4.5 AIR QUALITY

Does the project:	Potentially Significant Impact	Potentially Significant Unless Mitigation Incorporated	Less Than Significant Impact	No Impact
a) Violate any air quality standard or contribute to an existing or projected air quality violation?	☐	☒	☐	☐
b) Expose sensitive receptors to pollutants?	☐	☒	☐	☐
c) Alter air movement, moisture, or temperature, or cause any change in climate?	☐	☐	☐	☒
d) Create objectionable odors?	☐	☐	☒	☐

INTRODUCTION

This section addresses issues related to air pollutant emissions, including “criteria air pollutants” and “toxic air contaminants.” The term, “criteria air pollutants,” refers to those pollutants that are pervasive in urban environments and for which health-based state or national ambient air quality standards have been established. The term, “toxic air contaminants,” refers to those pollutants that occur at relatively low concentrations and are associated with carcinogenic and other adverse health effects, but for which no ambient air quality standards have been established.

REGIONAL SETTING

Air quality is a function of both the rate and location of pollutant emissions under the influence of meteorological conditions and topographic features. Atmospheric conditions such as wind speed, wind direction, and air temperature gradients, along with local topography, influence the movement and dispersal of pollutants and thereby provide the link between air pollutant emissions and air quality.

CLIMATE AND METEOROLOGY

The State of California is divided into air basins that are defined partly by their meteorological and topographical characteristics. The facilities that are the subject of this report are located in San Diego Air Basin, which is shown in Figure 4.5.1 along with the other California Air Basins.

San Diego Air Basin (Air Basin) is defined by the boundaries of San Diego County. The Air Basin gradually rises from west to east with mountain ranges in the eastern portion marking the eastern boundary of the Air Basin. The climate is strongly influenced by the Pacific Ocean and its semi-permanent pressure systems that produce wet winters and dry summers. The moderating

INSERT FIGURE 4.5.1
CALIFORNIA AIR BASINS

influence of the ocean extends from the coastal plain into the coastal valleys, and the daily temperature range increases with distance inland from the coast. In general, wind speeds are light to moderate. The sea breeze (i.e., on-shore wind flow) correlates well with the higher temperatures usually experienced during the afternoons. The high frequency of northwest winds in all seasons indicates the prevalence of the sea breeze. A thermal inversion layer, extending from the coast to the mountains at a typical elevation of 2,500 feet, is a prevalent feature in the summer months when elevated ozone concentrations are most common.

While air quality in a given air basin is usually determined by emission sources within the basin, air quality in some air basins can also be affected by pollutants transported from upwind air basins by prevailing winds. For instance, Santa Ana conditions in the South Coast Air Basin (i.e., strong northeasterly wind flow) can combine with the prevailing sea breeze to transport emissions generated in the greater Los Angeles metropolitan area into the San Diego Air Basin with subsequent adverse effects on regional air quality. Under certain other meteorological conditions, emissions generated in Mexico can adversely affect air quality in the San Diego Air Basin (California Air Resources Board, 1996).

CRITERIA AIR POLLUTANTS

The federal Clean Air Act requires the U.S. Environmental Protection Agency (U.S. EPA) to list air pollutant compounds which may endanger public health or welfare; to publish air quality “criteria” describing the latest scientific knowledge on these compounds, their pollutant interactions, and control techniques; and to identify National Ambient Air Quality Standards (national standards) protective of public health and welfare. Currently, U.S. EPA has established national standards for ozone, carbon monoxide, nitrogen dioxide, sulfur dioxide, particulate matter (PM-10 and PM-2.5), and lead. California has adopted more stringent standards for most of the criteria air pollutants (referred to as State Ambient Air Quality Standards, or state standards) and has adopted ambient air quality standards for some pollutants for which there are no corresponding national standards. Both sets of ambient air quality standards (i.e., national and state) are presented in Table 4.5.1.

State and national standards alike consist of two parts: an allowable concentration of a pollutant and an averaging time over which the concentration is to be measured. The allowable concentrations are based on the results of studies of the effects of the pollutants on human health, crops and vegetation, and, in some cases, damage to paint and other materials. The averaging times are based on whether the damage caused by the pollutant is more likely to occur during exposures to a high concentration for a short time (e.g., one hour), or to a relatively lower average concentration over a longer period (e.g., 8 hours, 24 hours, or 1 month). For some pollutants, there is more than one air quality standard, reflecting both its short-term and long-term effects.

Ozone

Ozone is a reactive pollutant, which is not emitted directly into the atmosphere, but is a secondary air pollutant produced in the atmosphere through a complex series of photochemical reactions involving reactive organic gases (ROG) and nitrogen oxides (NO_x). ROG and NO_x are known

TABLE 4.5.1
STATE AND NATIONAL AMBIENT AIR QUALITY STANDARDS

Pollutant	**Averaging Time**	**National**[a,c]	**State of California**[b,c]
Ozone	1 hour	0.12 ppm (235 μg/m^3)	0.09 ppm (180 μg/m^3)
	8 hour [d]	0.08 ppm (160 μg/m^3)	NA
Carbon Monoxide	1 hour	35 ppm (40,000 μg/m^3)	20 ppm (23,000 μg/m^3)
	8 hour	9 ppm (10,000 μg/m^3)	9.0 ppm (10,000 μg/m^3)
Nitrogen Dioxide	1 hour	NA	0.25 ppm (470 μg/m^3)
	Annual	0.053 ppm (100 μg/m^3)	NA
Sulfur Dioxide	1 hour	NA	0.25 ppm (655 μg/m^3)
	3 hour	0.5 ppm (1,300 μg/m^3)	NA
	24 hour	0.14 ppm (365 μg/m^3)	0.04 ppm (105 μg/m^3)
	Annual	0.03 ppm (80 μg/m^3)	NA
Particulate Matter (PM-10)	24 hour	150 μg/m^3	50 μg/m^3
	Annual	50 μg/m^3	30 μg/m^3
Particulate Matter (PM-2.5) [d]	24 hour	65 μg/m^3	NA
	Annual	15 μg/m^3	NA
Sulfates	24 hour	NA	25 μg/m^3
Lead	30 day	NA	1.5 μg/m^3
	Calendar Quarter	1.5 μg/m^3	NA
Hydrogen Sulfide	1 hour	NA	0.03 ppm (42 μg/m^3)
Vinyl Chloride	24 hour	NA	0.010 ppm (26 μg/m^3)

a National standards, other than for ozone and particulate matter and those based on annual averages, are not to be exceeded more than once per year. For the one-hour ozone standard, the ozone standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than one. The eight-hour ozone standard is met at a monitoring site when the three-year average of the annual fourth-highest daily maximum eight-hour average ozone concentration is less than or equal to 0.08 ppm.

b California standards for ozone, carbon monoxide, sulfur dioxide, nitrogen dioxide, particulate matter (PM-10) are values that are not to be exceeded. All other California standards shown are values not to be equaled or exceeded.

c ppm = parts per million by volume; μg/m^3 = micrograms per cubic meter.

d New standards effective September 16, 1997 (40 CFR 50.7 and 40 CFR 50.10).

NA: Not Applicable.

SOURCE: California Air Resources Board, *Maps and Tables of the Area Designations for the State and National Ambient Air Quality Standards and Expected Peak Day Concentrations and Designation Values*, January 1998.

as precursor compounds for ozone. Significant ozone production generally requires ozone precursors to be present in a stable atmosphere with strong sunlight for approximately three hours. Ozone is a regional air pollutant because it is not emitted directly by sources, but is formed downwind of sources of ROG and NO_x under the influence of wind and sunlight. Short-term exposure to elevated concentrations of ozone is linked to such health effects as eye irritation and breathing difficulties. Ozone may pose its worst health threat to those who already suffer from respiratory diseases (South Coast Air Quality Management District, 1993).

Carbon Monoxide

Carbon monoxide is a non-reactive pollutant that is a product of incomplete combustion. Ambient carbon monoxide concentrations generally follow the spatial and temporal distributions of vehicular traffic and are also influenced by meteorological factors such as wind speed and atmospheric mixing. Under inversion conditions, carbon monoxide concentrations may be distributed more uniformly over an area out to some distance from vehicular sources. When inhaled at high concentrations, carbon monoxide combines with hemoglobin in the blood and reduces the oxygen-carrying capacity of the blood. This results in reduced oxygen reaching the brain, heart, and other body tissues. This condition is especially critical for people with cardiovascular diseases, chronic lung disease or anemia, as well as fetuses.

Particulate Matter (PM-10 and PM-2.5)

PM-10 consists of particulate matter that is 10 microns or less in diameter (a micron is one-millionth of a meter), and PM-2.5 consists of particulate matter 2.5 microns or less in diameter. Both PM-10 and PM-2.5 represent fractions of particulate matter, which can be inhaled into the air passages and the lungs and can cause adverse health effects. Particulate matter in the atmosphere results from many kinds of dust- and fume-producing industrial and agricultural operations, fuel combustion, and atmospheric photochemical reactions. Some sources of particulate matter, such as demolition and construction activities, are more local in nature, while others, such as vehicular traffic, have a more regional effect.

National standards for particulate matter were first established in 1971. The original particulate matter standards were defined in terms of “total suspended particulate” (TSP), which includes particles that are 30 microns or smaller in diameter. In 1987, U.S. EPA re-defined the standards in terms of PM-10, instead of TSP, to focus on smaller-diameter particles, based on a comprehensive review of information on the health effects from inhaling particulate matter. Then, in December 1994, U.S. EPA began another review process to determine if the PM-10 standards set in 1987 provide a reasonable margin of safety, and if a new standard should be established for finer particles.

Based on numerous epidemiological studies and other health and engineering related information, U.S. EPA established new standards for fine particulate matter (PM-2.5) in 1997. Before establishing the new PM-2.5 standards, discussions were conducted with the Clean Air Scientific Advisory Committee (CASAC). CASAC is a group of nationally recognized experts in the fields related to air pollution, environmental health, and engineering. CASAC reviewed and commented on the information generated by U.S. EPA regarding proposed particulate matter standards.

Subsequent to these discussions and reviews, U.S. EPA established PM-2.5 concentration standards of 65 micrograms per cubic meter, 24-hour average, and 15 micrograms per cubic meter, annual average. U.S. EPA also re-affirmed the national PM-10 standards of 150 micrograms per cubic meter, 24-hour average, and 50 micrograms per cubic meter, annual average, as providing an adequate margin of safety for exposure to particles with diameters of 10 microns or less. The recommendations for new PM-2.5 standards and for maintaining the PM-10 standards were released in a staff report (U.S. Environmental Protection Agency, 1996) that presents the conclusions of the Agency and of the review committee, CASAC.

Several studies that U.S. EPA relied on for their staff report have shown an association between exposure to particulate matter, both PM-10 and PM-2.5, and respiratory ailments or cardiovascular disease (Pope et al., 1992; Thurston et al., 1992; Burnett et al., 1995). Other studies have related particulate matter to increases in asthma attacks (Whittemore and Korn, 1980; Pope et al., 1991). In general, these studies have shown that short-term and long-term exposure to particulate matter can cause acute and chronic health effects. Fine particulate matter (PM-2.5), which can penetrate deep into the lungs, causes more serious respiratory ailments.

Nitrogen Dioxide and Sulfur Dioxide

Nitrogen dioxide and sulfur dioxide are two gaseous compounds within a larger group of compounds, NO_x and sulfur oxides (SO_x), respectively, which are products of the combustion of fuel. NO_x and SO_x emission sources can elevate local nitrogen dioxide and sulfur dioxide concentrations, and both are regional precursor compounds to particulate matter. As described above, NO_x is also an ozone precursor compound and can affect regional visibility. (Nitrogen dioxide is the “whiskey brown” colored gas readily visible during periods of heavy air pollution.) Elevated concentrations of these compounds are associated with increased risk of acute and chronic respiratory disease.

NO_x and SO_x emissions can be oxidized in the atmosphere to form sulfates and nitrates, which contribute to acid rain. Large power plants with high emissions of these substances because of the use of coal or oil are subject to emissions reductions under the Phase I Acid Rain Program of Title IV of the 1990 Clean Air Act Amendments. Other power plants that use natural gas or other fuels with low sulfur content, are subject to the Phase II Program of Title IV. The Phase II program requires plants to install Continuous Emissions Monitoring Systems (CEMS) in accordance with the Code of Federal Regulations (40 CFR Part 75) and report annual emissions of NO_x and SO_x.

Lead

Gasoline-powered automobile engines used to be the major source of airborne lead in urban areas. Excessive exposure to lead concentrations can result in gastrointestinal disturbances, anemia, kidney disease, and in severe cases of neuromuscular and neurologic dysfunction. The use of lead additives in motor vehicle fuel has been eliminated in California, and lead concentrations have declined substantially as a result.

Suspended Sulfates

Sulfur dioxide is formed through the oxidation of elemental sulfur; suspended sulfates are the product of further oxidation of sulfur dioxide. In some parts of the state, elevated levels can also be due to natural causes, such as wind-blown dust and sea salt spray. Suspended sulfates contribute to overall particulate concentrations in ambient air which, if high enough, are suspected to be a cause of premature death in individuals with pre-existing respiratory disease.

Regulatory Context

Attainment/Non-attainment Designations

Under amendments to the federal Clean Air Act, U.S. EPA has classified air basins, or portions thereof, as either “attainment” or “non-attainment” for each criteria air pollutant, based on whether or not the national standards have been achieved. In 1988, the State Legislature passed the California Clean Air Act, which is patterned after the federal Clean Air Act to the extent that areas are designated as “attainment” or “non-attainment,” but with respect to the state standards, rather than the national standards. Thus, areas in California have two sets of attainment/non-attainment designations: one set with respect to the national standards and one set with respect to the state standards.

Table 4.5.2 shows the current attainment/non-attainment status of San Diego Air Basin for the various criteria air pollutants. As shown in Table 4.5.2, San Diego Air Basin is currently a “non-attainment” area for the state and national ozone standards and for the state PM-10 standard, and is either “attainment” or “unclassified” for the other criteria air pollutant standards.

Recently, California Air Resources Board (CARB) staff proposed a change in the designation of San Diego Air Basin to “non-attainment” for the state suspended sulfates standard based on an exceedance of that standard in 1997. This exceedance was measured at the San Diego (12th Avenue) monitoring station in May of 1997 (California Air Resources Board, 1998). CARB staff concluded that the likely emissions sources responsible for this exceedance include industrial facilities in the Rosarito area of Mexico, including a power plant and an oil tank farm, and marine vessels in the offshore shipping lanes along the immediate coast and in San Diego Harbor (California Air Resources Board, 1998).

Air Quality Plans and Programs

Under federal Clean Air Act Amendments, areas designated as “non-attainment” are required to prepare regional air quality plans, which set forth a strategy for bringing an area into compliance with the standards. Air quality plans developed to meet federal requirements are included in an overall program referred to as the State Implementation Plan (SIP).

TABLE 4.5.2
SAN DIEGO AIR BASIN ATTAINMENT/NON-ATTAINMENT DESIGNATIONS

Pollutant	Applicable Area	National	State
Ozone[a]	Basin-wide	Non-attainment	Non-attainment
Carbon Monoxide	West County	Attainment[b]	Attainment
	East County	Attainment	Attainment
Nitrogen Dioxide	Basin-wide	Attainment	Attainment
Sulfur Dioxide	Basin-wide	Attainment	Attainment
Particulate Matter (PM-10) [c]	Basin-wide	Unclassified	Non-attainment
Sulfates	Basin-wide	Not Applicable	Attainment[d]
Lead	Basin-wide	Unclassified	Attainment
Hydrogen Sulfide	Basin-wide	Not Applicable	Unclassified

a The designations for ozone relate to the one-hour-average state and national standards. Air Basins will not be classified with respect to the new eight-hour national ozone standard for several years.
b Attainment designation is effective on June 1, 1998 (see *Federal Register*, March 31, 1998). Since the "west county" area was "non-attainment" prior to its recent re-designation, the area is also referred to as a "maintenance" area.
c Since monitoring for PM-2.5 only began in 1998, air basins will not be classified with respect to the new national PM-2.5 standard until 2000 or later.
d The California Air Resources Board staff has recommended to its Board that it change San Diego's designation to "non-attainment" for the state suspended sulfates standard based on an high measured value in 1997 (California Air Resources Board, 1998). A decision by this agency is expected in September 1998.

SOURCE: California Air Resources Board, *Maps and Tables of the Area Designations for the State and National Ambient Air Quality Standards and Expected Peak Day Concentrations and Designation Values*, January 1998.

San Diego's original portion of the SIP, known as the *Regional Air Quality Strategy*, was developed in the early to mid-1970s. The focus of this original plan was photochemical smog. (The principal component of photochemical smog is ozone.) The *Regional Air Quality Strategy* was substantially revised in 1979 (1979 Strategy) to include a comprehensive air resources management program, which included most of the currently adopted control measures.

The 1979 Strategy also expanded its focus to address carbon monoxide, nitrogen dioxide, and particulates, in addition to photochemical smog, since San Diego County was designated as "non-attainment" at that time for those pollutants as well. The 1979 Strategy was updated in 1982 to include additional control measures. Based on the scientific knowledge of ground-level ozone production at that time, the 1979 and 1982 Strategies focused on control and reduction of ROG emissions (rather than on NO_x); NO_x control measures were included only to the extent necessary to address non-attainment of the national nitrogen dioxide standard. The 1982 Strategy was intended to bring San Diego into compliance with the national standards by 1987.

Under federal Clean Air Act Amendments of 1990, SIPs were required to be revised to meet new requirements for those regions, like San Diego Air Basin, that did not attain the national standards by 1987. By 1990, San Diego County was no longer "non-attainment" for national standards for nitrogen dioxide and particulates, and thus, SIP revisions focus on the pollutants, ozone and carbon monoxide, for which San Diego remained "non-attainment."

With respect to the national ozone standard, federal Clean Air Act Amendments of 1990 distinguished among various categories of "non-attainment," ranging from "marginal" to "extreme." San Diego Air Basin was designated as a "serious" ozone non-attainment area, and as such, SIP revisions were required in 1992, 1993, and 1994, each addressing specific requirements for "serious" non-attainment areas. The 1992 SIP submittal included revised regulations related to Reasonably Available Control Technology (or RACT, which refers to retrofit requirements for "major" existing sources), New Source Review and Transportation Control Measures. One of the revisions extends RACT requirements to major NO_x sources; prior RACT requirements had focused on ROG. [These regulations are administered by the San Diego Air Pollution Control District (SDAPCD)]. The 1993 SIP submittal addressed Rate-of-Progress requirements, and the 1994 SIP submittal represented the Attainment Demonstration. The 1994 SIP submittal predicts attainment of the national ozone standard by 1999 and was approved by U.S. EPA in January 1997. Relevant regulations incorporated into the current SIP include SDAPCD Regulation 68 (Fuel-Burning Equipment - Oxides of Nitrogen) and Regulation 69.3 (Stationary Gas Turbine Engines).

With respect to national carbon monoxide standards, U.S. EPA has re-designated San Diego Air Basin as "attainment" and has approved a "Maintenance Plan" that shows how the standard will continue to be maintained in the future. This Maintenance Plan represents the current carbon monoxide SIP for the San Diego Air Basin.

Under the California Clean Air Act of 1988, air quality plans are required for areas designated as "non-attainment" for the state standards (not including PM-10 non-attainment areas). Thus, just as many areas in California have two sets of attainment/non-attainment designations, they also have parallel sets of air quality plans: one set to meet federal requirements and one set to meet state requirements. In 1991, an air quality plan, the *1991 Regional Air Quality Strategy* (1991 Strategy), was developed to meet the requirements of the California Clean Air Act, and it addressed the "non-attainment" status of the County with respect to state standards for ozone, carbon monoxide, and nitrogen dioxide (San Diego Air Pollution Control District, 1992). Pursuant to the California Clean Air Act, the 1991 Strategy was developed to include every feasible control measure and an expeditious adoption schedule. Also, the 1991 Strategy specifies the level of control for all existing major stationary sources as Best Available Retrofit Control Technology (BARCT). BARCT is equal to or more stringent than RACT, which is required under the federal Clean Air Act. One of the more important rules adopted pursuant to the 1991 Strategy was SDAPCD Rule 69 (Electric Generating Steam Boilers, Replacement Units and New Units).

The California Clean Air Act requires plans, such as the 1991 Strategy, to be updated on a triennial basis. The *Triennial Update for the San Diego Air Basin* (1995 Update), was the first such update (San Diego Air Pollution Control District, 1995). The 1995 Update addressed the status of SDAPCD efforts through 1994 to implement the 1991 Strategy and revised the 1991 Strategy's control measure adoption schedule accordingly. Since San Diego is now "attainment" for the state carbon monoxide and nitrogen dioxide standards, the 1995 Update addressed only ozone non-attainment issues. A second triennial update (1998 Update) was adopted by SDAPCD in June 1998 (San Diego Air Pollution Control District, 1998). The 1998 Update includes four new SDAPCD control measures, but none of them affect emissions sources associated with electricity generation.

The 1995 and 1998 Updates incorporate the various federal SIP revisions, with their updated emissions inventories and emissions projections, by reference, with one exception. The exception relates to electric utility boilers. Controlling these boilers was not necessary to meet federal SIP requirements, and consequently was not reflected in the SIP emissions inventories and projections. However, control of the boilers is necessary to meet state mandates. Thus, the 1995 and 1998 Updates reflect NO_x emissions reductions required under SDAPCD Rule 69 (e.g., annual aggregate NO_x emission limits of 2,100 tons beginning in 1997, 800 tons beginning in 2001, and 650 tons beginning in 2005), while the federal SIP does not reflect such reductions.

The 1995 and 1998 Updates include revised growth factors for various source categories. For example, the revised growth factors account for the effect of the recession on such parameters as vehicle miles traveled (VMT). For electrical generation, the growth factors were revised from those used in the 1991 Strategy to reflect regulatory reform rather than the recession. The growth factors used in the 1991 Strategy assumed a 50% increase in locally generated electricity by the year 2000; the 1995 and 1998 Updates assume no growth in that factor, reflecting the uncertainty of deregulation of the electricity industry. The current SIP also reflects this no-growth assumption in electricity generation.

Regulatory Agencies

U.S. EPA has responsibility for enforcing, on a national basis, the requirements of many of the country's environmental and hazardous waste laws. U.S. EPA's responsibility in the state air pollution control programs focuses principally on reviewing submittals of State Implementation Plans (SIPs). A SIP is required by the federal Clean Air Act to demonstrate how all areas of a state will meet the national standards within the federally specified deadlines. The applicable SIP documents for the San Diego Air Basin are discussed above.

The California Air Resources Board (CARB) was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two existing state agencies. CARB's primary responsibilities are to develop, adopt, implement, and enforce the state's motor vehicle pollution control program; to administer and coordinate the state's air pollution research program; to adopt and update as necessary the state's ambient air quality standards; to review the operations of the local air pollution control districts (APCDs); and to review and coordinate preparation of the SIP for achievement of the state and national standards.

In addition to having primary responsibility for preparing air quality plans to address “non-attainment” pollutants, APCDs are also responsible for regulating stationary sources. Stationary sources, such as power plants, are regulated through a permitting process in which applicants must secure an Authority to Construct (ATC) and a Permit to Operate (PTO) from the applicable APCD prior to operation of new or modified equipment that may affect air quality. Stationary sources can also be subject to retrofit requirements imposed by the applicable APCD.

The project facilities lie within the jurisdiction of the APCD of San Diego County (SDAPCD). Applicable SDAPCD rules and regulations are discussed below.

Rules and Regulations of the Air Pollution Control District of San Diego County

SDAPCD rules and regulations include general prohibitions as well as specific standards for certain source categories, such as gas turbines and electrical-generating steam boilers. The rules with general applicability include Rule 50 (Visible Emissions), which limits visible emissions from any source to less than the opacity of a shade designated as Number 1 on the Ringelmann Chart; Rule 51 (Nuisance), which prohibits the discharge from any source whatsoever of such quantities of air contaminants or other material which cause injury, detriment, nuisance or annoyance; Rule 52 (Particulate Matter), which limits particulate matter emissions to 0.1 grains per dry standard cubic foot; and Rule 62 (Sulfur Content of Fuels), which limits the sulfur content of gaseous fuel to no more than 10 grains per 100 cubic feet of dry gaseous fuel and the sulfur content of any liquid or solid fuel to no more than 0.5 percent sulfur by weight.

SDAPCD rules that apply specifically to such sources as gas turbines or electrical-generating steam boilers include Rules 68, 69, and 69.3. Rule 68, Fuel-Burning Equipment-Oxides of Nitrogen, is applicable to fuel-burning equipment that has a maximum heat input rating of 50 million Btu per hour or more. Under SDAPCD Rule 68, emissions of NO_x are limited to a maximum stack concentration of 125 parts per million for gaseous fuel and 225 parts per million for liquid or solid fuels.

Rule 69, Electrical Generating Steam Boilers, Replacement Units and New Units, establishes a system-wide aggregate NO_x emissions limit for all SDG&E steam-electric boilers. As such, the aggregate NO_x emissions limit currently applies to the emissions from nine steam boilers: the five boilers at the Encina power plant and the four boilers at the South Bay plant. The Rule limits the aggregate NO_x emissions from these boilers to 2,100 tons per year beginning in 1997, 800 tons per year beginning in 2001, and 650 tons beginning in 2005. Upon the sale of a steam boiler or boilers to a new owner in which SDG&E does not have a controlling interest, the Rule reduces the aggregate annual NO_x emissions limit for the boilers remaining in SDG&E's control and imposes a boiler-specific NO_x emissions standard on the unit or units that have been sold. The boiler-specific emissions standards are 0.15 pound per megawatt-hour when burning natural gas and 0.40 pound per megawatt-hour when burning fuel oil, averaged over each calendar day. Under SDAPCD Rule 69, the new owner has two years from the date of transfer, but not later than January 1, 2001, to equip the steam boilers with adequate control technology to meet these boiler-specific NO_x standards.

Also, under SDAPCD Rule 69, since January 1997 (January 1998 for South Bay boiler #4), the boilers at the Encina and South Bay power plants have not been allowed to burn fuel oil unless SDAPCD has determined that no exceedance of the state ozone standard is predicted during the time of fuel oil burn. This provision, however, does not apply during periods of force majeure natural gas curtailment.

Rule 69.3, Stationary Gas Turbine Engines, specifically addresses NO_x emissions from stationary gas turbine engines and limits NO_x stack emissions to a maximum concentration of 42 parts per million when operated on a gaseous fuel and 65 parts per million when operated on a liquid fuel.

SDAPCD also administers the “Title V” program in San Diego County. “Title V” refers to the section of federal Clean Air Act Amendments of 1990 that established a comprehensive operating program for major stationary sources. The Title V program calls for major stationary sources to secure a single permit that includes a listing of all the emissions sources, applicable regulations, and requirements.

Existing Conditions

Table 4.5.3 provides a summary of regional air quality data and shows the relative contributions to the Basin-wide inventory from major source categories. As shown in Table 4.5.3, exceedances of the national standard for ozone are recorded on occasion in the San Diego Air Basin but no exceedances of the national PM-10 standard have been recorded over the past four years. Exceedances of the more-stringent state standards for ozone and PM-10, however, have occurred relatively frequently. As a separate source category, “on-road motor vehicles” contribute approximately 86 percent to the Basin-wide inventory for carbon monoxide, 57 and 77 percent to the Basin-wide inventory for ozone precursors (ROG and NO_x, respectively), and 39 percent to the Basin-wide inventory for PM-10. Electric utilities are included in “stationary and area sources.”

The 1998 Update of the *1991 Regional Air Quality Strategy* indicates that air quality in San Diego Air Basin improved significantly between 1994-1996 and the baseline planning period 1986-1988. Expected peak-day ozone concentrations at the El Cajon and Alpine monitoring stations (where the highest concentrations are typically measured) improved by 11 percent and 14 percent, respectively. Over that same period, the Basin-wide, population-weighted exposure indicator improved by 61 percent.

TOXIC AIR CONTAMINANTS

Regulatory Context

“Toxic air contaminants” are air pollutants that are believed to have carcinogenic or adverse non-carcinogenic effects but do not have a corresponding ambient air quality standard. There are hundreds of different types of toxic air contaminants, with varying degrees of toxicity. Sources of toxic air contaminants include industrial processes such as petroleum refining, electric utility and chrome plating operations, commercial operations such as gasoline stations and dry cleaners, and motor vehicle exhaust.

TABLE 4.5.3
SAN DIEGO AIR BASIN POLLUTANT SUMMARY

A) Summary of Region-wide Ambient Monitoring [a]

	Days over National Standard			
Pollutant	1994	1995	1996	1997
Carbon Monoxide	0	0	0	0
Ozone	9	12	2	1
Particulate Matter (PM-10) [b]	0/87	0/88	0/88	0/NR

	Days over State Standard			
Pollutant	1994	1995	1996	1997
Carbon Monoxide	0	0	0	0
Ozone	79	96	51	43
Particulate Matter (PM-10) [b]	25/87	23/88	16/88	NR

B) Percent Contribution by Source Category

	Percentage of Basin Inventory			
	Carbon	Ozone Precursors[d]		Particulate
Source Category	Monoxide	ROG	NO_x	Matter (PM-10)
Stationary and Area Sources	7	37	8	47
On-Road Motor Vehicles [c]	86	57	77	49
Other Mobile Sources	7	6	15	4
Total	100	100	100	100

a This table shows the number of days in which at least one air monitoring station in San Diego Air Basin recorded a violation of the state standard.

b PM-10 measurements are not taken every day. The table shows the number of days during which PM-10 concentrations exceeded the State standard at one or more of the monitoring stations in the Air Basin and the number of days during the year during which PM-10 measurements were recorded. Since monitoring for PM-2.5 only began in 1998, air basins will not be classified with respect to the new national PM-2.5 standard until 2000 or later.

c For PM-10, the percentage shown in this table includes road dust within the "on-road motor vehicles" emissions source category.

d Ozone is not emitted directly to the atmosphere but is a secondary pollutant resulting from photochemical reactions involving Reactive Organic Gases (ROG) and nitrogen oxides (NO_x) that are emitted directly by emissions sources. ROG and NO_x are referred to as ozone precursors.

NR = Not Reported.

SOURCES: California Air Resources Board, *Air Quality Data Summary*, 1993 through 1996; San Diego Air Pollution Control District, "Five-Year Summary," www.sdapcd.co.san-diego.ca.us, updated July 1998; California Air Resources Board, *Emission Inventory 1995*, approved November 1997.

Toxic air contaminants are regulated under both state and federal laws. Federal laws use the term "Hazardous Air Pollutants" (HAPs) to refer to the same types of compounds referred to as "Toxic Air Contaminants" (TACs) under State law. Both terms encompass essentially the same compounds. For the sake of simplicity, this report will use TACs when referring to these compounds rather than HAPs. Under the 1990 Clean Air Act Amendments, approximately 190 substances are regulated under a two-phase strategy. The first phase involves requiring facilities to install Maximum Achievable Control Technology (MACT); U.S. EPA has established MACT standards for 20 industries that emit toxic air contaminants and will develop MACT standards for others over the next several years. Electric Utility Boilers were omitted from the list of industries to be considered pending an U.S. EPA study that will determine if MACT is required. Even if MACT is established for a given source category, a facility in that category is subject to MACT only if the TAC emissions are 10 tons per year or more for any substance or 25 tons per year or more for any combination of TACs.

The second phase of control involves determining the residual health risk represented by TAC emissions sources after implementation of MACT standards. U.S. EPA will determine residual risks within eight years after MACT standards for a source category are set. Results of this analysis will be used to determine if the residual risks allow for a reasonable margin of safety for public health.

With respect to State law, in 1983 the State legislature adopted Assembly Bill 1807 (AB 1807), which established a process for identifying TACs and provided the authority for developing retrofit TAC control measures on a statewide basis. In 1992, the State legislature adopted Assembly Bill 2728 to provide a legal framework for the integration of the existing State air toxics programs, including those developed under AB 1807, with the new federal program discussed above.

TACs from industrial facilities are also subject to another state law, the Air Toxics "Hot Spots" Information and Assessment Act of 1987, Assembly Bill 2588 (AB 2588). Under AB 2588, TAC emissions from individual facilities are required to be quantified by the facility and reported to the local air pollution control agency. The facilities are prioritized by the local agencies based on the quantity and toxicity of these emissions, and their proximity to areas where the public may be exposed. High priority facilities are required to perform a health risk assessment, and if specific risk thresholds are exceeded, they are required to communicate the results to the public in the form of notices and public meetings. Depending on the health risk levels, emitting facilities can be required to implement varying levels of risk reduction measures.

Introduction to Risk Assessment

Health effects resulting from exposure to toxic air contaminants can be categorized as either carcinogenic (cancer-causing), or non-carcinogenic. Health effects from carcinogenic air toxics are usually described in terms of individual cancer risk. "Individual cancer risk" is the likelihood that a person exposed to concentrations of toxic air contaminants over a lifetime will contract cancer, based on the use of standard risk assessment methodology established for AB 2588. These cancer risks are based on the best estimates of plausible cancer potencies as determined by the State Office of Environmental Health Hazard Assessment.[1] When exposure to more than one

[1] In the U.S. approximately 400,000 of each million people will develop cancer in their lifetimes (American Cancer Society, 1995). Cancer can result from a number of causes, including chemical exposures.

potential carcinogen is evaluated, the risks posed by the various individual air toxics is summed; this sum is the overall cancer risk estimate.[2]

Incremental risks estimated through standard methods are typically compared to risks estimated by the same methods for other facilities, and to standards selected to define the acceptable incremental risk from a project or facility (e.g., the Proposition 65 standard risk of 10 in a million). Non-carcinogenic health effects associated with air toxics vary depending on the types and quantities of air toxics exposure. Adverse effects on health, as well as the potential for nuisance and other forms of irritation, depend largely on the susceptibility of the individual, and are evaluated for two different periods of exposure: acute (short-term exposure) and chronic (long-term exposure). Non-cancer health effects (both acute and chronic) are considered by comparing estimated exposure levels to known or estimated thresholds (termed “reference exposure levels”). Specific toxic air contaminants, such as formaldehyde, benzene, and metals, that are associated with the combustion of natural gas, fuel oil and distillate are described in the following paragraphs.

Formaldehyde

Formaldehyde (HCHO) is the toxic air contaminant emitted from power plant stacks in the largest quantities where natural gas is burned. Formaldehyde is a simple organic substance that can be generated by incomplete combustion of natural gas. Pure formaldehyde is a colorless volatile liquid with a characteristic pungent odor. It is soluble in water. Formaldehyde is considered to be a toxic substance and a carcinogen. The primary pathway of exposure to formaldehyde in stack emissions is through inhalation.

Benzene

Benzene (C_6H_6) is emitted from power plant stacks in smaller quantities than formaldehyde. Benzene is a trace contaminant, but it can be detected in stack emissions where natural gas is burned. Benzene, an organic compound, is a common industrial solvent and also is a component of unleaded gasoline. Chemically, the benzene molecule is the simplest aromatic hydrocarbon. Pure benzene is a clear, colorless, volatile liquid with a sweet aroma. The trace amounts of benzene in stack gases are too dilute to be detected by its aroma. Benzene is considered to be a toxic substance and a carcinogen. The primary pathway of exposure to benzene in stack emissions is through inhalation.

At trace concentrations, benzene does not pose an acute health hazard. Over the long term, benzene exposure might produce headaches or respiratory problems. The carcinogenic nature of benzene is its greatest health threat. Benzene attacks the liver and can alter genetic matter in bone marrow, causing leukemia.

[2] The summation of cancer risks for various chemicals is an approximation because either synergistic (i.e., cooperative, producing greater effect than expected) or antagonistic (i.e., opposing, producing less effect than expected) effects may occur as a result of exposure to various air toxics. Because sufficient data are not available to predict such health effects, health risk assessment guidelines, including federal and California procedures, assume that health risks are additive (California Air Pollution Control Officers Association, 1993).

Toluene

Toluene ($C_6H_5CH_6$) is emitted from power plant stacks in similar quantities as benzene. Benzene is a trace contaminant, but it can be detected in stack emissions where natural gas is burned. The major use of toluene is as a mixture added to gasoline to improve octane ratings. Toluene occurs as a colorless, flammable, refractive liquid, that is slightly soluble in water with a sweet, pungent aroma. The trace amounts of toluene in stack gases are too dilute to be detected by its aroma. Toluene is considered to be a toxic substance for acute (short-term) and chronic (long-term) exposures. The central nervous system is the primary target organ for toluene toxicity.

The primary pathway of exposure to toluene in stack emissions is through inhalation. Short-term exposure to moderate amounts of toluene can produce fatigue, confusion, general weakness, drunken-type actions, memory loss, nausea, and loss of appetite. Long-term exposure to low and moderate amounts of toluene has caused slight effects on the kidneys in some people, but these people were also exposed to other solvents at the same time and it is difficult to tell which chemical may have caused the effects.

Metals

Arsenic, Beryllium, Cadmium, Copper, Chromium (VI), Lead, Manganese, Mercury, Nickel, Selenium, and Zinc are emitted from power plant stacks in small quantities where fuel oil is burned. These metals are trace components of fuel oils and are classified as toxic substances and some are carcinogens. The primary pathway of exposure to metals in stack emissions is through both inhalation and non-inhalation.

Polycyclic Aromatic Hydrocarbons

Polycyclic aromatic hydrocarbons are emitted from power plant stacks in small quantities where fuel oil is burned and have been reported to produce carcinogenic, reproductive, and developmental effects as well as toxic effects on blood, the liver, eyes, and the immune system.

Methylene Chloride & Perchloroethylene

These two volatile organic compounds are emitted in small quantities from painting & cleaning operations and are classified as toxic substances and carcinogens. The primary pathway of exposure is through inhalation.

Gasoline Vapor

Gasoline vapor is emitted in small quantities from gasoline dispensing operations. The primary pollutant in gasoline vapor is benzene, which was discussed above. With the use of reformulated gasoline in 1996, which contains significantly less benzene, and the installation of gasoline vapor recover systems, the impacts caused by this pollutant have been reduced.

LOCAL SETTING

ENCINA POWER PLANT

Existing Local Air Quality

Table 4.5.4 summarizes that past five years of criteria air pollutant concentration data collected at the closest air quality monitoring station, which is located on Mission Street in Oceanside, and compares that data with the corresponding state standards. The Oceanside station is located approximately five miles north of the Encina Power Plant. Table 4.5.4 indicates that, with the exception of ozone and PM-10, background concentrations do not currently violate ambient standards.

General Plant Characteristics

The Encina Power Plant consists of five boilers, which supply steam to five electricity-generating units, and one combustion turbine. The boilers can burn either natural gas or fuel oil. The combustion turbine is typically used to facilitate start-up of the other units at the plant and can burn either natural gas or distillate fuel. The Encina Power Plant also includes a gasoline dispensing facility. Table 4.5.5 identifies the electric generating units at the plant along with their operating capacities and annual average fuel use for the years 1994–1996.

Compliance Status

SDG&E holds SDAPCD permits to operate five boilers, one combustion turbine, and additional miscellaneous air pollutant emitting sources. SDG&E submitted a Title V permit application in September, 1996 to SDAPCD. SDG&E certified that the facility is in compliance with all applicable requirements.

SDAPCD has determined that the Title V permit application is complete. SDG&E anticipates that SDAPCD will submit the draft of the final Title V permit for the power plant to the U.S. EPA later this year for approval. Final issuance of the Title V permit could occur in 1999. Upon sale of the plant, an application will be filed with the SDAPCD to transfer either the Title V permit application or, as appropriate, the Title V permit to the new owners. Similarly, an application will be filed with SDAPCD to transfer the Title IV permit, as appropriate, to the new owners. Title IV of the federal Clean Air Act allocates emissions of SO_x to each power plant in order to minimize acid deposition. SDG&E would transfer an appropriate allocation of SO_x allowances for the power plant to the new owners.

The Encina Power Plant has been cited for only a few notices of violation (NOVs) between 1991 and 1998. These NOVs alleged discharging of excess NO_x emissions and exceeding the visible emissions standard of 20% opacity. According to SDG&E, most of the NOVs were dismissed by the issuing agency without further action.

Criteria Air Pollutant Emissions Estimates

The primary source of air pollutant emissions from the Encina Power Plant is the combustion of fuel by the five steam boilers and one combustion turbine. The emissions from the plant depend

TABLE 4.5.4
CRITERIA AIR POLLUTANT CONCENTRATIONS NEAR THE ENCINA POWER PLANT, 1993-1997

Pollutant	**Standard**[c]	Monitoring Data by Year[a]				
		1993	**1994**	**1995**	**1996**	**1997**
Ozone:						
Highest 1-hr. average, ppm[b]	0.09	**0.16**	**0.11**	**0.11**	**0.11**	**0.11**
Number of exceedances[d]		7	2	5	4	6
Carbon Monoxide:						
Highest 1-hr. average, ppm	20	5	5	4	4	6
Number of exceedances		0	0	0	0	0
Highest 8-hr. average, ppm	9.0	3.3	4.0	3.3	2.8	2.9
Number of exceedances		0	0	0	0	0
Nitrogen Dioxide:						
Highest 1-hr. average, ppm	0.25	0.07	0.12	0.14	0.11	0.11
Number of exceedances		0	0	0	0	0
Annual Average, ppm	0.053	0.021	0.021	0.020	0.018	0.018
Sulfur Dioxide:						
Highest 1-hr. average, ppm	0.25	0.12	ND	ND	ND	ND
Number of exceedances		0	ND	ND	ND	ND
Particulate Matter (PM-10):						
Highest 24-hr. average, $\mu g/m^3$ [b]	50	**68**	**75**	**80**	**63**	50
Exceedances/Samples[e]		2/61	3/63	4/59	1/60	0/55
Annual Geometric Mean, $\mu g/m^3$	30	26.4	27.2	27.0	24.1	23.7

a Data for all pollutants are from the air quality monitoring station the City of Oceanside, which is located approximately five miles north of the Encina Power Plant.

b ppm = parts per million; $\mu g/m^3$ = micrograms per cubic meter.

c State standard, not to be exceeded, except for the annual-average nitrogen dioxide standard, which is a national standard.

d Except for ozone, "number of exceedances" refers to the number of measured violations in a given year of the applicable standard. For ozone, "number of exceedances" refers to the number of days in a given year during which at least one hour exceeded the standard.

e PM-10 is usually measured every sixth day (rather than continuously like the other pollutants). For PM-10, "exceedances/samples" indicates the number of exceedances of the state standard that occurred in a given year and the total number of samples that were taken that year.

NOTE: ND = No data available. Values shown in **bold** type exceed the applicable standard.

SOURCE: California Air Resources Board, *California Air Quality Data*, 1993, 1994, 1995, 1996; San Diego Air Pollution Control District, www.sdapcd.co.san-diego.ca.us/air.

TABLE 4.5.5
ENCINA POWER PLANT FUEL USAGE CHARACTERISTICS[a]

Unit	Capacity (MW)	Type	Electricity Produced (GWH)	Natural Gas Consumption Rate (MMCF)	Fuel Oil/Distillate Consumption Rate (Gallons)	Percent Fuel Oil/Distillate Consumed [b]
1	107	Steam Turbine	63	797	0	0.0
2	104	Steam Turbine	90	1,069	0	0.0
3	110	Steam Turbine	138	1,914	124,110	0.9
4	300	Steam Turbine	702	7,046	3,924,340	7.6
5	330	Steam Turbine	1,006	9,607	5,625,214	7.9
CT	14	Combustion Turbine	0.2	6.9	3,284	6.1

a Represents average annual fuel usage characteristics over the 1994 through 1996 period.
b Percentage of fuel oil/distillate used during the 1994–1996 operating period is based on the following heat contents: 1,050 Btu per standard cubic foot of natural gas, 150,000 Btu per gallon of fuel oil, and 139,000 Btu per gallon of distillate (used by the CT).

NOTE: GWH = giga (i.e., billion) watt-hours; MMCF = million cubic feet.

SOURCE: San Diego Gas & Electric Company, *Proponent's Environmental Assessment: San Diego Gas & Electric Company's Proposed Sale of Its Electrical Generation Facilities and Power Contracts,* December 19, 1997.

on the capacity factor of each unit, which varies from year to year, and the emission rate of each unit, which is itself dependent upon the fuel that is combusted and the type of emissions control technology that has been installed. NO_x emissions from the boilers are controlled through such combustion controls as low excess air, overfire air, and burners out of service. In 1997, boilers #4 and #5 were equipped to use fuel gas recirculation to further reduce NO_x emissions boiler and meet the aggregate NO_x emissions limit set forth in SDAPCD Rule 69. Water injection is the technique used to reduce emissions from the CT.

Annual average criteria air pollutant emissions have been estimated for the 1994 through 1996 period and are shown in Table 4.5.6. Table 4.5.6 also shows these emissions as a percentage of County-wide emissions in 1995. As shown in Table 4.5.6, emissions of SO_x from the Encina Power Plant represented approximately 6 percent of the County-wide inventory for that pollutant in 1995. NO_x emissions represented approximately 1 to 2 percent of the County-wide inventory for that pollutant, and the other emissions represented considerably less than 1 percent of the inventory.

Toxic Air Contaminant Emissions and Associated Risk Level Estimates

A health risk assessment was carried out for the Encina Power Plant in 1992 to evaluate the effects from exposure to emissions of TACs and to comply with AB 2588, the Air Toxics "Hot

TABLE 4.5.6
ENCINA POWER PLANT CRITERIA AIR POLLUTANT EMISSIONS

Pollutant	Emissions Estimates (tons per year)[a]	Emissions As Percent of San Diego County[b]
Carbon Monoxide	883	0.13
Reactive Organic Gases	92	0.09
Nitrogen oxides	1,222	1.43
Sulfur oxides	272	6.11
Particulate Matter	100	0.24

a Emissions estimates represent average annual emissions over the 1994 to 1996 period and are based on fuel consumption characteristics shown in Table 4.5.5, source test data for NO_x, and U.S. EPA emissions factors for the other criteria air pollutants (U.S. Environmental Protection Agency, 1998).
b Percentages are based on California Air Resource Board, *Emission Inventory 1995*, November 1997.

SOURCE: Environmental Science Associates

Spots" Information Act. Health risk assessments estimate the risk of cancer due to exposure to toxic air contaminant emissions and evaluate the potential for other (non-cancer) acute or chronic

health effects that may be caused by facility emissions. The calculated health risk is the worst-case reasonably foreseeable risk, considering the inherent uncertainties and assumptions made for the assessment.

For health risk assessments, computer modeling is carried out to determine the magnitude and location of the highest estimated ground-level concentrations of TACs emitted from a facility. A person at this location would have the greatest exposure to emissions from the plant. The hypothetical maximally exposed individual (MEI), whose exposure is used to evaluate the worst-case exposure level, would be located at this point. In residential areas, this MEI is assumed to be exposed to TAC emissions for 24 hours per day, 365 days per year, for 70 years. In non-residential areas, where the exposure relates to an occupational setting, the MEI is assumed to be exposed for eight hours per day, 240 days per year, for 46 years. These levels of exposure are highly unlikely in actual situations, and are typical of standard conservative health risk assessment assumptions (California Air Pollution Control Officers Association, 1993).

For carcinogens, the health risk at the MEI receptor is normally expressed as the chance in a million that an individual would contract cancer if he or she were exposed to the estimated concentration for 46 or 70 years, depending on whether the MEI is a worker or a resident. If, for example, there were a one percent chance that an individual would contract cancer from exposure, the risk would be ten thousand in a million.

The plant's 1992 health risk assessment (HRA) was performed using SDAPCD 1989 emissions inventory data and the ISCST model with 1984-1988 meteorological data from Lindbergh Field (IWG Corp, 1992a). The estimated emissions were based on information provided in SDG&E's

1989 AB 2588 Toxic Air Contamination Report. Health risks from exposure to toxic substances through non-inhalation pathways were estimated by using the ACE2588 program (Tran, 1991).

The results of the 1992 HRA were adjusted to reflect current (1996) emissions estimates to provide a basis for updating the estimated health risks associated with the Encina Power Plant. The current estimated cancer risk for a maximum exposed individual (MEI) at the location of highest impact and caused by existing plant emissions is lower than one in a million (0.96 in a million). The major contributing pollutant (91% of the total risk) was from gasoline vapor which is associated with the gasoline dispensing facility. Other contributing pollutants were methylene chloride and perchloroethylene from painting and cleaning operations, metals from fuel oil combustion by the boilers, and formaldehyde from natural gas combustion by the boilers.

Several air pollution control agencies in California, including the SDAPCD and the California Air Pollution Control Officer's Association (CAPCOA), consider an incremental risk from an existing facility to be acceptable if it is less than ten in a million. Ten in a million is used herein to identify significant levels of risk.

For non-cancer health effects, the potential for human health hazards is evaluated by calculating ratios ("hazard indices") which compare the estimated level of exposure for various substances to reference doses. Reference doses for non-cancer are levels established by the scientific community and by state and federal agencies responsible for protecting human health. Reference doses for some substances are based on observed effects on laboratory animals. The reference doses for humans are usually based on calculations conducted by the California Office of Environmental Health Hazard Assessment (OEHHA), in which a 100-fold safety factor is applied to "no observed effects level" (NOEL). When the ratio of the estimated concentration to the reference dose is less than 1.0, no health effect would be anticipated. In a conservative analysis, the ratios for the various substances considered are added together to obtain a "hazard index," which, when less than 1.0, would indicate no health effect.

For non-cancer pollutants, the maximum off-site impact from the Encina Power Plant was well below the level associated with adverse effects. The chronic hazard index for non-cancer effects from the entire plant were estimated to be approximately 0.003 at the location of maximum pollutant concentrations, which is well below the "safe level" index of 1.0. The maximum hazard index for acute exposure to non-cancer substances was calculated to be less than 0.10, which also is well below the significance threshold of 1.0.

Sensitive Receptors in Plant Vicinity

No hospitals, day-care centers, etc. are located near the power plant. However, residential areas are located north of the Agua Hedionda Lagoon and along Carlsbad Boulevard and Cannon Road, adjacent to the southwest borders of the plant site.

SOUTH BAY POWER PLANT

Existing Local Air Quality

Table 4.5.7 summarizes that past five years of criteria air pollutant concentration data collected at the closest air quality monitoring station, which is located in the City of Chula Vista, and compares that data with the corresponding state standards. The Chula Vista station is located approximately one mile east of the South Bay Power Plant. Table 4.5.7 indicates that, with the exception of ozone and PM-10, background concentrations do not currently violate ambient standards.

General Plant Characteristics

The South Bay Power Plant consists of four boilers, which supply steam to four electricity-generating units, and one combustion turbine. The boilers can burn either natural gas or fuel oil. The combustion turbine is typically used to facilitate start-up of the other units at the plant, and it burns jet fuel. The South Bay Power Plant also includes a gasoline dispensing facility. Table 4.5.8 identifies the electric generating units at the plant along with their operating capacities and annual average fuel use for the years 1994–1996.

Compliance Status

SDG&E holds valid permits for the South Bay Power Plant to operate four boilers, one combustion turbine, and additional miscellaneous air pollutant emitting sources. SDG&E submitted a Title V permit application in September, 1996 to SDAPCD. SDG&E certified that the facility is in compliance with all applicable requirements.

SDAPCD has determined that the Title V permit application is complete. SDG&E anticipates that SDAPCD will submit the draft of the final Title V permit for the power plant to the U.S. EPA later this year for approval. Final issuance of the Title V could occur in 1999. Upon sale of the plant, an application will be filed with the SDAPCD to transfer either the Title V permit application or, as appropriate, the Title V permit to the new owners. Similarly, an application will be filed with the SDAPCD to transfer the Title IV permit, as appropriate, to the new owners. SDG&E would transfer an appropriate allocation of SO_x allowances for the power plant to the new owners.

The plant has been cited for only a few NOVs between 1991 and 1998. These NOVs alleged discharging of excess NO_x emissions and exceeding the visible emissions standard of 20% opacity. According to SDG&E, many of these NOVs were dismissed by the issuing agency without further action.

Criteria Air Pollutant Emissions Estimates

The primary source of air pollutant emissions from the South Bay Power Plant is the combustion of fuel by four steam boilers and one combustion turbine. The emissions from the plant depend on the capacity factor of each unit, which varies from year to year, and the emission rate of each

TABLE 4.5.7
CRITERIA AIR POLLUTANT CONCENTRATIONS NEAR THE SOUTH BAY POWER PLANT, 1993-1997

Pollutant	Standard[c]	Monitoring Data by Year[a]				
		1993	1994	1995	1996	1997
Ozone:						
Highest 1-hr. average, ppm[b]	0.09	**0.13**	**0.10**	**0.14**	**0.10**	**0.12**
Number of exceedances[d]		12	4	7	1	10
Carbon Monoxide:						
Highest 1-hr. average, ppm	20	5	7	5	6	5
Number of exceedances		0	0	0	0	0
Highest 8-hr. average, ppm	9.0	3.5	3.8	4.0	4.0	3.6
Number of exceedances		0	0	0	0	0
Nitrogen Dioxide:						
Highest 1-hr. average, ppm	0.25	0.09	0.10	0.10	0.08	0.11
Number of exceedances		0	0	0	0	0
Annual Average, ppm	0.053	0.020	0.021	0.020	0.020	0.019
Sulfur Dioxide:						
Highest 1-hr. average, ppm	0.25	0.06	0.10	0.08	0.09	0.08
Number of exceedances		0	0	0	0	0
Annual Average, ppm	0.030	0.001	0.001	0.001	0.002	0.003
Particulate Matter (PM-10):						
Highest 24-hr. average, μg/m^3 [b]	50	**56**	**61**	**103**	**62**	**58**
Exceedances/Samples[e]		2/60	2/60	5/59	2/60	2/60
Annual Geometric Mean, μg/m^3	30	24.7	26.5	29.2	25.8	26.8

a Data for all pollutants are from the air quality monitoring station in the City of Chula Vista, which is located approximately one mile east of the South Bay Power Plant.

b ppm = parts per million; μg/m^3 = micrograms per cubic meter.

c State standard, not to be exceeded, except for the annual-average nitrogen dioxide and sulfur dioxide standards, which are national standards.

d Except for ozone, “number of exceedances” refers to the number of measured violations in a given year of the applicable standard. For ozone, “number of exceedances” refers to the number of days in a given year during which at least one hour exceeded the standard.

e PM-10 is usually measured every sixth day (rather than continuously like the other pollutants). For PM-10, “exceedances/samples” indicates the number of exceedances of the state standard that occurred in a given year and the total number of samples that were taken that year.

NOTE: ND = No data available. Values shown in **bold** type exceed the applicable standard.

SOURCE: California Air Resources Board, *California Air Quality Data*, 1993, 1994, 1995, 1996; San Diego Air Pollutant Control District, www.sdapcd.co.san-diego.ca.us/air.

TABLE 4.5.8
SOUTH BAY POWER PLANT FUEL USAGE CHARACTERISTICS[a]

Unit	Capacity (MW)	Type	Electricity Produced (GWH)	Natural Gas Consumption Rate (MMCF)	Fuel Oil Consumption Rate (Gallons)	% Fuel Oil Consumed [b]
1	146	Steam Turbine	608	6,133	192,192	0.5
2	150	Steam Turbine	674	6,700	321,902	0.7
3	175	Steam Turbine	638	6,541	0	0.0
4	222	Steam Turbine	70	835	1,080,842	16.0
CT	13	Combustion Turbine	0.2	0	20,286	100.0

a Represents average annual fuel usage characteristics over the 1994 through 1996 period.
b Percentage of fuel oil/distillate used during the 1994–1996 operating period is based on the following heat contents: 1,050 Btu per standard cubic foot of natural gas, 150,000 Btu per gallon of fuel oil, and 135,000 Btu per gallon of jet fuel (used by the CT).

NOTE: GWH = giga (i.e., billion) watt-hours; MMCF = million cubic feet.

SOURCE: San Diego Gas & Electric Company, *Proponent's Environmental Assessment: San Diego Gas & Electric Company's Proposed Sale of Its Electrical Generation Facilities and Power Contracts,* December 19, 1997.

unit, which is itself dependent upon the fuel that is combusted and the type of emissions control technology that has been installed. NO_x emissions from boilers #2, #3, and #4 are controlled through such combustion controls as low excess air and overfire air. In 1997, SDG&E installed selective catalytic reduction (SCR) equipment on boiler #1 to further reduce NO_x emissions from that boiler and meet the aggregate NO_x emissions limit set forth in SDAPCD Rule 69. Steam injection is used to reduce emissions from the CT at the South Bay Power Plant.

Annual average criteria air pollutant emissions have been estimated for the 1994 through 1996 period and are shown in Table 4.5.9. Table 4.5.9 also shows these emissions as a percentage of County-wide emissions in 1995. As shown in Table 4.5.9, emissions of NO_x and SO_x from the South Bay Power Plant represented approximately 1 to 2 percent of the County-wide inventory for those pollutants in 1995, and the other emissions represented considerably less than 1 percent of the inventory.

Toxic Air Contaminant Emissions and Associated Risk Level Estimates

A health risk assessment was prepared for the South Bay Power Plant in 1992 using SDAPCD 1989 emissions inventory data and the ISCST model with 1984-1988 meteorological data from Lindbergh Field (IWG Corp., 1992e). The estimated emissions were based on information provided in SDG&E's 1989 AB 2588 Toxic Air Contamination Report. SDG&E used a low sulfur, low ash fuel and as a result the concentration of many of the metals of concern were below

TABLE 4.5.9
SOUTH BAY POWER PLANT CRITERIA AIR POLLUTANT EMISSIONS

Pollutant	Emissions Estimates (tons per year)[a]	Emissions As Percent of San Diego County [b]
Carbon Monoxide	853	0.13
Reactive Organic Gases	88	0.09
Nitrogen Oxides	1,382	1.61
Sulfur Oxides	50	1.12
Particulate Matter	81	0.20

a Emissions estimates represent average annual emissions over the 1994 to 1996 period and are based on fuel consumption characteristics shown in Table 4.5.8, source test data for NOx, and U.S. EPA emissions factors for the other criteria air pollutants (U.S. Environmental Protection Agency, 1998).
b Percentages are based on California Air Resource Board, *Emission Inventory 1995*, November 1997.

SOURCE: Environmental Science Associates

the analytical detection levels. Therefore, SDAPCD chose to estimate the emissions from the South Bay Power Plant using assumed metals concentrations in the fuel oil rather than the actual measured emission values submitted in the Emissions Inventory. The use of assumed metals emission rather than actual measured emissions may overestimate the associated health risk.

The results of the 1992 HRA were adjusted to reflect current (1996) emissions estimates to provide a basis for updating the estimated health risks associated with the South Bay Power Plant. The current estimated cancer risk for a maximum exposed individual (MEI) at the location of highest impact and caused by existing plant emissions was lower than one in a million (0.72 in a million). The major contributing pollutants were methylene chloride & perchlorethylene (67% of the total risk) from painting & cleaning operations and formaldehyde (29% of the total risk) from natural gas combustion by the boilers. Other contributing pollutants were metals from fuel oil combustion by the boilers. For non-carcinogenic pollutants, the maximum off-site impact was well below the level associated with adverse effects. The chronic hazard index for non-carcinogenic effects from the entire plant were estimated to be less than 0.002 at the location of maximum pollutant concentrations, which is well below the “safe level” index of 1.0. The maximum hazard index for acute exposure to non-carcinogenic substances was calculated to be less than 0.20, which also is well below the significance threshold of 1.0.

Sensitive Receptors in Plant Vicinity

The closest residential population is about 1,000 feet to the south of the plant boundary and about 4,200 feet from the boiler stacks.

COMBUSTION TURBINES

SDG&E operates 19 combustion turbines at nine sites, including the two combustion turbines at Encina and South Bay Power Plants that were previously described. The remaining 17 are dispersed around the southwestern portion of SDG&E's service territory at seven different sites. They are peaking units operated generally less than 50 hours per year. Burning either natural gas or distillate oil, the 17 combustion turbines have a net capacity of approximately 270 MW.

Title V permit applications have not been requested by SDAPCD for the combustion turbines. Due to historic low capacity factors, emissions from the combustion turbines have been less than half of the "major source" emissions threshold and, therefore, have not triggered the requirement for a Title V permit.

According to SDG&E, none of the combustion turbine sites have been cited with notices of violation by SDAPCD.

Criteria Air Pollutant Emissions Estimates

In general, the pollutant emissions generated from the combustion of fuel by the combustion turbines are minor compared to the pollutant emissions generated from steam boilers at the power plants. Each of the combustion turbines is equipped with water injection to reduce emissions. Table 4.5.10 provides annual average emissions estimates for SDG&E's combustion turbines for the period 1994 through 1996.

Toxic Air Contaminant Emissions and Associated Risk Level Estimates

Health risk assessments were performed in 1992 for three CT sites (Naval Station, Naval Training Center, and North Island). For these 1992 assessments, the SCREEN dispersion model was used to estimate ambient concentrations of TACs surrounding the facilities. These concentrations were in turn used to derive a conservative estimate of health risks. The 1992 health risk assessments were based on estimated emissions provided in SDG&E's 1989 AB 2588 Toxic Air Contamination Report. Beginning in 1990, emissions from the combustion turbines declined substantially relative to prior years because the units began to function nearly exclusively as peaking electric power generators. In 1990, the units on average operated 3% of the total hours operated during 1989. Therefore, the emissions and calculated risks based on the decreased use of the combustion turbines are less than 3% of the reported risks in the 1992 HRAs. The referenced assessments are discussed below along with a discussion of sensitive receptors in the vicinities of the CT sites.

Division Street CT

The CT at the Division Street site has a similar net capacity (MW) as the CT at the Naval Training Center. Therefore, the distance to the hypothetical MEI would be roughly the same at both locations. At the Naval Training Center, the MEI is approximately 330 feet from the CT. Thus, risk levels at 330 feet from the Division Street CT would be similar to those described below for the Naval Training Center. With respect to sensitive receptors, the closest such receptors to the generating station are located approximately 500 feet to the northeast, across Harbor Drive in a residential/administrative area of the Naval Station. The closest city neighborhood is located east of Main Street, approximately 1,800 feet from the CT site.

TABLE 4.5.10
SDG&E'S COMBUSTION TURBINES CRITERIA AIR POLLUTANT EMISSIONS

	Emissions (tons per year) [a]				
Site	**CO**	**ROG**	**NO_x**	**SO_x**	**PM-10**
Division Street	0.1	< 0.05	0.4	1.2	< 0.05
El Cajon	< 0.05	< 0.05	0.2	0.1	< 0.05
Kearny	0.4	0.1	5.6	1.6	0.3
Miramar Yard	0.2	0.1	3.3	0.4	0.2
Naval Station	0.2	< 0.05	2.2	0.7	0.1
Naval Training Center	< 0.05	< 0.05	0.4	0.1	< 0.05
North Island	0.3	< 0.05	1.5	2.1	0.1
TOTAL:	1.3	0.3	13.7	6.2	0.7

a Emissions estimates are based on fuel consumption data provided in SDG&E, *Proponent's Environmental Assessment, San Diego Gas & Electric Company's Proposed Sale of its Electrical Generation Facilities and Power Contracts*, December 19, 1997; NO_x source test data; and U.S. EPA emissions factors (U.S. Environmental Protection Agency, 1998).

SOURCE: Environmental Science Associates

El Cajon CT

The CT at the El Cajon site has a similar net capacity (MW) as the CT at the Naval Training Center. Therefore, the distance to the hypothetical MEI would be roughly the same at both locations. At the Naval Training Center, the MEI is approximately 330 feet from the CT. Thus, risk levels at 330 feet from the El Cajon CT would be similar to those described below for the Naval Training Center.

With respect to sensitive receptors, the closest such receptors to the generating station are a residential area 400 feet to the south, and a school approximately 1,600 feet to the northeast. The closest residential neighborhood is south of the commercial properties that line the south side of West Main Street.

Kearny CTs

The nine CTs at the Kearny site have similar net capacities (MW) as the CT at the Naval Training Center. The total emissions from the Kearny site are expected to be nine times greater than emissions from the Naval Training Center. The distance to the MEI at the Naval Training Center was approximately 330 and a similar distance to the MEI would be expected at Kearny. Thus, the health risks are expected to be nine times higher at the MEI at Kearny than described for the MEI at the Naval Training Center site. However, the health risks to the surrounding community from the Kearny CTs are minimal since there are no air pollution-sensitive receptors within one-half mile of the Kearny site.

Miramar Yard CTs

The two CTs at the Miramar Yard site have similar net capacities (MW) as the CTs at the North Island site. Therefore, the discussion of health risks at the MEI at the North Island site are similar to those at the Miramar Yard site (i.e., 3,500 feet from the CTs). Presently, there are no air pollution-sensitive receptors within one-half mile of the generating station and no residential land uses in the vicinity.

Naval Station CT

The 1992 HRA estimated cancer risk for the MEI, which has found to be located approximately 400 feet from the CT. The estimated cancer risk at the MEI was well below one in a million (0.21 in a million) (IWG Corp., 1992d). The major contributing pollutants were metals from burning of fuel oil and benzene from burning of natural gas.

For non-carcinogenic pollutants, the maximum off-site impact was well below the level associated with adverse effects. The chronic hazard index for non-carcinogenic effects from the entire plant were estimated to be less than 0.0016 at the location of maximum pollutant concentrations, which is well below the “safe level” index of 1.0. The maximum hazard index for acute exposure to non-carcinogenic substances was calculated to be 0.0047, which also is well below the significance threshold of 1.0.

Presently, the closest air pollution-sensitive receptors to the generating station are located approximately 1,200 feet to the northeast, across Harbor Drive in a residential/administrative area of the Naval Station. The surrounding area consists of heavy industrial uses that are associated with the repair and maintenance of military vessels. There are no residential uses in the immediate vicinity of the CTs.

Naval Training Center CT

The 1992 HRA estimated cancer risk for the MEI, which was found to be located approximately 330 feet from the CT. The estimated cancer risk was well below one in a million (0.042 in a million) (IWG Corp., 1992b). The major contributing pollutants were metals from burning of fuel oil and benzene from burning of natural gas.

For non-carcinogenic pollutants, the maximum off-site impact was well below the level associated with adverse effects. The chronic hazard index for non-carcinogenic effects from the entire plant were estimated to be less than 0.00053 at the location of maximum pollutant concentrations, which is well below the “safe level” index of 1.0. The maximum hazard index for acute exposure to non-carcinogenic substances was calculated to be 0.0027, which also is well below the significance threshold of 1.0.

Presently, the closest air pollution-sensitive receptors to the generating station are a multi-family residential area located approximately one-half mile to the north and a single-family residential area approximately 3,000 feet to the northwest. Land surrounding this facility is undeveloped or has been developed for airport and military training uses.

North Island CTs

The 1992 HRA estimated cancer risk for the MEI, which was found to be located approximately 3,500 feet from the CTs. The estimated risk was well below one in a million (0.06 in a million) (IWG Corp., 1992c). The major contributing pollutants were metals from burning of fuel oil and benzene from burning of natural gas.

For non-carcinogenic pollutants, the maximum off-site impact was well below the level associated with adverse effects. The chronic hazard index for non-carcinogenic effects from the entire plant were estimated to be less than 0.0005 at the location of maximum pollutant concentrations, which is well below the “safe level” index of 1.0. The maximum hazard index for acute exposure to non-carcinogenic substances was calculated to be 0.0027, which also is well below the significance threshold of 1.0.

Presently, the closest air pollution-sensitive receptor to the generating station is a residential area located approximately 2,500 feet to the southeast. Surrounding land uses are military and industrial and include a natural gas terminal and a cogeneration facility. Other adjacent land uses are associated with the support of naval operations.

CHECKLIST ISSUES

a) VIOLATION OF AIR QUALITY STANDARDS

Regional Issues

As discussed in the setting, the facilities proposed for divestiture by SDG&E are located in San Diego Air Basin, which is a non-attainment area for state and national ambient air quality standards for ozone and the state standard for PM-10, and which has been proposed as a non-attainment area for the state suspended sulfates standard (see Table 4.5.2). Considerable effort is expended in the region to meet air quality standards, and in the case of electric power plants, controlling NO_x emission sources (a precursor to ozone formation) to reduce ozone levels is the primary focus of the SDAPCD.

The project would involve the transfer of ownership of the Encina Power Plant, South Bay Power Plant, and various combustion turbines from SDG&E to a new owner or owners. While the transfer itself would not have air quality effects, the change in ownership could theoretically lead to changes in emissions generated by the power plants and combustion turbines due to changes in the amount or pattern of electricity generation, changes in the type of fuel used, or changes in pollution control technologies employed.

The first factor that could influence future power plant emissions is the amount and pattern of electricity generation. For this Initial Study, emissions estimates have been developed to correspond to different operational scenarios, including “baseline” estimates and “analytical maximum,” or “A-Max” estimates.[3] Baseline estimates represent the condition whereby SDG&E would continue to own and operate the two power plants and the combustion turbine sites, i.e., the no project alternative. The A-Max estimates represent the condition whereby the plants would be run at their highest possible capacities in light of technical and demand constraints. The A-Max estimates assume that natural gas could be purchased at a 25 percent discount from the least expensive supply of natural gas assumed to be available.

The purpose of these A-Max assumptions is to remove, to a great degree, the cost of fossil fuel from the new owner’s decision whether and when to generate power. Although it is extremely unlikely that such a reduced gas price could be obtained, this assumption further strengthens the conservative nature of the impact analysis. With a discounted price for natural gas, the power generated by the new owner would have a competitive advantage over other generators and would thus generate more power and higher corresponding emissions. The difference between the two values, i.e., between the baseline values and the A-Max values, represents the maximum possible impact of the project in 1999. The actual impact of the project may be less and may approach zero (i.e., no difference between the emissions with a new owner and those with SDG&E).

The second factor that could influence power plant emissions is the type of fuel that would be consumed. SDG&E steam boilers at Encina and South Bay are permitted to burn both natural gas and fuel oil. However, during the last five years, fuel oil has been used less frequently and has been used primarily to facilitate start-up of the units and during periods of natural gas curtailment. In 1997, for example, of the total fuel used at both Encina and South Bay Power Plants, approximately 99.5% was natural gas. In addition, SDAPCD Rule 69 restricts fuel oil combustion by the boilers to those periods during which SDAPCD forecasts no exceedances of the state ozone standard.

Despite the downward trend in fuel oil consumption, the emissions estimates for analysis year 1999 assume a low price for fuel oil and thus greater consumption of fuel oil than would otherwise be expected. This assumption was used to ensure a reasonable worst-case analysis. Nonetheless, even with a low price for fuel oil, natural gas would continue to be the primary fuel for the boilers. The combustion turbines, by and large, are assumed to use natural gas except for those three combustion turbines that must burn some other fuel (e.g., jet fuel or distillate).

The third factor that could influence future power plant emissions relates generally to the regulatory context under which the plants operate. Under the project, SDG&E would “transfer” its existing air quality permits for the power plants to the new owners. Typically, APCD regulations technically prohibit transfer of permits from one owner to another upon change of ownership of a facility. However, state law requires APCD to provide a mechanism for reissuing

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3 For a detailed explanation of the “analytical maximum,” see Chapter 3, Approach to Environmental Analysis, of this Initial Study.

a permit to a new owner or operator and prohibits the imposition of more stringent controls or operating conditions solely as a result of a change of ownership (Health and Safety Code §42301(f)). Thus, the new owner of a power plant acquired as a result of the project would be required to apply for and obtain new permits from the applicable air district, but the new permits cannot contain limitations or other requirements that are more stringent than those contained in the existing permits.

However, there would be one notable change in the regulatory context with the transfer of Encina and South Bay Power Plants to a new owner or owners. With the transfer of Encina and South Bay Power Plants to a new owner or owners, the aggregate annual NO_x emissions limits set forth in SDAPCD Rule 69 would no longer apply and would be replaced by boiler-specific emission standards defined in terms of pounds of NO_x per megawatt-hour. Specifically, with new owners, Encina and South Bay Power Plants would no longer by subject to the annual NO_x emissions limit of 2,100 tons per year, which began in 1997, a limit of 800 tons per year beginning in 2001, and a limit of 650 tons per year beginning in 2005. Instead, the new owner or owners would have two years, but not later than January 1, 2001, in which to equip the boilers to meet the boiler-specific emissions standards.

Emissions estimates have been made for the Encina and South Bay Power Plants as well as the seven combustion turbine sites, taking into account the three main factors discussed above. The following tables show estimates of criteria air pollutants for the Encina Power Plant (Table 4.5-11), the South Bay Power Plant (Table 4.5.12), and the seven combustion turbine sites (Table 4.5-13). Each of these tables shows emissions estimates under different operational scenarios including existing conditions, 1999 baseline, 1999 analytical maximum (with and without mitigation agreed to by SDG&E), and two variant 2005 cumulative cases. While both of the 2005 cumulative cases assume that upgrades would be made to increase electric power transmission capacity to San Diego County; variant #1 assumes that the South Bay Power Plant would remain operational while variant #2 assumes that South Bay Power Plant would be retired and replaced with a new power plant at Otay Mesa.

The emissions estimates shown in Tables 4.5.11 (Encina), 4.5.12 (South Bay). and 4.5.13 (combustion turbine sites) are based on power generation and fuel consumption forecasts described in Attachment D and emissions factors that reflect the type of emissions source (boiler or combustion turbine), the type of fuel (natural gas fuel), and the type of control technology installed on a given boiler or combustion turbine [e.g., flue gas recirculation or Selective Catalytic Reduction (SCR)]. The NO_x emissions estimates also account for variations in power load (i.e., megawatts) on an hourly basis for a given steam boiler or combustion turbine and for start-up conditions. Composite NO_x emissions factors are shown in Attachment D. The NO_x emissions estimates for year 1999 assume continued operation of flue gas recirculation on Encina boilers #4 and #5 and SCR on South Bay boiler #1. Under the cumulative 2005 cases, full SCR is assumed for all of the boilers to meet the boiler-specific NO_x emissions requirements contained in SDAPCD Rule 69. For the combustion turbines, water/steam injection is assumed for both years 1999 and 2005.

TABLE 4.5.11
ENCINA POWER PLANT
CRITERIA AIR POLLUTANTS EMISSIONS ESTIMATES, 1999 AND 2005

	Estimated Emissions in Tons Per Year[a]					
Pollutant	**Existing[b]**	**1999 Baseline**	**1999 Analytical Maximum**	**1999 A-Max (with mitigation)[c]**	**2005 Cumulative A-Max (South Bay operational)[d] (Variant 1)**	**2005 Cumulative A-Max (South Bay retired)[d] (Variant 2)**
Carbon Monoxide	883	588	2,100	1,086	1,308	1,899
Reactive Organic Gases	92	61	219	112	136	195
Nitrogen Oxides	1,222	403	2,473	1,089	271	344
Sulfur Oxides	272	11	579	95	256	95
Particulate Matter (PM-10)	100	54	233	105	137	178

a Baseline and analytical maximum emissions estimates were developed using fuel consumption estimates developed by Sierra Energy and Risk Assessment, Inc. for this report, source test data for NOx and U.S. EPA emissions factors for the other pollutants (U.S. Environmental Protection Agency, 1998).
b Existing emissions reflect an annual average of emissions over the 1994 to 1996 period.
c Proposed as project mitigation, SDG&E would request that SDAPCD modify its permits for the boilers at the Encina and South Bay plants to include aggregate NO_x emissions limits consistent with the limits that would otherwise have applied to SDG&E had SDG&E not divested the plants.
d The 2005 Cumulative emissions estimates reflect a mitigation measure (also proposed as project mitigation) that would modify the permits for the boilers at the Encina and South Bay power plants to require the exclusive use of natural gas (i.e., would prohibit use of fuel oil) except under conditions of force majeure natural gas curtailment. This restriction would become effective on January 1, 2001.

SOURCE: Environmental Science Associates

TABLE 4.5.12
SOUTH BAY POWER PLANT
CRITERIA AIR POLLUTANTS EMISSIONS ESTIMATES, 1999 AND 2005

	Estimated Emissions in Tons Per Year[a]					
Pollutant	**Existing[b]**	**1999 Baseline**	**1999 Analytical Maximum**	**1999 A-Max (with mitigation)[c]**	**2005 Cumulative A-Max (South Bay operational)[d] (Variant 1)**	**2005 Cumulative A-Max (South Bay retired)[d] (Variant 2)**
Carbon Monoxide	853	617	1,566	958	1,064	0
Reactive Organic Gases	88	64	166	99	111	0
Nitrogen Oxides	1,382	682	2,882	996	250	0
Sulfur Oxides	50	25	949	53	242	0
Particulate Matter (PM-10)	81	58	212	91	114	0

a Baseline and analytical maximum emissions estimates were developed using fuel consumption estimates developed by Sierra Energy and Risk Assessment, Inc. for this report, source test data for NOx and U.S. EPA emissions factors for the other pollutants (U.S. Environmental Protection Agency, 1998).
b Existing emissions reflect an annual average of emissions over the 1994 to 1996 period.
c Proposed as project mitigation, SDG&E would request that SDAPCD modify its permits for the boilers at the Encina and South Bay plants to include aggregate NO_x emissions limits consistent with the limits that would otherwise have applied to SDG&E had SDG&E not divested the plants.
d The 2005 Cumulative emissions estimates reflect a mitigation measure (also proposed as project mitigation) that would modify the permits for the boilers at the Encina and South Bay power plants to require the exclusive use of natural gas (i.e., would prohibit use of fuel oil) except under conditions of force majeure natural gas curtailment. This restriction would become effective on January 1, 2001.

SOURCE: Environmental Science Associates

TABLE 4.5.13
COMBUSTION TURBINE SITES
CRITERIA AIR POLLUTANTS EMISSIONS ESTIMATES, 1999 AND 2005

	Estimated Emissions in Tons Per Year[a]				
Pollutant	**Existing[b]**	**1999 Baseline**	**1999 Analytical Maximum**	**2005 Cumulative A-Max (South Bay operational)**	**2005 Cumulative A-Max (South Bay retired)**
Division Street CT:					
Carbon Monoxide	0.1	< 0.05	< 0.05	< 0.05	< 0.05
Reactive Organic Gases	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05
Nitrogen Oxides	0.4	< 0.05	< 0.05	0.1	< 0.05
Sulfur Oxides	1.2	< 0.05	< 0.05	0.3	0.1
Particulate Matter (PM-10)	< 0.05	< 0.05	< 0.05	< 0.05	< 0.05
El Cajon CT:					
Carbon Monoxide	< 0.05	< 0.05	< 0.05	0.3	0.2
Reactive Organic Gases	< 0.05	< 0.05	< 0.05	0.1	0.1
Nitrogen Oxides	0.2	0.3	0.6	6.0	4.3
Sulfur Oxides	0.1	< 0.05	< 0.05	0.1	0.1
Particulate Matter (PM-10)	< 0.05	< 0.05	< 0.05	0.3	0.2
Kearny CTs:					
Carbon Monoxide	0.4	0.1	0.3	2.7	1.9
Reactive Organic Gases	0.1	< 0.05	0.1	1.0	0.7
Nitrogen Oxides	5.6	2.5	5.3	56.2	38.6
Sulfur Oxides	1.6	< 0.05	0.1	0.8	0.6
Particulate Matter (PM-10)	0.3	0.1	0.3	2.6	1.9
Miramar Yard CTs:					
Carbon Monoxide	0.2	0.1	0.1	0.8	0.5
Reactive Organic Gases	0.1	< 0.05	< 0.05	0.3	0.2
Nitrogen Oxides	3.3	1.0	1.6	15.3	11.0
Sulfur Oxides	0.4	< 0.05	< 0.05	0.2	0.2
Particulate Matter (PM-10)	0.2	0.1	0.1	0.7	0.5

TABLE 4.5.13 (Continued)
COMBUSTION TURBINE SITES
CRITERIA AIR POLLUTANTS EMISSIONS ESTIMATES, 1999 AND 2005

Pollutant	Existing[b]	1999 Baseline	1999 Analytical Maximum	2005 Cumulative A-Max (South Bay operational)	2005 Cumulative A-Max (South Bay retired)
Naval Station CT:					
Carbon Monoxide	0.2	< 0.05	< 0.05	0.5	0.3
Reactive Organic Gases	< 0.05	< 0.05	< 0.05	0.2	0.1
Nitrogen Oxides	2.2	0.7	0.9	9.4	6.6
Sulfur Oxides	0.7	< 0.05	< 0.05	0.1	0.1
Particulate Matter (PM-10)	0.1	< 0.05	< 0.05	0.5	0.3
Naval Training Center CT:					
Carbon Monoxide	< 0.05	< 0.05	< 0.05	0.3	0.2
Reactive Organic Gases	< 0.05	< 0.05	< 0.05	0.1	0.1
Nitrogen Oxides	0.4	0.3	0.6	5.9	4.4
Sulfur Oxides	0.1	< 0.05	< 0.05	0.1	0.1
Particulate Matter (PM-10)	< 0.05	< 0.05	< 0.05	0.3	0.2
North Island CTs:					
Carbon Monoxide	0.3	< 0.05	0.1	0.3	0.2
Reactive Organic Gases	< 0.05	< 0.05	< 0.05	0.1	0.1
Nitrogen Oxides	1.5	0.3	0.5	4.0	2.9
Sulfur Oxides	2.1	0.2	0.3	0.4	0.1
Particulate Matter (PM-10)	0.1	< 0.05	< 0.05	0.2	0.2
Total:					
Carbon Monoxide	1.3	0.3	0.5	4.8	3.4
Reactive Organic Gases	0.3	0.1	0.2	1.7	1.2
Nitrogen Oxides	13.7	5.1	9.6	94.8	67.9
Sulfur Oxides	6.2	0.3	0.4	2.0	1.2
Particulate Matter (PM-10)	0.7	0.3	0.5	4.6	3.3

a Baseline and analytical maximum emissions estimates were developed using fuel consumption estimates developed by Sierra Energy and Risk Assessment, Inc. for this report, source test data for NOx and U.S. EPA emissions factors for the other pollutants (U.S. Environmental Protection Agency, 1998).
b Existing emissions reflect an annual average of emissions over the 1994 to 1996 period.
Source: Environmental Science Associates

For the estimates of other criteria air pollutant emissions, factors were developed using the latest U.S. EPA guidance (U.S. Environmental Protection Agency, 1998). These emissions factors are provided below in pounds of pollutant per million Btu of fuel input. For natural gas combustion by the boilers, the emissions factors are 0.0824 (carbon monoxide), 0.0085 (ROG), 0.0006 (sulfur oxides), and 0.0075 (PM-10). For fuel oil combustion by the boilers, the corresponding factors are 0.0333 (carbon monoxide), 0.0051 (ROG), 0.3663 (sulfur oxides), and 0.0300 (PM-10), based on a fuel oil sulfur content of 0.35 percent.

For natural gas combustion by the combustion turbines, the emissions factors in pounds of pollutant per million Btu are 0.0075 (carbon monoxide), 0.0027 (ROG), 0.0023 (sulfur oxides), and 0.0073 (PM-10). For distillate fuel combustion by the combustion turbines, the corresponding factors are 0.0791 (carbon monoxide), 0.0037 (ROG), 0.6619 (sulfur oxides), and 0.0115 (PM-10).

Table 4.5.14 combines the annual emissions projections shown in Tables 4.5.11 (Encina), 4.5.12 (South Bay), and 4.5.13 (combustion turbine sites) with estimates for a possible new power plant in Otay Mesa (under 2005 Cumulative Variant 2). Table 4.5.14 then shows the difference between emissions estimates under the 1999 Baseline case and the A-Max case, which is the maximum project effect in 1999. The maximum cumulative effects in 2005 is shown as the difference in annual emissions under the 2005 A-Max cases and the 1999 Baseline case.

Year 1999/Project Analytical Maximum

As shown in Table 4.5.14, power plant emissions under a new owner or owners could substantially exceed those that would be expected if SDG&E were to continue to own the plants in 1999. As a general matter, these emissions increases would not be considered significant because they would be allowed under SDAPCD permits to operate. However, the *1998 Regional Air Quality Strategy* (1998 Update) assumes that power plant emissions of NO_x would be no greater than the aggregate emissions limits allowed under SDAPCD Rule 69 (i.e., 2,100 tons per year in 1999).

In contrast, Table 4.5.14 indicates that power plant NO_x emissions under the 1999 A-Max case would be 5,364 tons per year, or 3,264 tons more than that assumed by the 1998 Update. Given the extent to which 1999 A-Max NO_x emissions estimates would exceed the assumptions in the 1998 Update, the project would be inconsistent with that plan; and as such, would have a significant effect. This effect would be temporary in that the boiler-specific standards would be in place by 2001 and these boiler-specific standards would reduce NO_x emissions from the power plants to levels more consistent with those assumed in the plan. In response to this significant effect, SDG&E has agreed to a mitigation measure whereby SDG&E would request that SDAPCD modify their permits to operate to reflect aggregate annual NO_x emissions limits of 1,100 tons per year for the boilers at Encina and 1,000 tons per year for the boilers at South Bay for a maximum total of 2,100 tons per year for the two plants. These emissions limits would apply during years 1999 and 2000.

TABLE 4.5.14
SAN DIEGO AIR BASIN POWER PLANT EMISSIONS SUMMARY, 1999 AND 2005

	Estimated Emissions in Tons Per Year[a]									
		Year 1999					Year 2005 Cumulative[c]			
Pollutant	**Existing[b]**	**Baseline**	**Analytical Maximum**	**A-Max with Mitigation**	**Difference between A-Max and 1999 Baseline**	**Difference between A-Max with Mitigation & 1999 Baseline**	**A-Max with South Bay (Variant 1)**	**A-Max with No South Bay (Variant 2)**	**Difference between 2005 A-Max with South Bay and 1999 Baseline (Variant 1)**	**Difference between 2005 A-Max without South Bay and 1999 Baseline (Variant 2)**
Carbon Monoxide	1,738	1,206	3,666	2,044	2,461	838	2,377	2,224	1,171	1,018
Reactive Organic Gases	181	125	385	211	261	87	249	369	124	245
Nitrogen Oxides	2,617	1,091	5,364	2,087	4,273	996	611	987	-480	-105
Sulfur Oxides	328	36	1,529	149	1,492	112	500	124	464	88
Particulate (PM-10)	182	112	445	196	333	84	256	387	144	275

a With the exception of the existing case and the 1999 A-Max case with mitigation, all other emissions estimates are based on fuel consumption estimates developed by Sierra Energy and Risk Assessment, Inc. for this report. NOx emissions estimates reflect source test data and the other criteria pollutant emissions estimates reflect the most recent emissions factors published by U.S. EPA (U.S. Environmental Protection Agency, 1998).

b Existing emissions reflect an average of emissions over the 1994 to 1996

c The Year 2005 cumulative case (with no South Bay power plant) includes emissions from operation of a new power plant at Otay Mesa, which is assumed to include a 960-MW combined cycle unit and a 100-MW combustion turbine.

SOURCE: Environmental Science Associates

Table 4.5.14 shows emissions estimates developed for the mitigated case in 1999. These estimates were made by adjusting the estimates developed for the 1999 A-Max case to meet the power-plant-specific annual NO_x emissions limits described above. In developing the mitigated case emissions estimates, consumption of fuel oil was assumed to be substantially reduced relative to the 1999 A-Max case because fuel oil combustion generates more NO_x per megawatt-hour than natural gas, and a new owner or owners would likely minimize fuel oil use to generate the most electricity possible within the emissions limit. Specifically, the mitigated case assumes that the new owner or owners would use just that volume of fuel oil that is currently available at the plants and that is excess to the minimum amount (10-day burn) required to be maintained on-site. With the mitigation, the potential inconsistency would be avoided and the corresponding impact would be reduced to less-than-significant.

Year 2005/Cumulative Analytical Maximum

Tables 4.5.11 through 4.5.14 shows emissions estimates for two 2005 cumulative cases. Under 2005 Cumulative Variant 1, the South Bay Power Plant is assumed to remain operational and in 2005 Cumulative Variant 2, the South Bay Power Plant is assumed to be retired and replaced by a new power plant at Otay Mesa. Both 2005 cumulative cases reflect a high price for fuel oil, which approximates the effect of a different mitigation measure agreed to by SDG&E (see Mitigation Measure 4.5.b.1), namely, the prohibition on fuel oil use, except under circumstances of force majeure natural gas curtailment.

As shown in Table 4.5-14, NO_x emissions under 2005 Cumulative Variant 1 would be less than 650 tons per year, which is the amount expected from power plants in the 1998 Update. Under 2005 Cumulative Variant 2, in contrast, NO_x emissions would be approximately 988 tons per year in 2005. While Variant 2 would exceed the amount anticipated in the 1998 Update, the 2005 cumulative impact is not considered significant for the following reasons:

- Under Variant 2, the potential inconsistency with emissions forecasts for power plants in the 1998 Update would be approximately 338 tons per year (i.e., 988 minus 650 tons), which would be an order of magnitude less than that projected in 1999 (3,264 tons);

- Under Variant 2, the new power plant at Otay Mesa would emit 576 tons of NO_x in 2005, or approximately 60 percent, of the cumulative power plant total of 988 tons and this new power plant would be subject to Lowest Achievable Emission Rates or Best Available Control Technology as applicable under SDAPCD Rule 69(d)(2), which may be more restrictive, and achieve greater NO_x control, than was assumed for this Initial Study; and

- Given the triennial review process mandated by the California Clean Air Act, SDAPCD will have two opportunities to modify the Regional Air Quality Strategy with more stringent emissions controls for power plants or other emissions sources in the Air Basin, if necessary, to offset any control strategies (e.g., Rule 69) that do not provide the emissions reductions originally envisioned.

Local Issues

Maximum concentrations over averaging periods ranging from one hour to 24 hours would not be affected by the project since the power plants currently run at full capacity over such periods on occasion and would continue to do so in the future with or without the project resulting in the same local concentrations. However, annual-average concentrations may be affected since annual capacity factors may increase under a new owner or owners leading to increases in annual emissions and corresponding annual-average concentrations. To quantify this effect, maximum annual average concentrations of nitrogen dioxide, sulfur dioxide and PM-10/PM2.5 were estimated for the 1999 baseline, 1999 A-Max (with and without mitigation), 2005 Cumulative Variant 1 and 2005 Cumulative Variant 2 by adjusting the concentration estimates provided in the health risk assessments prepared for the Encina and South Bay Power Plants to reflect the annual emissions estimates prepared for this report.

The results are shown in Table 4.5.15. As shown in Table 4.5.15, the local power plant increment to the annual-average background concentrations would not result in violations of ambient standards under any of the future analytical scenarios. Therefore, the local impact would be less than significant.

Conclusion

Tables 4.5.11 through 4.5.14 show increases in emissions for certain pollutants relative to existing and baseline cases. Since these emissions increases would occur under APCD permits and would be consistent with all emissions limitations and standards, they are not considered to be significant unless they would result in any significant increase in local concentrations of criteria air pollutants (see above under local issues), a significant increase in health risks in the vicinities of the plants [see checklist item B) Exposure of Sensitive Receptors, below], or significant increases relative to emissions projections used in regional air quality plans, such as the *1998 Regional Air Quality Strategy* (1998 Update).

The above analysis indicates that 1999 A-Max power plant NO_x emissions would be substantially greater than the 2,100 tons per year envisioned in the 1998 Update. Thus, the emissions would be inconsistent with the regional air quality plan, and the effect would therefore be significant. With mitigation agreed to by SDG&E, however, this effect would be reduced to less-than-significant since, with the mitigation, power plant NO_x emissions in 1999 and 2000 would not exceed 2,100 tons per year. The impact on local concentrations of criteria air pollutants would be less-than-significant.

Mitigation Measures

4.5.a.1: If, prior to the sale of either the Encina or South Bay Power Plants, SDAPCD has not adopted revisions to District Rule 69 that would extend the aggregate NO_x emissions limit of 2,100 tons per day to the new owner or owners of the Encina and South Bay power plants though year 2000, then:

TABLE 4.5.15
MAXIMUM ANNUAL-AVERAGE CRITERIA AIR POLLUTANT CONCENTRATIONS IN VICINITY OF ENCINA AND SOUTH BAY POWER PLANTS, 1999 AND 2005

	Annual Average Concentration in micrograms per cubic meter							
				Power Plant Concentration Increment				
							Year 2005 Cumulative	
Pollutant	**State Standard**	**National Standard**	**Ambient Background**[a]	**1999 Baseline**	**1999 A-Max**	**1999 A-Max with Mitigation**	**A-Max with South Bay (Variant 1)**	**A-Max with No South Bay (Variant 2)**
Encina Power Plant:								
Nitrogen Dioxide	NA	100	38	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005
Sulfur Dioxide	NA	80	3	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005
PM-10	30	50	27.0	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005
PM-2.5	NA	15	ND	< 0.005	< 0.005	< 0.005	< 0.005	< 0.005
South Bay Power Plant:								
Nitrogen Dioxide	NA	100	38	0.80	3.36	1.16	0.29	0.0
Sulfur Dioxide	NA	80	3	0.03	1.1	0.06	0.27	0.0
PM-10	30	50	29.2	0.07	0.38	0.11	0.16	0.0
PM-2.5	NA	15	ND	0.07	0.38	0.11	0.16	0.0

a Ambient background concentrations represent the highest annual average concentrations (adjusted to micrograms per cubic meter) measured at the monitoring stations closest to the Encina and South Bay Power Plants over the past three years (see Tables 4.5.4 and 4.5.7).

NA = Not Applicable; ND = No Data.

SOURCE: Environmental Science Associates

To assure that NO_x emissions from the electrical generating steam boiler units as operated by a new owner or owners would not significantly exceed NO_x emissions that would have been generated by SDG&E during the two-year period in which a new owner or owners would achieve compliance with unit-specific NO_x standards, SDG&E will request that SDAPCD modify the permits to operate the electrical generating steam boiler units at the Encina and South Bay Power Plants to include the following provisions:

- **No person shall operate the Encina power plant unless such person has demonstrated that the aggregate annual emissions of nitrogen oxides (NO_x), from all electrical generating steam boiler units at the power plant are not greater than 1,100 tons per year in calendar years 1999 and 2000, except for adjustments to allowable aggregate NO_x emissions for force majeure natural gas curtailments as provided in Section (d)(4)(iv) of District Rule 69, and except as provided in Section (d)(5) of District Rule 69.**

- **No person shall operate the South Bay power plant unless such person has demonstrated that the aggregate annual emissions of nitrogen oxides (NO_x), from all electrical generating steam boiler units at the power plant are not greater than 1,000 tons per year in calendar years 1999 and 2000, except for adjustments to allowable aggregate NO_x emissions for force majeure natural gas curtailments as provided in Section (d)(4)(iv) of District Rule 69, and except as provided in Section (d)(5) of District Rule 69.**

The transfer of title for the Encina and South Bay Power Plants will not occur until the plants' permits to operate have been modified in the manner described above.

Monitoring Action:	SDG&E provides the CPUC mitigation monitor with a copy of either the revised District Rule 69 or the modified permits to operate.
Responsibility:	CPUC
Timing:	At least ten business days prior to the transfer of title.

Conclusion

With the above mitigation, the project will not result in significant air quality impacts.

b) EXPOSURE OF SENSITIVE RECEPTORS

The project would have the potential to increase local pollutant concentrations in the vicinity of the generating stations. While keeping within permit limits, a new operator, seeking to maximize revenue and profits from the plants to be divested, would have a tendency to increase operations above those expected if SDG&E were to retain the plants in the restructured electric industry.

The types and concentrations of hazardous air pollutants (HAPs) emitted during power plant operations are dependent on the plant's fuel mix and level of operation. Increased operations using natural gas could result in increased concentrations of benzene, toluene, and formaldehyde. Increased fuel oil use could result in increased concentrations of a larger number of hazardous air pollutants, including nickel and hexavalent chromium. Based on SDG&E's 1993 HRAs for Encina and South Bay power plants and three CT sites, health risks associated with the projected increase in fuel use show no significant increase in either cancer risk, noncarcinogenic chronic risk, or noncarcinogenic acute risk. The main contributors to the risk were hexavalent chromium and nickel, both of which are emitted only when burning fuel oil. The foreseeable scenarios of divestiture include increased use of the power plants but not substantial increases in the burning of fuel oil.

The new owner of each of the plants would need to comply with the requirements of the Air Toxics "Hot Spots" Information and Assessment Act. This would include the preparation of health risk assessments periodically to determine toxic effects of plant emissions. If in completing a health risk assessment a "significant health risk" were determined to exist, all exposed individuals must be notified of those risks identified.

Encina Power Plant

The predicted maximum health risk from emissions of carcinogenic substances under existing conditions was reported earlier in this section. The maximum reported risk under existing conditions (0.96 in a million) was primarily caused by vapor emissions from the gasoline dispensing facility and by methylene chloride and perchloroethylene emissions from painting and cleaning operations, with only small contributions by metals from the burning of fuel oil and benzene from the burning of natural gas. Health risks associated with non-combustion sources (gasoline dispensing and painting and cleaning operations) are assumed to remain the same under divestiture, since these maintenance activities are not expected to change. The risks from these activities under existing conditions are actually lower than those reported in the 1992 HRA, because of the change to reformulated gasoline with lower benzene content and because of the change to nontoxic paints and cleaners. Health risks from the plant under divestiture would therefore change only because of changes in fuel use at the boilers and the combustion turbine.

Since the same fuel types will be burned in 1999 and 2005, the risks from exposure to carcinogenic substances will change in proportion to the amount of annual fuel use changes in future years. Both the 1999 A-Max and 2005 Cumulative A-Max show the potential for the plant to increase operations. Those levels are quantified in Chapter 3 and Appendix D of this Initial Study. The fuel usage rates and corresponding emissions are scaled in relation to the 1993 HRA emission rates to determine net changes in health risks (IWG Corp., 1992). Table 4.5.16 summarizes the estimated health risks for the two fossil-fueled plants under existing, 1999 Baseline, 1999 A-Max, 1999 A-Max (with mitigation proposed as part of the project), and both Variant 1 and Variant 2 2005 Cumulative A-Max conditions. Under the 1999 Baseline conditions, the estimated maximum carcinogenic risk would remain at 0.96 in a million, because the major risks from non combustion sources will not change and emissions from the boilers and the combustion turbine are extremely small contributors to the total maximum risk. Under divestiture, assuming that the plant operates at its analytical maximum capacity, annual fuel use is expected to increase, thus increasing emissions of carcinogenic substances. However, the estimated cancer risk from additional fuel usage under the 1999 A-Max scenario with low priced secondary fuel oil is expected to increase by only 0.001 in a million over the 1999 Baseline case. This represents less than 1 percent of the total cancer risk. The total cancer risk in 1999 A-Max is therefore estimated to be 0.96 in a million. Gasoline and solvent vapor emissions remain the major contributors to the maximum risk. Since the total estimated cancer risk is well below the

TABLE 4.5.16
SUMMARY OF HEALTH RISKS FOR SDG&E POWER PLANTS

Plant	Existing Conditions[a] Cancer Risks[d] (in a million)	Existing Conditions[a] Hazard Index[c] Chronic	Existing Conditions[a] Hazard Index[c] Acute[e]	1999 Baseline (low priced oil)[b] Cancer Risks (in a million)	1999 Baseline (low priced oil)[b] Hazard Index[c] Chronic	1999 Baseline (low priced oil)[b] Hazard Index[c] Acute[e]	1999 A-Max (low priced oil)[b] Cancer Risks[d] (in a million)	1999 A-Max (low priced oil)[b] Hazard Index[c] chronic	1999 A-Max (low priced oil)[b] Hazard Index[c] acute[e]	1999 (Mitigated)[b] Cancer Risks[d] (in a million)	1999 (Mitigated)[b] Hazard Index[c] chronic	1999 (Mitigated)[b] Hazard Index[c] Acute[e]
Encina	0.96	0.003	0.10	0.96	0.003	0.10	0.96	0.003	0.10	0.96	0.003	0.10
Incremental Increase[f]	NA	NA	NA	NC	NC	NC	0.001	3.95E-5	NA	0.0003	9.54E-6	NA
South Bay	0.72	0.002	0.20	0.65	0.001	0.20	1.40	0.021	0.20	0.74	0.002	0.20
Incremental Increase[f]	NA	NA	NA	NC	NC	NC	0.76	0.020	NA	0.10	0.001	NA

Plant	2005 Cumulative A-Max Variant 1 (South Bay operational)[b] Cancer Risks[d] (in a million)	Variant 1 Hazard Index[c] Chronic	Variant 1 Hazard Index[c] Acute[e]	Variant 2 (South Bay Retired)[b] Cancer Risks (in a million)	Variant 2 Hazard Index[c] Chronic	Variant 2 Hazard Index[c] Acute[e]
Encina	0.96	0.003	0.10	0.96	0.003	0.10
Incremental Increase[f]	0.0004	1.8E-5	NA	0.0001	2.2E-5	NA
South Bay	0.88	0.006	0.20	NA	NA	NA
Incremental Increase[f]	0.23	0.005	NA	NA	NA	NA

a Cancer risks and Hazard Indices are based on the results reported in San Diego Gas and Electric Company Air Toxics Hot Spots Risk Assessments (1993), adjusted to current emissions (1996).
b Risks are adjusted to projected 1999 and 2005 emissions.
c Hazard index is the ratio of the maximum exposure level and the reference dose of each toxic substance. The reference dose is the level with no observed health effect. A hazard index less than 1.0 indicates no health effect.
d The significance threshold for incremental cancer risk is 10 in a million.
e The acute hazard risk index is not expected to change since it is based on a one-hour maximum.
f The incremental increase is the difference between the 1999 Baseline and the scenario.

SOURCE: Environmental Science Associates

significance threshold of 10 in a million, the health risk from exposure to carcinogenic substances under divestiture would be less than significant.

The predicted maximum hazard index for chronic exposure to non-carcinogens is estimated to be approximately 0.003, and the estimated acute hazard index would remain the same as for the 1999 Baseline case (less than 0.1). The incremental increase from additional fuel usage under the 1999 A-Max scenario is estimated to be extremely small (3.95E-5). For chronic and acute exposure to non-carcinogens, the hazard indices would therefore remain well below the significance threshold of 1.0 and would be less than significant.

South Bay Power Plant

Under the 1999 Baseline conditions, emissions of carcinogenic substances are expected to decrease slightly from existing conditions, and the estimated maximum risk would be 0.65 in a million. Under divestiture, assuming that the plant operates at its analytical maximum capacity, annual fuel use is expected to increase, thus increasing emissions of carcinogenic substances slightly. The estimated risk from additional fuel usage under the 1999 A-Max scenario with low priced secondary fuel oil is expected to increase by 0.76 in a million over 1999 baseline conditions. The total risk in 1999 A-Max is therefore estimated to be 1.40 in a million with contributions from fuel combustion representing 66% of the total cancer risk. The purpose of the 1999 Mitigated scenario is to limit NO_x emissions below 2,100 tons per year per SDAPCD's Rule 69 by reducing the annual fuel usage rate. This decrease in fuel usage also reduces the cancer risk to 0.74 in a million with contributions from fuel combustion representing 35 percent of the total cancer risk. Since the total estimated risk is below the significance threshold of 10 in a million, the health risk from exposure to carcinogenic substances under divestiture would be less than significant.

The predicted 1999 Analytical Maximum hazard index for chronic exposure to non-carcinogens is estimated to be approximately 0.021, and the estimated acute hazard index would remain the same as for the 1999 Baseline (less than 0.2 in a million). The incremental increase from additional fuel usage under the 1999 A-Max scenario for chronic exposure is 0.020. For chronic and acute exposure to non-carcinogens, the hazard indices would therefore remain well below the significance threshold of 1.0 and would be less than significant.

Combustion Turbine Sites

As discussed in the Local Setting, 1992 HRA estimated health risks for three CT sites were based on operating rates that far exceeded current operating rates. Current emissions and health risks were estimated to be approximately 3% of the reported values in the 1992 HRAs. Since health risk assessments were not available for all of the combustion turbine sites, a worst case analysis was used for the Kearny Site. This site was selected because it has the largest increase in fuel use relative to the 1999 baseline case. Health risks reported for the Naval Training Center site were scaled to the Kearny site based on emission changes at Kearny. This methodology is appropriate since the health risks were estimated by using a conservative screening model which does not use site specific meteorological conditions and also since no air pollution-sensitive receptors are within one-half mile of the Kearny site. Cancer risks for the combustion turbine sites will not change significantly and are well below the significance threshold of 10 in a million. Chronic and acute hazard indices remain well below the significance threshold of 1.0. Health risks from CT sites under 1999 analytical maximum and both 2005 cumulative conditions are expected to be below health risks reported in SDG&E's 1992 HRAs and are less than significant.

Year 2005/Cumulative Analytical Maximum

Under Variant 1, 2005 cumulative conditions would include both Encina and South Bay power plants. Under Variant 2, South Bay power plant would be retired and a new power plant would be operated in Otay Mesa. Table 4.5.16 shows that the cancer risks for the Encina plant under both conditions will not change significantly compared to 1999 Baseline conditions. The cancer risk at the Encina Plant is estimated to remain the same as the 1999 Baseline (0.96 in a million). The cancer risk decreases slightly from the 1999 Baseline to 0.88 in a million for South Bay under Variant 1 and is not considered under Variant 2 since the plant would be retired. Determination of health risks associated with the new plant are not within the scope of this project. However, before the new power plant could be constructed SDAPCD would require the owner to conduct a health risk assessment to demonstrate that health risks would be below significance thresholds. Maximum risks at both plants being divested remain well below the significance threshold of 10 in a million under both 2005 cumulative conditions.

Table 4.5.16 shows that, under both 2005 A-Max scenarios, the chronic and acute hazard indices remain well below the significance threshold of 1.0 at each of the plants being divested. These impacts would remain less than significant.

Mitigation Measure 4.5.a.1 (described earlier in this Air Quality section) would limit aggregate annual emissions of nitrogen oxides (NO_x) from all electrical generating steam boiler units at the power plants in calendar years 1999 and 2000 and would likewise limit the amount of fuel oil burned since combustion of fuel oil produces higher NO_x emissions than natural gas. As discussed earlier, increased fuel oil use could result in increased concentrations of a larger number of hazardous air pollutants, including nickel and hexavalent chromium.

After calendar year 2000, under new ownership, an aggregate annual emissions limit for NO_x would no longer apply and instead boiler-specific NO_x emissions standards of 0.15 pound per megawatt-hour when burning natural gas and 0.40 pound per megawatt-hour when burning fuel oil, averaged over each calendar day would apply. Without an additional mitigation measure that would only allow fuel oil use during a force majeure natural gas curtailment there remains a possibility under a future low-cost fuel oil condition that new owners could burn large amounts of fuel oil. Although it would not be expected that these levels would reach health risk significance thresholds, mitigation measures can limit this type of activity. The following mitigation measure is recommended.

Mitigation Measures

4.5.b.1: If, prior to the sale of either the Encina or South Bay Power Plants, SDAPCD has not adopted revisions to District Rule 69 that would broaden the current restriction on fuel oil firing, then:

To assure that health risks associated with emissions from the electrical generating steam boiler units as operated by a new owner or owners would not significantly exceed the risks from those units as operated by SDG&E, SDG&E will request that SDAPCD modify the permits to operate the electrical generating steam boiler units at the Encina and South Bay Power Plants to include the following provisions:

- **A person shall not fire an electric power generating steam boiler at the Encina power plant with non-gaseous fuel after January 1, 2001, unless gaseous fuel is not available because of a force majeure natural gas curtailment as defined in Section (c)(8) of District Rule 69.**
- **A person shall not fire an electric power generating steam boiler at the South Bay power plant with non-gaseous fuel after January 1, 2001, unless gaseous fuel is not available because of a force majeure natural gas curtailment as defined in Section (c)(8) of District Rule 69.**

The transfer of title for the Encina and South Bay Power Plants will not occur until the plants' permits to operate have been modified in the manner described above.

Monitoring Action:	SDG&E provides the CPUC mitigation monitor with a copy of the modified permits to operate.
Responsibility:	CPUC
Timing:	At least ten business days prior to the transfer of title.

Conclusion

Any fuel oil burning under force majeure conditions would be expected to occur regardless of the entity that owns and operates the plant and therefore the project would not result in substantial additional exposure of sensitive receptors to hazardous air pollutants; therefore, the impact would be less than significant.

c) CHANGE IN CLIMATE

The project would not significantly alter air movement, moisture, temperature, or cause any change in climate at any of the power plants to be divested and their vicinity. Typically, changes in these climatological factors are associated with development projects that involve the construction of very large structures that can affect surface wind conditions or large reservoirs that can affect local relative humidity and temperature. The project by itself would not result in the types of development that would significantly affect regional air movement, moisture, temperature, or climate. The transfer of ownership may require some new construction, which would likely be limited to activities necessary to separate the divested generating units from on-site transmission and distribution equipment, ownership of which would be retained by SDG&E.

Conclusion

The project will not impact air movement, moisture, temperature, or cause any change in climate.

d) ODORS

The perception of odor is a physio-psychological response to the inhalation of an odoriferous chemical substance. Unpleasant odors may affect our sense of well-being. Responses to a variety of malodors can include nausea, vomiting, headaches, coughing, sneezing, induction of shallow breathing, disturbed sleep, appetite disturbance, sensory irritation, annoyance, and depression. Effects may be physiological, psychological, or both. The severity of odor impacts hinges on a number of factors, including: the nature, frequency and intensity of the source; wind speed and direction; and the sensitivity and proximity of nearby sensitive receptors to the odor source.

Based on a review of the Notices of Violation issued to SDG&E, odor has not been an environmental concern in the vicinities of the power plants or combustion turbine sites. Any potential for odor complaints would most likely stem from combustion of fuel oil (by the boilers) or distillate (by the combustion turbines), rather than from combustion of natural gas, because sulfur compounds, commonly associated with odor, are emitted to a much greater extent with combustion of the former types of fuels compared to combustion of natural gas.

Thus, while it is a foreseeable scenario that divestiture would result in a tendency for increased operations, the increased fuel combustion would be primarily from natural gas, which generates negligible odors. Furthermore, SDG&E proposes to request that SDAPCD modify their permits to operate to prohibit use of fuel oil for the boilers beginning in 2001. Permit conditions, as modified, would then be passed on to the new owner or owners (see Mitigation Measure 4.5.b.1, above).

Conclusion

Even without the mitigation agreed to by SDG&E, the potential for odor impacts would be less than significant. However, considering that SDG&E would agree to a mitigation measure restricting use of fuel oil beginning in 2001, the possibility of a significant odor impact in the vicinities of the power plants and combustion turbine sites would be even more unlikely.

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