% control efficiency unless UL certification would be voided. [District Rule 2201]
<u>**Verification:**</u> The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-58 NOx emissions shall not exceed 7.2 g/hp-hr. [District Rule 2201].
<u>**Verification:**</u> The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-59 The sulfur content of the diesel fuel used shall not exceed 0.05% by weight. [District Rule 2201]
<u>**Verification:**</u> Please refer to **Condition AQ-62**.

AQ-60 Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
<u>**Verification:**</u> The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

AQ-61 The engine shall be operated only for maintenance, testing, and required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 200 hours per year. [District Rules 2201 and 4701]

<u>**Verification:**</u> The project owner shall compile records of hours of operation of any of the IC engines and include those records as part of the quarterly reports submitted to the CPM under **Condition AQ-35**.

AQ-62 The project owner shall maintain records of hours of non-emergency operation and of the sulfur content of the diesel fuel used. Such records shall be made available for District inspection upon request for a period of five years. [District Rules 2201 and 4701]

Verification: The project owner shall compile records of hours of operation of the IC engines and of the diesel fuel purchased that includes the sulfur content, and maintain the data for a period of five years. The project owner shall make the site available for inspection by representatives of the District, CARB and the Commission.

REFERENCES

CARB 1998 – California Air Resource Board. “Proposed Amendments to the Designation Criteria and Amendments to the Area Designations for State Ambient Air Quality Standards”. August 1998.

CARB, 1993-1997. California Air Quality Data, Annual and Quarterly Summaries. Aerometric Division. Sacramento.

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EHPP (Elk Hill Power Project) 1999a. Application for Certification, Elk Hills Power Project (99-AFC-1). Submitted to the California Energy Commission, February 24, 1999

EHPP 1999b. Application for Certification, Addendum I, Elk Hills Power Project (99-AFC-1). Submitted to the California Energy Commission, March 14, 1999

EPA (US Environmental Protection Agency) 1995. Compilation of Air Emission Factors. Document AP-42.

Chow, et al 1993. Judith C. Chow, John G. Watson and Douglas H. Lowenthal. “PM10 and PM2.5 Compositions in California’s San Joaquin Valley” Aerosol Science and Technology, the Journal of the American Association for Aerosol Research.

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Sylte 1999. Submittal from William W. Sylte entitled “The Use of PM10 Precursor Offsets for the Proposed La Paloma Generating Project” to California Energy Commission, Docket Unit. January 1999.

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Compliance. Submitted to the California Energy Commission on April 4, 2000.

APPENDIX A

CUMULATIVE AIR QUALITY IMPACT ANALYSIS

Air Permitting Specialists

Technical Note
Cumulative Air Quality Impact Analysis
La Paloma Generating Station
Kern County, California

May 12, 1999

Prepared for:
Siting and Environment Division
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

1. INTRODUCTION

The objective of this modeling analysis is to quantify cumulative air quality impacts associated with the operation of La Paloma generating station with two other planned generating stations: Sunrise and Elk Hills. All three generating stations are to be located in Western Kern County, California.

In the present analysis, "cumulative" air quality impact means the sum total of air quality impacts from the three generating stations (GS) plus background concentration. The focus of this study is on the following pollutants:

- Carbon Monoxide (CO)
- Oxides of Nitrogen (NOx)
- Sulfur Dioxide (SO_2)
- Fine Particulate (PM-10)
- Sulfate (SO_4)

2. CRITERIA FOR SIGNIFICANT IMPACT

In order for the cumulative impacts to be considered significant, two criteria would have to be met:

The maximum ground level concentration of any air pollutant emitted by the La Paloma GS would increase as a result of contribution from other existing or proposed sources. For the purposes of this analysis, there are no existing sources near the La Paloma GS and the only proposed emission sources are the Elk Hills and Sunrise generating stations.

Cumulative maximum ground level concentration would exceed California or Federal ambient air quality standards.

Cumulative air quality impact is considered insignificant unless both criteria are satisfied.

3. MODELING METHODOLOGY

The basic modeling methodology consisted of the following steps:

Run ISCST3 with emissions from La Paloma alone.
Re-run ISCST3 with emissions from all three plants. (La Paloma, Sunrise and Elk Hills).
If there is an increase in the ground level concentration (GLC) at the point of max as determined in Step 1, assess if the increased concentration is likely to violate applicable ambient air quality standard.
If there is no increase in max GLC at the point of max concentration, conclude that emissions from Sunrise and Elk Hills would not contribute to the max GLC associated with operation of La Paloma

3.1 SELECTION OF EMISSIONS/OPERATIONAL SCENARIO

Emissions from the three generating stations vary depending on ambient temperature and whether the plants are operating in 'normal' or 'start-up' modes. For the purposes of this analysis it was assumed that La Paloma and Sunrise were operating normally at an ambient temperature of 65 F; it was assumed that Elk Hills was in a start-up mode. These emissions scenarios were selected in consultation with CEC staff. A summary of emissions and other input data used in the modeling analysis are summarized below. The data were obtained from data files provided by the applicants.

Parameter	**Units**	**La Paloma**	**Elk Hills**	**Sunrise**
CO	Lbs/hr	18.8	37.0	26.8
NOx	Lbs/hr	15.7	46.6	15.4
SO2	Lbs/hr	0.87	2.1	3.3
PM-10	Lbs/hr	7.86	18.	18.
No. of Stacks		4	2	2
Stack Height	Meters	30	36.6	30.5
Stack Diameter	Meters	5.3	5.49	5.79
Exhaust Temp.	K	362	345.	368.
Exit Velocity	meters/sec	18.5	12.5	13.0
Note: Emissions (lbs/hr) are per stack.				

3.2 MODELING OF SOX AND NOX CONVERSION TO PARTICULATE MATTER

For NOx emissions, the results of a recent modeling study by Desert Research Institute (DRI 1999) were used. This study concluded that approximately 33% of the NOx, emissions were converted to particulate matter. The time scale involved in this conversion is between 18 to 24 hours. Using these results, the maximum predicted ground level concentration was adjusted to allow for conversion form oxides of nitrogen (NO and NO_2) to nitrate. An estimate of particulate concentration due to secondary formation of nitrate would equal:

Max. Particulate concentration = Max. NO_2 Conc. x (100-66)/100

This approach yields only an order of magnitude estimate of nitrate concentration. A more refined approach that takes into account detailed atmospheric chemistry and the time variation of various chemical species affecting nitrate formation is beyond the scope of this evaluation.

For oxides of sulfur conversion to sulfate, it was assumed that emissions consisted entirely of SO_2 and that the conversion could be modeled as a first order chemical reaction. Under this assumption, one can model the SO_2 to sulfate conversion using a simple decay coefficient or a half-life for SO_2. The half-life of SO_2 varies between 1 to 4 days (Stern, et al, 1984). For the present analysis, a half-life of 8 hours was assumed. That is, 50% of the

SO_2 is converted to sulfate in 8 hours. This half-life can be used in ISCST3 to account for the SO_2 to sulfate conversion.

3.3 CHOICE OF AIR DISPERSION MODEL

EPA's ISCST3 air dispersion model was employed for this analysis. This model is recommended by the EPA's Guidelines of Air Quality Models for use in simple and complex terrain. Version 98356 was used to perform the model runs.

3.4 CHOICE OF METEOROLOGICAL DATA

One year (1993) of hourly meteorological data were used to conduct the analysis. The surface data from McKittrick (Station 99991) were supplemented by upper air data from Bakersfield (99992). These data were taken from the input files provided by the applicant for the La Paloma project.

Since the focus of this study was on the cumulative air quality impacts associated with emissions from all three GS, the use of additional years of meteorological data would not change the results or conclusions reached in this study. In other words, the *relative contributions* of the Elk Hills and Sunrise GS emissions to the maximum GLC associated with the operation of La Paloma would remain the same.

3.5 SELECTION OF MODELING GRID

A 2 kilometer grid (100 meter x 100 meter) was used to determine the location of GLC for each source. A second larger grid was used to enclose all three sources. This grid extended 20 km x 20km and was centered at the La Paloma GS. A rectangular coordinate system was used employing the UTM coordinate system.

RESULTS

The results of the analysis show that there would be minimal cumulative impact associated with operation of all three generating stations. For example, the maximum 1-hour NO_2 concentration due solely to emissions from La Paloma would not increase as a result of all three generating stations operating concurrently. For annual NO_2 concentration, there would be a minor increase. Specifically, the results were as follows:

Pollutant	Averaging Time	La Paloma GS	All 3 Stations
NO_2	1-hour	25.31	25.31
	Annual	0.300	0.343
PM-10	24-hour	1.10	1.12
	Annual	0.150	0.172
SO_2	24-hour	0.123	0.124
	Annual	0.0167	0.0202
CO	1-hour	30.45	30.46
	8-hour	7.72	7.72

Overall, the analysis showed that inclusion of emissions from the proposed Sunrise and Elk Hills generating stations leads to a new point of maximum ground level concentration. This shown in the attached contour plots of concentration for emissions from (a) La Paloma; (2) La Paloma, Elk Hills and Sunrise, and (3) Elk Hills and Sunrise. A comparison of Figures 1 and 2 (1-hour NO2, La Paloma and All 3 Stations), shows negligible contribution in the vicinity of La Paloma from the other two plants.

Figure 2 shows that a new point of maximum concentration near Elk Hills and Sunrise generating stations. This is due entirely from emissions from these two plants as can be confirmed in Figure 3 (Sunrise and Elk Hills). The same pattern was identified for annual NO_2 concentrations as shown in Figures 4-6.

Particulate impacts associated with the conversion of NO_2/NO to nitrate are estimated to be 1 ug/cubic meter. This is based on 33% conversion of the maximum 24-hour averaged NO_2 concentration associated with operation of La Paloma GS. The latter range between 0 to 0.3 ug/cu/meter on a 24 hour basis. The impact of secondary nitrate formation on the PM-10 concentration is not considered significant.

It was noted in Section 3.2 that the time scale for the conversion of NO_2/NO to nitrate is between 18 to 24 hours. This means that areas that are located 175 to 200 miles to the southeast would be impacted with higher nitrate particulate. This would transport the plume out of Kern County to adjacent counties located to the East or Southeast. This estimate is based on the fact that on an annual basis, the predominant winds in Kern County are from the NE with an average annual speed of 8.9 mph (Ref: California Surface Wind Climatology, CARB, June 1984).

Use of the ISCST3 model with a half-life of 8 hours indicates that the maximum 24-hour ground level concentration of SO_2 would decrease from 2.5 ug/cu meter to 2.4 ug/cu meter. This means that about 4% of the SO_2 (0.1 ug/cu meter) would be converted to sulfate. Since the state standard for sulfate is 25 ug/cu meter, the secondary formation of sulfate is not considered significant.

As with NO_2/NO conversion to nitrate, the SO_2 to sulfate conversion takes place over a period of 1-4 days. On this time-scale the emissions would be transported several hundred miles to the East or Southeast. Therefore the highest concentration of sulfate would not occur near the power plants but several hundred miles to the East or Southeast. For example, in 2 days the plume would travel approximately 400 miles from the source. This would transport the sulfate (and nitrate particulates) out of Kern County and possibly, out of state.

APPENDIX B

EXCEL SPREADSHEETS FOR THE CONSTRUCTION AND OPERATION EMISSION ESTIMATES AND IMPACTS

This Appendix contains spreadsheets used to estimate the Elk Hills Power Project emissions for construction and operations. The construction emissions include fugitive dust and all other emissions. This analysis separates the emissions from the project site and linear facilities, but does not separate out the individual linear facilities. Construction emission impacts are based on a modeling analysis provided by the applicant, Elk Hills. Since the modeling analysis was completed and submitted, the emission rates have been refined. However, because the model that was used (ICST3) it is still possible to use the modeling results. The resulting impacts of an ISC modeling run are directly proportional to the emission rate at the source. Therefore, if only the emission rate changes then the impact results can be factored (up or down) by the new emission rates. This is the technique employed by staff to determine a new construction emission impact. The operational emissions and impacts were also refined after the modeling was submitted to the Energy Commission. Therefore, they also have been modified in a similar manner.

APPENDIX C

REVISED BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS
TOWANTIC ENERGY PROJECT

APPENDIX D

ELK HILLS POWER, LLC
MODIFIED BACT ANALYSIS