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APPENDIX [in Volume II]

Appendix G Air Quality Data and Modeling Protocol

8.1 AIR QUALITY

This analysis of the potential air quality impacts of the Colusa Generating Station (CGS) project was conducted according to CEC power plant siting requirements. It also addresses U.S. Environmental Protection Agency (U.S. EPA) Prevention of Significant Deterioration (PSD) requirements and Colusa County Air Pollution Control District (CCAPCD) permitting requirements for Determination of Compliance/Authority to Construct (DOC/ATC). The analysis is reported as follows:

- Section 8.1.1 describes the local environment surrounding the CGS. Meteorological data, including wind speed and direction (i.e., windroses), temperature, relative humidity, and precipitation are discussed, and ambient concentrations for the appropriate criteria pollutants are summarized.

- Section 8.1.2 evaluates the project's air quality impacts from emissions of nitrogen oxides (NO_X), carbon monoxide (CO), sulfur dioxide (SO_2), precursor organic compound (POC), particulate matter less than 10 micrometers in diameter (PM_{10}), and particulate matter less than 2.5 micrometers in diameter ($PM_{2.5}$). Emission estimates are presented for these pollutants for project construction and operation over a range of operating modes, including startup and shutdown. The modeling analysis conducted for nitrogen dioxide (NO_2), CO, SO_2, and PM_{10} is presented; the results show no exceedances of the California and federal Ambient Air Quality Standards (AAQS) or to any applicable PSD increments from the proposed project. Also, air quality–related values (AQRVs) are evaluated; no negative impact to visibility, terrestrial, or aquatic resources is predicted.

- Section 8.1.3 presents the results of cumulative impacts analysis (including off-project sources that have been permitted but historically have operated at less than their full potential to emit air pollutants, or are in the process of being permitted, and are not yet operational).

- Section 8.1.4 describes the proposed project's emission offsets.

- Section 8.1.5 describes all applicable laws, ordinances, regulations, and standards. Section 8.1.5 also provides an analysis of best available control technology (BACT) for gas-fired turbines, and explains how the use of Dry Low NO_X combustors and selective catalytic reduction (SCR) with ammonia injection will meet NO_X BACT requirements, and how the use of an oxidation catalyst meets the CO BACT requirements. Mitigation of fugitive dust during construction is also discussed.

- Section 8.1.6 lists the agency contacts used to conduct the air quality assessment.

- Section 8.1.7 lists the permits required and provides a permit schedule.

- Section 8.1.8 lists the references used to conduct the air quality assessment.

Some air quality data are presented in other sections of this AFC, including an evaluation of toxic air pollutants (see Section 8.6, Public Health) and information related to the fuel characteristics, heat rate, and expected capacity factor of the proposed facility (see Chapter 3, Facility Description and Location).

8.1.1 Affected Environment

This section describes the regional climate and meteorological conditions that influence transport and dispersion of air pollutants and the existing air quality within the project region. The data presented in this section are representative of the CGS site.

CGS is proposed to be located about 4 miles west of I-5 in Colusa County, California on a 100-acre site, as shown on Figures 8.1-1A and 8.1-1B. The power plant and switchyard will occupy approximately 27.2 acres within the 100-acre project site. The site is currently undeveloped agricultural land used for grazing cattle. The site topography is rolling hills from 170 to 190 feet above mean sea level. Figures 8.1-1A and 8.1-1B also show the topography within a 10-mile radius of the CGS site. The Cortina Rancheria of Wintun Indians of California is located about 25 miles south of the site. This is well beyond the range of any significant air quality impacts from the proposed project.

8.1.1.1 Climatology

Colusa County is part of the Sacramento Valley Air Basin, which is surrounded by the Coastal Mountain Range to the west, the Sierra Nevada to the east, the Cascade Range to the north, and the San Joaquin Valley Air Basin to the south. The Sacramento Valley has a moderate Mediterranean climate, which is characterized by hot, dry summers and cool, rainy winters. The annual average rainfall is approximately 16 inches. The majority of rain falls between October and April. During the winter, the North Pacific storm track intermittently dominates the valley weather, with periods of dense and persistent low-level fog often occurring between storms. The frequency and persistence of the heavy fog in the valley diminishes with the approach of spring, when the days lengthen and the intensity of the sun increases.

During the summer, the Pacific storm track is usually north of the Sacramento Valley, the afternoon temperatures are warm to hot, while nights are usually mild due to cool marine air intrusion from the San Francisco Bay Area. Long-term average temperature and precipitation data have been collected at the Colusa 2 SSW Station, the surface meteorological station nearest to the project site, and are presented in Table 8.1-1. The data indicate that July is usually the warmest month of the year, with a normal daily maximum temperature of 95°F, and a normal daily minimum of 77.1°F. In the fall and spring, the afternoon temperatures are mild, in the 60s and 70s, while nights are cooler, in the 40s and 50s. In the winter, temperatures are cool in the afternoon and crisp at night. The coldest month is usually January, with a normal daily maximum of 54°F and a normal daily minimum of 37°F.

The annual and seasonal wind roses are presented in Figures A-1 through A-5 of the Colusa Modeling Protocol, which is included in Appendix G. The windroses show that on an annual basis the predominant winds for the project site are from the southeast and east-southeast directions. The spring and fall quarters follow the annual pattern. The winter quarter is dominated by north winds, while the summer quarter sees large southeast and east-southeast components.

Atmospheric stability and mixing heights are important parameters in the determination of pollutant dispersion. Atmospheric stability reflects the amount of atmospheric turbulence and mixing. In general, the less stable an atmosphere, the greater the turbulence, resulting in more mixing and better dispersion. The mixing height, measured from the ground upward, is the height of the atmospheric layer in which convection and mechanical turbulence promote mixing. Good ventilation results from a high mixing height and at least moderate wind speeds within the mixing layer. Although marine air generally flows into the basin from the San Joaquin River Delta, the region's topographic features restrict air movement through and out of the basin. The Coastal Range hinders wind access into the air basin from the west, and the high Sierra Nevada range is a significant barrier to the east. These topographic features result in weak air flow that becomes blocked vertically by high barometric pressure.

8.1.1.2 Existing Air Quality

Ambient air quality standards have been set by both the federal government and the State of California to protect public health and welfare with an adequate margin of safety. Pollutants for which National Ambient Air Quality Standards (NAAQS) or California Ambient Air Quality Standards (CAAQS) have been set are often referred to as "criteria" air pollutants. The term is derived from the comprehensive health and damage effects review that culminates in pollutant-specific air quality criteria documents,

which precede NAAQS and CAAQS standard setting. These standards are reviewed on a legally prescribed frequency and revised as new health and welfare effects data warrant.

Each NAAQS or CAAQS is based on a specific averaging time over which the concentration is measured. Different averaging times are based upon protection of short-term, high-dosage effects or longer-term, low dosage effects. NAAQS may be exceeded no more than once per year. CAAQS are not to be exceeded.

A protocol was submitted to air regulatory agencies with jurisdiction over this project that included the list of locations of available California Air Resources Board (CARB) ambient air quality monitoring stations (URS, 2006). The ambient air quality in Colusa County is represented by data monitored at three permanent air monitoring stations. The monitoring station within the county closest to the proposed project site is the Colusa-Sunrise Boulevard Station, within 20 miles from the project site. However, this station only measures ozone, PM_{10} and $PM_{2.5}$ and does not measure all criteria pollutant concentrations, and data from other stations are necessary. Monitoring stations at Yuba City–Almond Street Station (in Sutter County, 38 miles), and Sacramento–Del Paso Manor (in Sacramento County, 60 to 70 miles) are also located near the project site. Gaseous pollutants monitored at these two stations include ozone, CO, NO_2, SO_2, PM_{10}, and $PM_{2.5}$. Air quality measurements taken at these stations are presented in Tables 8.1-2 through 8.1-7. For the air quality impact analysis, the maximum background concentration from the past 3 years from all monitoring stations was used.

The monitoring data indicate that the air is in compliance with all federal NAAQS and California AAQS for NO_2, CO, and SO_2 for all averaging periods.

Table 8.1-2 shows that the federal 8-hour ozone AAQS of 0.08 parts per million (ppm) has not been exceeded in the past 4 years at the Colusa Station and that the federal 1-hour ozone AAQS of 0.12 ppm (a standard revoked by the U.S. EPA on June 15, 2005) has not been exceeded in the last 10 years at the Colusa Station. The more stringent 1-hour California AAQS of 0.09 ppm has not been exceeded in the past 4 years at the Colusa Station. The federal standard requires maintaining 0.08 ppm as a 3-year average of the fourth-highest daily maximum value. Therefore, the number of days that the maximum concentration exceeds the standard concentration is not the number of violations of the standard for the year.

The PM_{10} data in Table 8.1-3 show that the 24-hour average California AAQS of 50 micrograms per cubic meter ($\mu g/m^3$) is frequently exceeded in the Colusa area. The federal 24-hour average PM_{10} AAQS of 150 $\mu g/m^3$ was exceeded in 1999. The single 1999 occurrence is the only time within the past 10 years that the federal 24-hour PM_{10} AAQS has been exceeded. The maximum 24-hour PM_{10} background concentration of 171 $\mu g/m^3$ was measured at the Colusa-Sunrise Air Monitoring Station on October 15, 1999. On this day, unusually strong north winds combined with inversion capping of the valley, which resulted in a severe dust storm. The second highest 24-hour PM_{10} concentration measured at the Colusa-Sunrise Monitoring Station in 1999 is 89 $\mu g/m^3$; this occurred the week following a dust storm (on October 21).

The annual PM_{10} data are also presented in Table 8.1-3. The annual geometric mean is also called the state annual average and is a geometric mean of all measurements. The annual arithmetic mean is also called the national annual average and is an arithmetic average of the four arithmetic quarterly averages (the federal PM_{10} standard was revoked on September 22, 2006). Most of the annual geometric concentrations are above the California PM_{10} ambient air quality standard of 20 $\mu g/m^3$.

The annual and 24-hour $PM_{2.5}$ data are presented in Table 8.1-4. $PM_{2.5}$ data have a relatively short collection history. The 3-Year Average, 98th Percentile is below the federal AAQS of 35 $\mu g/m^3$. The 3-Year Average, Arithmetic Mean is below the California AAQS of 12 $\mu g/m^3$.

The data in Table 8.1-5, Table 8.1-6, and Table 8.1-7 show that the measured concentrations of CO, NO_2, and SO_2, respectively, are all below the applicable federal and California standards.

8.1.2 Environmental Consequences

This section describes the analyses conducted to assess the potential air quality impacts from the proposed project. Impacts from the proposed project are considered significant if, when combined with background ambient levels, they would exceed an ambient air quality standard, or if by themselves, they would exceed an applicable PSD significant impact amount. These amounts are discussed later in Section 8.1.5. Emissions estimates for both construction and operation of the proposed project are presented. Dispersion model selection and setup are also described (i.e., emissions scenarios and release parameters, building wake effects, meteorological data, and receptor locations) and analysis results are presented.

8.1.2.1 Construction Emissions

The primary emission sources during construction include heavy equipment emissions and fugitive dust from disturbed areas due to grading, excavating, and construction at the site. A particulate matter emission factor of 0.11 ton of PM_{10} per acre per month was used to estimate fugitive dust emissions (MRI, 1996). The construction schedule calls for the following approximate amounts of acreage to be disturbed during various construction phases (these are not cumulative acreages):

- Months 1-2: 73.7 acres;
- Month 3-5: 35.9 acres;
- Months 6-20: 38 acres; and
- Months 21-24: 2.55 acres.

Based on this construction schedule, the worst-case monthly emissions associated with fugitive dust would occur during the first and second months of construction when 73.7 acres of land are estimated as disturbed. This would result in uncontrolled emissions of approximately 8.11 tons of PM_{10} per month. Assuming 90 percent control efficiency from a fugitive dust suppression program to mitigate construction-related emissions (see Section 8.1.5.10.2 for details on fugitive dust control measures), the controlled worst-case construction dust emissions are estimated to be 0.81 ton/month. The worst-case annual average fugitive dust emissions are estimated to be approximately 5.7 tons/year, based on the average disturbed land acreage listed above for months 1 through 12 and assuming the same fugitive dust emission factor and control efficiency. The worst-case 24-hour average fugitive dust emissions are estimated to be approximately 74 lbs/day, and the worst-case 1-hour average is estimated to be 7.4 lbs/hr.

This project also has another feature that will generate fugitive dust. Fugitive dust will also be generated from earth moving activities required to level the site. There are going to be 337,000 cubic yards (cy) of earth moved at the site during the first 3 months of construction. The analysis was conducted to addresses this activity, considering that the earth is going to be first removed and pushed by backhoes and bulldozers, then loaded into dump trucks by excavator loaders, transported, and finally unloaded.

The fugitive dust sources considered for this activity are the following: dirt pushing and bulldozing, loading of trucks, transportation of earth on unpaved roads, and unloading of trucks. Table 8.1-8 includes required earth-moving equipment, which consists of three dozer tractor crawlers in each of the first 3 months and six dump trucks in month 1 and three dump trucks in months 2 and 3 to accomplish the earthmoving.

The AP-42 calculation methods were used to estimate the PM_{10} fugitive dust emissions. Table 8.1-9 presents the controlled PM_{10} emissions per month of construction and fugitive dust source for this activity. The detailed calculations are presented in Appendix G.

A second source of emissions during construction is equipment exhaust. Equipment-specific emissions factors were used to estimate emissions for all criteria pollutants from construction equipment (SCAQMD, 2005). Table 8.1-8 presents a list of equipment needed during construction and the estimated number of pieces of equipment that would operate during each month of construction. Emissions from equipment would occur over a 24-month construction period. The detailed calculations are presented in Appendix G.

The estimated worst-case hourly, monthly, and annual emissions are presented in Table 8.1-10. Construction emission calculations are provided in Appendix G. Worst-case monthly emissions estimates are based on an assumption that each piece of equipment would operate 50 hours per week (or 200 hours per month) during each month of scheduled activity. Worst-case hourly emissions were estimated by dividing worst-case monthly emissions by 200. Annual emissions were estimated by summing the monthly emissions for all equipment and determining the 12-month period having the highest emissions; emissions for this 12-month period (i.e., months 5 through 16 for NO_X emissions and months 2 through 13 for all other criteria pollutant emissions) were summed to get the annual emissions. Peak emissions of PM_{10} originating from the combination of general construction activities, earth-moving activities and construction vehicle exhaust are presented in Table 8.1-11. Table 8.1-11 presents the combined worst case from the three construction activities that emit PM_{10}.

Secondary emissions of criteria pollutants from the increase in vehicle trips caused by construction and operation are presented in Tables 8.1-12 and 8.1-13, respectively. Included are tailpipe emissions within a 10-mile radius of the site for vehicles carrying workers and for trucks making deliveries. Vehicle type-specific emissions factors were used to estimate emissions for all criteria pollutants from construction equipment (CARB, 2002). The detailed calculations are presented in Appendix G.

Traffic on McDermott Road would increase should the Teresa Creek Bridge detour option be selected (see discussion in Chapter 3). The approximately 1.5 mile portion of McDermott Road between Dirks Road and the Glenn County Line is unpaved gravel. The projected increase in vehicle traffic on the unpaved portion of McDermott Road could result in an increase of fugitive dust emissions while the detour is in effect. This impact will be mitigated through twice daily watering of the unpaved portion of McDermott Road during the entire duration of the detour should the detour option be selected.

8.1.2.2 Operational Emissions

Turbine Emissions. Operational emissions from the two turbines were estimated for all applicable scenarios using base emission rates and startup/shutdown emissions. The base criteria pollutant emission rates provided by the turbine vendor and the engineer for three load conditions (50 percent, 75 percent, and 100 percent) and three ambient temperatures (18ºF, 59ºF, and 114ºF) are presented in Table 8.1-14. Because startup and shutdown events typically had higher emission rates than operating conditions, they were incorporated into the short- and long-term emissions estimates for each turbine for modeling purposes. The expected emissions and duration of startup events are summarized in Table 8.1-15. These worst-case emission estimates are included in Appendix G.

The number of startups were estimated for each quarter. To calculate quarterly emissions, emissions from these startups were added to operational emissions, assuming 100 percent load and 59ºF for the specified number of hours per quarter and duct burner operation at 59°F for the specified number of hours. The analysis is conservative because no credit was taken for estimated downtime associated with each shutdown. Estimated annual emissions for the two turbines are presented in Table 8.1-16. Emissions and calculations for all scenarios are contained in Appendix G.

Worst-case short-term emissions from the turbines were calculated for use in the air quality modeling. For worst 1-hour emissions, the worst-case startup condition was used. Based on the startup information,

NO_X, CO, and VOC emissions during a cold startup is the worst-case condition. PM_{10} and SO_X emissions are maximized at peak fuel usage. The maximum amount of fuel is used when the turbines and duct burners are running 100 percent and the ambient temperature is 18°F.

The 3-hour SO_X emission rate was based on the scenario when the turbine and duct burners are running 100 percent and the ambient temperature is 18°F. The 8-hour CO emission rate was calculated assuming one full cold start, one shutdown and the balance (3.0 hours) operating at the worst-case operating condition (both turbines and duct burners are running 100 percent and the ambient temperature is 18°F).

The 24-hour NO_X, CO, and VOC emission rates were calculated assuming one cold start, one shutdown and the balance (19 hours) operating at the worst-case operating condition (turbine and duct burners are running 100 percent and the ambient temperature is 18°F). PM_{10} and SO_X worst-case 24-hour emission rates were calculated assuming the turbine and duct burners are running at 100 percent for 24 hours and the ambient temperature is 18°F for SO_X and 114°F for PM_{10}.

Estimates of worst-case short-term emissions are shown in Table 8.1-17.

Combustion Turbine Commissioning Emissions. The commissioning period as it relates to air quality is discussed in this section. Cold, pre-operational equipment checks will be required; however, these checks will not require the equipment to be running or emitting air pollutants. The Applicant proposes a commissioning period of approximately 6 months during which all installed equipment will be run and tested. The period will be divided into four phases:

1. Gas Turbine 1 (GT-1) Commissioning
2. Gas Turbine 2 (GT-2) Commissioning
3. Commissioning of both HRSGs and the steam turbine
4. Performance and Reliability Testing of the entire plant together

The gas turbine commissioning periods begin when the turbines first burn natural gas. The Applicant will make every effort to minimize emissions of CO, VOC, and NO_x during the commissioning period. However, not all of the equipment to abate these emissions will be fully operational at the start of the commissioning period. The Applicant requests a maximum of 500 hours of partially abated emissions for each gas turbine train.

Once it has been installed, the oxidation catalyst in each train will abate CO and VOC emissions from the gas turbine and the duct burners because it is essentially a passive device. While the SCR catalyst is in some cases able to be installed prior to initial startup of the combustion turbines, it may not be installed until later in the commissioning period, after completion of steam blows which could deposit debris and otherwise damage the catalyst. The SCR catalyst may not be installed at the same time as the oxidation catalyst. NO_x emissions from the gas turbines and the duct burners may be only partially abated during times that the gas turbine burners are being tuned and the SCR system is being tested. Regardless of the fact that the oxidation catalyst and SCR may not be installed until late in the commissioning process, the inherent low emissions of NO_x, CO, and VOC associated with the DLN combustors will ensure that the impacts of these emissions are minimized.

Commissioning emission estimates were very conservatively estimated as worst case by assuming that the control efficiency of the applicable abatement systems is essentially zero during significant portions of the commissioning phase. The emissions during the commissioning period are shown in Table 8.1-18. Peak emission rates of CO and NO_x will only occur from one gas turbine at a time. Where applicable, emission offsets will be the proposed mitigation of these emissions.

The continuous emissions monitoring system (CEMS) will also be undergoing commissioning at this time. Once the CEMS is commissioned, it will record emissions of NO_x and CO. Emissions of SO_2 and PM_{10} may be quantified by using emission factors based on fuel flow.

Auxiliary Boiler. Auxiliary boiler emissions are based on 2,400 hours of operation per year. Emissions are based on vendor supplied emission factors. NO_X emissions are based on 7 ppm. A summary of auxiliary boiler emissions is presented in Table 8.1-19. Emissions and calculations are included in Appendix G.

Emergency Generator Engine and Firewater Pump Engine. The project will include one 1,340 brake horsepower (BHP) diesel engine to power an electrical generator and one 160 BHP diesel engine to power a firewater pump. Emissions were estimated based on hourly emission rates provided by the manufacturers for NO_X, CO, PM_{10}, and VOC. Manufacturers' data sheets on U.S. EPA Tier 2 and CARB Certified candidate engines for these two applications are included in Appendix G. SO_2 emissions were estimated using ultra-low sulfur diesel fuel containing 15 ppm sulfur. Emissions estimates for these two diesel engines are shown in Table 8.1-20. Annual emissions from these engines included in Table 8.1-20 are based on a maximum non-emergency use rate of 50 hours of operation per year for each engine.

Combined Annual Emissions. Total combined annual emissions are shown in Table 8.1-21.

8.1.2.3 Air Dispersion Modeling

The purpose of the air dispersion modeling analysis is to demonstrate that air emissions from the CGS will not cause or contribute to exceeding any state or federal AAQS and will not negatively impact visibility in Class I areas, and to evaluate impacts relative to applicable PSD increments. The modeling addresses emissions from construction activities and routine plant operations. The impacts from construction activities include fugitive dust and emissions associated with combustion byproducts from diesel- and gasoline-fueled equipment. The impacts from routine plant operations are associated with combustion byproducts from the turbine, duct burners, auxiliary boiler, and the two diesel engines. Separate modeling analyses were performed for the construction and the plant operation sources because they will occur during different time periods and have different emission rates. The modeling approach for assessing the CGS impacts is discussed below.

Model and Model Options. The modeling was conducted using the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) (U.S. EPA, 2004). In November 2005, the U.S. EPA officially recognized AERMOD as the preferred dispersion model for regulatory applications, replacing the Industrial Source Complex Short Term 3 (ISCST3) model. U.S. EPA allowed a one-year "grace period" commencing November 9, 2005 during which the use of either model is acceptable, depending on the preference of the local air quality jurisdiction. For this analysis, AERMOD was selected, because this is consistent with the most recent U.S. EPA policy and the data needed to support its application are available in Colusa County. AERMOD was run with the following additional options:

- Final plume rise at all receptors
- Stack-tip downwash
- Buoyancy-induced dispersion
- Calms processing
- Default wind profile exponents
- Default vertical potential temperature gradients
- Rural dispersion coefficients

Building Wake Effects. The effect of building wakes (i.e., downwash) on the stack plumes was evaluated for the routine plant operating emissions (downwash is not applicable to area sources, i.e., construction activities) in accordance with U.S. EPA guidance (U.S. EPA, 1985). Direction-specific building data were generated for stacks below good engineering practice (GEP) stack height using U.S. EPA's Building Profile Input Program – Prime (BPIP-Prime) (U.S. EPA, 1995). Structures from the proposed CGS layout were included in the analysis. The results of the BPIP analysis were included in the AERMOD input files to assess downwash effects. The AERMOD model considers direction-specific downwash using both the Huber-Snyder and Schulman-Scire algorithms as evaluated in the BPIP program. Input and output files for the BPIP-Prime analysis are included in Appendix G.

Meteorological Data. Meteorological data suitable for input to AERMOD were obtained from Western Weather Group of Chico, California from their Maxwell meteorological station, outside the town of Maxwell (population about 1,300), located approximately 8 miles south of the CGS project site. The 5 years of meteorological data to be used in this modeling analysis include data from 2001 through 2005. Data were missing from each year's dataset, although none of the years was missing 10 percent or more of the data. U.S. EPA-approved techniques were followed to fill in missing data. A protocol was submitted to air regulatory agencies with jurisdiction over this project that identified available meteorological data (URS, 2006). Maxwell data were selected based on subsequent discussions with all these agencies. An electronic copy of the Maxwell data, including relative humidity data and the occurrence of fog and rain, is being provided to the CEC under separate cover.

The hourly atmospheric stability (1-6) was estimated using sigma theta (standard deviation of horizontal wind vector) per U.S. EPA modeling guidelines. The hourly mixing height data used was 600 meters (m) for all hours, as stated in the Modeling Protocol.

The meteorological data recorded at Maxwell are acceptable for use at CGS for two reasons: proximity and terrain similarity, including the very important parameter of surface roughness. As mentioned above, the Maxwell meteorological station is located approximately 8 miles south of the CGS site. The station and the CGS site are located in the west side of the Sacramento Valley with the closest elevated terrain approximately 1 to 2 miles to the west. The terrain in the Sacramento Valley area is relatively flat and only slightly above sea level. The Coast Range provides the terrain boundary of the valley to the west. The highest points in the Coast Range in the area are just above 2,000 feet and lie about 15 miles west. The Sacramento Valley is more than 25 miles across at this point. The Sacramento River lies about 12 miles east of the site. An analysis has been conducted to determine what significant terrain features surround the CGS. The mountains of the Mendocino National Forest to the west of the CGS contain the only significant terrain features. It was determined that only a handful of the receptors within the 10-kilometer modeling grid will have terrain features that rise more than 10 percent. All of these features will be incorporated in the AERMAP analysis, where the terrain domain will be set to cover 25 kilometers to the west of the facility and 15 kilometers to the north, east, and south.

The Maxwell meteorological station is the meteorological recording station closest to the CGS site, and there are no intervening terrain features between the two locations; thus meteorological conditions at the CGS site will be very similar to those at the Maxwell meteorological station. The terrain and land use at both the proposed project site and the meteorological station are identical, having mostly level ground, and both are designated agricultural, which encompasses operations including open space, cattle grazing, or irrigated crops.

The closest National Weather Service (NWS) stations are at Red Bluff (60 miles), Sacramento (70 miles) and Redding (90 miles). None of these stations have land use or terrain as similar to the conditions at the CGS site as the Maxwell Station. Therefore, these sites are not as representative of the meteorological conditions of the project site and were not used as the primary source of meteorological data in the permit modeling for the CGS project. However, it is proposed that the cloud cover data collected at Red Bluff be

used to supplement the Maxwell data because cloud cover data is not recorded at Maxwell. Upper air data from Oakland Airport will also be used in AERMOD.

Annual and seasonal wind roses produced from the 5 years of data from the Maxwell meteorological station are provided in Appendix G.

The land use characteristics surrounding both the CGS and the Maxwell Station are presented in Appendix G. The land use classifications were obtained from the USGS National Land Cover Data (NLCD), 1992. These data show that there are four dominant land use classifications surrounding the facility and the meteorological station. The definitions of these land use classifications are:

- Grasslands/Herbaceous – Areas dominated by upland grasses and forbs. In rare cases, herbaceous cover is less than 25 percent, but exceeds the combined cover of the woody species present. These areas are not subject to intensive management, but they are often utilized for grazing.

- Pasture/Hay – Areas of grasses, legumes, or grass-legume mixtures planted for livestock grazing or the production of seed or hay crops.

- Row Crops – Areas used for the production of crops, such as corn, soybeans, vegetables, tobacco, and cotton.

- Small Grains – Areas used for the production of graminoid crops such as wheat, barley, oats, and rice.

All four classifications encompass rural agricultural or grazing lands. The examination of each on the twelve 30-degree sectors of compass direction surrounding both the facility and meteorological station determined that all sectors are comprised of rural agricultural or grazing lands. Two data sources were used to determine the appropriate surface characteristics, albedo, Bowen ratio and surface roughness, for use in the AERMET meteorological processing: Boundary Layer Climates by T.R. Oke (Oke 1987), and Tables 4-1, 4-2a, 4-2b, 4-2c, and 4-3 in the AERMET manual.

The albedo, the fraction of total incident solar radiation reflected by the surface back to space without absorption, for all four land use classifications is between 0.16 and 0.26 per Oke and 0.14 and 0.20 per AERMET (excluding winter). Because very little snow falls, and even less accumulates, the winter surface characteristics described in the AERMET manual are not applicable to these sites. The albedo is dependant upon the amount of vegetation. From the land use definitions above for all four classifications and analysis of aerial photos of the area, very little variation in the albedo is expected around either the facility or meteorological station. Hence, for all sectors surrounding the facility and meteorological station an albedo of 0.18 will be used for spring through autumn and an albedo of 0.4 will be used for winter.

The Bowen ratio is a measure of atmospheric moisture. Oke states that for grasslands the value is between 0.4 and 0.8. At the nearest NWS meteorological station, Red Bluff, the average annual precipitation is 23.5 inches. Because this is neither an arid or excessively moist area, the Bowen ratios for average moisture conditions from the AERMET manual were examined. The Bowen ratios ranged from 0.3 to 1.0 (excluding winter). Thus it was determined that the appropriate Bowen ratio for areas surrounding the facility and meteorological station is 0.4 for spring, 0.6 for summer, 0.8 for autumn, and 1.0 for winter.

The surface roughness length, z_o, is related to the height of the obstacles the wind must flow over. The surface roughness rule-of-thumb, as described by Oke, is $z_o = 1/10$ h, where h is the canopy height. The canopy height is the height of the vegetation, and the height of the vegetation is dependant upon the

season and the type of crop. Oke describes the surface roughness for crops and grasslands to be between 0.04 and 0.20 meter(m). The AERMET characterizes surface roughness to be between 0.01 and 0.20 m (excluding winter). Hence it was determined that the appropriate surface roughness length to describe the lands surrounding both the facility and meteorological station is 0.04 m for spring, 0.15 m for summer, 0.07 m for autumn, and 0.01 m for winter.

Receptors. AERMOD used the following receptor spacing:

- 25-meter spacing along the property line and extending from the property line out to 100 meters;
- 100-meter spacing within 1 kilometer of project sources for any locations not covered by the 25-meter grid;
- 500-meter spacing within 1 to 5 kilometers of project sources;
- 1,000-meter spacing within 5 to 10 kilometers of project sources; and
- If maximum concentrations are predicted where the grid spacing is less dense than 25 meter, a 25-meter spaced nested grid of receptors was placed surrounding the receptor where the maximum concentration was predicted. This nested grid extended out 500 meters in all directions or until the next regular grid receptors was encountered.

The receptor locations were designated using Universal Transverse Mercator (UTM) coordinates. Receptor elevations were obtained from U.S. Geological Survey (USGS) 7.5-minute electronic data.

Emission Scenarios. The modeling for the CGS required the determination of worst-case emissions scenarios for the following averaging periods and pollutants to demonstrate compliance with AAQS:

- 1-hour for CO, NO_2, and SO_2;
- 3-hour for SO_2;
- 8-hour for CO;
- 24-hour for $PM_{10,}$ $PM_{2.5}$ and SO_2; and
- Annual for $PM_{10,}$ $PM_{2.5}$, NO_2, and SO_2.

Project Site Construction Impact Modeling. For construction activities at the project site, it was assumed that the combustion equipment emissions would be released in the area of the construction zone within the CGS property boundary. Due to the large amount of construction equipment needed for the proposed project, it was necessary to define a representative source or sources. For construction equipment emissions, it was assumed that the equipment exhaust emissions would be emitted from two volume sources within the construction zone. PM_{10} emissions from fugitive dust were modeled using two area sources. The area sources were placed to include the construction, laydown, and contractor parking areas. See Figure 3.2-1 for a definition of these areas.

The worst-case hourly and annual emission rates were used to model short-term and annual emissions, respectively. Fugitive dust emissions were included for both annual and 24-hour PM_{10} impacts. The modeled release parameters for the construction activities are presented in Table 8.1-22.

Turbine Impact Screening Modeling. Screening modeling was performed to determine which turbine operating modes (i.e., load level, duct burner firing, ambient temperature) produced “worst-case” impacts for each pollutant and averaging time. AERMOD was used for the screening analysis, with the 2001 meteorological data, building wake information and the receptor grid previously described.

The model simulated natural gas combustion emissions from two 19-foot-diameter (5.8-m), 175-foot-tall (53.34-m) stacks. The stacks were modeled as point sources at their proposed locations. The stack parameters for each operating mode are shown in Table 8.1-22. Table 8.1-23 also details the screening modeling results for the twelve combustion turbine operating conditions.

Refined Modeling. Refined modeling was performed to identify offsite, criteria pollutant impacts from operational emissions of the proposed project. The modeling was performed as previously described. However, in addition to the turbine/HRSG, the generator and fire pump engines and auxiliary boiler were also included in the refined modeling analysis.

Based on the screening results, stack parameters from the 50 percent load, with no duct firing, at 114°F ambient temperature simulate worst-case 1-hour dispersion. These parameters were used in the modeling to provide a conservative value for the pollutant dispersion. Pollutant emission rates for warm startups and cold startups (summarized in Table 8.1-15) were applied to these dispersion impacts to represent worst-case, short-term impacts of CO (1-hour) and NO_2 (1-hour), respectively.

The SO_2 1-hour impact was estimated using the actual emission rate and stack parameters for the 100 percent load, with duct firing, at 18°F ambient temperature operating mode.

Annual average impacts were estimated using the stack parameters for the 100% load, with duct firing, at 59F ambient temperature operating mode. Annual emission rates for NO_2, $PM_{10,}$ and SO_2, shown in Table 8.1-8, were used in the analysis. PM_{10} 24-hour impacts were based on the actual emission rate and stack parameters for the 100 percent load, with duct firing, at 114°F ambient temperature operating mode. Short-term, worst-case emission rates are summarized in Table 8.1-24.

Hourly NO_2 impacts were estimated using the ozone limiting method (OLM) with the AERMOD-OLM model (Version 96113). Ozone data used in the OLM model was obtained from the Willows Station.

Fumigation Analysis. Fumigation occurs when a plume that was originally emitted into a stable layer of air is mixed rapidly to ground level when unstable air below the plume reaches plume level. Fumigation can cause very high ground-level concentrations. Fumigation can occur during the break up of the nocturnal radiation inversion by solar warming of the ground surface (inversion breakup fumigation). Such conditions are short-lived and are typically compared only with 1-hour standards. A fumigation analysis was performed using the U.S. EPA SCREEN3 model (Version 96043). Fumigation impacts are summarized in Table 8.1-25.

Combustion Turbine Impact Modeling During Commissioning. Impacts were estimated for NO_2 and CO during commissioning using AERMOD. Ambient air quality impacts from the commissioning phase of this project for 1-hour NO_2 were shown to be 209.8 $\mu g/m^3$. The commissioning impacts for 1-hour and 8-hour CO were shown to be 1,630 $\mu g/m^3$ and 496 $\mu g/m^3$, respectively. The NO_2 impacts are lower for commissioning that during cold startup because only one turbine has high NO_x emissions at a time during commissioning. CO impacts during commissioning are slightly higher than during startup but would not pose any threat to the CO AAQS. As indicated in Table 8.1-18, commissioning produces no emission changes for SO_x and PM_{10}, only for VOC, CO, and NO_x. VOC impacts are not modeled. Results of modeling NO_2 and CO during gas turbine commissioning are shown in Appendix G.

8.1.2.4 Compliance with Ambient Air Quality Standards

Air dispersion modeling was performed as described in Section 8.1.2.3 to evaluate the increase in pollutant ground level concentrations from the project emissions relative to the applicable short-term and long-term AAQS. The impacts from construction activities and plant operations were analyzed separately because they would occur during different time periods. The maximum increases were added to the maximum background concentrations based on air quality data collected for the most recent 3 years (i.e.,

2003 to 2005) except for the 1-hour NO_2 background which used the arithmetic average of the three 1-hour maxima from the 2003 – 2005 period. The impact was then compared with the most stringent state or federal AAQS. Modeled impacts are summarized in Table 8.1-24 for construction activities and plant operations.

Construction Activities. Air dispersion modeling of construction emissions was performed to satisfy CEC requirements. All maximum criteria pollutant concentrations for construction at the project site, were predicted to occur at receptors along or within 50 meters (or within the first two rows of receptors) of the boundary of the facility. Model output for these runs are included in Appendix G. Construction impacts on AAQS are not the primary focus of the air regulatory agencies because construction emissions would be temporary in nature and would not coincide with emissions from plant operations. Construction mitigation measures, described in Section 8.1.5.10.2, will be used to minimize impacts from temporary construction emissions.

Normal Plant Operations. Maximum modeled impacts are below applicable federal PSD significant impact levels for all criteria pollutants. Modeled impacts due to plant operation emissions from the proposed project would not cause a violation of any federal or state AAQS and would not significantly contribute to the existing violations of the state PM_{10} or ozone standards.

Almost all of the particulate matter emissions from the CGS under normal operations will be equal to or less than 2.5 microns in diameter because it will be generated exclusively from combustion processes. The modeled PM_{10} impacts from operation therefore also could be viewed as representing $PM_{2.5}$ impacts. Doing so, and adding the $PM_{2.5}$ impacts from the CGS to the monitored $PM_{2.5}$ background concentrations (see Table 8.1-4) and comparing the results to the applicable AAQS demonstrates that no violation of any federal or state $PM_{2.5}$ AAQS would be caused by the CGS. Therefore, no mitigation specific to $PM_{2.5}$ impacts is included later in Section 8.1.4. However, the proposed PM_{10} mitigation measures discussed in Section 8.1.4 are also heavily drawn from combustion processes so $PM_{2.5}$ mitigation will result.

The 24-hr PM_{10} impact from normal operation shown in the modeling results on Table 8.1-24 represents the second highest modeled output out of 5 years of meteorological data (representing a period of about 1,825 days). This approach was necessary because the results from the operating scenario of both gas turbines in the 50% load, 114 F case for the full 24-hour period contained one day with an impact greater than the EPA 24-hr PM_{10} Significant Impact Level (SIL) of 5 $\mu g/m^3$. The modeled concentration for that day was 6.11 $\mu g/m^3$ at a location about 4.5 km west of the site. No other day modeled for any of the remaining eleven operating scenarios evaluated for any day of the entire five-year period produced results equal to or greater than 5 $\mu g/m^3$ at any receptor location. Removing the results of this one day was done specifically for comparison to the EPA SIL. It has no measurable impact when comparing the results to any federal or state AAQS. This approach is consistent with the modeling protocol (URS, 2006) and demonstrates that the SIL will not be exceeded. This day was discounted for only this instance. All other impacts reported from operations use the highest impact modeled.

Fumigation impacts were estimated as described in Section 8.1.2.3 and are summarized in Table 8.1-25. Fumigation impacts are all below PSD significance thresholds. Predicted Class 1 Area Pollutant Concentrations from the CGS compared to proposed and adopted SILS are listed in Table 8.1-26.

Emission Offsets. The emission offset requirement was developed to facilitate net air quality improvement. The proposed project impacts for the nonattainment pollutants (PM_{10} and ozone) and their precursors (NO_X, VOC, SO_2 and PM_{10}) will be mitigated by emission offsets. These offsets have not been accounted for in the modeled impacts noted above. Thus, the proposed project's modeled impacts may significantly overestimate actual project impacts because they do not account for the effect of removing future PM_{10}, NO_X, and VOC from areas surrounding the project site.

8.1.2.5 Impacts on Air Quality–Related Values in Class I Areas

Specific national parks, wilderness areas, and national monuments are designated as Class I areas and are protected by the most stringent PSD requirements. The PSD regulations require an assessment of the impacts of major sources on AQRVs in Class I areas. AQRVs include:

- Visibility;
- Terrestrial resources (e.g., vegetation, geological features, wildlife); and
- Aquatic resources (e.g., lakes, streams, aquatic biota).

This section addresses potential impacts on AQRVs in the closest Class I area, which is Yolla Bolly-Middle Eel Wilderness, located approximately 88 kilometers northwest of the proposed project site, and administered by the National Park Service.

Effects on Visibility. The Clean Air Act (CAA) established the importance of visibility for Class I areas by declaring a goal to prevent future visibility impairment and remedy existing visibility impairment due to man-made air pollution. The CAA also specifically requires that visibility be addressed as an AQRV within all Class I areas. However, visibility is not uniformly affected by air pollution. Visibility varies on a site-by-site basis and is affected by meteorology, topography, the relative position of the viewer and the sun, and other variables. In addition, the assessment of visibility depends on subjective human perceptions. As a result, it is often difficult to assess the condition of the visibility AQRV.

This analysis was conducted using the screening version of the CALPUFF model and the same meteorological input data used for the AAQS modeling analysis. Applicable recommendations from the CALPUFF Reviewer's Guide (Draft) of September 2005 prepared for the National Park Service and the National Forest Service were implemented in the screening version of CALPUFF AQRV modeling.

Using weather from 2001 through 2004 in CALPUFF resulted in between 8 and 15 days per year with 5 percent extinction change. Reviewing the precipitation data for those days of exceedance, almost half of those exceedance days had precipitation. Visibility is affected by rainfall.

Because relative humidity plays an important role in the growth of light scattering particles, periods of high humidity due to clouds and rain would naturally compromise visibility and therefore these few suggested high visibility impacts likely coincide with periods of naturally obscuring phenomena and can be discounted. Further review of the remaining 4 to 6 days per year of 5 percent extinction indicated that wind direction on those days was from the Class 1 area toward the CGS. Therefore, the emissions from the CGS would not be carried in the direction of the Class I area. Therefore, the CGS screening successfully passed all screening criteria.

Terrestrial Resources. Maximum modeled annual NO_2 and SO_2 impacts from normal plant operations, as well as estimates of total nitrogen and sulfur deposition estimated by CALPUFF, were compared against Deposition Analysis Threshold (DAT) for individual sources established by the National Park Service (NPS) for vegetation and ecosystems for Class I Wilderness Areas. Table 8.1-27 summarizes the maximum modeled impacts versus the NPS and the USFS significance criteria. All impacts are below the significance criteria.

Aquatic Resources. A significant effect of NO_x and SO_2 emissions on aquatic resources is nitrogen and sulfur deposition and subsequent acidification. However, because any increased nitrogen and sulfur deposition due to the proposed project would be minimal, impacts to water acid neutralizing capacity (ANC) and pH, and, therefore, acidification or eutrophication, are not likely to occur.

8.1.3 Cumulative Impacts Analysis

CEC requirements specify that an analysis is required to determine the cumulative impacts of the Colusa Generating Station project and other projects within a 6-mile radius that have received construction permits but are not yet operational, are in the permitting process, or that have not historically operated at their full potential to emit. The cumulative impact analysis assesses whether estimated emissions concentrations may cause or contribute to a violation of any ambient air quality standard.

A request was sent to CCAPCD for a listing of facilities that are permitted but not yet in operation within a 6-mile radius of the proposed project site or are in the permitting process. No facilities were identified by the CCAPCD meeting these criteria.

CCAPCD has confirmed that the only sources required to be included in the Cumulative Impact Analysis other than the Colusa Generating Station are the three gas turbines at the PG&E Delevan Compressor Station. The PG&E Delevan Compressor Station is adjacent to the CGS. The approach to be used for the DCS modeling was included in the Colusa Modeling Protocol (URS, 2006). The Delevan Compressor Station emits NO_X, CO, PM_{10} and SO_2 so the cumulative analysis focused only these pollutants. Year 2003 was the year with the highest background NO_X measurements within the last 3 years. Therefore, the operation of the DCS was modeled both for a full load hour and for the increment between actual 2003 annual hours of operation and full year (8,760) hours of operation.

The results of the cumulative impact analysis are reported in Table 8.1-28. The cumulative impact analysis results for CO are well below significance levels. The cumulative impact analysis for NO_x shows that the worst-case 1-hour result would occur about 2 km west of the CGS site. All cumulative impacts demonstrated compliance.

8.1.4 Mitigation Measures

This section discusses the mitigation measures proposed by the Applicant that will be implemented to reduce project-related impacts to air quality.

AIR-1 Emission Reduction Credits

CCAPCD rules require that operational emissions of the proposed project be offset by emission reduction credits (ERCs) at other sources within or outside the CGS. Specifically, Regulation 3, Rule 3-6 for permitted new sources requires that emission offsets are required for the portion of that source's emissions of nonattainment criteria pollutants (and their precursors) exceeding 25 tons per year (tpy). The nonattainment criteria pollutants in Colusa County per CCAPCD rules are ozone and PM_{10}. Ozone precursors are NO_X and VOC. PM_{10} precursors are PM_{10} and SO_2. Colusa County is in attainment status for ozone and PM_{10} as nonattainment criteria pollutants in Colusa County. Furthermore, the CCAPCD ERC rule is not included in the portion of the CCAPCD rules that have received federal approval in the State Implementation Plan (SIP). Therefore, there are no federal requirements either to provide ERCs or for federal oversight of the CCAPCD approval of ERCs. The ERC requirements for the CGS therefore are the amount of ozone precursors (NO_X and VOC) that exceeds 25 tons per year and that amount of PM_{10} (and $SO_{2)}$ that exceeds 25 tons per year.

These credits must be provided at ratios corresponding to the distance of the credit generating source from the CGS for offsite ERCs. These pollutants must be offset within the same quarter of the year in which they are emitted. Project emissions will be offset with credits from the following two ERC sources:

1. Offsite ERCs resulting from emissions reductions at stationary sources available from the CCAPCD ERC banking system or other APCD banking systems within the air basin.

These ERCs will be provided at a ratio corresponding to the distance of the reduction source from the CGS; and

2. Emission offsets from emission reductions associated with the elimination of open biomass burning of agricultural residue. CCAPCD has specific provisions in Rule 3-16 to provide for the creation of emission reduction credits for reduced open burning. The rule sets forth the basis for calculating emission offsets based on:

   - Quantity of biomass displaced (acres);
   - Emission factor for each biomass type;
   - Location of displaced open burning;
   - Historical burn fractions (HBF) for each crop type by county, representing the fraction of the planted crop that has historically been open burned; and
   - Quarterly distribution fractions (QDF) for each crop type by county, representing the historical distribution of open burning in each of the calendar quarters of the year.

   Open biomass burning ERCs also will be provided at a ratio corresponding to the distance of the reduction source from the CGS.

E&L Westcoast has obtained options to purchase ERCs to meet the offset needs of the proposed project. These option contracts will be submitted under separate cover to protect certain confidential information.

8.1.5 Laws, Ordinances, Regulations, and Standards

The applicable laws, ordinances, regulations, and standards (LORS) related to the potential air quality impacts from the CGS are described below, and shown in Table 8.1-29. These LORS are administered (either independently or cooperatively) by the CCAPCD, U.S. EPA Region IX, the CEC, and the California Air Resources Board. The area of responsibility for each of these agencies is described below.

U.S. EPA has ultimate responsibility for ensuring, pursuant to the CAAA, that all areas of the United States meet, or are making progress toward meeting, the federal AAQS. The State of California falls under the jurisdiction of U.S. EPA Region IX, which is headquartered in San Francisco. U.S. EPA requires that all states submit State Implementation Plans (SIPs) for nonattainment areas that describe how the federal AAQS will be achieved and maintained. Attainment plans must be approved by CARB before they are submitted to U.S. EPA.

Regional or local air quality management districts (or air districts), such as CCAPCD are responsible for preparation of plans for attainment of federal and state standards. CARB is responsible for overseeing attainment of the California AAQS, implementation of nearly all phases of California's motor vehicle emissions program, and oversight of the operations and programs of the regional air districts.

Each air district is responsible for establishing and implementing rules and control measures to achieve air quality attainment within its district boundaries. The air district also prepares an air quality management plan (AQMP) that includes an inventory of all emission sources within the district (both man-made and natural), a projection of future emissions growth, an evaluation of current air quality trends, and an assessment of any rules or control measures needed to attain the AAQS. This AQMP is submitted to CARB, which then compiles AQMPs from all air districts within the state into the SIP. The responsibility of the air districts is to maintain an effective permitting system for existing, new, and

modified stationary sources, to monitor local air quality trends, and to adopt and enforce such rules and regulations as may be necessary to achieve the AAQS.

8.1.5.1 Ambient Air Quality Standards

U.S. EPA, in response to the federal Clean Air Act of 1970, established federal AAQS in Title 40 Code of Federal Regulations (CFR) Part 50. The federal AAQS include both primary and secondary standards for six "criteria" pollutants. These criteria pollutants are ozone (O_3), CO, NO_2, SO_2, PM_{10}, and lead (Pb). Primary standards were established to protect human health, and secondary standards were designed to protect property and natural ecosystems from the effects of air pollution.

The 1990 Clean Air Act Amendments (CAAA) established attainment deadlines for all designated areas that were not in attainment with the federal AAQS. In addition to the federal AAQS described above, a new federal standard for $PM_{2.5}$ and a revised O_3 standard were promulgated in July 1997. The new federal standards were challenged in a court case during 1998. The court required revisions in both standards before U.S. EPA can enforce them. The U.S. Supreme Court upheld an appeal of the District Court decision in February 2001. These issues were resolved and the 1-hour O_3 standard revoked in 2005 while the revised $PM_{2.5}$ standard was made effective in 2006. The State of California has adopted California AAQS that are in some cases more stringent than the federal AAQS. The state and federal AAQS relevant to the CGS are summarized in Table 8.1-30.

The U.S. EPA, CARB, and the local air pollution control districts determine air quality attainment status by comparing local ambient air quality measurements from the state or local ambient air monitoring stations with the federal and California AAQS. Those areas that meet ambient air quality standards are classified as "attainment" areas; areas that do not meet the standards are classified as "nonattainment" areas. Areas that have insufficient air quality data may be identified as unclassifiable areas. These attainment designations are determined on a pollutant-by-pollutant basis. The CCAPCD is designated a state nonattainment area for PM_{10} and ozone based on air quality monitoring data showing exceedances of the state standards. Table 8.1-31 presents the attainment status (both federal and state) for Colusa County.

As mentioned above, both U.S. EPA and CARB are involved with air quality management in the Colusa area along with CCAPCD. .

8.1.5.2 Prevention of Significant Deterioration Requirements

In addition to the ambient air quality standards described above, the federal Prevention of Significant Deterioration program has been established to protect deterioration of air quality in those areas that already meet NAAQS. The PSD program specifies allowable concentration increases for attainment pollutants due to new emission sources. These increases allow economic growth while preserving the existing air quality, protecting public health and welfare, and protecting Class I areas (national parks and wilderness areas). The PSD regulations require major stationary sources to undergo a preconstruction review that includes an analysis and implementation of BACT, a PSD increment consumption analysis, an ambient air quality impact analysis, and analysis of AQRVs (impacts on visibility). The CGS is subject to these requirements.

The incremental emission PSD triggers for SO_2, NO_X, PM_{10}, and CO are as shown in Table 8.1-32. For project emissions of SO_2, NO_X, or PM_{10} above these PSD triggers, the Applicant must demonstrate through modeling that such emissions will not interfere with the attainment or maintenance of the applicable NAAQS and will not cause an exceedance of the applicable PSD increments shown in Table 8.1-34. For project emissions of CO that exceed the trigger levels, the Applicant must demonstrate through modeling that the increase in emissions will not interfere with the attainment or maintenance of the CO NAAQS. Allowable PSD increments for SO_2, NO_X, and PM_{10} are summarized in Table 8.1-33.

There are no Class I areas within CCAPCD. Yolla Bolly-Middle Eel Wilderness and Caribou Wilderness are the Class I areas nearest to the site. All areas within the district are Class II areas; there are no Class III areas within the CCAPCD.

8.1.5.3 Acid Rain Program Requirements

Title IV of the CAAA applies to sources of air pollutants that contribute to acid rain formation, including certain sources of SO_2 and NO_X emissions. Title IV is implemented by the U.S. EPA under 40 CFR 72, 73, and 75. Allowances of SO_2 emissions are set aside in 40 CFR 73. Sources subject to Title IV are required to obtain SO_2 allowances, to monitor their emissions, and obtain SO_2 allowances when a new source is permitted. Sources such as the CGS that use pipeline-quality natural gas are exempt from many of the acid rain program requirements. However, these sources must still estimate SO_2 and CO_2 emissions, and monitor NO_X emissions with certified continuous emissions monitoring systems (CEMS). All subject facilities must submit an acid rain permit application to U.S. EPA 24 months prior to commencing operation.

8.1.5.4 New Source Performance Standards

New Source Performance Standards (NSPS) have been established by U.S. EPA to limit air pollutant emissions from certain types of new and modified stationary sources. The NSPS regulations are contained in 40 CFR 60 and cover nearly 70 source categories. Stationary gas turbines are regulated under Subpart KKKK

In general, local emission limitation rules or BACT requirements are more restrictive than the NSPS requirements. For example, the controlled NO_X emissions from the CGS's stationary gas turbine will be controlled to 2.0 or less parts per million by volume dry (ppmvd) at 15 percent oxygen, significantly less than the NSPS limit of 15 ppmvd at 15 percent oxygen.

The NSPS fuel requirements for SO_2 will be satisfied by the use of natural gas, and emissions and fuel monitoring will be performed to comply with NSPS, acid rain, and other regulatory requirements.

8.1.5.5 Federally Mandated Operating Permits

Title V of the CAA requires U.S. EPA to develop a federal operating permit program that is implemented under 40 CFR 70. This program is administered by CCAPCD under Regulation 3, Rule 3.17. Permits must contain emission estimates based on potential-to-emit, identification of all emission sources and controls, a compliance plan, and a statement indicating each source's compliance status. The permits must also incorporate all applicable federal, state, or CCAPCD orders, rules and regulations.

Because the facility will constitute a new stationary source, the Applicant will submit a complete Title V permit application for a Title V permit to operate within 12 months after plant startup.

8.1.5.6 Power Plant Siting Requirements

Under the California Environmental Quality Act (CEQA), the CEC has been charged with assessing the environmental impacts of each new power plant and considering the implementation of feasible mitigation measures to prevent potential significant impacts. CEQA Guidelines (Title 14, California Administrative Code, Section 15002(a)(3)) state that the basic purpose of CEQA is to "prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible."

The CEC's siting regulations require that, except under certain conditions, a new power plant can only be approved if the proposed project complies with all federal, state, and local air quality rules, regulations,

standards, guidelines, and ordinances that govern the construction and operation of the proposed project. A project must demonstrate that project emissions will be appropriately controlled to mitigate significant impacts from the project and that it will not jeopardize attainment and maintenance of the AAQS. Cumulative impacts, impacts due to pollutant interaction, and impacts from noncriteria pollutants must also be considered.

8.1.5.7 Air Toxics "Hot Spots" Program

As required by the California Health and Safety Code Section 44300, all facilities with criteria air pollutant emissions in excess of 10 tons per year are required to submit air toxic "Hot Spots" emissions information. This requirement is applicable only after the start of operation. Section 8.6, Public Health, indicates that air toxics impacts from the CGS would be less than significant.

8.1.5.8 Determination of Compliance, Authority to Construct and Permit to Operate

Under Regulation 3, Rule 3.6, CCAPCD administers the air quality regulatory program for the construction, alteration, replacement, and operation of new power plants. The proposed project is required to obtain a preconstruction Determination of Compliance from the CCAPCD. Regulation 3, Rule 3.6 incorporates other CCAPCD rules that pertain to sources that may emit air contaminants through the issuance of air permits (i.e., Authority to Construct and Permit to Operate). This permitting process allows the CCAPCD to adequately review new and modified air pollution sources to ensure compliance with all applicable prohibitory rules and to ensure that appropriate emission controls are used. An ATC allows for the construction of the air pollution source and remains in effect until the Permit to Operate (PTO) application is granted, denied, or canceled. For power plants under the siting jurisdiction of the CEC, the CCAPCD issues a Determination of Compliance in lieu of an ATC. The Determination of Compliance is incorporated into the CEC license. Once the project commences operations and demonstrates compliance with the Determination of Compliance, CCAPCD will issue a PTO. The PTO specifies conditions that the air pollution source must meet to comply with other air quality standards and will incorporate applicable Determination of Compliance requirements. An application for the Determination of Compliance will be submitted to the CCAPCD simultaneously with the filing of the AFC.

8.1.5.9 New Source Review Requirements

The federal Clean Air Act, U.S. EPA regulations, and the California Clean Air Act establish the criteria for siting new and modified emission sources. The federally mandated process for permitting new or modified sources in federal nonattainment areas is referred to as Nonattainment New Source Review (NNSR). This requirement is not applicable in this case because the county is in attainment from the federal perspective. Due the state-level non-attainment status, CCAPCD is responsible for NSR rule development and enforcement for sources in Colusa County. The District's NSR rules are contained in Regulation 3, Rule 3.6. The rules required that first, Best Available Control Technology (BACT) must be applied to any new source that emits above the level specified in Regulation 3, Rule 3.6. Second, all potential emission increases from the sources above specified thresholds must be offset by real, quantifiable, surplus, permanent, and enforceable emission decreases in the form of ERCs, Regulation 3, Rule 3.16 "Emission Reduction Credit and Banking" (see Section 8.1.4). Third, ambient air quality impact assessments must be conducted to confirm that the proposed project does not cause or contribute to a violation of a federal or California AAQS (see Section 8.1.2.4) or jeopardize public health (see Section 8.6). Finally, the Applicant must certify that all major sources owned or operated in the State of California are either in compliance or on an approved schedule for compliance with applicable air quality regulations.

8.1.5.10 Colusa County Air Pollution Control District Requirements

The CCAPCD has been delegated responsibility for implementing the federal, state, and local regulations on air quality in Colusa County. The proposed project is subject to CCAPCD regulations that apply to new sources of emissions, to the prohibitory regulations that specify emissions standards, and to the requirements for evaluation of air pollutant impacts for both criteria and toxic air pollutants. The following sections include the evaluation of the project's compliance with the applicable CCAPCD requirements.

8.1.5.10.1 Rules and Regulations

The following paragraphs outline the CCAPCD rules and regulations that apply to the proposed project.

Regulation 1 – General Provisions

Rule 1.8 "Emission Monitoring": The Air Pollution Control Officer may require the owner of any air contaminant source to install, use, and maintain monitoring equipment; sample emissions; establish and maintain records; and make periodic emission reports in a format acceptable to the Air Pollution Control Officer.

Rule 1.9 "Records and Reports": Air pollution monitoring data, facility operation records, and such fuel composition data as deemed necessary shall be recorded, compiled, and submitted to the Air Pollution Control Officer by the owner of a stationary source.

Rule 1.10 "Tests": All tests shall be made and the results calculated in accordance with test procedures approved by the Air Pollution Control Officer. All tests shall be made under the direction of person qualified by training and experience in the field of air pollution control and approved by the Air Pollution Control Officer.

The Air Pollution Control Officer may conduct or require the owner of a stationary source to conduct tests of emissions of air contaminants from any source. Upon request of the Air Pollution Control Officer, the person responsible for the source to be tested shall provide necessary holes in stacks or ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices as may be necessary for proper determination of the emission of air contaminants.

Rule 1.11 "Field Inspection": Each source of air pollution subject to permit or registration shall be inspected or tested at such intervals of time so that no extended periods of violations will occur.

Rule 1.12 "Air Pollution Equipment, Scheduled Maintenance": In the case of shutdown or restart of air pollution control equipment for necessary scheduled maintenance, the intent to shut down such equipment shall be reported to the Air Pollution Control Officer at least 24 hours prior to the planned shutdown. Such prior notice shall include, but is not limited to the following:

- Identification of the specific facility to be taken out of service as well as its location and permit number;
- The expected length of time that the air pollution control equipment will be out of service;
- The nature and quantity of emissions of air contaminants likely to occur during the shutdown period;

- Measures such as the use of off-shift labor and equipment that will be taken to minimize the length of the shutdown period;

- The reasons that it would be impossible or impractical to shutdown the source operation during the normal facility maintenance period.

Rule 1.13 "Equipment Breakdown": In the event that any emission source, air pollution control equipment, or related facility breaks down in such a manner that may cause the emission of air contaminants in violation of this article, the person responsible for such equipment shall immediately notify the Air Pollution Control Officer of such failure or breakdown and subsequently provide a written statement giving all pertinent facts, including the estimated duration of the breakdown. The Air Pollution Control Officer shall be notified when the condition causing the failure or breakdown has been corrected and the equipment is again in operation.

Regulation 2 – Prohibitions

Rule 2.10 "Nuisance": In accordance with Section 41700 of the California Health and Safety Code, a person shall not discharge from any source whatsoever such quantities of air contaminants or other materials that cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public or that endanger the comfort, repose, health, or safety of any such person or the public or which cause or have a natural tendency to cause injury or damage to business or property. The air quality impact analysis is designed to ensure that the proposed project will not cause any public nuisance.

Rule 2.13 "Visible Emissions": As provided by Section 41701 of the California Health and Safety Code, a person shall not discharge into the atmosphere from any single source of emissions whatsoever, any air contaminants for a period or periods aggregating more than 3 minutes in any 1 hour which is

a. As dark or darker in shade as that designated as No. 2 on the Ringelmann Chart, as published by the United States Bureau of Mines; or

b. Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subsection a., above.

Rule 2.15 "Particulate Matter Concentration": A person shall not discharge into the atmosphere from any source, except as allowed by Rule 2.14, subsection a. and c. of this regulation, particulate matter in excess of 0.3 grain per standard dry cubic foot of gas. Emissions from each source at the site are expected to be compliant with this regulation. PM_{10} emissions are not expected to exceed 0.02 grain per dry standard cubic feet.

When the source involves a combustion process, the concentration must be calculated to 12 percent carbon dioxide (CO_2). In measuring the combustion, contaminants from incinerators used to dispose of combustible refuse by burning the CO_2 produced by combustion of any liquid or gaseous fuels shall be excluded from the calculation to 12 percent of CO_2.

Rule 2.16 "Dust and Fumes": A person shall not discharge in any 1 hour from any source whatsoever, except as provided by Rule 2.14, subsections a. and c. of this regulation, dust or fumes in total quantities in excess of the amounts shown in the following table:

Process Weight Rate		Rate of Emission	Process Weight Rate		Rate of Emission
Lb./Hr.	**Ton/Hr.**	**Lb./Hr.**	**Lb./Hr.**	**Ton/Hr.**	**Lb./Hr.**
100	0.15	0.551	16,000	8.0	16.5
200	0.10	0.877	18,000	9.0	17.9
400	0.20	1.40	20,000	10.0	19.2
600	0.30	1.83	30,000	15.0	25.2
800	0.40	2.22	40,000	20.0	30.5
1,000	0.50	2.58	50,000	25.0	35.4
1,500	0.75	3.38	60,000	30.0	40.0
2,000	1.00	4.10	70,000	35.0	41.3
2,500	1.25	4.70	80,000	40.0	42.5
3,000	1.50	5.38	90,000	45.0	43.6
3,500	1.75	5.96	100,000	50.0	50.0
4,000	2.00	6.52	120,000	60.0	46.3
5,000	2.50	7.58	140,000	70.0	47.8
6,000	3.00	8.56	180,000	80.0	49.0
7,000	3.50	9.49	200,000	100.0	51.2
8,000	4.00	10.4	1,000,000	500.0	69.0
9,000	4.50	11.2	2,000,000	1,000.0	77.6
10,000	5.00	12.0	6,000,000	3,000.0	92.7
12,000	6.00	13.6			

Rule 2.17 "Separation of Emissions": If air contaminants from a single source operation are emitted through two or more emission points, the total emitted quantity of any air contaminant limited in this regulation cannot exceed the quantity that would be the allowable emission through a single emission point; the total emitted quantity of any such air contaminant shall be taken as the product of the highest concentration measured in any of the emission points and the combined exhaust gas volume from all emission points, unless the person responsible for the source operation establishes, to the satisfaction of the Air Pollution Control Officer, the correct total emitted quantity.

Rule 2.18 "Combination of Emissions":

a. If air contaminants from two or more source operations are combined prior to emission and there are adequate and reliable means reasonably susceptible to confirmation and use by the Air Pollution Control Officer for establishing a separation of the components of the combined emission to indicate the nature, extent, quantity, and degree of emission arising from each source operation, then all of the applicable prohibitions shall apply to each such source operation separately.

b. If the air contaminants from two or more source operations are combined prior to emission, and the combined emissions cannot be separated according to the requirements of subsection a. of this rule, then all applicable prohibitions shall be applied to the combined emission as if it originated in a single source operation, subject to the most stringent limitations and requirements placed by these prohibitions on any of the source operations whose air contaminants are so combined.

Rule 2.22 "Sulfur Oxides": A person shall not discharge into the atmosphere from any single source of emission whatsoever, any sulfur oxides in excess of 0.2 percent by volume (2,000 ppm) collectively calculated as sulfur dioxide (SO_2).

Rule 2.23 "Reduced Sulfur Compounds": a. It shall be unlawful for any person to permit the emissions of air contaminants from any premises that will result in ground level concentrations of total reduced sulfur compounds, expressed as hydrogen sulfide, in excess of 0.03 ppm for a period of 60 minutes.

Rule 2.39 "Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters Oxides of Nitrogen Control Measure" (adopted 1/23/96): The purpose of this rule is to reduce oxides of nitrogen emissions to levels consistent with reasonably available control technology (RACT). Gaseous fired units with a rated heat input capacity greater or equal to 5 million BTU per hour shall demonstrate compliance with the emission limit of 0.084 lbs/MMBtu of heat input or 70 ppmv for oxides of nitrogen.

Regulation 3 – Permits

Rule 3.0 "General Requirements":

a. No person shall cause or permit the construction or modification of any new source of air contaminants without first obtaining an Authority to Construct from the Air Pollution Control Officer so as to comply with applicable regulations and rules and ambient air quality standards of the District.

b. The Control Officer shall not approve such construction or modification unless the applicant demonstrates to the satisfaction of the Air Pollution Control Officer that the new source can be expected to comply with all the applicable state laws and District regulations and rules.

Rule 3.1 "Permits Required" (amended 4/12/94): The permits required are the Authority to Construct and a Title V Permit to Operate issued by the Air Pollution Control Officer under Title V of the Federal Clean Air Act as amended in 1990.

Rule 3.6 "Standards for Authority to Construct (New Source Review) (adopted 09/14/93): The purpose of this rule is to establish preconstruction review requirements for new and modified stationary sources of air pollution for use of BACT, analysis of air quality impacts, and to ensure that the operation of such sources does not interfere with the attainment or maintenance of ambient air quality standards.

1. Best Available Control Technology: An Applicant shall apply BACT to any new emissions unit or modification of an existing emissions unit, which results in an emissions increase and the potential to emit for the emissions unit that equals or exceeds the following amounts:

Pollutant	Pounds Per Day
Reactive organic compounds	25.0
Nitrogen oxides	25.0
Sulfur oxides	80.0
Particulate matter (PM_{10})	80.0
Carbon monoxide	500.0
Lead	3.2
Asbestos	0.03
Beryllium	0.002
Mercury	0.5
Vinyl chloride	5.0
Fluorides	15.0
Sulfuric acid mist	35.0
Hydrogen sulfide	50.0
Total reduced sulfur compounds	50.0
Reduced sulfur compounds	50.0

2. Offset Requirements, General: Offsets shall be required for a new stationary source with a potential to emit, calculated pursuant to Rule 3.6.d.4., of nonattainment pollutants or their precursors equal to or exceeding 25 tons per year. The amount of offsets required shall be at least equal to that portion of the potential to emit that exceeds 25 tons per year.

3. Location of Offsets and Offsets Ratios: Offset ratio and the corresponding distances from the proposed stationary source shall be:

   A. Onsite, at a ratio of 1:1
   B. Within 20 miles, at a ratio of 1.2:1
   C. 20 to 50 miles, at a ratio of 1.5:1
   D. Over 50 miles, at a ratio of 2:1

4. Interpollutant Offsets: The Air Pollution Control Officer may approve interpollutant offsets on a case-by-case basis, provided that the Applicant demonstrates to the satisfaction of the Air Pollution Control Officer, through the use of an impact analysis, that the emission increases from the new or modified source will result in a net air quality benefit and will not cause or contribute to a violation of any air quality standard. In such cases, the Air Pollution Control Officer may, based upon an air quality analysis, impose offset ratios greater than the requirements of this rule.

5. Ambient Air Quality Standards: In no case shall the emissions from the new or modified stationary source cause or make worse the violation of an Ambient Air Quality Standard. An impact analysis shall be used to estimate the effects of a new or modified source. In making this determination, the Air Pollution Control Officer shall take into account the mitigation of emissions through offsets obtained pursuant to this rule.

Table 8.1-35 summarizes the LORS.

8.1.5.10.2 Best Available Control Technology

Federal requirements pertaining to control of pollutants subject to PSD review (i.e., attainment pollutants) were promulgated by U.S. EPA in 40 CFR 42.21 (j). This regulation defines BACT as emission limits "based on the maximum degree of reduction for each pollutant." BACT determinations are made on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs. Federal requirements pertaining to control of nonattainment pollutants, or Lowest Achievable Emission Rate (LAER), were promulgated by U.S. EPA under 40 CFR 51.165 (a). This regulation defines LAER as the emissions limit based on either (1) the most stringent emission rate contained in a State Implementation Plan, unless the [source] demonstrates the rate is not achievable; or (2) the most stringent emissions limitation that is achieved in practice. The federal LAER does not consider the cost impacts of control.

The CCAPCD defines BACT in Rule 3.6 as the most stringent emission limit or control technology that either:

1. Has been achieved in practice; or
2. Is contained in a State Implementation Plan approved by U.S. EPA unless demonstrated not to be achievable; or
3. Emission limits found by the Air Pollution Control Officer to be feasible and cost-effective for such class or category of sources or specific source.

The primary air emission sources for the proposed project are two parallel power generation trains. Each train consists of one natural-gas-fired "7FA" technology combustion turbine generator (CTG) set and a supplementary-fired heat recovery steam generator (HRSG). The steam produced by the two HRSGs will be combined and sent to a single steam turbine generator (STG). The proposed project will have a nominal rating of approximately 660 MW.

Applicable BACT levels are shown in Table 8.1-34. CCAPCD Rule 3.6 requires the proposed project to apply BACT if the project's emission levels are in excess of the applicability levels shown in the table. The criteria air pollutants to be emitted at the HRSG stacks include NO_X, CO, PM_{10}, SO_2, and POCs. Given these thresholds, BACT will be required for NO_X, POC, PM_{10}, and CO emissions control for the proposed project.

In addition to the power generation train, an auxiliary boiler and two emergency diesel engines will also be air emission sources on the site. The auxiliary boiler will have a heat input of 40 MMBtu/hr and will operate a maximum of 2,400 hours per year. The auxiliary boiler will emit criteria air pollutants at levels below the BACT significant thresholds shown in Table 8.1-34. BACT will be applied to the auxiliary boiler even though the auxiliary boiler does not require BACT. The two emergency diesel engines will operate no more than 50 hours per year and no more than 1 hour per day each. The emergency diesel engines would not emit NO_X or any other pollutant at levels above the BACT significant thresholds shown in Table 8.1-34; therefore, BACT will not apply.

8.1.5.10.2.1 BACT Assessment for CTG/HRSG

The project proposes for NO_X control the use of Dry Low-NO_X (DLN) combustors and SCR with ammonia injection designed to achieve a NO_X emission limit of 2.0 ppmvd (at 15 percent O_2) for a 3-hour average.

Other technologies have either not achieved a NO_X level of 2.0 ppm (at 15 percent O_2) in practice for gas turbines of a similar size to that proposed for the CGS project, or offer equivalent NO_X control efficiency with other less desirable features. Also, the project proposes a CO emission limit of 3.0 ppmvd for a 3-hour average with an oxidation catalyst as a post-combustion control technology. The oxidation catalyst will also reduce VOC emissions. The remainder of this section contains the BACT analysis conducted for the proposed project, and demonstrates that the proposed CTG controls summarized in Table 8.1-35 comply with BACT requirements.

BACT Assessment Methodology

The BACT assessment conducted for the CTGs proposed for the project considered all NO_X and CO control technologies currently proposed or in use on large natural gas–fired combustion turbines (>50 MMBtu/hr heat input). To identify feasible emission limits, several information sources were consulted, including the following:

- U.S. EPA's BACT/LAER Clearinghouse and updates;
- CARB's BACT Clearinghouse database and CARB's BACT Guidelines for Power Plants (adopted 7/22/99);
- South Coast Air Quality Management District (SCAQMD) BACT Guidelines Manual;
- Discussions with permitting staff from U.S. EPA Region IX;
- Recent CEC Applications for Certification; and
- Research conducted by Colusa Generating Station project design engineers.

Table 8.1-36 lists selected recent NO_x BACT determinations for natural-gas-fired combined cycle power projects in California using advanced technology combustion turbines. BACT for the most recent projects that have come on line in the state has been determined to be either 2.0 or 2.5 ppm by volume (ppmvd) (at 15 percent oxygen [O_2]), to be achieved by means of SCR with ammonia injection. All of the five most recent projects to be approved by CEC committed to a NO_x BACT level of 2.0 ppmvd at 15% O_2. The CTG in this project will achieve the BACT concentration of 2.0 ppmvd at 15 percent O_2 using dry low-NO_x combustor technology (rather than steam or water injection, as a means of water conservation), and SCR.

Similarly, the most recent combined cycle turbine projects have been approved with a CO emissions limit between 2 and 6 ppmvd and a ROC emissions limit at or near 2 ppmvd (both at 15 percent O_2), based on the use of an oxidation catalyst. The CTG in this project will employ the same control technology to achieve comparable CO and ROC stack exhaust levels. Exclusive use of natural gas fuel has been determined to be BACT for SO_x and PM_{10} in all other comparable projects for several years.

NO_X Control Technologies

Based on a review of materials described above, the following NO_X control technologies were evaluated to determine whether they are able to achieve BACT NO_X levels in practice:

- DLN and XONON™;
- DLN and Goal Line SCONOx™; and
- DLN and SCR with ammonia injection.

XONON™. The XONON combustion system improves the combustion process by lowering the peak combustion temperature to prevent the formation of NO_X while avoiding the increases in CO and unburned hydrocarbons (UHC) associated with other NO_X control technologies (such as water injection and dry low-NO_x). Most gas turbine emission control technologies remove air contaminants from exhaust gas prior to release to the atmosphere. In contrast, the overall combustion process in the XONON system is a

partial combustion of the fuel in the catalyst module followed by completion of the combustion downstream of the catalyst. In the catalyst module a portion of the fuel is combusted without a flame (i.e., at relatively low temperature) to produce a hot gas. A homogeneous combustion region is located immediately downstream where the remainder of the fuel is combusted.

The key feature of the XONON combustion system is a proprietary catalytic component, called the XONON Module, which is integral to the gas turbine combustor. XONON combusts the fuel without a flame, thus eliminating the peak flame temperatures that lead to NO_X. Turbine performance is not affected.

XONON is an innovative technology that is currently being commercialized on smaller-scale projects with support from the U.S. Department of Energy, California Energy Commission, and the CARB. The CARB has reported on the pilot effort underway in Santa Clara where the XONON system is operating at a 1.5 MW simple-cycle pilot facility. The CARB indicated in their June 1999 Stationary Source Division Report *Guidance for Power Plant Siting and Best Available Control Technology*, page 23 (CARB 1999): "Emission levels from 1.33 to 4.04 ppmvd NO_X at 15 percent oxygen (O_2) have been achieved at Silicon Valley Power utilizing the XONON™ technology." But they further indicate that "there is not sufficient operating experience to ensure reliable performance on large gas turbines."

Because XONON s not currently commercially demonstrated technology for the General Electric Frame 7FA combustion turbine model and it has received very limited trial operation only on much smaller CTG units, XONON is not considered as a viable NO_X emissions control option for CGS.

SCONOx™. SCONOx is a new NO_x reduction system produced by Goal Line Environmental Technologies (now distributed by EmeraChem) for gas turbine applications. This system uses a coated catalyst to oxidize both NO_x and CO, thereby reducing plant emissions of these pollutants. CO emissions are reduced in SCONOx by the oxidation of CO to CO_2. A two-step process reduces the NO_x emissions. First, NO_x emissions are oxidized to NO_2 and then adsorbed onto the catalyst. In the second step, a proprietary regenerative gas is periodically passed through the catalyst. This gas de-desorbs the NO_2 from the catalyst and reduces it to N_2. The system does not use ammonia as a reagent; rather, it uses natural gas as the basis for a proprietary catalyst regeneration process.

As demonstrated by an initial installation on several gas turbines where energy is recovered from the exhaust gas to produce steam, SCONOx is capable of achieving NO_x emission concentrations of 2 ppm based on a maximum inlet concentration of 25 ppm, and 90 percent CO reduction based on a maximum inlet concentration of 50 ppm. However, the effectiveness of the SCONOx technology has not been demonstrated on turbines as large as the GE 7FA turbine proposed for the CGS project.

Vendors of the SCONOx technology have stated that it is commercially ready for turbines of any size. However, the largest turbine that SCONOx has actually been applied to thus far is a GE LM2500, approximately 25 MW in capacity, or about one-fifth the size of the proposed project. The Otay Mesa Power Project (which would have used Frame 7F turbines in a combined cycle configuration) was permitted with a commitment to use the SCONOx technology as the primary NO_x and CO control method if possible, but construction of that project has been postponed for several years. The AFC filed in 2000 for the Nueva Azalea Project also proposed to use the SCONOx technology, but this project was ultimately never built.

SCONOx would not require an oxidizing catalyst or the use of ammonia reagent to control CO and NO_x emissions. The SCONOx technology employs a reactive catalyst that must be regenerated on a regular basis. The catalyst reacts with CO and NO to form CO_2, which is emitted, and NO_2, which is absorbed on the surface of the catalyst until it is saturated. Prior to saturation, the catalyst is regenerated. This is accomplished by sealing off the catalyst from the exhaust stream by means of a pair of mechanical louver

doors and subjecting it to a mixture of natural gas and steam that forms hydrogen to produce elemental nitrogen and CO_2, which are emitted through the stack.

The manufacturer of SCONOx recommends that the catalyst in each module be removed and put through a regenerative bathing process once a year. An on-line catalyst washing system design has not yet been fully developed. There is some concern that the bathing process may result in an additional hazardous waste stream. The time required for this process is not clearly known, but it is likely to be approximately 1 to 2 weeks. Also, there may be a requirement that liquefied natural gas be stored on site for use during the regular regeneration process of the catalyst throughout the year.

For large gas turbines, an assembly of multiple SCONOx modules would be required to control NO_x and CO to 2 ppm each. For example, proposals for installation of the technology on Frame 7F turbine have specified up to 15 such modules, with a capital cost of $26 million (Three Mountain Power Plant, 99-AFC-2). Testing has not yet been conducted to demonstrate the successful operation of the louver doors used by each module under realistic flow and emissions conditions that would be found in large turbines. Also, control algorithms have not yet been developed or tested for controlling large numbers of SCONOx modules. Due to the lack of appropriate testing and information, some HRSG manufacturers have expressed reluctance to issue guarantees for their equipment if SCONOx is installed (Beck, 2000).

Although the SCONOx technology has been demonstrated to be an effective NO_x and CO emission abatement system on a few small combined cycle turbine installations and does not require the use of ammonia reagent, an SCR system has virtually the same NO_x emissions guarantee as the SCONOx at a much lower price, and has been successfully demonstrated extensively on large Frame-type turbines.

Potential advantages of the SCONOx process include:

- **No ammonia.** The SCONOx process does not use ammonia. This eliminates the ammonia storage and transportation safety issues entirely and the potential for ammonia slip or ammonia-based particulate formation.

- **Carbon monoxide reduction.** SCONOx will reduce CO emissions as well as NO_x emissions.

Potential disadvantages of the SCONOx process include:

- **Unproven for large gas turbines.** While demonstrated to be effective on smaller turbines, several aspects of the technology have not been demonstrated for a system configured for a larger turbine.

- **Catalyst "washing."** A proprietary catalyst washing system must be used and an on-line catalyst washing system design has not yet been fully developed. If an on-line catalyst washing system is not used, then the facility must be shut down for cleaning.

- **High capital and operating cost.** SCONOx is significantly more expensive than SCR with ammonia injection, primarily due to the higher cost of initial and replacement catalyst. The SCONOx catalyst is a precious metal catalyst, which is very expensive.

Because the performance of SCONOx has not been sufficiently demonstrated as "achieved in practice" on large combined cycle turbines, as discussed above, SCONOx does not represent BACT for the CGS project at this time.

SCR with Ammonia Injection. SCR with ammonia injection systems for reduction of NO_x emissions have been widely used in combined cycle gas turbine applications for many years and are considered a

proven technology. SCR systems are commercially available from several vendors, unlike SCONOx, which is available from a single vendor. The SCR process involves the injection of ammonia into the flue gas stream via an ammonia injection grid upstream of a catalyst. The ammonia reacts with the NO_x gases in the presence of the catalyst. The catalyst is not regenerated and requires periodic replacement. SCR vendors typically offer a 3-year guarantee on catalyst life. SCR with ammonia injection systems have been used in numerous larger combined cycle applications including 7FA Class units.

Dry Low-NO_x combustion is a system design employed by several major turbine vendors. Virtually all gas turbine manufacturers are continuing to research and improve on these advanced combustion technologies because they represent the most cost-effective NO_X reduction approach. The source of NO_X emissions from natural gas turbines is the thermal NO_X formation reaction, which is very dependent on combustor design. This reaction converts natural atmospheric nitrogen and oxygen to NO_X at the high temperatures of combustion. Dry Low-NO_x combustion results in turbine exhaust NO_X emission rates of 25 ppmvd (at 15 percent O_2) or less.

As noted in Table 8.1-36, for large turbines that are similar in capacity to the CGS turbines, dry low-NO_x and SCR have been permitted at NO_X emissions of 2.0 ppm (at 15 percent O_2). Thus, Dry Low-NO_x with SCR with ammonia injection, designed to achieve a NO_X emission limit of 2.0 ppm (at 15 percent O_2) on a 3-hour average, is considered BACT.

CO Control Technologies

CO emissions from the CTGs/HRSGs will be controlled by the use of post-combustion oxidation catalysts to be located in the HRSGs. The CGS CTGs/HRSGs with CO oxidation catalyst are guaranteed to achieve 3.0 ppm (at 15 percent O_2) on a 3-hour average, except during startup and shutdown. A review of recent BACT determinations in Table 8.1-37 indicates that the CARB BACT guideline CO emission limit of 3 ppmvd (at 15 percent O_2) has been required of recent projects. The proposed BACT limit for the CGS CTGs/HRSGs more than satisfies the BACT requirements. CO oxidizing catalysts have been used with natural gasfired turbines for over a decade. CO catalysts operate at elevated temperatures within the HRSG.

POC and PM_{10} Control Technologies

The proposed CGS BACT level of 2.0 ppmvd (at 15 percent O_2) for VOC control with effective combustion conforms with CARB guidelines. The CGS turbines are not expected to exceed 2.0 ppm VOC when the duct burners are firing. The CGS VOC emissions are consistent with those of other recent projects. PM_{10} emissions will be controlled through the use of clean burning pipeline quality natural gas.

8.1.5.10.2.2 Fugitive Dust Control

Other controls that will be implemented at the CGS site include best achievable control measures (BACM) during construction. Fugitive dust control measures that are stipulated by CCAPCD Rule 2-16 include the following:

- Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the construction of roadways or the clearing of land; and

- Application of asphalt, oil, water, or suitable chemicals on dirt roads, materials stockpiles, and other surfaces which can give rise to airborne dusts.

The CGS proposes to use the following fugitive dust suppression program to reduce construction-related emissions. These may be considered as mitigations to air pollutant impacts. Fugitive dust emissions are expected to be reduced by 90 percent. The use of chemical additives is not planned.

- Frequent watering of unpaved roads and disturbed areas (at least twice a day).
- Limit speed of vehicles on the construction areas to no more than 10 miles per hour.
- Construction site entrance shall be posted with visible speed limit signs.
- Sweep paved internal roads after the evening peak period.
- Increase frequency of watering when wind speeds exceed 15 miles per hour.
- Employ tire washing and gravel ramps prior to entering a public roadway to limit accumulated mud and dirt deposited on the roads.
- Treat the entrance roadways to the construction site with soil stabilization compounds.
- Place sandbags adjacent to roadways to prevent runoff to public roadways.
- Install windbreaks at the windward sides on construction areas prior to the soil being disturbed. The windbreaks shall remain in place until the soil is stabilized or permanently covered.
- Employ dust sweeping vehicles at least twice a day to sweep at least the first 500 feet of public roadways that are used by construction and worker vehicles.
- Sweep newly paved roads at least twice weekly.
- Replace ground cover in disturbed areas as quickly as possible.
- Cover all trucks hauling dirt, sand, soil or other loose materials and maintain a minimum of 6 inches of freeboard between the top of the load and the top of the trailer.
- Limit on equipment idle times (no more than 15 minutes.)
- Employ electric motors for construction equipment when feasible.
- Apply covers or dust suppressants to soil storage piles and disturbed areas that remain inactive for over 2 weeks.
- Pre-wet the soil to be excavated during construction.
- Designate a person to oversee the implementation of the fugitive dust control program.

8.1.5.10.2.3 Construction Equipment Exhaust Emissions

As further mitigations to air pollutant impacts, to reduce construction-related emissions associated with equipment exhaust, CGS proposes the following program:

- All diesel-fueled engines used for construction of the facility shall be fueled only with ultra-low sulfur diesel which contains no more than 15 ppm sulfur.

- All diesel-fueled engines used in the construction shall have clearly visible tags showing that the engine meets the conditions set forth in this program.

- All construction diesel engines rated at 100 horsepower or above shall meet at least the California Tier 2 Emissions Standards. If a Tier 2 engine is not available, a Tier 1 engine shall be provided. In the case that no Tier 1 engine is available for a particular application, the engine shall be equipped with a catalyzed diesel particulate filter (soot filter), unless the use of a soot filter is certified as not practical by the engine manufacturer.

- All earthmoving equipment and heavy-duty construction related trucks shall be properly maintained and the engines tuned to the manufacturer's specifications.

- Diesel heavy construction equipment shall not remain running at idle for more than 5 minutes, to the extent practical.

8.1.6 Involved Agencies and Agency Contacts

Agency contacts regarding public health assessment of the proposed project are as follows:

Issue	Agency/Address	Contact/Title	Telephone
Air Quality	California Energy Commission 1519 Ninth Street Sacramento, CA 95814	Eileen Allen, Siting Program Manager Keith Golden, Senior Mechanical Engineer	(916) 654-3940
Air Quality	Colusa County Air Pollution Control District 100 Sunrise Blvd. #F Colusa, CA 95932-3246	Harry Krug, Director of Air Quality Standards	(530) 458-0590
Air Quality	U.S. Environmental Protection Agency 75 Hawthorne Street San Francisco, CA 94105	Gerardo Rios, Chief, New Source Review Section Carol Bohnenkamp, Regional Modeler	(415) 744-1500
Air Quality	California Air Resources Board P.O. Box 2815 Sacramento, CA 95812	Michael Tollstrup, Chief, Project Assessment Branch Stationary Source Division	(916) 322-6026
Air Quality	Wintun Environmental Protection Agency P.O. Box 1839 Williams, CA 95987	Kesner Flores, Cortina Rancheria	(530) 473-3318

8.1.7 Permits Required and Permitting Schedule

This section lists the required permits related to air quality for the proposed project. The permits are summarized in the following table.

Responsible Agency	Permit/Approval	Schedule
Colusa County Air Pollution Control District (CCAPCD)	Authority to Construct/Permit to Operate	Application to be filed concurrent with AFC filing. 180-day application review period.
U.S. Environmental Protection Agency	Prevention of Significant Deterioration (PSD) Permit Application	Application to be filed concurrent with AFC filing. 180-day application review period will be requested.

Under Regulation 3, Rule 3-6, CCAPCD regulates the construction, alteration, replacement, and operation of new power plants. The proposed project is required to obtain a preconstruction Determination of Compliance from the CCAPCD. Regulation 3, Rule 3-1 incorporates other CCAPCD rules pertaining to sources that may emit air contaminants through the issuance of air permits (i.e., Authority to Construct and Permit to Operate). This permitting process allows the CCAPCD to adequately review new and modified air pollution sources to ensure compliance with all applicable prohibitory rules and to ensure that appropriate emission controls are used. An Authority to Construct allows for the construction of the air pollution source and remains in effect until the Permit to Operate application is granted, denied, or canceled. For power plants under the siting jurisdiction of the CEC, the CCAPCD issues a Determination of Compliance in lieu of an Authority to Construct. The Determination of Compliance is incorporated into the CEC license. Once the project commences operation and demonstrates compliance with the Determination of Compliance, CCAPCD will issue a Permit to Operate. The Permit to Operate specifies conditions that the air pollution source must meet to comply with other air quality standards and will incorporate applicable Determination of Compliance requirements. The Final Determination of Compliance should be issued within 6 months after receipt of complete applications.

8.1.8 References

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Table 8.1-1
Temperature and Precipitation Data for Colusa 2 SSW Station, Colusa, California

Month	Average Temperatures (°F) [a]			Average Precipitation (inches)
	Low	High	Daily	
January	36.7	53.6	45.2	3.48
February	40.2	60.3	50.3	2.81
March	42.2	65.6	53.9	2.27
April	45.2	73.7	59.5	0.95
May	51.9	81.8	66.9	0.53
June	56.9	89.7	73.3	0.21
July	59	95.2	77.1	0.04
August	57.3	93.7	75.5	0.07
September	54	89.4	71.7	0.28
October	47.8	79	63.4	0.89
November	40.8	64	52.4	2.16
December	36.5	54.2	45.4	2.55
Annual Average	47.4	75	61.2	16.23

Source: NWS, 2001.
Note:
[a]Average temperature and precipitation data represent 1948–2000.

Table 8.1-2
Ambient Ozone Levels at Colusa Region, 1996-2005 (ppm)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Colusa–Sunrise Boulevard Station, Colusa County										
Maximum 1-Hour Average	0.111	0.093	0.099	0.095	0.092	0.101	0.094	**0.089**	0.084	0.085
Number of Days Exceeding California 1-Hour Standard (0.09 ppm)	5	0	2	1	0	5	0	0	0	0
Number of Days Exceeding Federal 1-Hour Standard (0.12 ppm)	0	0	0	0	0	0	0	0	0	0
Maximum 8-Hour Average	0.091	0.081	0.088	0.085	0.072	0.088	0.081	0.071	0.073	**0.074**
Number of Days Exceeding Federal 8-Hour Standard (0.08 ppm)[a]	3	0	1	1	0	3	0	0	0	0

Source: California Air Resources Board (CARB), 2006, www.arb.ca.gov.
Notes:
[a] Number of days with an 8-hour average exceeding federal standard concentration of 0.08 ppm. Regulatory standard is to maintain 0.08 ppm as a 3-year average of the fourth-highest daily maximum. Therefore, number of days exceeding standard concentration is not the number of violations of the standard for the year.
[1] Maximum average values occurring during the most recent 3 years are indicated in bold.
[2] National standards, other than those for ozone and based on annual averages, are not to be exceeded more than once a year. 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.
[3] New federal 8-hour ozone and fine particulate matter ($PM_{2.5}$) standards were promulgated by U.S. EPA on July 18, 1997. The federal 1-hour ozone standard was revoked by U.S. EPA on June 15, 2005.

ppm = parts per million

Table 8.1-3
Ambient PM_{10} Levels in the Colusa Region, 1996-2005 ($\mu g/m^3$)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Colusa–Sunrise Boulevard Station, Colusa County										
Maximum 24-Hour Average	57	57	58	171	48	76	64	69	81	**92**
Annual Geometric Mean	22.1	21.9	16	24.7	18.7	25.2	--	--	--	**25.5**
Annual Arithmetic Mean	26.8	24.5	19.5	33.4	22.7	13.8	14.5	11.5	15.5	**23.8**
Estimated Number of Days Exceeding California 24-Hour Standard (50 $\mu g/m^3$)	18	9	6	60	0	7.1	0	0	0	**25.8**

Source: California Air Resources Board (CARB), 2006, www.arb.ca.gov.
Notes:
Maximum average values occurring during the most recent 3 years are indicated in bold.

-- = Data not available
$\mu g/m^3$ = micrograms per cubic meter
µm = micrometer

Table 8.1-4
Ambient $PM_{2.5}$ Levels in the Colusa Region, 1996-2005 ($\mu g/m^3$)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Colusa–Sunrise Boulevard Station, Colusa County										
Maximum 24-Hour Average	--	--	37	55	28	36	57	30	45	**47**
Estimated Number of Days Exceeding Federal 24-Hour Standard (35 $\mu g/m^3$)	--	--	0	0	0	0	0	0	0	**0**
1-Year 98th Percentile	--	--	--	--	26	31	--	27	**34**	16
3-Year Average, 98th Percentile[a]	--	--	--	--	--	--	--	--	--	**26**
Annual Arithmetic Mean	--	--	--	--	8	9.6	--	**8**	7.3	7
3-Year Average, Arithmetic Mean[b]	--	--	--	--	--	10	10	10	7	**11**

Source: California Air Resources Board (CARB), 2006, www.arb.ca.gov.
Notes:
[a] The 3-Year Average, 98th Percentile is below the federal AAQS of 35 $\mu g/m^3$.
[b] The 3-Year Average, Arithmetic Mean is below the California AAQS of 12 $\mu g/m^3$
Maximum average values occurring during the most recent 3 years are indicated in bold.
-- = Data not available
$\mu g/m^3$ = micrograms per cubic meter
µm = micrometer

Table 8.1-5
Ambient Carbon Monoxide Levels at Colusa Region, 1996-2005 (ppm)

Averaging Time	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Yuba City–Almond Street Station, Sutter County										
Maximum 1-Hour Average [a]	7.7	6.1	7.3	7.2	5.8	6.9	4.7	3.2	**5.8**	4.4
Maximum 8-Hour Average [b]	4.66	4.08	4.86	4.37	3.6	3.94	3.45	2.36	2.54	**3.39**

Source: California Air Resources Board (CARB), 2006, www.arb.ca.gov.
Notes:
Maximum average values occurring during the most recent 3 years are indicated in bold.
[a] All 1-hour concentrations are below the federal and California CO ambient air quality standards of 35 ppm and 20 ppm, respectively.
[b] All 8-hour concentrations are below the federal and California CO ambient air quality standard of 9 ppm.
ppm = parts per million

Table 8.1-6
Ambient Nitrogen Dioxide Levels at Colusa Region, 1996-2005 (ppm)

Averaging Time	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Yuba City–Almond Street Station, Sutter County										
Maximum 1-Hour Average [a]	0.068	0.073	0.074	0.085	0.072	0.079	0.068	**0.080**	0.066	0.062
Annual Average [b]	0.012	0.014	0.013	0.014	0.013	0.014	0.015	**0.014**	0.012	0.012

Source: California Air Resources Board (CARB), 2006, www.arb.ca.gov.
Notes:
Maximum average values occurring during the most recent 3 years are indicated in bold.
Arithmetic average 1-hour for 2004 – 2005 period equals 0.064 ppm.
[a] All 1-hour concentrations are below the California NO_2 ambient air quality standard of 0.25 ppm.
[b] All annual average concentrations are below the federal NO_2 ambient air quality standard of 0.053 ppm.
ppm = parts per million.

Table 8.1-7
Ambient Sulfur Dioxide Levels at Colusa Region, 1996-2005 (ppm)

Averaging Time	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Sacramento–Del Paso Manor Station, Sacramento County										
Maximum 1-Hour Average [a]	0.013	0.015	--	--	--	0.023	0.007	**0.006**	0.005	0.003
Maximum 24-Hour Average [b]	0.006	0.006	0.018	0.014	0.008	0.017	0.005	**0.003**	0.003	0.003
Annual Average [c]	0.002	0.002	0.003	0.004	0.005	0.002	0.001	**0.001**	0.001	0.001

Source: California Air Resources Board (CARB), 2006, www.arb.ca.gov.
Notes:
Maximum average values occurring during the most recent 3 years are indicated in bold.
[a] All 1-hour average concentrations are below the California SO_2 ambient air quality standard of 0.5 ppm (1,300 µg/m^3)
[b] All 24-hour average concentrations are below the California SO_2 ambient air quality standard of 0.04 ppm (105 µg/m^3) and the federal ambient air quality standard of 0.14 ppm (365 µg/m^3).
[c] All annual average concentrations are below the federal SO_2 ambient air quality standard of 0.03 ppm (80 µg/m^3).
-- = Data not available
µg/m^3 = micrograms per cubic meter
ppm = parts per million

Table 8.1-8
Estimated Number of Pieces of Construction Equipment and Schedule
(Page 1 of 2)

Construction Equipment	Average Hours per Day	Average Units On Site Per Month																								Total Months
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
Excavator Loader	7	1	3	3	3	2	2	1	1	1	1	1	1													20
Excavator Backhoe	7	1	3	3	3	2	2	1	1	1	1	1	1													20
Dozer Tractor Crawler	7	3	3	3																						9
Front End Loader	7				1	1	1	1	1	1	1	1	1	1	1	1	1									13
Trenching Machine	6	1	2	2	1																					6
Excavator Motor Grader	7	1	1	1																						3
Vibrating Plate Compactor	6	1	2	2	2	2	3	3	3	3	3	3	2	1	1	1	1	1								34
Roller Vibrator	6	1	1	1	1	1	2	2	2	2	1	1	1	1												17
Water Truck	6	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1								17
Concrete Mixer	3		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1								16
Concrete Pump, trailer mount	3				1	1	1	1	1	1	1	1														8
Mortar Mixer	4			1	1	2	2	2	2	2	2	1	1	1		1										18
Paving Machine	5	1	1															1	1	1						5
Dump Truck	7	6	3	3	1	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	47
Crane (6-ton)	7		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1							17
Crane (20-ton)	7	1	2	2	2	2	2	3	3	3	3	3	3	2	2	2	1									36
Crane (50-ton)	7	1	2	2	2	3	3	3	3	4	4	4	3	3	2	2	1	1								43
Crane (100-ton)	7					1	1	1	1	1	1	1	1	1	1	1										11

Table 8.1-8
Estimated Number of Pieces of Construction Equipment and Schedule
(Page 2 of 2)

Construction Equipment	Average Hours per Day	Average Units On Site Per Month																								Total Months
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
Crane (300-ton)	8							1	1	1	1	1	1													6
Crane (360-ton)	8							1	1	1	1	1	1													6
Crane (500-ton)	8							1	1	1	1															4
Manlift, telescoping	4				1	1	2	2	2	2	2	2	2	2	1	2	1	1	1	1	1	1	1	1	1	30
Welder (250 amp)	6		1	1	2	2	2	3	4	4	4	3	3	2	2	2	2	2	1	1						41
Air Compressor (185 cfm)	8	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1					20
Air Compressor (750 cfm)	8					1	2	2	2	2	2	2	1	1	1	1	1	1	1							20
Generator (6 kW)	8	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2								30
Forklift (2-ton)	6	1	1	1	1	1	1	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	27
Forklift (4-ton)	6			1	1	2	2	2	2	2	2	2	2	2	2	2	2									26
Fuel/Lube Truck	4	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	24
Pickup Truck (1/2-ton)	5	3	3	3	3	3	5	5	5	5	5	5	5	5	5	5	5	5	4	4	3	2	2	2	2	94
Stakebed Truck	6	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1							18
Hydraulic Boom Truck	4		1	1	1	1	1	1	1	1		1	1	1	1	1	1	1	1	1						17
Concrete Trowel	3	1	1	2	2	2	2	2	2	1	1	1														17
Concrete Floor Saw	2					1	1	1	1	1	1	1	1	1	1	1	1									12
Bobcat Skip Loader	6	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2								32
Hydrotest Pump	3															1	1	1	1							4

Note: Above estimates are for a single shift and five 10-hour-day work week.

Table 8.1-9
Controlled Fugitive Dust as PM_{10} Emissions from Earth Moving

Fugitive Dust Source	PM_{10} Emissions Pounds Per Month		
	Month 1	Month 2	Month 3
Loading of Dump Trucks with Excavated Material	420.9	210.4	210.4
Unloading of Dump Trucks	22.8	11.4	11.4
Transportation of Earth on Unpaved Roads	766.9	383.5	383.5
Dirt Pushing and Bulldozing	224.6	224.6	224.6
Total	1,435.2	829.9	829.9

Note:
Worst 1-hour would be 7.2 lb/hr

Table 8.1-10
Estimated Criteria Pollutant Emissions From Construction Equipment Exhaust

	NO_X	CO	VOC	SO_X	PM_{10}
Worst-Case Monthly Emissions (lbs/month)	5,797.2	3,567.3	892.7	6.1	464.4
Worst-Case Hourly Emissions (lbs/hr)[a]	29.9	17.8	4.5	0.03	2.3
Worst-Case Annual Emissions (lbs/yr)[b]	59,018.7	36,310.2	8,968.1	65.4	4806.8

Notes:
[a] Worst-case hourly emissions were estimated by dividing worst-case monthly emissions by 200 hours (20 days of 10 hours each). Total emissions were based on projected daily hours of equipment operation in a given month. Daily average hours of operation are shown in Appendix G.
[b] Worst-case annual emissions were estimated by summing emissions for each 12-month period (i.e., months 1 to 12, 2 to 13, etc.) during the 24-month construction period and taking the maximum emissions for the worst 12-month period (i.e., month 1 to 12 for CO, VOC, SO_X, PM_{10}, and NO_X).

Table 8.1-11
Estimated Peak PM_{10} Emissions During Construction

Emissions Estimate Scenario	Fugitive Dust PM_{10} Peak	Exhaust PM_{10} (during fugitive dust peak)[a]	Total PM_{10} Combined Peak
Worst-Case Monthly Emissions (lbs/month)	3,056.6	349.3	3,405.9
Worst-Case Hourly Emissions (lbs/hr)[b]	15.2	1.8	17
Worst-Case Hourly Emissions (lbs/day)[b]	152.8	17.5	170.3
Worst-Case Annual Emissions (lbs/yr)[c]	14,577.1	4,806.8	19,338.9

Notes:
[a] Exhaust PM_{10} peak month shown in Table 8.1-8 above does not occur in same month as Fugitive Dust Emissions peak month.
[b] Worst-case hourly emissions were estimated by dividing worst-case monthly emissions by 200 hours (20 days of 10 hours each). Total emissions were based on projected daily hours of equipment operation in a given month. Daily average hours of operation are shown in Appendix G.
[c] Worst-case annual emissions were estimated by summing emissions for each 12-month period (i.e., months 1 to 12, 2 to 13, etc.) during the 24-month construction period and taking the maximum emissions for the worst 12-month period.

Table 8.1-12
Estimated Criteria Pollutant Emissions From Vehicle Trips During Construction

Vehicle Type	One-Way Trips	NO_X	CO	VOC	SO_X	PM_{10}
Peak Emissions		**Pounds Per Day**				
Construction Employee Cars	223	2.4	27.2	3.0	<0.1	0.2
Construction Employee Trucks	223	4.4	42.2	4.1	<0.1	0.2
Delivery Trucks	16	4.9	3.3	0.4	<0.1	0.1
Total	**462**	**11.7**	**72.7**	**7.5**	**<0.1**	**0.4**
Average Emissions		**Pounds Per Day**				
Construction Employee Cars	99	1.1	12.2	1.3	<0.1	0.1
Construction Employee Trucks	100	2.0	18.8	1.8	<0.1	0.1
Delivery Trucks	15	4.6	3.1	0.4	<0.1	0.1
Total	**214**	**7.6**	**34.1**	**3.5**	**<0.1**	**0.2**

Notes:
Vehicle type and number of trips taken from Table 8.10-10.
Vehicle emissions within 10 miles of the project site included.
EMFAC 2002 Datum, Analysis Year 2007
EMFAC output shown in Appendix G.
Numbers may not add due to rounding.

Table 8.1-13
Estimated Criteria Pollutant Emissions From Vehicle Trips During Operation

Vehicle Type	One-Way Trips	NO_X	CO	VOC	SO_X	PM_{10}
Peak Hour Emissions		**Pounds Per Hour**				
Employee Cars	9	0.1	0.8	0.1	<0.1	<0.1
Employee Trucks	9	0.1	1.4	0.1	<0.1	<0.1
Delivery Trucks	1	0.3	0.2	0.0	<0.1	<0.1
Total	**19**	**0.5**	**2.4**	**0.2**	**<0.1**	**<0.1**
Average Daily Emissions		**Pounds Per Day**				
Employee Cars	15	0.1	1.5	0.2	<0.1	<0.1
Employee Trucks	16	0.3	2.4	0.2	<0.1	<0.1
Delivery Trucks	3	0.8	0.5	0.1	<0.1	<0.1
Total	**34**	**1.1**	**4.3**	**0.4**	**<0.1**	**<0.1**

Notes:
Vehicle type and number of trips taken from Table 8.10-10.
Vehicle emissions within 10 miles of the project site included.
EMFAC 2002 Datum, Analysis Year 2009
EMFAC output shown in Appendix G.
Numbers may not add due to rounding.

Table 8.1-14
Estimated Criteria Pollutant Emission Rates for the Colusa Generating Station Project Turbines and SCR with Ammonia Injection During Normal Operation (pounds per hour for two turbines)

Load	Pollutant	Ambient Temperature		
		18ºF	59ºF	114ºF
100%	VOC	6.8	6.2	6.0
	Ammonia Slip	28.4	26.2	25.0
	CO	28.0	26.0	24.6
	NO_X	30.6	28.4	27.0
	SO_2	2.4	2.2	2.2
	PM_{10}	25.8	25.6	25.6
75%	VOC	5.4	5.0	5.0
	Ammonia Slip	22.8	21.2	20.4
	CO	22.6	21.0	20.0
	NO_X	24.6	23.0	22.0
	SO_2	2.0	1.8	1.8
	PM_{10}	25.4	25.4	25.2
50%	VOC	4.4	4.2	4.2
	Ammonia Slip	18.0	16.8	15.8
	CO	17.8	16.6	15.6
	NO_X	19.4	18.2	17.2
	SO_2	1.6	1.4	1.4
	PM_{10}	25.2	25.0	25.0
100% with Duct Burners	VOC	14.4	13.6	13.2
	Ammonia Slip	38.4	36.4	35.2
	CO	37.8	35.8	34.8
	NO_X	41.4	39.2	38.0
	SO_2	3.2	3.0	3.0
	PM_{10}	40	39.8	40.2

Table 8.1-15
Expected Criteria Pollutant Emission Rates for the Colusa Generating Station Project Turbines During Startup and Shutdown (for each turbine)

	Cold Startup		Warm Startup		Hot Startup		Shutdown	
	270 Minutes		180 Minutes		90 Minutes		30 Minutes	
Pollutant	Max lb/hr	Total lb/270 min	Max lb/hr	Total lb/180 min	Max lb/hr	Total lb/90 min	Max lb/hr	Total lb/30 min
NO_X	333.3	779.10	152.00	456.20	249.90	259.90	115.00	115.00
CO	373.60	1355.60	370.30	790.50	429.60	679.60	483.50	483.50
VOC	27.7	106.70	27.7	47.40	27.7	38.00	23.9	23.90
SO_2	0.40	1.01	0.40	0.58	0.40	0.33	0.20	0.20
PM_{10}	12.00	48.80	12.00	30.80	12.00	12.80	6.00	6.00

Table 8.1-16
Estimated Criteria Pollutant Annual Emissions for the Turbines

Pollutant	1st Quarter Emissions (tons)[a]	2nd Quarter Emissions (tons)[a]	3rd Quarter Emissions (tons)[a]	4th Quarter Emissions (tons)[a]	Annual Emissions (tons)[a]
NO_X	45.1	43.1	50.9	43.8	182.9
CO	53.4	51.6	106.3	53.1	264.4
VOC	12.3	11.6	11.8	11.7	47.4
PM_{10}	35.1	35.2	35.4	35.5	141.2
SO_2	3	2.8	2.6	2.8	11.2

Notes:
[a] Includes emissions from two turbines. See Appendix G for details.

Table 8.1-17 Estimated Worst-Case Short-Term Emission (per turbine)	
1-Hour Emissions (lbs/hr)	
NO_X	333.30
CO	483.50
VOC	27.7
PM_{10}	20.1
SO_2	1.60
3-Hour Emissions (lbs/3-hr)	
SO_2	4.80
8-Hour Emissions (lbs/8-hr)	
CO	1,896
24-Hour Emissions (lbs/day)	
NO_X	1,497.30
CO	3,829.50
VOC	315.30
PM_{10}	482.4
SO_2	38.4
Normal operation excluding commissioning	

Table 8.1-18
Estimated Criteria Pollutant Emissions from Gas Turbine Commissioning

	VOC	CO	NO_x	SO_x	PM_{10}
Worst-Case Commissioning Emissions (lbs/hr/ct)[a]	7.2	<950	<500	1.60	20.1
Total Commissioning Period Emissions (tons/ct)[b]	6.75	152	48.5	0.6	7

Notes:
[a] Worst-case hourly emissions for VOC, SO_x, and PM_{10} from Table 8.1-14 adjusted to reflect one turbine. CO and NO_x emission rates stated equal worst-case hourly emissions which will not be exceeded during commissioning.
[b] Worst-case commissioning period emissions estimated by design engineer.

Table 8.1-19
Auxiliary Boiler Emissions

Pollutant[a]	Emission Factor (lb/MMBtu)	Emissions	
		lb/hr	ton/yr[b]
NO_X	0.0108	0.48	0.57
CO	0.037	1.63	1.95
PM_{10}	0.005	0.18	0.26
SO_2	0.0006	0.03	0.03
VOC	0.004	0.18	0.21

Notes:
[a] NO_X emissions are based on 7 ppm @ 3% O_2 dry. Emissions based on vendor information.
[b] Annual emissions based on 2,400 hours of operation.

Table 8.1-20
Non-Emergency Emissions for Generator and Firewater Pump Engine

	Generator	Firewater Pump
Estimated brake horsepower	1,340	160
Hourly Emissions (pounds per hour)		
NO_X	13.88	1.73
CO	0.32	0.19
VOC	0.15	<0.01
PM_{10}	0.01	<0.00
SO_2	0.09	0.05
Annual Emissions (tons per year)		
NO_X	0.347	0.043 [a]
CO	0.008	0.005
VOC	0.004	0.000 [a]
PM_{10}	0.000	<0.001
SO_2	0.002	0.001

kw = kilowatts
Basis: Manufacturers emissions data, 15 ppm sulfur diesel fuel, Annual emissions based on a maximum of 50 non-emergency hours per year of operation.
[a] NO_X and VOC are combined and reported as NO_X

Table 8.1-21
Quarterly and Annual Estimated Emissions From CGS

Pollutant	1st Quarter Emissions (tons)	2nd Quarter Emissions (tons)	3rd Quarter Emissions (tons)	4th Quarter Emissions (tons)	Annual Emissions (tons)
NO_X	45.77	43.77	51.57	44.47	185.58
CO	55.35	53.55	108.25	55.05	272.20
VOC	12.51	11.81	12.01	11.91	48.24
PM_{10}	35.36	35.46	35.66	35.76	142.24
SO_2	3.03	2.83	2.63	2.83	11.32

Notes:
Includes emissions from two turbines, duct burners, auxiliary boiler, and emergency generator and emergency firewater pump engines.

Table 8.1-22
Modeled Construction Emissions Release Parameters for the Proposed Project

Equipment Exhaust Emissions Source	Stack Characteristics (for the Construction Zone)		
	Release Height (m)	Horizontal Dimension (m)	Vertical Dimension (m)
Volume 1	10	58.14	2.326
Volume 2	10	37.21	2.326
Fugitive Dust Areas	**Release Height (m)**	**East-West Distance (m)**	**North-South Distance (m)**
Fugitive Dust Area 1	3	240	240
Fugitive Dust Area 1	3	150	150

Table 8.1-23
Turbine Impact Screening Results

	Winter Minimum (18 ºF)				Yearly Average (59 ºF)				Summer Maximum (114 ºF)			
CTG Load	**100%**	**100%**	**75%**	**50%**	**100%**	**100%**	**75%**	**50%**	**100%**	**100%**	**75%**	**50%**
Duct Burner Status	On	Off	Off	Off	On	Off	Off	Off	On	Off	Off	Off
Stack Velocity (ft/sec)	68.6	71	55.1	44.3	63.7	66	52.3	42.8	63.1	63.7	51.5	42
Stack Temperature (ºF)	162	193	181	175	161	193	181	175	186	202	188	167
AERMOD Results [µg/mg^3]/[g/s]												
1-hour	14.54	12.46	15.29	22.37	15.38	12.69	16.62	23.24	13.61	12.65	15.85	**25.21**
3-hour	7.92	5.87	8.48	10.22	8.58	6.37	8.88	10.52	7.10	6.21	8.63	**11.37**
8-hour	4.70	4.46	5.26	7.63	5.29	4.58	5.70	7.98	4.67	4.55	5.44	**8.80**
24-hour	1.55	1.43	1.76	2.43	1.69	1.46	1.84	2.54	1.51	1.46	1.81	**2.80**
Annual	0.22	0.17	0.25	0.33	0.25	0.19	0.26	0.34	0.21	0.18	0.25	**0.37**

Bolded screening results represent maximum.
Note:
g/s = grams per second
µg/mg^3 = micrograms per cubic milligram

Table 8.1-24
Proposed Colusa Generating Station Project AERMOD Modeling Results

Pollutant	Averaging Period	Maximum Modeled Impact ($\mu g/m^3$)	PSD Significant Impact Level[a] ($\mu g/m^3$)	Background[b] ($\mu g/m^3$)	Total Predicted Concentration ($\mu g/m^3$)	AAQS ($\mu g/m^3$)	UTM Coordinates East (m)	UTM Coordinates North (m)
Construction Impacts								
CO	1-hour	1,224	NA	6,444	7,668	23,000	562,750	4,357,230
	8-hour	317.2	NA	3768	4085.2	10,000	562,100	4,357,800
NO_2	1-hour[c]	203.3	NA	120.3	343.6	470	562,750	4,357,230
	Annual[c]	8.3	NA	26.3	34.6	100	562,750	4,357,621
PM_{10}	24-hour	200.5	NA	92	292.5	50	562,799	4,357,940
	Annual	11.6	NA	25.5	37.1	30	563,084	4,357,131
SO_2	1-hour	2.06	NA	15.6	17.7	655	562,750	4,357,230
	3-hour[d]	0.8	NA	15.6	16.4	1,300	562,000	4,357,700
	24-hour	0.08	NA	7.8	7.9	105	562,799	4,357,940
	Annual	0.01	NA	2.6	2.6	80	562,750	4,357,621
Routine Plant Operation Impacts								
CO	1-hour	1,396	2,000	6,444	7,840	23,000	558,375	4,359,450
	8-hour	293	500	3768	4061	10,000	558,325	4,359,325
NO_2	1-hour[c]	336.5	NA	120.3	456.8	470	558,800	4,353,925
	Annual[d]	0.64	1	26.3	27.0	100	562,750.2	4,357,572
PM_{10}	24-hour	4.35	5	92	96.3	50	562,600	4,357,800
	Annual	0.5	1	25.5	26.0	30	562,425	4,358,075
SO_2	1-hour	4.4	NA	15.6	20.0	655	558,350	4,359,500
	3-hour[d]	1.85	NA	15.6	17.4	1,300	559,025	4,355,700
	24-hour	0.35	NA	7.8	8.1	105	562,600	4,357,800
	Annual	0.04	NA	2.6	2.6	80	562,425	4,358,075

Notes:
[a] Source: 40 CFR 52.21.
[b] Background represents the maximum value measured at various air monitoring stations around the CGS site, 2003-2005 (except for 1-hour NO_2 which uses the arithmetic average of 2004-2005 measurements).
[c] Results used OLM to estimate NO_2 impacts.
[d] Background 3-hour SO_2 not reported, used 1-hr background

AAQS = Most stringent ambient air quality standard for the averaging period
NA = Not applicable
NR = Not reported
m = meters
OLM = ozone limiting method
$\mu g/m^3$ = micrograms per cubic meter
CO = carbon monoxide
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than or equal to 10 microns in diameter
SO_2 = sulfur dioxide

Table 8.1-25
Proposed Project Operations Fumigation Impact Summary

Pollutant	Source	Inversion Impact ($\mu g/m^3$)	Distance to Max. Impact (m)
NO_2 1 hour	Normal Operation Turbine	3.09	15,953
NO_2 1 hour	Turbine Startup	52.45	15,953
CO 1 hour	Normal Operation Turbine	76.09	15,953
CO 1 hour	Turbine Startup	2.82	15,953
SO_2 1 hour	Turbine – Normal Operations or Startup	0.25	15,953
SO_2 3 hour	Turbine – Normal Operations or Startup	0.25	15,953

Notes: 1-hr SCREEN3 results multiplied by 0.9 to convert to 3-hour and 0.7 to convert to 8-hour.
$\mu g/m^3$ = micrograms per cubic meter

Table 8.1-26
Predicted Class I Area
Pollutant Concentrations from the CGS Compared to Proposed and Adopted Significant Impact Levels
($\mu g/m^3$)

Class I and Other Areas of Interest	Maximum Predicted Concentration					
	NO_2[a]	PM_{10}		SO_2		
	Annual Average	24-Hour Average	Annual Average	3-Hour Average	24-Hour Average	Annual Average
USEPA Proposed SIL[b]	0.1	0.3	0.2	1	0.2	0.1
FLM Recommended SIL[b]	0.03	0.27	0.08	0.48	0.07	0.03
Class I Area PSD Increment[c]	2.5	8	4	25	5	2
CGS Maximum Impact	0.008	0.198	0.018	0.031	0.009	0.001

Notes:
a NO was conservatively assumed to be 100 percent converted to NO_2.
b SIL = Significant Impact Level; USEPA proposed and FLM recommended from the Federal Register, Vol. 61, No. 142, p. 38292, July 23, 1996.
c PSD = Adopted Prevention of Significant Deterioration level; from 40 CFR 52.21(c)
d $\mu g/m^3$ = micrograms per cubic meter

Table 8.1-27
Maximum Modeled Soil and Vegetation Impacts of the Proposed Project

Pollutant	USFS Significance Level	Maximum Project Impact
SO_2 Annual	8 ppbv	0.0004 ppbv (0.001 μg/m^3)
SO_2 Hourly	40 ppbv	0.012 ppbv (0.031 μg/m^3)
NO_2 Annual	15 ppbv	0.0043 ppbv (0.008 μg/m^3)
Total Sulfur Deposition	0.005 kg/ha-yr[a]	0.00025 kg/ha-yr
Total Nitrogen Deposition	0.005 kg/ha-yr[a]	0.0017 kg/ha-yr

Notes:
[a] Deposition Analysis Threshold (DAT) for individual sources established by the National Park Service (NPS).
kg/ha-yr = kilograms per hectare per year ppbv = parts per billion, by volume
mg/m$_3$ = micrograms per cubic meter USFS = U.S. Forest Service

Table 8.1-28
Cumulative Impact AERMOD Modeling Results

Pollutant	Averaging Period	CGS Maximum Modeled Impact (μg/m^3)	Contribution of Delevan Compressor Station (μg/m^3)	Background[a] (μg/m^3)	Total Predicted Concentration (μg/m^3)	AAQS (μg/m^3)
NO_2	1-hour	336.5	36.8	120.3	465.6	470
	Annual	0.64	0.66	26.3	27.6	100
PM_{10}	24-hour	4.35	0.45	92	96.8	50
	Annual	0.5	<0.02	25.5	26.0	30

Notes:
[a] Background represents the maximum value measured at various air monitoring stations around the CGS site, 2003-2005 (except for 1-hour NO_2 which uses the arithmetic average of 2004-2005 measurements).
Cumulative impacts for CO and SO_2 did not exceed impacts from CGS alone that are presented in Table 8.1-24.

Table 8.1-29
Applicable Air Quality Laws, Ordinances, Regulations, and Standards
(Page 1 of 3)

Laws, Ordinances, Regulations, and Standards	Administering Agency	Applicability	AFC Section
Federal			
Federal CAAA of 1990; 40 CFR 50	U.S. EPA Region IX, CARB, CCAPCD	National Ambient Air Quality Standards	8.1.4.1
40 CFR 52.21	U.S. EPA Region IX, CARB	PSD Requirements	8.1.4.2
40 CFR 72, 73, 75	U.S. EPA Region IX	Acid rain requirements, SO_2 allowances	8.1.4.3
40 CFR 60, Subpart KKKK	CCAPCD	New Source Performance Standards (NSPS); 0.0015 by volume (15 ppmv) for NO_X and 0.015% by volume (150 ppmv) for SO_2	8.1.4.4
40 CFR 70	CCAPCD	Federally Mandated Operating Permit (Title V) for major sources	8.1.4.5
State			
California Administrative Code, Title 14, §15002(a)(3), CEQA Guideline	CEC	Power plant sitting requirements	8.1.4.6
H&S Code § 44300	CCAPCD	Air toxics "Hot Spots" emission inventory	8.1.4.7
Local			
Regulation 1, Rule 1.8	CCAPCD	Requires to install, use and maintain monitoring equipment	8.1.4.10.1
Regulation 1, Rule 1.9	CCAPCD	Submittal of records and reports to the Air Pollution Control Officer	8.1.4.10.1
Regulation 1, Rule 1.10	CCAPCD	Tests procedures	8.1.4.10.1
Regulation 1, Rule 1.11	CCAPCD	Field inspection	8.1.4.10.1
Regulation 1, Rule 1.12	CCAPCD	Air pollution equipment, scheduled maintenance	8.1.4.10.1

Table 8.1-29
Applicable Air Quality Laws, Ordinances, Regulations, and Standards
(Page 2 of 3)

Laws, Ordinances, Regulations, and Standards	Administering Agency	Applicability	AFC Section
Regulation 1, Rule 1.13	CCAPCD	Notification of equipment breakdown	8.1.4.10.1
Regulation 2, Rule 2.10	CCAPCD	Nuisance; prohibits discharge of emissions which cause injury, illness, detriment, nuisance, etc., to any considerable number of persons or to the public	8.1.4.10.1
Regulation 2, Rule 2.13	CCAPCD	Visibility; prohibits visible emissions as dark or darker than No. 2 on the Ringelmann chart	8.1.4.10.1
Regulation 2, Rule 2.15	CCAPCD	Particulate matter emission limit of 0.3 grain per cubic foot of gas at dry standard conditions	8.1.4.10.1
Regulation 2, Rule 2.16	CCAPCD	Fugitive dust; prohibits the emission of fugitive dust from being airborne beyond the project's property line during construction activities	8.1.4.10.1
Regulation 2, Rule 2.17	CCAPCD	Separation of emissions; air contaminants from a single source operation emitted through two or more emission points cannot exceed the allowable emission through a single emission point	8.1.4.10.1
Regulation 2, Rule 2.18	CCAPCD	Combination of emissions; air contaminants from two or more source operations that are combined prior to emission shall be separated if possible, the prohibitions applying to each source separately	8.1.4.10.1
Regulation 2, Rule 2.22	CCAPCD	Sulfur oxides; prohibits discharging from any single source more than 2,000 ppm of sulfur oxides	8.1.4.10.1
Regulation 2, Rule 2.23	CCAPCD	Reduced sulfur compounds; prohibits emissions which would result in more than 0.03 ppm of ground-level concentration of total reduced sulfur compounds (as H_2S) for a period of 60 minutes	8.1.4.10.1

Table 8.1-29
Applicable Air Quality Laws, Ordinances, Regulations, and Standards
(Page 3 of 3)

Laws, Ordinances, Regulations, and Standards	Administering Agency	Applicability	AFC Section
Regulation 2, Rule 2.39	CCAPCD	Steam generators NO_x control measure; RACT limit of 0.084 lbs/MMBTU or 70 ppmv for NO_x	8.1.4.10.1
Regulation 3, Rule 3.1	CCAPCD	Authority to Construct and Permit to Operate.	8.1.4.10.1
Regulation 3, Rule 3.6	CCAPCD	New Source Review.	8.1.4.10.1

Table 8.1-30
Relevant Federal and California Ambient Air Quality Standards

Pollutant	Averaging Time	California AAQS[a,b]	Federal AAQS[b,c]	
			Primary	Secondary
Ozone (O_3)	1-hour	0.09 ppm (180 μg/m^3)	0.12 ppm (235 μg/m^3)	Same as primary standard
	8-hour[d]	0.07 ppm (137 μg/m^3)	0.08 ppm (157 μg/m^3)	
Carbon Monoxide (CO)	8-hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)	NA
	1-hour	20 ppm (23 mg/m^3)	35 ppm (40 mg/m^3)	
Nitrogen Dioxide (NO_2)[e]	Annual (Arithmetic Mean)	NA	0.053 ppm (100 μg/m^3)	Same as primary standard
	1-hour	0.25 ppm (470 μg/m^3)	NA	
Sulfur Dioxide (SO_2)	Annual (Arithmetic Mean)	NA	0.03 ppm (80 μg/m^3)	NA
	24-hour	0.04 ppm[f] (105 μg/m^3)	0.14 ppm (365 μg/m^3)	NA
	3-hour	NA	NA	0.05 ppm (1,300 μg/m^3)
	1-hour	0.25 ppm (655 μg/m^3)	NA	NA
Respirable Particulate Matter (PM_{10})	Annual (Geometric Mean)	20 μg/m^3 [h]	NA [h]	Same as primary standard
	24-hour	50 μg/m^3	150 μg/m^3	
	Annual (Arithmetic Mean)	NA	NA	
Fine Particulate Matter ($PM_{2.5}$)[d]	24-hour	NA	35 μg/m^3 [h]	Same as primary standard
	Annual (Arithmetic Mean)	12 μg/m^3 [h]	15 μg/m^3	
Visibility Reducing Particles	1 observation	See footnote g.	No federal standard	No federal standard

Notes:

[a] Title 17, California Code of Regulations, California AAQS for ozone (as volatile organic compounds), carbon monoxide, sulfur dioxide (1-hour), nitrogen dioxide, and particulate matter (PM_{10}), are values that are not to be exceeded. The visibility standard is not to be equaled or exceeded.

[b] 40 CFR 50. National AAQS, other than those for ozone and based on annual averages, are not to be exceeded more than once a year. 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.

[c] Concentrations are expressed first in units in which they were promulgated. Equivalent units are given in parentheses and based on a reference temperature of 25°C and a reference pressure of 760 mm of mercury. All measurements of air quality area to be corrected to a reference temperature of 25°C and a reference pressure of 760 mm of mercury (1,013.2 millibar); ppm in this table refers to ppm by volume, or micromoles of pollutant per mole of gas.

[d] New federal 8-hour ozone and fine particulate matter ($PM_{2.5}$) standards were promulgated by U.S. EPA on July 18, 1997. The federal 1-hour ozone standard continues to apply in areas that violated the standard.

[e] Nitrogen dioxide (NO_2) is the compound regulated as a criteria pollutant; however, emissions are usually based on the sum of all oxides of nitrogen (NO_X).

[f] At locations where the state standards for ozone and/or PM_{10} are violated. National standards apply elsewhere.

[g] Insufficient amount to reduce the prevailing visibility to less than 10 miles when the relative humidity is less than 70%. "Prevailing visibility" is defined as the greatest visibility, which is attained or surpassed around at least half of the horizon circle, but not necessarily in continuous sectors.

[h] The federal respirable particle matter (PM_{10}) standard was revoked on September 22, 2006. The fine particulate matter ($PM_{2.5}$) standard was modified on September 22, 2006. The California respirable particle matter (PM_{10}) standard was modified and a new fine particulate matter ($PM_{2.5}$) standard promulgated on July 5, 2003.

AAQS = Ambient Air Quality Standard
NA = Not Applicable
mg/m^3 = milligrams per cubic meter
μg/m^3 = micrograms per cubic meter
ppm = parts per million

Table 8.1-31
Federal and State Attainment Status for Colusa County

Pollutant	Federal Attainment Status	State Attainment Status
Ozone	Unclassifiable/Attainment	Nonattainment/Transitional[a]
CO	Unclassifiable/Attainment	Unclassified[a]
NO_2	Unclassifiable/Attainment	Attainment
SO_2	Unclassifiable	Attainment
PM_{10}	Unclassifiable	Nonattainment
$PM_{2.5}$	Unclassifiable/Attainment	Unclassified[a]

Notes:
Attainment status obtained from 40 CFR 81
[a] Proposed designations for 2006.

Table 8.1-32
Prevention of Significant Deterioration Threshold Triggers

Pollutant	Significant Thresholds (tons per year)	Project Emissions Increase (tons per year)
SO_2	100	11.32
NO_2	100	185.58
POC	100	48.24
PM_{10}	100	142.24
CO	100	272.20
Lead (Pb)	0.6	<0.6 (negligible)

Table 8.1-33
Prevention of Significant Deterioration Allowable Increments (μg/m^3)

Standard	Class I Area	Class II Area	Class III Area
PM_{10} Annual Arithmetic Mean	4	17	34
PM_{10} 24-Hour Maximum	8	30	60
SO_2 Annual Arithmetic Mean	2	20	40
SO_2 24-Hour Maximum	5	91	182
SO_2 3-Hour Maximum	25	512	700
NO_2 Annual Arithmetic Mean	2.5	25	50

μg/m^3 = micrograms per cubic meter

Table 8.1-34
Applicable Best Available Control Technology Levels

Pollutant	Significant Thresholds (lbs. per highest day)
POC (VOC or NPOC)	25
NO_X	25
SO_2	80
PM_{10}	80
CO	500

Notes:
CO = carbon monoxide
NO_X = nitrogen oxides
NPOC = non-precursor organic compounds
PM_{10} = particulate matter less than 10 microns in diameter
POC = precursor organic compounds
SO_2 = sulfur dioxide
VOC = volatile organic compounds

Table 8.1-35
Summary of Colusa Generating Station Project Best Available Control Technology

Pollutant	Control Technology	Concentration ppm @ 15% O_2 dry
NO_X	Dry low-NO_X combustors and SCR with ammonia injection	2.0
CO	Catalytic oxidation	3.0
POC	Catalytic oxidation	2.0
SO_X	Pipeline quality natural gas	<1.1
PM_{10}	Pipeline quality natural gas	Not Applicable

Notes:
CO = carbon monoxide
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
POC = precursor organic compounds
SO_X = sulfur oxides

Table 8.1-36
Summary of Recent NO_X Best Available Control Technology Determinations for Combustion Turbine Generators Rated Greater than 50 MW

Name	Location	Emission Limit[a]	Control(s)	Permit Date
PICO	CA	2.0 ppm	SCR with Ammonia	March 05
Metcalf	CA	2.5 ppm	SCR with Ammonia	May 05
Pastoria	CA	2.5 ppm	SCR with Ammonia	July 05
Magnolia	CA	2.0 ppm	SCR with Ammonia	September 05
Malburg	CA	2.0 ppm	SCR with Ammonia	October 05

Notes:
[a] Based on 3-hour average.
ppm = Parts per million by volume, dry basis, at 15% oxygen
SCR = Selective catalytic reduction

Table 8.1-37
Summary of Recent Combustion Turbine CO and VOC BACT Determinations

Project Name	State	Date	CO BACT Level, ppm (at 15% O_2)	VOC BACT Level, ppm (at 15% O_2)
Von Raesfeld (formerly Pico)	CA	3/05	4.0	2.0
Metcalf	CA	5/05	6.0	2.0
Pastoria	CA	7/05	3.0	6.0
Magnolia	CA	9/05	2.0	2.0
Malburg	CA	10/05	2.0	2.0

COMPLEX TERRAIN WITHIN 10 MILES OF THE COLUSA GENERATING STATION (WEST HALF)

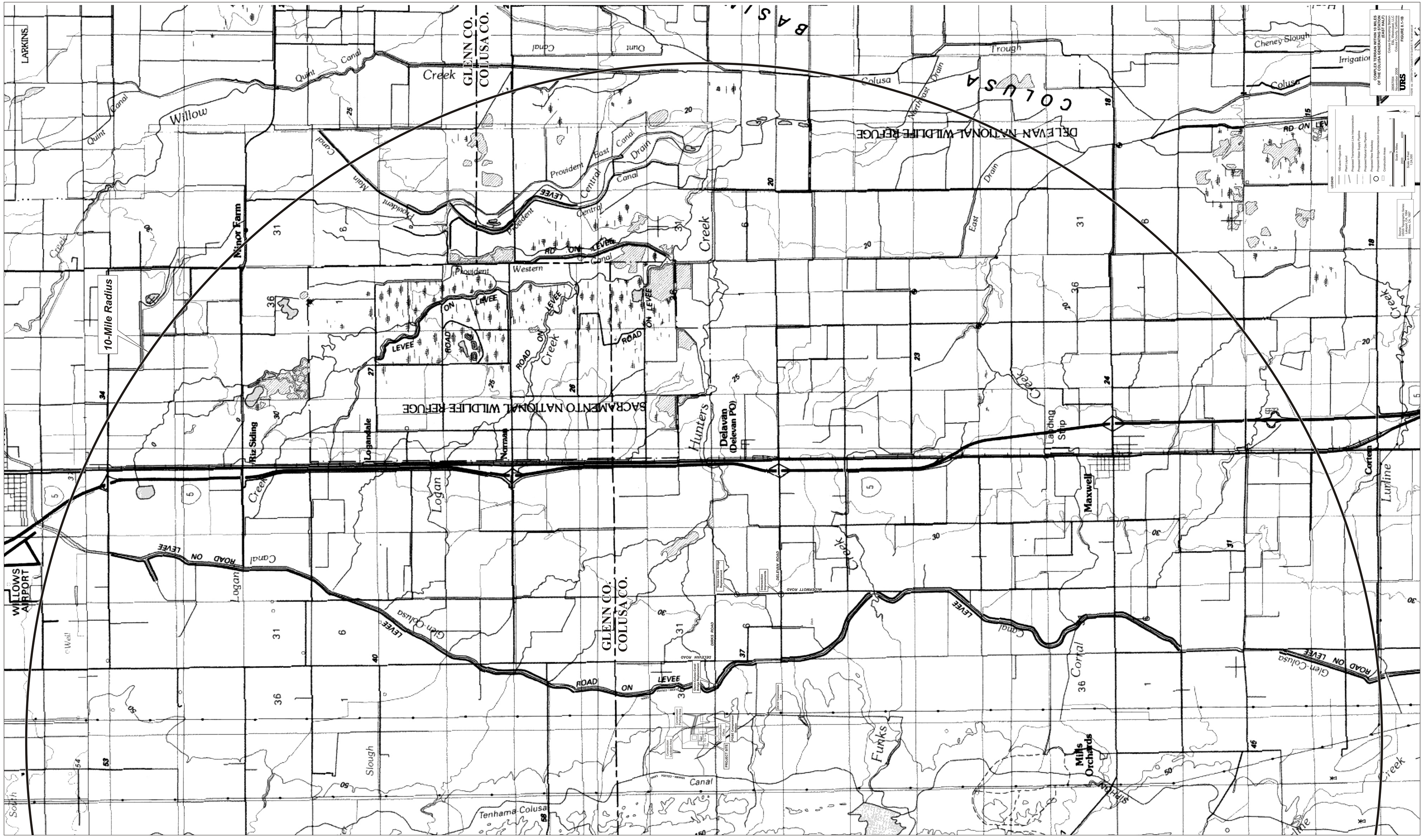
28067004
November 2006

Colusa Generating Station
E&L Westcoast, LLC
Colusa County, California

URS

FIGURE 8.1-1A

11/02/06 vsa ..\28067004 CPV Colusa\8.01 Air Quality\8.1-1A_terrain-west.cdr


10-Mile Radius
GLENN CO.
COLUSA CO.
SACRAMENTO NATIONAL WILDLIFE REFUGE
DELEVAN NATIONAL WILDLIFE REFUGE
WILLOWS AIRPORT
LARKINS
Willow
Creek
Quint Canal
Minor Farm
Ritz Siding
Logandale
Norman
Delavan (Delevan PO)
Maxwell
Corter
Lurline
Hunters
Logan
Glen-Colusa
Canal
Slough
Tenhama-Colusa
Funks
Mills Orchards
Corral
Colusa
Trough
Cheney Slough
Irrigation
Northeast Drain
East Drain
Provident
Central
East
Western
LEVEE
ROAD ON LEVEE
RD ON LEVEE
Landing Strip
Cartier
Lurline
COMPLEX TYPOGRAPHY WITHIN 10 MILES OF PROJECT SITE (EAST HALF)
20070304
Cheney Ranch Project
Ed. Thompson, LLC
Colusa County, California
URS
FIGURE 6-1-19
Source: Geographic Series
Sacramento, CA 95817
Version: 1.0
Date: 4/4/2007
Scale: 1:100,000
LEGEND
Site Center Point
Plant Location
Proposed Transmission Line Interconnection
Proposed Water Supply Pipeline
Proposed Gas or Gas Pipeline
Proposed Access Road
Proposed Drainage/Irrigation Improvements
Construction Areas
Miles
0
2
4
8
12
16
Scale 1:100,000
Scale 1:200,000