STAFF REPORT

Final Staff Assessment (Part 2 - Air Quality)

DELTA ENERGY CENTER

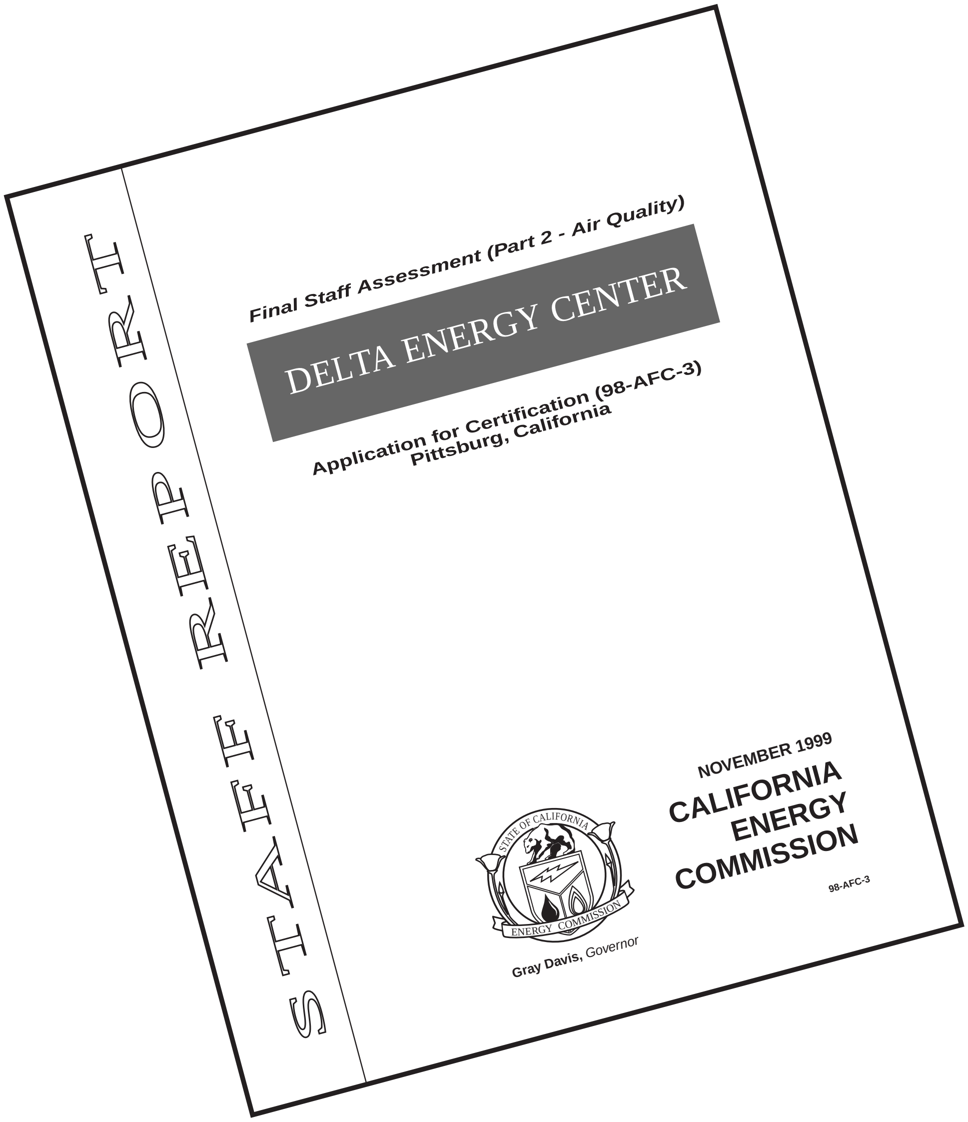
Application for Certification (98-AFC-3)
Pittsburg, California

NOVEMBER 1999

CALIFORNIA ENERGY COMMISSION

Gray Davis, *Governor*

98-AFC-3



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AIR QUALITY

Magdy Badr

INTRODUCTION

This analysis addresses the potential air quality impacts resulting from criteria air pollutant emissions created by the construction and operation of the Delta Energy Center project. Criteria air pollutants are those for which a state or federal standard has been established. They include nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), ozone (O_3) and its precursors (nitrogen oxides (NO_x) and volatile organic compounds (VOC)), and particulate matter less than 10 and 2.5 microns in diameter (PM10 and PM2.5) and their precursors: NO_x, VOC, and SO_x.

In carrying out its analysis, the California Energy Commission staff evaluates the following points:

- whether the Delta Energy Center project is likely to conform with applicable Federal, State, and Bay Area Air Quality Management District (BAAQMD) air quality laws, regulations and standards, as required by Title 20, California Code of Regulations, sections 1744(b) and 1744.5 (b),

- whether the Delta Energy Center is likely to cause significant air quality impacts, including new violations of ambient air quality standards or contributions to existing violations of those standards, as required by Title 20, California Code of Regulations, sections 1742(b) and 1742.5 (b) , and

- whether the mitigation proposed for the Delta Energy Center is adequate to lessen the potential impacts to a level of less than significant, as required by Title 20, California Code of Regulations, section 1742(b), and 1742.5(a).

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

The federal Clean Air Act requires any new major stationary sources of air pollution and any major modifications to major stationary sources to obtain an air pollution permit before commencing construction. This process is known as New Source Review (NSR). Its requirements differ depending on the attainment status of the area where the major facility is to be located. Prevention of Significant Deterioration (PSD) requirements apply in areas that are in attainment of the national ambient air quality standards. The Non-attainment area NSR requirements apply to areas that have not been able to demonstrate compliance with national ambient air quality standards. The entire program, including both PSD and Non-attainment NSR permit reviews, is referred to as the federal NSR program.

Title V of the federal Clean Air Act requires states to implement and administer an operating permit program to ensure that large sources operate in compliance with the requirements included in the Code of Federal Regulations 40, part 70. A Title V permit contains all of the requirements specified in different air quality regulations which affect an individual project.

The U.S. Environmental Protection Agency (EPA) has reviewed and approved the Bay Area Air Quality Management District's (BAAQMD) regulations and has delegated to the BAAQMD the implementation of the federal PSD, Non-attainment NSR, and Title V programs. The BAAQMD implements these programs through its own rules and regulations, which are, at a minimum, as stringent as the federal regulations.

STATE

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

The state's Air Resources Board (ARB) promulgates state-level ambient air quality standards, which are, in general, more stringent than the national ambient air quality standards. Table 5.2-2 in the Application for Certification (AFC) presents a summary of the current national and state ambient air quality standards.

LOCAL

The proposed facility is subject to various BAAQMD rules and regulations. Regulation 2, Rule 2 is the more relevant local air quality rule for this project. This rule, entitled "New Source Review," applies to all new and modified stationary sources. It defines requirements related to Best Available Control Technology (BACT), offsets, emission calculation procedures to estimate bankable emission reduction credits (ERCs), and requirements for the federal acid rain program.

A more discussion of the applicable rules and regulations can be found in section 8.1, regulatory setting of the AFC and data responses. An in-depth discussion how the Delta Energy Center will comply with all applicable rules and regulations is provided in the BAAQMD's Final Determination of Compliance (FDOC).

SETTING

METEOROLOGY AND CLIMATE

A presentation of the meteorological and climatological characteristics of the region can be found in section 8.1 of the AFC. In addition, the BAAQMD has published an excellent discussion on this subject, entitled "Climate, Physiography, and Air Pollution Potential - Bay Area and its Subregions" (BAAQMD, 1999).

The Delta Energy Center, if approved, would be located in a climatological subregion of the Bay Area known as the Carquinez Strait region. This region covers the areas surrounding the Carquinez Strait, including cities such as Martinez, Pittsburg, Antioch, Fairfield, and Suisun City.

The project area is characterized by prevailing strong winds from the west, particularly during the spring, summer and fall. However, sometimes a weak westerly flow (flow from the east) develops, causing elevated pollutant levels in the Bay Area. During these periods the Bay Area, in general, is affected by low wind speeds and shallow mixing depths, thereby allowing the build up of pollution levels.

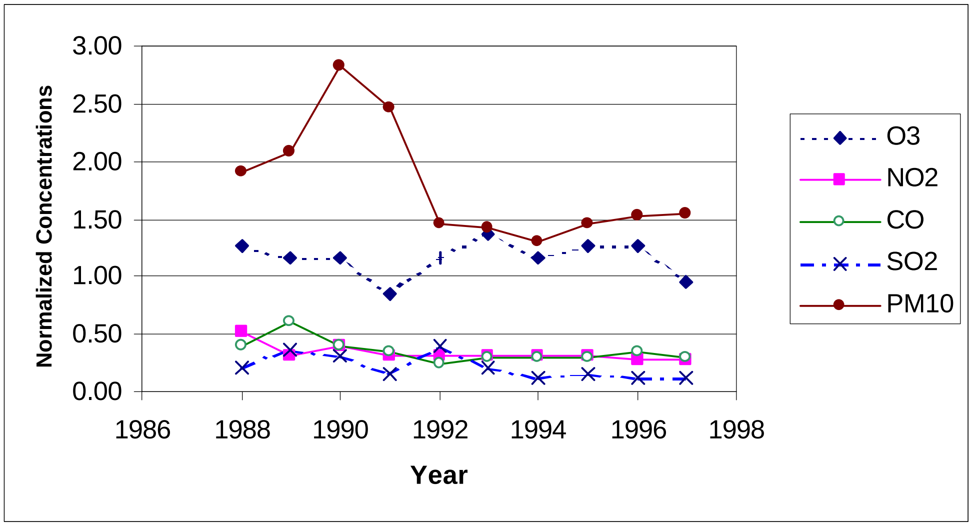
Pacific Gas and Electric (PG&E) collects meteorological data in Pittsburg. The data collected or subsequently estimated by PG&E includes wind direction, wind speed, temperature, and atmospheric stability class. The data collection monitor is located approximately four miles northwest (upwind) from the proposed project. The BAAQMD has deemed the data collected by this monitor as representative of the area's meteorology, and that it is appropriate to use for air dispersion modeling analyses for this project.

EXISTING AMBIENT AIR QUALITY

A summary of the existing ambient air quality conditions in the Project area can be found in the Delta Energy Center's AFC section 8.1. **AIR QUALITY Figure 1** summarizes the historical air quality data for project location for particulate matter less than 10 microns (PM10), CO, SO_2, O_3, and NO_2. In **AIR QUALITY Figure 1** normalized concentrations are presented, which represent the ratio of the highest measured concentrations in a given year to the most stringent applicable national or state ambient air quality standard. Therefore, normalized concentrations lower than one indicate that the measured concentrations were lower than the most stringent ambient air quality standard. The particulate matter data correspond to the data collected at Bethel Island, which has traditionally been higher than the concentrations measured at other sites in Contra Costa County.

Following is a more in-depth discussion of ambient air quality conditions in the Pittsburg area for O_3, CO, NO_2, and PM.

AIR QUALITY Figure 1
Normalized Maximum Short-Term Historical Air Pollutant Concentrations:1988-1997. Pittsburg Area



A Normalized Concentration is the ratio of the measured concentration to the applicable most stringent air quality standard. For example, in 1997 the highest 24-hour average PM10 concentration measured in Bethel Island was 77 $\mu g/m^3$. Since the most stringent ambient air quality standard is 50 $\mu g/m^3$, the 1997 normalized concentration is 77/50 = 1.54.
Source: ARB, 1998a as reported in Delta Energy Center, 1998.

OZONE

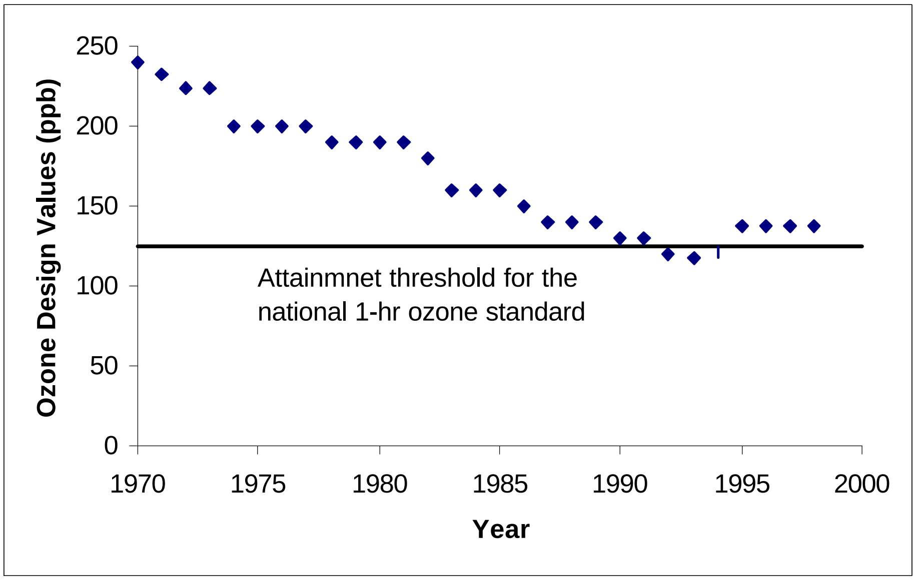
The Pittsburg area has experienced, in general, an average of four or five days with violations of the 1-hour state ambient air quality standard for ozone in a year. The EPA still applies the 1-hour national ozone standard to areas that have been unable to attain the previous national ozone ambient air quality standard. The San Francisco Bay Area is one of the areas in this situation.

Ozone formation is influenced significantly by year-to-year changes in atmospheric conditions. For this reason, a long-term trend in ambient ozone levels is needed to understand if a region is experiencing reductions in its ambient ozone concentrations or not. As shown in **AIR QUALITY Figure 2**, the long-term statistics of ozone levels in the San Francisco Bay Area region shows that this region has made significant strides toward attainment of the previous federal ozone 1-hour standard.

The reasons for the recent violations of the federal ozone standard shown in the **AIR QUALITY Figure 2** are not known. However, one important characteristic of the last few years is that more exceedences have been observed during weekends, when NO_x emissions are expected to go down by 30 percent, and VOC emissions would only be reduced by 10 percent from the emission levels expected during weekdays (SCAQMD 1997). The “weekend effect”, modeling analyses, and other corroborative analyses suggest that the air basin may be VOC limited. This means that any reductions in NO_x emissions may be counterproductive unless accompanied by reductions in VOC emissions. The BAAQMD is developing its

1999 State Implementation Plan (SIP) to identify a strategy to bring the air basin back to attainment of the national 1-hour standard (BAAQMD 1998). Additional studies will be conducted in the future to better understand the ozone problem in the Bay Area air basin and surrounding air basins. The study results will be used to develop equitable and more effective air quality management strategies to reach attainment of federal air quality standards.

AIR QUALITY Figure 2
District Ozone Design Value 1970-1998



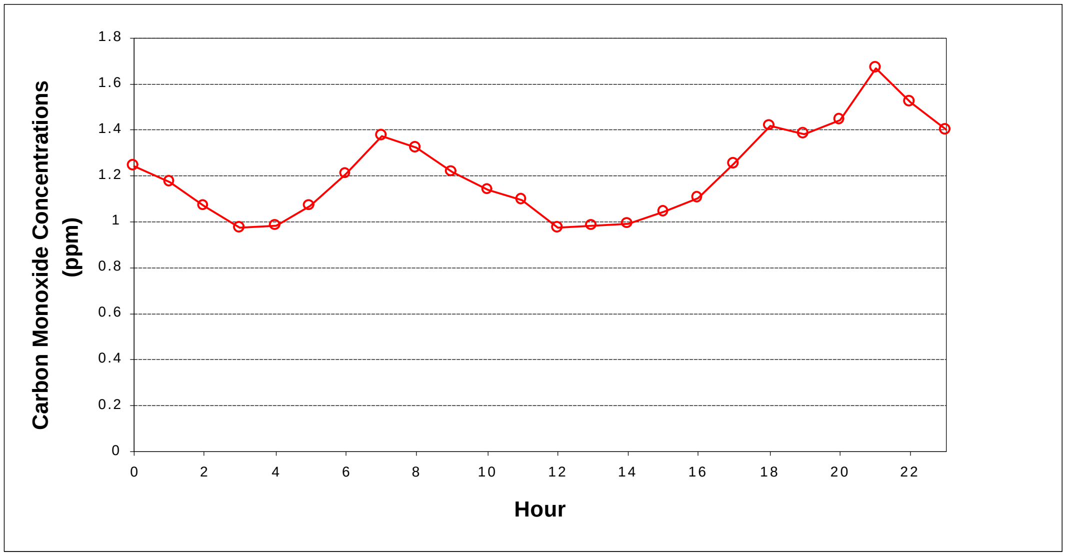
Each design value represents the fourth highest concentration recorded in the air basin during the previous three years. Design values are used to determine attainment status.
Source: BAAQMD, 1998

While high maximum hourly ozone concentrations are important, they do not reflect the geographical and temporal extent of ozone levels. The population weighted ozone exposure level is a better measure of public exposure and a more meaningful measure of public health concerns. This parameter has had a downward trend in Contra Costa County. For example, the most recent estimated per capita ozone exposure levels above the state standard in the 1994-1996 period are 16 percent lower than the values measured in the 1986-88 period (BAAQMD 1997a). Pittsburg does not experience, in general, violations of the less stringent national ozone 1-hour average ambient ozone air quality standard.

CARBON MONOXIDE (CO)

The highest CO concentration levels measured in Pittsburg are at least one-half lower than the most stringent California ambient air quality standards (see **AIR QUALITY Figure 1**). The highest concentrations of CO occur when low wind speeds and a stable atmosphere trap the pollution emitted at or near ground level in what is known as the stable boundary layer. These conditions occur frequently in the wintertime late in the afternoon, persist during the night and may extend one or two hours after sunrise. Since the mobile sector (cars, trucks, busses) is the main source of CO, we expect ambient concentrations of CO to be highly dependent on emissions from the mobile sector. In fact, the peak CO concentrations occur during the rush hour traffic in the morning and afternoon. In Pittsburg CO concentrations may also peak late in the evening, as shown in **AIR QUALITY Figure 3**. This is probably the result of CO emissions from wood burning in residential fireplaces in Pittsburg and/or adjacent areas.

AIR QUALITY Figure 3
Average Diurnal CO Profile
Pittsburg, January 1 - 15, 1996



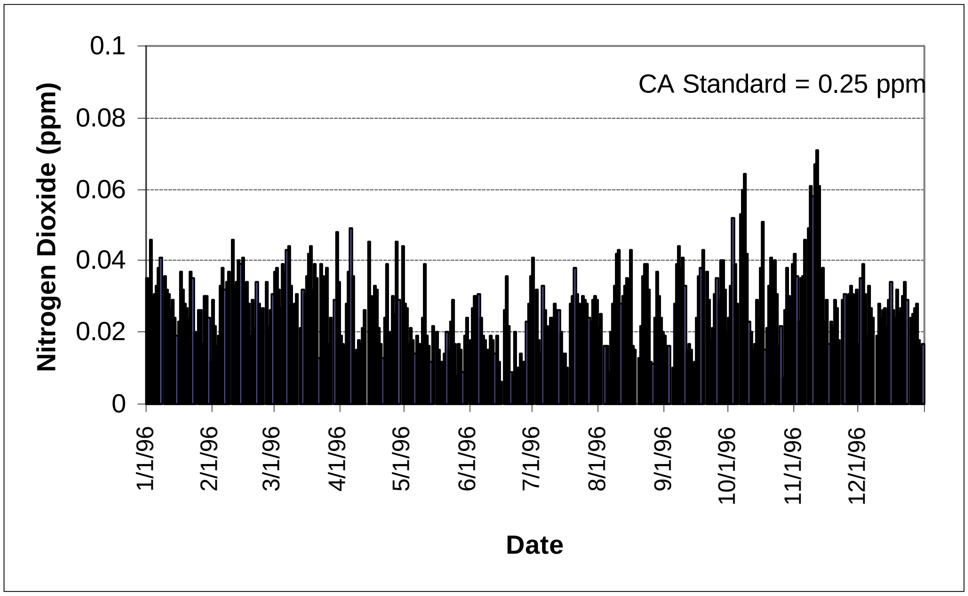
Source: ARB, 1998a

Carbon monoxide concentrations in Pittsburg and the rest of the state have declined significantly due to two state-wide programs: 1) the 1992 wintertime oxygenated gasoline program, and 2) Phases I and II of the reformulated gasoline program. New vehicles with oxygen sensors and fuel injection systems have also contributed to the decline in CO levels in the state. Today all the counties in California, with the sole exception of Los Angeles County, are in compliance with the CO ambient air quality standards. Recently the California Air Resources Board rescinded the requirements for a minimum level of oxygen in the wintertime fuel when allowed by federal law (ARB 1998b). Even with this action, county-wide and state-wide forecasted CO inventories show a decline (ARB, 1998b). Therefore, compliance with the CO standards are expected to continue in the future.

NITROGEN DIOXIDE (NO_2)

NO_2 levels in Pittsburg are no more than one-half of the most stringent NO_2 ambient air quality standards, as shown in **AIR QUALITY Figure 1**. Approximately 90 percent of the NO_x emitted from combustion sources is NO, while the balance is NO_2. NO is oxidized in the atmosphere to NO_2 but some level of photochemical activity is needed for this conversion. This is why the highest concentrations of NO_2 occur during the fall (see **AIR QUALITY Figure 4**) and not in the winter when atmospheric conditions favor the trapping of ground level releases but lack significant photochemical activity (less sun light). In the summer the conversion rates of NO to NO_2 are high but the relatively high temperatures and windy conditions (atmospheric unstable conditions) disperse pollutants, preventing the accumulation of NO_2 to levels approaching the 1-hour ambient air quality standard.

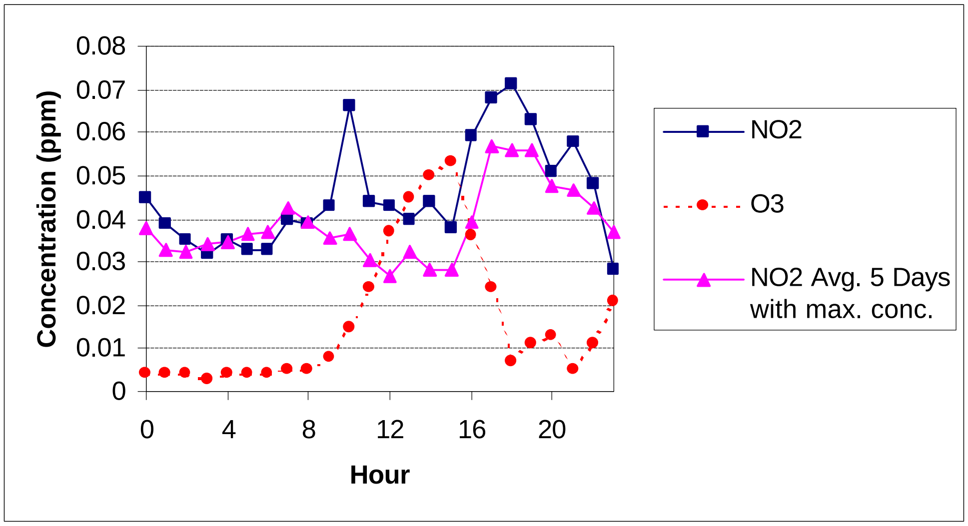
AIR QUALITY Figure 4
Maximum Daily 1-hour average NO_2 Concentrations measured in 1996: Pittsburg Station



Source: ARB,1998a

AIR QUALITY Figure 5 presents the diurnal profile of NO_2 and O_3 concentrations observed on November 11, 1996 (Monday) when the highest ambient 1-hour NO_2 concentration was recorded in 1996. This figure also shows the average diurnal NO_2 profile for the five days with the highest measured concentrations in 1996, all occurring in the fall.

AIR QUALITY Figure 5
Diurnal Profile for NO_2 and O_3
Pittsburg Station: 11/11/96 and the five days with the highest concentrations



Source: ARB, 1998a.

One important thing to notice from **AIR QUALITY Figure 5** is that the highest NO_2 concentrations, which occur late in the afternoon, are possibly linked to the rapid reaction of NO emissions from ground level sources with the ground level ozone, as shown in the following equation:

$$NO + O_3 \rightarrow NO_2 + O_2$$

As indicated before, fresh NOx (NO plus NO_2) emissions from combustion sources are mainly NO emissions. The above reaction explains why, in urban areas, ozone concentrations at ground level drop substantially at night, while aloft and in rural areas (without sources of fresh NO_x emissions) ozone concentrations can remain relatively high.

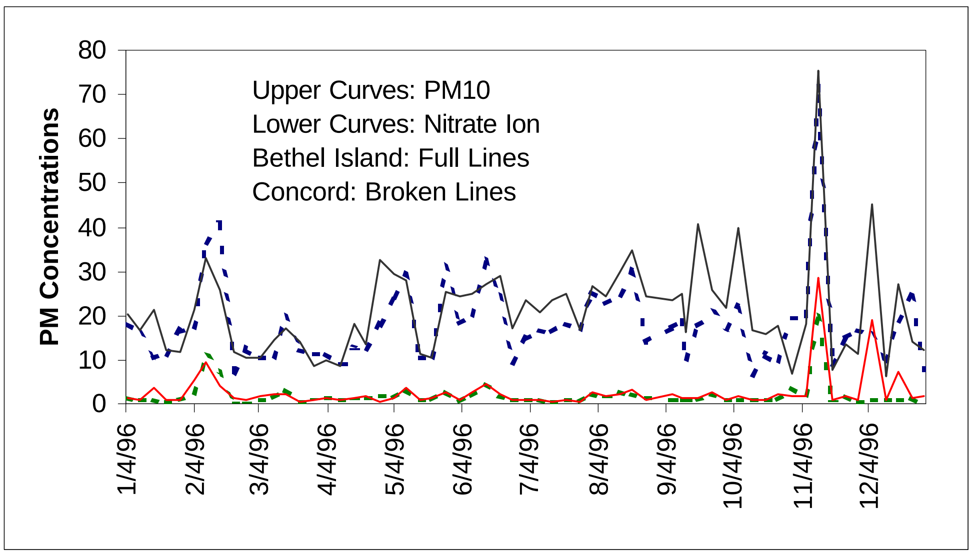
PARTICULATE MATTER (PM)

As shown in **AIR QUALITY Figure 1**, PM concentrations measured at the Bethel Island monitoring station have declined in the last few years. The same trend has been observed at other sites at Contra Costa County, including the City of Concord.

One issue that has been raised by the public is the lack of a PM monitoring station in Pittsburg. The concern is that PM concentrations in Pittsburg may be higher than the PM concentrations in Concord. To address this issue, we will use in our analysis the PM concentrations measured at Bethel Island, which have been traditionally the highest measured concentrations in the county. In addition, as shown in **Air Quality Figure 6**, PM concentrations in both Concord and Bethel Island track each other reasonably well, suggesting that Pittsburg should also have a similar PM profile. This is confirmed by the measurements taken in Crockett a few years ago, which show that PM concentrations there were not significantly different from concentrations measured at other Contra Costa County sites and were lower than measurements taken at Bethel Island.

PM nitrate (mainly ammonium nitrate) is formed in the atmosphere from the reaction of nitric acid and ammonia. Nitric acid in turn originates from NO_x emissions from combustion sources. **AIR QUALITY Figure 6** also shows that the nitrate ion concentrations during the winter time are a significant portion of the total PM10 and should be even a higher contributor to particulate matter of less than 2.5 microns (PM2.5). The nitrate ion is only a portion of the PM nitrate, which can be in the form of ammonium nitrate (ammonium plus nitrate ions) and some as sodium nitrate. If we consider the ammonium and the sodium associated with the nitrate ion, we can estimate much higher PM nitrate contributions to the total PM than can be inferred by just looking at **AIR QUALITY Figure 6**.

AIR QUALITY Figure 6
Total PM10 and PM Nitrate Ion
Measured in Concord and Bethel Island: 1996



Source: ARB, 1998a

The air agencies in California are now deploying PM2.5 ambient air quality monitors throughout the state. PM2.5 ambient air quality attainment plans, if needed, are due to the U.S. EPA by 2005. As with PM10, information from existing PM2.5 research monitors in California indicates that there have been significant reductions in ambient PM2.5 concentrations in the state (Watson 1998) and that the San Francisco Bay Area air basin may be in attainment of the new PM2.5 standards.

The highest PM concentrations are measured in the winter. During wintertime high PM episodes, the contribution of ground level releases to ambient PM concentrations is disproportionately high. For example, wood smoke contributes approximately 47 percent of the PM10 mass in San Jose, while the contribution at Pittsburg may be on the order of 30 percent (Chow et al. 1995). The contribution of woodsmoke particles to the PM2.5 concentrations may be even higher, considering that most of the woodsmoke particles are smaller than 2.5 microns.

OTHER AIR POLLUTANTS

There are also ambient air quality standards for sulfates and lead. A full description of the measured ambient air concentrations in Pittsburg is contained in section 8.1.3 of the AFC (Delta Energy Center, 1998). The ambient concentrations of these pollutants are well below their respective standards.

DELTA ENERGY CENTER ESTIMATED EMISSIONS

CONSTRUCTION PHASE

The construction phase includes the power plant and ancillary facilities (i.e., steam line, transmission lines, and pipelines for reclaimed water, natural gas, fire and potable water). The construction of the proposed power plant will result in temporary emissions for approximately 14 months.

All construction scheduling is based on a 40-hour work week. The worst-daily fugitive dust emissions are expected to occur during the first two to three months of construction. Tables 8.1E-1 through 8.1E-3 in the AFC present detailed construction emission estimates for PM10, NO_x, CO, SO_x, and VOC emissions from vehicle and equipment combustion and from site grading activities. It is important to understand that construction estimated emissions are highly speculative since detailed activity data can not be forecast accurately and the emission factors used in these estimations are known to be worst case estimates. For example, the Air Resources Board has recently measured PM emissions from actual construction sites and has revised its estimated PM10 construction related emissions downward by 67 percent (ARB 1997).

COMMISSIONING AND OPERATIONAL PHASES

The proposed Delta Energy Center is a combined cycle power plant with three new power trains. Each power train consists of a gas turbine rated at 200 MW, a duct burner and a heat recovery steam generator (GT/HRSG). The steam from the heat recovery steam generators will be fed to a steam turbine rated at 300 MW and part of steam will be delivered to the Dow Chemical Company Complex. The actual operation of turbines will range between 70 percent to 100 percent of their maximum rated output. Supplemental firing will be provided by the duct burners up to 200 MMBtu/hr to maintain required electricity and steam production rates. The facility will also include two 200,000 lb/hr auxiliary boilers for added steam, a 14-cell mechanical cooling tower, emergency generator, and a fire pump engine.

The existing facility at the site, consists of three Pratt and Whitney FT4 natural gas fired gas turbines with fired HRSGs. These turbines are used to provide electricity and steam to the Dow Chemical Company Complex and will continue to operate at a lower capacity in conjunction with the new turbines.

The Delta Energy Center will burn only natural gas, with no provisions for an alternative backup fuel. The exclusive use of natural gas an inherently clean fuel, compared to oil or coal, will limit the formation of VOC, PM10, and SO_x emissions. The combustion turbines will be equipped with low-NOx combustors to minimize NO_x formation. After combustion, the turbine exhaust gasses will be treated by Selective Catalytic Reduction (SCR) systems to further reduce NO_x emissions. Calpine/Bechtel is not proposing to use post-combustion oxidizing catalyst at this time to further control CO and VOC emissions.

"Commissioning" is the technical term used to describe, in general, all the initial operations of the power plant once it has been physically installed but is not yet in commercial operation. Commissioning starts with the first firing of fuel in the GT/HRSG or in the auxiliary boilers. During commissioning the control systems are tested, the burners are tuned up, the inside and outside of tubes are cleaned up, and the control systems are installed after determining that there are no contaminants in the GT/HRSG that may damage the surfaces of the catalysts. It is important to emphasize that for a short period of time during the commissioning period, which can last for several months, the power plant will operate without emission controls. Commissioning ends with the start of commercial operation, which is usually signaled by the issuance of the Permit to Operate (PTO) from the local air district.

AIR QUALITY Table 1 presents the estimated maximum emission concentration for NO_2 over a one hour averaging times. The table also shows that during the commissioning of the project using the start-up hourly average emissions, and given the existing background, the maximum concentration per turbine does not violate the State one hour ambient air quality standard of 470 ($\mu g/m^3$).

CO and NO_x emissions are relatively easy to measure, even during commissioning, because calibrated continuous emission monitors for both pollutants will be installed before commissioning begins. The amount of fuel burned and the sulfur content of the fuel will limit SO_x emissions. There is no additional control on CO emissions since the Calpine/Bechtel is not proposing one and the BAAQMD is not requiring it. Therefore, CO and VOC emissions will be at the same levels during the commissioning and normal operation of the Delta Energy Center. Finally, PM10 emissions during commissioning are not expected to exceed the daily emissions established for normal operation because natural gas combustion does not produce high PM emissions and the amount of fuel consumed during this period is expected to be lower than during normal operations.

AIR QUALITY Table 1
Maximum NOx Emission Impact During Commissioning per Gas Turbine

Pollutant/Averaging Time	Maximum Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)
NO_2 1-hour	219	153	372

Source: Calpine/Bechtel response to data request AQ-10 dated April 20,1999.

Operational Scenarios Of The DEC

The maximum facility emission levels presented in **AIR QUALITY Table 2** are calculated based on the following assumptions:

Delta Energy Center Hourly Emission Assumptions:

- One turbine is in hot start-up mode with no duct burner, while the other two turbines operate at full load with duct burners;
- One auxiliary boiler operating at full load, and the other operating at 10% load;
- Cooling tower is in operation;
- Emergency generator or fire pump is in operation.

Delta Energy Center Maximum Daily Emission Assumptions:

- Each turbine has one cold start-up (three hours) and one hot start-up (one hour);
- Each turbine operates at full load for the remaining hours;
- Duct burners operate for 16 hours each;
- One auxiliary boiler operates at full load, and the other operates at 10% load;
- Emergency generator or fire pump is in operation;
- Cooling tower operates 24 hours.

Delta Energy Center Maximum Annual Emission Assumptions:

- Each turbine has 52 cold start-up (156 hours) and 260 hot start-up (260 hours);
- Each turbine operates at full load for the remaining 8,344 hours;
- Duct burners operate for 1500 hours;
- One auxiliary boiler operates for 540 hours at full load, and the other operates at 40 hours per year at full load. The remaining time, both boilers are operating at minimum load;
- The fire pump operates 200 hours per year;
- Emergency generator operates 200 hours per year;
- Cooling tower operates 8760 hours per year.

These assumptions are for the new equipment only. However, Calpine/Bechtel will continue to operate the existing facility as needed, but at lower capacity and limited annual operating profile. Condition of certifications 38 through 45 specify the limitations on the operation of the existing facility.

AIR QUALITY Table 2
Maximum Hourly, Daily, and Annual Emissions

	NO_x	CO	VOC	PM10	SO_x
GT1 (lb/hr)	18.1	44.1	5.33	10.0	1.2
GT2 (lb/hr)	18.1	44.1	5.33	10.0	1.2
GT3 (lb/hr)	18.1	44.1	5.33	10.0	1.2
GT1 w/DB (lb/hr)	19.2	113.5	5.33	12.0	1.3
GT2 w/DB (lb/hr)	19.2	113.5	5.33	12.0	1.3
GT3 w/ DB (lb/hr)	19.2	113.5	5.33	12.0	1.3
Boiler1@ 100% (lb/hr)	2.82	9.3	0.53	2.0	0.26
Boiler1@ 10% (lb/hr)	0.34	1.0	0.11	0.5	0.026
Boiler 2 @ 100% (lb/hr)	2.82	9.3	0.53	2.0	0.26
Boiler2@ 10% (lb/hr)	0.34	1.0	0.11	0.5	0.026
Cooling Tower (lb/hr)	-	-	-	3.2	-
GT-S (lb/hr)	80	838	16.0	-	
EG (lb/hr)	4.9	13.3	6.3	1.1	0.014
FPE (lb/hr)	3.9	3.6	0.48	0.2	0.106
Total Facility Daily Emissions (lb/day)					
	2,123.5	13,204.4	503.6	876.3	105.2
Total Facility Annual Emissions (ton/year)					
	279.7	1,116	74.4	140.6	18.6

GT1 = the first gas turbine.
GT1 w/ DB = the first gas turbine and Duct Burner.
GT-S = Start-up emissions from either GT.
EG = Emergency Generator
FPE = Fire Pump Engine

Source: FDOC dated October 25, 1999 and Calpine/Bechtel AFC Appendix 8.1I

AIR QUALITY Table 3 delineates the maximum heat rate in million Btu (MMBtu) assumptions underlying the emission calculations for the new equipment for the Delta Energy Center shown in table 2.

AIR QUALITY Table 3
Maximum Hourly, Daily, and Annual Fuel Consumption

	Hourly	Daily	Annual
	(MMBtu/hr)	(MMBtu/day)	(MMBtu/yr)
GT1 w/ DB	2125	50,024	17,727,252
GT2 w/ DB	2125	50,024	17,727,252
GT3 w/ DB	2125	50,024	17,727,252
Boiler 1	256	6,144	351,960
Boiler 2	256	6,144	351,960
Total Facility	6,887	162,358	53,770,676

Source: AFC Table 8.1-15

PROJECT IMPACTS

MODELING APPROACH

Calpine/Bechtel used the SCREEN model to select the worst case turbine configuration that would produce the highest emission impacts. The SCREEN model, which is approved EPA, is designed to provide conservative estimates of emission impacts. Based on the results of the SCREEN model, Calpine/Bechtel modeled the Westinghouse gas turbines and HRSGs configuration using a more refined modeling analysis. This more refined modeling analysis was done with the EPA approved Industrial Source Complex (ISC) model, used near-by meteorological data collected at the PG&E Pittsburg power plant between 1994 and 1997.

CONSTRUCTION IMPACTS

Calpine/Bechtel estimated the impacts of construction-related emissions using the ISC model. **AIR QUALITY Table 4** provides a summary of the maximum estimated impacts. The modeling results indicate that the construction-related emissions under worst conditions would cause violations of the one hour NO_2 standard and 24 hour and annual PM10 standards. The impact estimates are very conservative because of a potential over estimation of emission levels, the lack of consideration of rapid deposition of PM fugitive (dust) emissions, and potential overestimation of impacts from ground-level releases using the ISC model. It is also important to note that these are temporary impacts that would only occur during the construction phase of the project, and they do not reflect the implementation of construction related mitigation measures included in conditions proposed by Energy Commission staff to minimize emissions.

AIR QUALITY Table 4
Maximum Estimated Construction-Related Incremental Impacts

Pollutant	Averaging Time	Incremental Impacts ($\mu g/m^3$)	Maximum Background ($\mu g/m^3$)	Maximum Total Impacts ($\mu g/m^3$)	State Limiting Standard ($\mu g/m^3$)	Federal Limiting Standard ($\mu g/m^3$)	Percent of the Standard (%)
NO_2 [2]	1-hour	460 [1]	153	613	470		130.4
	Annual	10.1	33	43.1	-	100	43.1
PM10	24-hour	117 [1]	77	194	50	150	388
	Annual	9.8	23.3	33.1	30	-	110.3
CO	1-hour	592.8 [1]	8149	8741.8	23000	40000	38.0
	8-hour	288.3 [1]	3725	4013.3	10000	10000	40.1
SO_2	1-hour	55.0	106	161	650	-	24.8
	24-hour	11.9 [1]	32	43.9	109	365	40.3
	Annual	0.37	5.3	5.7	-	80	7.12

[1] Based on maximum daily emissions during the construction period.
[2] Ozone limiting method applied to the 1-hour average using the maximum background levels in the last three years.

Sources: AFC Table 8.1E-4 from AFC.

In addition, we should add that the maximum fugitive dust PM10 emission levels and impacts would not occur during the winter time, when the highest measured PM concentrations are historically measured in the San Francisco air basin. This is due to the fact that the ground tends to be wet during the winter because of the rains, and the relative humidity is high, which reduces the likelihood and amount of fugitive dust formation.

PROJECT NORMAL OPERATIONAL IMPACTS

Calpine/Bechtel has assessed the impact of the operation of the facility using EPA-approved air quality dispersion models without considering the offsets that will be provided. The AFC presents the SCREEN and the ISC modeling analyses in Appendix 8.1B. The impact analyses were used to determine the worst case ground level impacts of the facility. The results show that the facility, by itself, does not violate the State or Federal ambient air quality standards. However, the PM10 impact from the facility, when added to the existing background levels, which are already above the State Standard, will further violate the 24 hour State Standard. Staff finds the Calpine/Bechtel analysis of the operational impact to be acceptable. The applicant will mitigate the project's PM10 impact by providing emission offsets as discussed in the mitigation section below. **AIR QUALITY Table 5** presents a summary of the ISC modeling results for the proposed Delta Energy Center.

AIR QUALITY Table 5
ISC Modeling Results

Pollutant	Averaging Time	Facility Maximum Impact ($\mu g/m^3$)	Maximum Background ($\mu g/m^3$)	Maximum Total Impacts ($\mu g/m^3$)	State Limiting Standard ($\mu g/m^3$)	Federal Limiting Standard ($\mu g/m^3$)	Percent of Standard (%)
NO_2	1-hour	267	153	420	470		84.7
	Annual	1	33	34	-	100	34
CO	1-hour	725	8149	8874	23000	40000	38.6
	8-hour	244	3725	3969	10000	10000	39.7
PM10	24-hour	4.95	77	82	50	150	164
	Annual	0.3	23.3	24	30	-	80
SO_2	1-hour	33	106	139	650	-	21.4
	24-hour	0.5	32	32.5	109	365	29.8
	Annual	0.03	5.3	5.3	-	80	6.6

Source: AFC Table 8.1-28, Appendix 8.1 B and Table 1 in letter dated June 28, 1999.

CUMULATIVE IMPACT ANALYSES

The cumulative impact analysis addresses the combined effects of the Pittsburg District Energy Facility (PDEF), the proposed Delta Energy Center (DEC), and the existing Contra Costa and Pittsburg power plants, which were previously owned by PG&E but recently purchased by Southern Energy Inc. The emissions of other existing industrial sources in the area, such as Dow Chemical Company and oil refineries are accounted for in the ambient background air quality data used in the modeling.

In this discussion, staff refers to these former PG&E power plants as the Southern power plants. Staff assumed that the emissions of the Southern power plants would increase from their historical levels because of changes in ownership, an assumption which attempts to account for a cumulative worst-case level of emission. The

Southern Contra Costa power plant would, in the worst case scenario, increase emissions by 361 tons per year (tpy) for NO_x and 83 tpy for PM10. This represents an increase in emissions from historical levels (1995 to 1997 period) of about 50 percent and 160 percent for NO_x and PM10 respectively. For the Southern Pittsburg power plant, we assumed an increase in emissions of 1,642 tpy for NO_x and 205 tpy for PM10. This represents an increase in emissions from historical levels of about 90 percent and 146 percent for NO_x and PM10, respectively. We calculated these numbers using the results of the electricity system modeling performed for the Environmental Impact Report (EIR) prepared for the divestiture (selling) of the PG&E power plants (CPUC, 1998). These emissions correspond to the modeled incremental emissions from a modeled baseline that may occur in 2001, when the PDEF power plant would be in operation. The DEC will probably begin operating in 2002; however, for the purpose of this analysis we assumed that the DEC would be in operation in 2001.

It is important to note that the BAAQMD Regulation 9, Rule 11 limits the amount of NO_x and CO that can be emitted from all the previously owned PG&E power plants inside the BAAQMD's boundaries. To comply with this rule, the PG&E system-wide NO_x emission rate in pounds per million Btu must go down every year, ending in the year 2005, to a rate that is one tenth of the 1997 system-wide emission rate. Because these plants have been sold, Rule 11 will have to be modified to take into account that the power plants may have multiple owners. The BAAQMD has indicated that the rule modification will maintain the intent of the original rule, e.g., to reduce NO_x and CO emissions from the existing power plants under its jurisdiction.

Staff only modeled the incremental emissions because we are interested in the potential incremental impacts from the Southern power plants that have not been already accounted for in the existing background ambient concentrations measured in the Pittsburg region. We only examined PM10 and NO_2 impacts, since the impacts of the other pollutants, CO and SO_2, are relatively minor. Even if we assume (incorrectly) for CO and SO_2 that the impacts from PDEF and DEC occur at the same place at the same time, the total impacts are far below the most stringent applicable ambient air quality standards. In addition, in the case of carbon monoxide, the proposed permitted levels (concentration at the stack) for the new power plants are on the order of 10 parts per million (ppm). Since this concentration is well below the California 1-hour average ambient air quality standard of 20 ppm, it is inconceivable to expect any significant impact on ambient CO concentrations.

The CALMET/CALPUFF modeling system was used for the analysis. This new modeling system is currently being proposed by the EPA for use in estimating short range impacts in situations with complex topography and meteorology (Paine, 1999). Several features of the CALMET/CALPUFF model are important for this application, including its ability to more realistically estimate mixing heights, to take into consideration the three dimensional nature of the wind fields, as well as the factors of transport and diffusion. Given the CALMET/CALPUFF's ability to consider three-dimensional wind fields, it should more realistically estimate impacts from multiple sources.

AIR QUALITY Table 6 presents the results of the modeling analysis. As shown in this table, NO_2 impacts are below the most stringent NO_2 ambient air quality standards. This is in spite of the fact that the cumulative modeling analysis was done assuming that all the NO_x emissions leaving the stack are in the form of NO_2. It is well known that most NO_x emissions will be in the form of NO. Although NO_x emissions include both NO and NO_2, NO has to be oxidized in the atmosphere to NO_2 in order to have an air quality NO_2 impact.

There has been a decline in NO_x emissions in the San Francisco Bay Area air basin that has resulted in declining NO_2 ambient concentrations throughout the air basin, including NO_2 concentrations measured in Pittsburg (see **AIR QUALITY Figure 1** in

AIR QUALITY Table 6
Summary of CALPUFF Cumulative Impact Modeling

Pollutant	Averaging Time	Cumulative Impact ($\mu g/m^3$)	Maximum Background ($\mu g/m^3$)	Maximum Total Impacts ($\mu g/m^3$)	State Limiting Standard ($\mu g/m^3$)	Federal Limiting Standard ($\mu g/m^3$)	Percent of Standard (%)
$NO_{Appendix}$	1-hour	157	188	345	470		73.4
	Annual	17	32.1	49.1	-	100	49.1
PM10	24-hour	13	87	100	50	150	200
	Annual	2.3	20.2	22.5	30	-	75

Source: Modeling Assessment of Cumulative Air Quality Impacts of the Pittsburg District Energy Facility and Other Incremental Sources. Prepared for the California Energy Commission by Joseph S. Scire, April 12, 1999.

the March, 1999 staff assessment). Ambient NO_2 concentrations should, at a minimum, not increase in the foreseeable future due to the implementation of the control measures already included in the air quality management plans approved by the BAAQMD. For example, the 1997 Clean Air Plan (BAAQMD, 1997) estimates that NO_x emissions in the air basin will go down by approximately 11 and 27 percent from 1997 levels by 2000 and 2010, respectively.

The maximum cumulative NO_2 impacts from all the sources considered are mostly due to the higher emissions from the southern Pittsburg power plant, because it is an older, less efficient power plant. The emissions from the southern power plant will not contribute substantially to the maximum expected cumulative impacts from the modeled power plants because its plume do not substantially interact with the plume from the other modeled power plants.

The worst case 24-hour average PM10 cumulative impact is due primarily to the PM10 emissions from the Southern power plant. PDEF will not contribute to these maximum cumulative 24-hour average PM10 impacts. The maximum 24-hour average impact from the PDEF is on the order of 3.47 $\mu g/m^3$. This impact level is probably overestimated due to the fact that the assumed emission level of 17 pounds per hour per gas turbine is well above the emission levels measured in other similar power plants in California.

The maximum total 24-hour and annual PM10 impacts presented in **AIR QUALITY Table 6** represent the worst case scenario because the worst case incremental impacts are assumed to coincide in time with the worst-case background concentrations. However, the maximum PM10 background concentrations are usually observed in the wintertime while the maximum modeled cumulative incremental impacts do not occur during this time of the year.

There has also been a decline in PM10 concentrations in Contra Costa County as shown in **AIR QUALITY Figure 1** in the March 1999 assessment. This situation is expected to continue in the future due to continue reduction of NO_x, SO_x, and VOC emissions, which are PM10 precursors. For example, VOC emissions in the year 2010 are expected to be 26 percent lower than the 1997 emission levels (BAAQMD, 1997). SO_x emissions have also decreased and are expected to continue below historical levels, mainly due to the introduction of phase 2 reformulated gasoline (Kirchstetter, 1999). Finally the BAAQMD's Spare the Air Tonight voluntary program may result in significant reductions of PM10 emissions from woodburning, which is believed to be responsible for about 30 percent of the PM10 ambient concentrations during winter time PM10 episodes.

In summary, the operation of the Delta Energy Center project added to the existing and planned "projects" in the same area will not result in violations of the NO_2 standard. The incremental impacts from the Delta Energy Center project will not result in cumulative significant PM10 impacts.

MITIGATION

APPLICANT'S PROPOSED MITIGATION

Calpine/Bechtel is proposing to mitigate the project's potential air quality impacts using a state of the art combustion technology, installing post-combustion control devices, and providing offsets, as required by the BAAQMD's regulations. Calpine/Bechtel is proposing to install a gas turbine equipped with Low NO_x combustors that can achieve low NO_x concentrations. The GT/HRSG will be equipped with SCR to control NO_x to 2.5 ppm without the need for steam or water injection. The auxiliary boilers will comply with the Best Available Control Technology (BACT) limitations determined by the BAAQMD. Calpine/Bechtel is not proposing to install a CO catalyst to reduce CO emissions.

ADEQUACY OF PROPOSED MITIGATION

BACT (state definition) levels applicable to individual projects are typically determined by the local air district with input from the Air Resources Board (ARB) and EPA. Recently, in both the High Desert and Sutter Power Plant AFC cases, the EPA has clearly stated their position regarding what they consider to be BACT (federal definition) and Lowest Achievable Emission Rates (LAER).

Control of NOx Emissions

The project's NO_x emissions consist primarily of nitric oxide (NO) and a small percentage of nitrogen dioxide (NO_2). Thermal NO_x is the product of the oxidation of NO_2 (present in the air used for combustion) at the temperatures present in the combustion process. Some NO_x is formed from the oxidation of nitrogen present in the fuel. Nitrogen is not present in significant quantities in natural gas, so most of the NO_x emissions from this project are due to thermal NO_x.

Combustion chamber NO_x can be controlled by reducing the flame temperature in the combustion chamber through quenching steam and dilution using water and steam injection. Additionally, thermal NO_x can be controlled with combustor designs that premix the air and fuel and stage the combustion process (a reducing atmosphere followed by an oxidizing atmosphere). NO_x emissions from the Delta Energy Center will be controlled through the use of dry low NO_x combustors in the CTGs and the use of SCR as a post-combustion emission control. The turbines will be equipped with a number of dry low-NO_x combustors to ensure optimal uniform temperature distribution in the primary air zone. A reduction in NO_x emissions is also achieved by raising the mean air/fuel ratio. The use of dry-low NO_x burners produces emissions as low as 25 ppm when natural gas is burned before entering the SCR.

In addition, Calpine/Bechtel's proposed SCR system will control NO_x emission levels to 2.5 ppm corrected @ 15 percent O_2. SCR is a process that chemically reduces NO_x by injecting ammonia (NH_3) over a catalyst in the presence of oxygen (O_2). The process is termed selective because the NH_3 reducing agent preferentially reacts with NO_x rather than O_2 to form N_2 in the presence of excess O_2 at temperatures in the range of 400 to 750 ^oF. If the temperature is lower than 400^oF, the ammonia reaction rate is low, and therefore, NH_3 emissions (called ammonia slip) will increase.

Control of Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

Combustion turbines inherently generate low CO and VOC emissions. High combustion temperatures, fuel/air mixing, and the excess air inherent in the CTG's combustion process favor complete combustion of fossil fuels. These conditions, however, also lead to higher NO_x emissions. Current CTG designs attempt to balance achieving low NO_x emissions (from the CTG prior to post-combustion controls) while keeping CO and VOC emissions low. In all power plants previously licensed by the Commission oxidation catalysts have been proposed to control CO emission and reduce VOC emission levels. Good operating and maintenance practices are the only measures proposed for this project to limit the project's CO and reduce VOC emissions.

For VOC, the BAAQMD's BACT determination guidelines, copy is provided in Appendix B, identify an "oxidation catalyst" as the "typical technology" used to minimize emissions, with 50% reduction by weight in VOC emissions. However, no specific emission concentration limit (e.g ppm) is specified. Alternatively, Calpine/Bechtel proposed to meet a 2 ppm concentration level during all scenarios of operation of the project without installing an oxidation catalyst. The BAAQMD has agreed to the 2 ppm concentration level during all scenarios of operation of the project and has specified limitations in terms of mass emissions (lb/hr, lb/day, and tons per year) in the conditions of certification. The 2 ppm concentration limit is consistent with the CARB siting guidelines published in June 1999, titled "Guidance for Power Plant Siting and Best Available Control Technology".

With respect to CO, Calpine/Bechtel is not proposing to install a CO catalyst. They propose to meet a limit of 10 ppm over a three hour averaging time during all operating scenarios. They claim that the CO catalyst would increase the project PM10 emissions by approximately 2 lb/hour. Calpine/Bechtel submitted an analysis to support their argument on May 7, 1999. Staff reviewed this issue and believes that the analysis does not justify Calpine/Bechtel's position (see Appendix A which addresses this issue in more detail).

Control of PM10

Natural gas fuel contains only trace quantities of noncombustible material. Particulate emissions (PM_{10}) will be controlled by inlet air filtering for the combined cycle CTG and HRSG unit. In addition, Calpine/Bechtel proposes to use a cooling tower which includes 0.0006% drift eliminator efficiency to reduce PM10 emissions associated with its operation. This is the best control technology available for this purpose.

Sulfur Dioxide Emissions Control

The Delta Energy Center SO_2 emissions will be controlled by burning only natural gas, which typically contains only traces of sulfur. The emissions from the project's CTGs are expected to be very small without the use of any additional post-combustion SO_2 control equipment. Since natural gas contains only 2000 grains of sulfur per million cubic feet, the resulting SO_2 emission concentrations should be less than 1.0 ppm @15% O_2.

Emission Offsets

Emission reduction credits (ERCs) can be created when existing permitted emission sources cease operation or reduce their operation below permitted levels. The ERCs are reviewed and approved by the local air district and recorded in their "bank" for future use. To fully mitigate the facility's potential emission increases, Calpine/Bechtel plans to purchase emission reduction credits (ERCs) from BAAQMD ERCs bank and the Yolo-Solano District ERC bank as shown in Table 7. Calpine/Bechtel has signed option contracts with the owners of some of these sources of ERCs and has purchased other ERCs. AIR QUALITY Table 7 provides a summary of all proposed sources of ERCs, including quantities and contract types.

Offsets, in the form of ERCs, are required for the Delta Energy Center for NO_x, VOC, and PM10 in order to assure the project will not interfere with BAAQMD's future attainment of ozone and PM10 standards. In past siting cases some intervenors have argued that the ERCs are not actual mitigation since the emission reductions have already occurred and, therefore, ambient air quality can only deteriorate with the new source of emissions. However, the BAAQMD, in its Air quality Management Plan (AQMP), includes banked ERCs in its planning emissions inventories for future years as actual ongoing emissions (BAAQMD, 1997b). Therefore, the future effects of new sources due to emission increases are already taken into account in the AQMP, including the use of ERCs as a source of mitigation or offsets. The new source will not detract from the BAAQMD's attainment strategy. Consequently, we believe that banked offsets in this case constitute real mitigation of potential impacts from the proposed project in the context of the BAAQMD's overall attainment strategy.

Table 7
Valid Emission Reduction Credits Proposed by Calpine/Bechtel as of October 20, 1999

Company Name	Location	BAAQMD Certificate Number[s]	VOC (ton/yr)	NO_x (ton/yr)	SOx (ton/yr)	PM10 (ton/yr)
C&H Sugar	Crockett	16446	0	0	71.59	0
Courtaulds Aerospace, Inc.	Berkeley	14108	3.12	0	0	0
Courtaulds Aerospace, Inc.	Berkeley	16693	20.60	0	0	0
Crown Cork & Seal	Pittsburg	32763	2.783	0	0	0
Crown Cork & Seal	Richmond	10865	53.26	0	0	0
Dexter Hysol	Pittsburg	9539	19.20	0	0	0
Dupont	Antioch	27269	1.60	14.56	0	2.21
Homestake Mining	Napa	18058	0	22.07	1.30	21.72
Spreckels	Yolo County	N/A	0	0	0	21.15
P.G.&E.	Rodeo	1388	8.00	162.35	60.73	65.00
Total Emission Reduction Credits			108.56	198.98	133.62	110.8
Contemporaneous Emission Reduction			8.92	77.71	1.2	13.32
BAAQMD required ratio			1.15:1	1.15:1	N/A	1.0:1.0
Required Offsets			75.3	23.17	0	141.47
Surplus (+) / Shortage (-)			**+33.26**	**-33.19**	**+133.6**	**-31.39**

[a]original banking application; includes evaluation report that certifies that the emission reduction credits are real, quantifiable, permanent, and enforceable.

Cooling towers under the BAAQMD is not a permitted source of emissions and therefore, PM10 emissions associated with cooling towers are not required to mitigated under the BAAQMD's rules.

Interpollutant Trading Ratios

Calpine is using interpollutant trading of VOC ERCs for NOx ERCs as part of their offset strategy, which is identified and evaluated by the BAAQMD in the FDOC and reflected in table 7 above. Both VOCs and NOx are precursors to the formation of ozone in the atmosphere. The premise of interpollutant trading is based on "interprecursor offsets", which are limited to those pollutants which are precursors to the same secondary pollutant. The BAAQMD's New Source Review Rules allow for such trading. Calpine/Bechtel is proposing to use the surplus VOC ERCs (+33.26) identified in table 7 to offset the remaining NOx liability (-33.19) at a ratio of 1.0:1.0 and similarly SOx ERCs will be used to offset PM10 at a ratio of 3.0:1.0. These ratios are consistent with the BAAQMD rules.

STAFF PROPOSED SUPPLEMENTAL MITIGATION

A. Construction Emissions Mitigation

Project construction activities will occur over a year and half period. The fugitive dust emissions from the construction of the project, switchyard and transmission line and all linear facilities will be controlled by periodic watering of the site, assuming a 50 percent effectiveness, along with the mitigation measures proposed by staff in conditions of certification 74 through 76.

B. Mitigating Cooling Tower PM10 emissions

To fully mitigate the project's emissions, staff requested that all PM10 emissions including cooling tower emissions be mitigated by the applicant. The PM10 emissions from cooling towers are 14.1 tons per year. Calpine/Bechtel agreed to provide 21.15 tons (a distance ratio of 1.5:1) of PM10 emission reductions, above what the District needed, from the Spreckels facility located in Clarksburg to fully mitigate the Delta Energy Center PM10 emissions. This facility is located 34 miles from Delta Energy Center site in Yolo-Solano Air Quality Management District. The credits were created by the shutdown of process equipment associated with the operation of a beet sugar manufacturing operation.

COMPLIANCE WITH LORS

FEDERAL

EPA has delegated the implementation of its Prevention of Significant Deterioration (PSD) and Non-attainment New Source Review (NSR) requirements to the BAAQMD. This delegation is only done for air districts that are able to demonstrate to the satisfaction of EPA that their regulatory programs are at least as stringent as the federal PSD and Non-attainment NSR programs. The BAAQMD will issue an Authority to Construct (ATC) only after this project secures a license from the California Energy Commission, which will be based, in part, on the BAAQMD's Final Determination of Compliance (FDOC). The ATC will be equivalent to a federal PSD and federal Non-attainment NSR permit. In addition, the EPA has also delegated to the BAAQMD the authority to implement the federal Clean Air Act Title V operating permit program. This operating permit is issued only after a facility is in operation and will be included in the BAAQMD's Permit to Operate. Therefore, compliance with the BAAQMD's rules and regulations should result in compliance with federal requirements.

STATE

The project complies with the BAAQMD's rules and regulations, and therefore, with Section 41700 of the California State Health and Safety Code.

LOCAL

The BAAQMD issued its FDOC on October 22, 1999. Based on a review of the FDOC, and the BAAMQ's interpretation of their rules, staff has determined that the project will comply with applicable BAAQMD rules and regulations.

FACILITY CLOSURE

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

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

If the Delta Energy Center were to decide to dismantle the project, there would likely be fugitive dust emissions associated with this dismantling effort. The Facility Closure Plan to be submitted to the Energy Commission Compliance Project Manager should indicate that the applicant will comply with the applicable construction related permit conditions included in the Conditions of Certification, which includes the control of fugitive dust emissions.

CONCLUSIONS AND RECOMMENDATIONS

Based upon the evidence of record, and assuming the implementation of the following Conditions of Certification, including the conditions contained in the FDOC, the Commission staff agrees with the BAAQMD's findings and concludes that the Delta Energy Center will meet all applicable air quality requirements and will not cause any significant air quality impacts.

PROPOSED CONDITIONS OF CERTIFICATION

Delta Energy Center

Permit Conditions

Definitions:

Clock Hour:	Any continuous 60-minute period beginning on the hour.
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours.
Year:	Any consecutive twelve-month period of time
Heat Input:	All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in BTU/scf.
Rolling 3-hour period:	Any three-hour period that begins on the hour and does not include start-up or shutdown periods.
Firing Hours:	Period of time during which fuel is flowing to a unit, measured in fifteen minute increments.
MM BTU:	million british thermal units
Gas Turbine Start-up Mode:	The lesser of the first 180 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 27(b) and 27(d).
Gas Turbine Shutdown Mode:	The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 27(b) through 27(d) until termination of fuel flow to the Gas Turbine.
Auxiliary Boiler Start-up:	The lesser of the first 120 minutes of continuous fuel flow to an Auxiliary Boiler after fuel flow is initiated; or the period of time from fuel flow initiation until the Boiler achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 37(b) and 37(d).
Auxiliary Boiler Shutdown:	The lesser of the 30 minute period immediately prior the termination of fuel flow to the Auxiliary Boiler; or the period of time from non-compliance with any requirement listed in

	Conditions 37(a) through 37(d) until termination of fuel flow to the auxiliary boiler.
Specified PAHs:	The polycyclic aromatic hydrocarbons listed below shall be considered to Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds. Benzo[a]anthracene Benzo[b]fluoranthene Benzo[k]fluoranthene Benzo[a]pyrene Dibenzo[a,h]anthracene Indeno[1,2,3-cd]pyrene
Corrected Concentration:	The concentration of any pollutant (generally NO_x, CO, or NH_3) corrected to a standard stack gas oxygen concentration. For emission point P-1 (S-1 Gas Turbine and S-2 HRSG including Duct Burner), emission point P-2 (S-3 Gas Turbine and S-4 HRSG including Duct Burner), and emission point P-3 (S-5 Gas Turbine and S-6 HRSG including Duct Burner) the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis. For emission point P-4 (S-7 Auxiliary Boiler #1) and emission point P-5 (S-8 Auxiliary Boiler #2), the standard stack gas oxygen concentration is 3% O_2 by volume on a dry basis.
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the DE construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, auxiliary boiler, and associated electrical delivery systems.
Commissioning Period:	The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange.
Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager
DEC:	Delta Energy Center

Conditions for the Commissioning Period

1. The owner/operator of the Delta Energy Center (DEC) shall minimize emissions of carbon monoxide and nitrogen oxides from S-1, S-3, & S-5 Gas Turbines, S-2, S-4, & S-6 Heat Recovery Steam Generators (HRSGs), and S-7 & S-8 Auxiliary Boilers to the maximum extent possible during the commissioning period. Conditions 1 through 18 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 19 through 73 shall apply after the commissioning period has ended.

   Verification: The owner/operator shall submit a monthly compliance report to the California Energy Commission Compliance manager (CPM). In this report the owner/operator shall indicate how this condition is being implemented.

2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the combustors of S-1, S-3, & S-5 Gas Turbines, S-2, S-4, & S-6 Heat Recovery Steam Generators, and S-7 & S-8 Auxiliary Boilers shall be tuned to minimize the emissions of carbon monoxide and nitrogen oxides.

   Verification: In the monthly compliance report the owner/operator shall indicate how this condition is being implemented.

3. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the A-1, A-2, and A-3 SCR Systems shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-1, S-3, & S-5 Gas Turbines and S-2, S-4, & S-6 Heat Recovery Steam Generators.

   Verification: In the monthly compliance report the owner/operator shall indicate how this condition is being implemented.

4. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the A-4 & A-6 Oxidation Catalysts and A-5 & S-7 SCR Systems shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-7 & S-8 Auxiliary Boilers.

   Verification: In the monthly compliance report the owner/operator shall indicate how this condition is being implemented.

5. Coincident with the steady-state operation of A-1, A-2, & A-3 SCR Systems pursuant to conditions 3, 10, 11, and 12, the Gas Turbines (S-1, S-3, & S-5) and the HRSGs (S-2, S-4, & S-6) shall comply with the NO_x and CO emission limitations specified in conditions 27(a) through 27(d).

   Verification: In the monthly compliance report the owner/operator shall indicate how this condition is being implemented.

6. Coincident with the steady-state operation of A-5 & A-7 SCR Systems and A-4 & A-6 Oxidation Catalysts pursuant to conditions 4, 13, and 14, the Auxiliary Boilers (S-7 & S-8) shall comply with the NO_x and CO emission limitations specified in conditions 37(a) through 37(d).

Verification: In the monthly compliance report the owner/operator shall indicate how this condition is being implemented.

7. The owner/operator of the DEC shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-1, S-3, or S-5 Gas Turbines describing the procedures to be followed during the commissioning of the turbines, HRSGs, auxiliary boilers, and steam turbine. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-NO_x combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and NO_x continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-1, S-3, & S-5), HRSGs (S-2, S-4, & S-6), and Auxiliary Boilers (S-7 & S-8) without abatement by their respective SCR Systems and/or oxidation catalysts.

Verification: Submission of a complete plan including information required that useful to establish the procedures to follow for conditions 1 through 3 shall be deemed a verification of this condition.

8. During the commissioning period, the owner/operator of the DEC shall demonstrate compliance with conditions 10 through 14, 16, and 17 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

   firing hours
   fuel flow rates
   stack gas nitrogen oxide emission concentrations,
   stack gas carbon monoxide emission concentrations
   stack gas oxygen concentrations.

   The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-1, S-3, & S-5), HRSGs (S-2, S-4, & S-6), and Auxiliary Boilers (S-7 & S-8). The owner/operator shall use District-approved methods to calculate heat input rates, nitrogen dioxide mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request.

Verification: In the monthly compliance report to the CPM the owner/operator shall indicate how this condition is being implemented.

9. The District-approved continuous monitors specified in condition 8 shall be installed, calibrated, and operational prior to first firing of the Gas Turbines (S-1, S-3, & S-5), Heat Recovery Steam Generators (S-2, S-4, & S-6), and Auxiliary Boilers (S-7 & S-8). After first firing of the turbines and auxiliary boilers, the detection range of these continuous emission monitors shall be adjusted as necessary to accurately measure the resulting range of CO and NO_x emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

Verification: In the monthly compliance report to the CPM the owner/operator shall indicate how this condition is being implemented.

10. The total number of firing hours of S-1 Gas Turbine and S-2 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-1 SCR System shall not exceed 300 hours during the commissioning period. Such operation of S-1 Gas Turbine and S-2 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.

Verification: In the monthly compliance report the owner/operator shall indicate how this condition is being implemented.

11. The total number of firing hours of S-3 Gas Turbine and S-4 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-3 SCR System shall not exceed 300 hours during the commissioning period. Such operation of S-3 Gas Turbine and S-4 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.

Verification: In the monthly compliance report the owner/operator shall indicate how this condition is being implemented.

12. The total number of firing hours of S-5 Gas Turbine and S-6 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-3 SCR System shall not exceed 300 hours during the commissioning period. Such operation of S-3 Gas Turbine and S-4 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 300 firing hours without abatement shall expire.

Verification: In the monthly compliance report the owner/operator shall indicate how this condition is being implemented.

13. The total number of firing hours of S-7 Auxiliary Boiler #1 without abatement of carbon monoxide emissions by A-4 Oxidation Catalyst and/or abatement of nitrogen oxide emissions by A-5 SCR System shall not exceed 100 hours during the commissioning period. Such operation of S-7 Auxiliary Boiler without abatement by A-4 and/or A-5 shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 100 firing hours without abatement shall expire.

Verification: In the monthly compliance report the owner/operator shall indicate how this condition is being implemented.

14. The total number of firing hours of S-8 Auxiliary Boiler #2 without abatement of carbon monoxide emissions by A-6 Oxidation Catalyst and/or abatement of nitrogen oxide emissions by A-7 SCR System shall not exceed 100 hours during the commissioning period. Such operation of S-8 Auxiliary Boiler without abatement by A-6 and/or A-7 shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 100 firing hours without abatement shall expire.

Verification: In the monthly compliance report the owner/operator shall indicate how this condition is being implemented.

15. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM_{10}, and sulfur dioxide that are emitted by the Gas Turbines (S-1, S-3, & S-5), Heat Recovery Steam Generators (S-2, S-4, & S-6), and Auxiliary Boilers (S-7 & S-8) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 49.

Verification: In the monthly compliance report the owner/operator shall indicate how this condition is being implemented.

16. Combined pollutant mass emissions from the Gas Turbines (S-1, S-3, & S-5 and Heat Recovery Steam Generators (S-2, S-4, & S-6) shall not exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-1, S-3, & S-5).

NO_x (as NO_2)	5,266 pounds per calendar day	400.4 pounds per hour

CO	16,272 pounds per calendar day	1,192 pounds per hour
POC (as CH_4)	686 pounds per calendar day	
PM_{10}	756 pounds per calendar day	
SO_2	82.5 pounds per calendar day	

Verification: In the monthly compliance report the owner/operator shall indicate how this condition is being implemented.

17. Pollutant emissions from the Auxiliary Boilers (S-7 & S-8) shall not exceed the following limits during the commissioning period. These emission limits shall include emissions that occur during Auxiliary Boiler start-ups.

NO_x (as NO_2)	428 pounds per calendar day	33 pounds per hour
CO	368 pounds per calendar day	22 pounds per hour
POC (as CH_4)	25.4 pounds per calendar day	
PM_{10}	96 pounds per calendar day	
SO_2	12.4 pounds per calendar day	

Verification: In the monthly compliance report the owner/operator shall indicate how this condition is being implemented.

18. Prior to the end of the Commissioning Period, the Owner/Operator shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with condition 28. The source test shall determine NO_x, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. Twenty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.

Verification: Approval of the source test plan and receipt of the source test reports is the verification of compliance with this condition.

Conditions for the Gas Turbines (S-1, S-3, & S-5) and the Heat Recovery Steam Generators (HRSGs; S-2, S-4, & S-6).

19. The Gas Turbines (S-1, S-3, and S-5) and HRSG Duct Burners (S-2, S-4, and S-6) shall be fired exclusively on natural gas. (BACT for SO_2 and PM_{10})

Verification: As part of the semiannual Air Quality Reports (as required by AQ-43), the project owner shall indicate the date, time, and duration of any violation of this condition.

20. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2, S-3 & S-4, and S-5 & S-6) shall not exceed 2,125 MM BTU per hour, averaged over any rolling 3-hour period. (PSD for NO_x)

Verification: As part of the Air Quality monthly Reports, the owner/operator shall include information on the date and time when the hourly fuel consumption exceed this hourly limit.

21. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2 and S-3 & S-4) shall not exceed 50,024 MM BTU per calendar day. (PSD for PM_{10})

Verification: As part of the Air Quality monthly Reports, the owner/operator shall include information on the date and time when the daily fuel consumption exceed this daily limit.

22. The combined cumulative heat input rate for the Gas Turbines (S-1, S-3, & S-5) and the HRSGs (S-2, S-4, & S-6) shall not exceed 53,188,532 MM BTU per year. (Offsets)

Verification: As part of the Air Quality annual Reports, the owner/operator shall include information on the date and time when the annual fuel consumption exceed this annual limit.

23. The HRSG duct burners (S-2, S-4, and S-6) shall not be fired unless its associated Gas Turbine (S-1, S-3, and S-5, respectively) is in operation. (BACT for NO_x)

Verification: As part of the Air Quality Reports, the owner/operator shall include information on the date, time, and duration of any violation of this permit condition.

24. S-1 Gas Turbine and S-2 HRSG shall be abated by the properly operated and properly maintained A-1 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-1 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall provide information on any major problem in the operation of the Oxidizing Catalyst and Selective Catalytic Reduction Systems for the Gas Turbines and HRSGs. The information shall include, at a minimum, the date and description of the problem and the steps taken to resolve the problem.

25. S-3 Gas Turbine and S-4 HRSG shall be abated by the properly operated and properly maintained A-2 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-2 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall provide information on any major problem in the operation of the Oxidizing Catalyst and Selective Catalytic Reduction Systems for the Gas Turbines and HRSGs. The information shall include, at a minimum, the date and description of the problem and the steps taken to resolve the problem.

26. S-5 Gas Turbine and S-6 HRSG shall be abated by the properly operated and properly maintained A-3 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-3 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall provide information on any major problem in the operation of the Oxidizing Catalyst and Selective Catalytic Reduction Systems for the Gas Turbines and HRSGs. The information shall include, at a minimum, the date and description of the problem and the steps taken to resolve the problem.

27. The Gas Turbines (S-1, S-3, & S-5) and HRSGs (S-2, S-4, & S-6) shall comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode and steam injection power augmentation mode. Requirements (a) through (h) do not apply during a gas turbine start-up or shutdown.
(BACT, PSD, and Toxic Risk Management Policy)

(a) Nitrogen oxide mass emissions (calculated as NO_2) at P-1 (the combined exhaust point for the S-1 Gas Turbine and the S-2 HRSG after abatement by A-1 SCR System) shall not exceed 19.2 pounds per hour or 0.00904 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-2 (the combined exhaust point for the S-3 Gas Turbine and the S-4 HRSG after abatement by A-3 SCR System) shall not exceed 19.2 pounds per hour or 0.00904 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-3 (the combined exhaust point for the S-5 Gas Turbine and the S-6 HRSG after abatement by A-3 SCR System) shall not exceed 19.2 pounds per hour or 0.00904 lb/MM BTU (HHV) of natural gas fired. (PSD for NO_x)

(b) The nitrogen oxide emission concentration at emission points P-1, P-2, and P-3 each shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any 1-hour period. (BACT for NO_x)

a) Carbon monoxide mass emissions at P-1, P-2, and P-3 each shall not exceed 0.022 lb/MM BTU (HHV) of natural gas fired or 46.75 pounds per hour, averaged over any rolling 3-hour period. If compliance test results or continuous emissions monitoring data indicate that this level cannot be achieved during power steam augmentation operations, the owner/operator may seek approval for a higher CO mass emission limit for this operating mode, not to exceed 113.7 pounds per hour or 0.0535 lb/MM BTU of natural gas fired. (PSD for CO)

(d) The carbon monoxide emission concentration at P-1, P-2, and P-3 each shall not exceed 10 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. If compliance test results or continuous emissions monitoring data indicate that this level cannot be achieved during power steam augmentation operations, the owner/operator may seek approval for a higher CO emission limit for this operating mode, not to exceed 24.3 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. (BACT for CO)

(e) Ammonia (NH_3) emission concentrations at P-1, P-2, and P-3 each shall not exceed 10 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-1, A-2, and A-3 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-1, A-2, and A-3 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1, P-2, and P-3 shall be determined in accordance with permit condition #54. (TRMP for NH_3)

(f) Precursor organic compound (POC) mass emissions (as CH_4) at P-1, P-2, and P-3 each shall not exceed 5.33 pounds per hour or 0.00251 lb/MM BTU of natural gas fired. (BACT)

(g) Sulfur dioxide (SO_2) mass emissions at P-1, P-2, and P-3 each shall not exceed 1.49 pounds per hour or 0.0007 lb/MM BTU of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-1, P-2, and P-3 each shall not exceed 12 pounds per hour or 0.00565 lb/MM BTU of natural gas fired. (BACT)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall indicate the date, time, and duration of any violation of this Condition. The owner/operator shall also include quantitative information on the severity of the violation.

28. The regulated air pollutant mass emission rates from each of the Gas Turbines (S-1, S-3, and S-5) during a start-up or a shutdown shall not exceed the limits established below. (PSD)

	Cold Start-Up (lb/start-up)	Hot Start-Up (lb/start-up)	Shutdown (lb/shutdown)
Oxides of Nitrogen (as NO_2)	240	80	18.1
Carbon Monoxide (CO)	2,514	902	44.1
Precursor Organic Compounds (as CH_4)	48	16	8

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall indicate the date, time, and duration of any violation of this Condition. The owner/operator shall also include quantitative information on the severity of the violation.

29. No more than one of the Gas Turbines (S-1, S-3, and S-5) shall be in start-up mode at any one time. (PSD)

Verification: In the monthly compliance report the owner/operator shall indicate how this condition is being implemented.

30. The heat recovery steam generators (S-2, S-4, & S-6) and associated ducting shall be designed such that an oxidation catalyst can be readily installed and properly operated if deemed necessary by the APCO to insure compliance with the CO emission rate limitations of conditions 27(c) and 27(d). (BACT)

Verification: In the semiannual compliance report the owner/operator shall indicate how this condition is being implemented.

Conditions for Auxiliary Boilers (S-7 and S-8)

31. S-7 and S-8 Auxiliary Boilers shall be fired exclusively on natural gas. (BACT for SO_2 and PM_{10})

Verification: As part of the semiannual Air Quality Reports (as required by AQ-43), the project owner shall indicate the date, time, and duration of any violation of this condition.

32. The heat input rate to each Auxiliary Boiler (S-7 and S-8) shall not exceed 256 million BTU per hour, averaged over any rolling 3-hour period. (Cumulative Increase)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall include information on the date and time when the hourly fuel consumption exceed this hourly limit.

33. The daily heat input rate to each Auxiliary Boiler (S-7 and S-8) shall not exceed 6,144 million BTU per day. (Cumulative Increase)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall include information on the date and time when the daily fuel consumption exceeds this daily limit.

34. The combined cumulative heat input rate to S-7 Auxiliary Boiler #1 and S-8 Auxiliary Boiler #2 shall not exceed 582,234 million BTU per consecutive twelve month period. (Cumulative Increase)

Verification: As part of the annual Air Quality Reports, the owner/operator shall include information on the date and time when the annual fuel consumption exceeds this annual limit.

35. S-7 Auxiliary Boiler #1 exhaust gas shall be abated by A-4 Oxidation Catalyst and A-5 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at S-7 and the A-5 catalyst bed has reached minimum operating temperature. (BACT)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall provide information on any major problem in the operation of the Oxidizing Catalyst and Selective Catalytic Reduction Systems for Auxiliary Boiler #1and HRSGs. The information shall include, at a minimum, the date and description of the problem and the steps taken to resolve the problem.

36. S-8 Auxiliary Boiler #2 exhaust gas shall be abated by A-6 Oxidation Catalyst and A-7 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at S-8 and the A-7 catalyst bed has reached minimum operating temperature. (BACT)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall provide information on any major problem in the operation of the Oxidizing Catalyst and Selective Catalytic Reduction Systems for Auxiliary Boiler #2 and HRSGs. The information shall include, at a minimum, the date and description of the problem and the steps taken to resolve the problem.

37. S-7 and S-8 Auxiliary Boilers shall comply with requirements (a) through (h) listed below at all times, except during an auxiliary boiler start-up or shutdown. (BACT, PSD)

(a) Nitrogen oxide mass emissions (calculated as NO_2) at P-4 (the exhaust point for S-7 Auxiliary Boiler #1, after abatement by A-4 Oxidation Catalyst and A-5 SCR System) shall not exceed 0.0108 lb/MM BTU (HHV) of natural gas fired or 2.9 pounds per hour, averaged over any rolling 3-hour period. Nitrogen oxide mass emissions (calculated as NO_2) at P-5 (the exhaust point for S-8 Auxiliary Boiler #2, after abatement by A-6 Oxidation Catalyst and A-7 SCR System) shall not exceed 0.0108 lb/MM BTU (HHV) of natural gas fired or 2.9 pounds per hour, averaged over any rolling 3-hour period. (PSD for NO_x)

(b) The nitrogen oxide emission concentration at P-4 and P-5 each shall not exceed 9.0 ppmv, on a dry basis, corrected to 3% O_2, averaged over any rolling 3-hour period. (BACT for NO_x)

d) Carbon monoxide mass emissions at P-4 (the exhaust point for S-7 Auxiliary Boiler #1, after abatement by A-4 Oxidation Catalyst) shall not exceed 0.0365 lb/MM BTU (HHV) of natural gas fired or 9.34 pounds per hour, averaged over any rolling 3-hour period. Carbon monoxide mass emissions at P-5 (the exhaust point for S-8 Auxiliary Boiler #2, after abatement by A-6 Oxidation Catalyst) shall not exceed 0.0365 lb/MM BTU (HHV) of natural gas fired or 9.34 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

d) The carbon monoxide emission concentration at P-4 and P-5 each shall not exceed 50 ppmv, on a dry basis, corrected to 3% O_2, averaged over any rolling 3-hour period. (BACT for CO)

e) The precursor organic compound (POC) mass emission rates at P-4 and P-5 each shall not exceed 0.53 pounds per hour. (BACT for POC)

f). The ammonia (NH_3) emission concentrations at P-4 and P-5 each shall not exceed 10 ppmv, on a dry basis, corrected to 3% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-5 and A-7 SCR Systems. The correlation between the auxiliary boiler heat input rates, A-5 and A-7 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-4 and P-5 shall be determined in accordance with permit condition 56. (TRMP for NH_3)

(g) Sulfur dioxide (SO_2) mass emissions at P-4 and P-5 each shall not exceed 0.18 pounds per hour or 0.0007 lb/MM BTU of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-4 and P-5 each shall not exceed 2 pounds per hour or 0.0195 lb/MM BTU of natural gas fired. (BACT)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall indicate the date, time, and duration of any violation of this Condition. The owner/operator shall also include quantitative information on the severity of the violation.

Conditions for Existing Sources
(S-67, S-70 & S-73 Gas Turbines and S-68, S-71, & S-74 Waste Heat Boilers)

38. Cumulative combined emissions from the Calpine/Dow Gas Turbines (S-67, S-70, and S-73) and Waste Heat Boilers (S-68, S-71, and S-74), including emissions generated during Gas Turbine Start-ups and Shutdowns shall not exceed the following limits during any consecutive twelve-month period:

(a)	18.5 tons of NO_x (as NO_2) per year	(Offsets)
(b)	113.3 tons of CO per year	(Cumulative increase)
(c)	4.7 tons of POC (as CH_4) per year	(Offsets)
(d)	7.1 tons of PM_{10} per year	(Offsets)
(e)	0.6 tons of SO_2 per year	(Cumulative increase)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall indicate the date of any violation of this Condition including quantitative information on the severity of the violation.

39. The cumulative combined heat input rate to the Calpine/Dow Gas Turbines (S-67, S-70, and S-73) and Waste Heat Boilers (S-68, S-71, and S-74) shall not exceed 2,060,652 million BTU per consecutive twelve-month period. (offsets)

Verification: As part of the Air Quality Reports, the owner/operator shall include information on the date after which this annual limit was exceeded.

40. The combined exhaust gas from S-67 Gas Turbine T-1 and S-68 Waste Heat Boiler #1 shall be abated by A-188 Selective Catalytic Reduction System whenever fuel is combusted at S-67 or S-68 and the A-188 catalyst bed has reached minimum operating temperature. (Regulation 9-9-301.3)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall provide information on any major problem in the operation of the Oxidizing Catalyst and Selective Catalytic Reduction Systems for the Gas Turbines and HRSGs. The information shall include, at a minimum, the date and description of the problem and the steps taken to resolve the problem.

41. The combined exhaust gas from S-70 Gas Turbine T-2 and S-71 Waste Heat Boiler #2 shall be abated by A-189 Selective Catalytic Reduction System whenever fuel is combusted at S-70 or S-71 and the A-189 catalyst bed has reached minimum operating temperature. (Regulation 9-9-301.3)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall provide information on any major problem in the operation of the Oxidizing Catalyst and Selective Catalytic Reduction Systems for the Gas Turbines and HRSGs. The information shall include, at a minimum, the date and description of the problem and the steps taken to resolve the problem.

42. The combined exhaust gas from S-73 Gas Turbine T-3 and S-74 Waste Heat Boiler #3 shall be abated by A-190 Selective Catalytic Reduction System whenever fuel is combusted at S-73 or S-74 and the A-190 catalyst bed has reached minimum operating temperature. (Regulation 9-9-301.3)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall provide information on any major problem in the operation of the Oxidizing Catalyst and Selective Catalytic Reduction Systems for the Gas Turbines and HRSGs. The information shall include, at a minimum, the date and description of the problem and the steps taken to resolve the problem.

43. The owner/operator of S-67, S-70, and S-73 Gas Turbines shall perform a source test to determine the NO_x, CO, and POC mass emission rates and the accuracy of the NO_x CEMs during gas turbine start-ups and shutdowns. The source test shall also determine the accuracy of the NO_x CEMs during gas turbine start-ups and shutdowns. If the NO_x CEMs do not accurately assess emissions during start-ups and/or shutdowns (as determined by APCO), then the District-approved source test results for NO_x mass emissions shall be utilized as an emission factor for the purposes of determining compliance with condition 38(a). The District-approved source test results for CO and POC mass emissions shall be utilized as emission factors for the purposes of determining compliance with conditions 38(b) and 38(c).
(offsets, cumulative increase)

Verification: Approval of the source test protocols shall be deemed as verification for this condition. The owner/operator shall notify the District and the CEC CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CEC CPM within 30 days of the date of the tests.

44. The owner/operator of S-67, S-70, and S-73 Gas Turbines and S-68, S-71, and S-74 Waste Heat Boilers shall perform a District-approved source test for NO_x, POC, and PM_{10} mass emission rates in lb/hr and lb/MM BTU of natural gas fired at maximum operating rates at least once every 8,000 hours of turbine operation or every three calendar years, whichever comes first. (offsets, cumulative increase)

Verification: Approval of the source test shall be deemed as verification for this condition. The owner/operator shall notify the District and the CEC CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CEC CPM within 30 days of the date of the tests.

45. The owner/operator shall demonstrate compliance with conditions 38(a), 38(c), 38(d), and 39 by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up and Shutdown periods) for all of the following parameters:

(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-67, S-68, S-70, S-71, S-73, and S-74
(b) Oxygen (O_2) Concentrations and Nitrogen Oxides (NO_x) Concentrations at each of the following exhaust points: P-67, P-73, and P-79.

The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing hours, the average hourly fuel flow rates, and pollutant emission concentrations.

The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

(c) Combined Heat Input Rate for S-67, S-68, S-70, S-71, S-73, and S-74
(d) Corrected NO_x concentrations, and NO_x mass emissions (as NO_2) at each of the following exhaust points: P-67, P-73, and P-79.

For each source, source grouping, or exhaust point, the owner/operator shall record the parameters specified in conditions 45(c) and 45(d) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall utilize the data specified in 45(c) and 45(d) and the source test results specified in condition 44 to calculate and record the following data:

a) total combined Heat Input Rate for the previous consecutive twelve month period

(f) on a monthly basis, the cumulative total NO_x mass emissions (as NO_2), POC mass emissions, and PM_{10} mass emissions for the previous consecutive twelve month period for all six sources (S-67, S-68, S-70, S-71, S-73, and S-74) combined.

(1-520.1, 9-9-501, Offsets)

Verification: At least 60 days before the initial operation, the owner/operator shall submit to the CEC CPM a plan on how the measurements and recordings required by this condition will be performed. Submittal of the reports will also provide verification of compliance with this condition.

Conditions for All New Sources
(S-1, S-3, & S-5 Gas Turbines, S-2, S-4, & S-6 HRSGs, and S-7 & S-8 Auxiliary Boilers)

46. The combined heat input rate to the Gas Turbines (S-1, S-3, and S-5), HRSGs (S-2, S-4, and S-6), and Auxiliary Boilers (S-7 and S-8) shall not exceed 162,360 million BTU per calendar day. (PSD, CEC Offsets)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall include information on the date and time when the daily fuel consumption exceeds this daily limit.

47. The cumulative heat input rate to the Gas Turbines (S-1, S-3, and S-5), HRSGs (S-2, S-4, and S-6), and Auxiliary Boilers (S-7 and S-8) combined shall not exceed 53,770,760 million BTU per year. (Offsets)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall include information on the date and time when the annual fuel consumption exceeds this annual limit.

48. Total combined emissions from the Gas Turbines, HRSGs, and Auxiliary Boilers (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8), including emissions generated during Gas Turbine start-ups and shutdowns, Auxiliary Boiler start-ups and shutdowns, shall not exceed the following limits during any calendar day:

(a)	2,123.5 pounds of NO_x (as NO_2) per day	(CEQA)
(b)	13,204.4 pounds of CO per day	(PSD)
(c)	503.6 pounds of POC (as CH_4) per day	(CEQA)
(d)	876.3 pounds of PM_{10} per day	(PSD)
(e)	105.2 pounds of SO_2 per day	(BACT)

Verification: As part of the semiannual Air Quality Reports, the owner/operator shall indicate the date of any violation of this Condition including quantitative information on the severity of the violation.

49. Cumulative combined emissions from the Gas Turbines, HRSGs, and Auxiliary Boilers (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8), including emissions generated during gas turbine start-ups, gas turbine shutdowns, auxiliary boiler start-ups, and auxiliary boiler shutdowns, shall not exceed the following limits during any consecutive twelve-month period:

(a)	279.7 tons of NO_x (as NO_2) per year	(Offsets, PSD)
(b)	1,116 tons of CO per year	(Cumulative Increase)
(c)	74.4 tons of POC (as CH_4) per year	(Offsets)
(d)	140.57 tons of PM_{10} per year	(Offsets, PSD)
(e)	18.6 tons of SO_2 per year	(Cumulative Increase)

Verification: As part of the annual Air Quality Reports, the owner/operator shall indicate the date of any violation of this Condition including quantitative information on the severity of the violation.

50. The maximum projected annual toxic air contaminant emissions (per condition 52) from the Gas Turbines, HRSGs, and Auxiliary Boilers combined (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8) shall not exceed the following limits:
    (a) 5,945 pounds of formaldehyde per year
    (b) 709 pounds of benzene per year
    (c) 120.5 pounds of Specified polycyclic aromatic hydrocarbons (PAHs) per year

    unless requirement (d) is satisfied:

    (d) The owner/operator shall perform a health risk assessment using the emission rates determined by source test and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This risk analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will result in a cancer risk of not more than 1.0 in one million, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

Verification: As part of the annual Air Quality Reports, the owner/operator shall indicate the date of any violation of this Condition including quantitative information on the severity of the violation.

51. The owner/operator shall demonstrate compliance with conditions 20 through 23, 27(a) through 27(d), 28, 29, 32 through 34, 37(a) through 37(d), 46, 47, 48(a), 48(b), 49(a),

and 49(b) by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up and Shutdown periods) for all of the following parameters:

a) Firing Hours and Fuel Flow Rates for each of the following sources: S-1 and S-2 combined, S-3 and S-4 combined, S-5 and S-6 combined, S-7, and S-8.
(b) Oxygen (O_2) Concentrations, Nitrogen Oxides (NO_x) Concentrations, and Carbon Monoxide (CO) Concentrations at each of the following exhaust points: P-1, P-2, P-3, P-4, and P-5.
(c) Ammonia injection rate at A-1, A-2, A-3, A-5, and A-7 SCR Systems
(d) Steam injection rate at S-1, S-3, & S-5 Gas Turbine Combustors

The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing hours, the average hourly fuel flow rates, and pollutant emission concentrations.

The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

(e) Heat Input Rate for each of the following sources: S-1 and S-2 combined, S-3 and S-4 combined, S-5 and S-6 combined, S-7, and S-8.
(f) Corrected NO_x concentrations, NO_x mass emissions (as NO_2), corrected CO concentrations, and CO mass emissions at each of the following exhaust points: P-1, P-2, P-3, P-4, and P-5.

For each source, source grouping, or exhaust point, the owner/operator shall record the parameters specified in conditions 51(e) and 51(f) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

(g) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.
(h) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined, each Auxiliary Boiler, and all eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, & S-8) combined.
(i) the average NO_x mass emissions (as NO_2), CO mass emissions, and corrected NO_x and CO emission concentrations for every clock hour and for every rolling 3-hour period.
(j) on an hourly basis, the cumulative total NO_x mass emissions (as NO_2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, the Auxiliary Boilers, and all eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8) combined.
(k) For each calendar day, the average hourly Heat Input Rates, Corrected NO_x emission concentrations, NO_x mass emissions (as NO_2), corrected CO emission

concentrations, and CO mass emissions for each Gas Turbine and associated HRSG combined and each Auxiliary Boiler.

(l) on a daily basis, the cumulative total NO_x mass emissions (as NO_2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8) combined.

(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

Verification: As part of the annual Air Quality Reports, the owner/operator shall indicate the date of any violation of this Condition including quantitative information on the severity of the violation.

52. To demonstrate compliance with conditions 27(f), 27(g), 27(h), 28, 48(c) through 48(e), and 49(c) through 49(e), the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter (PM_{10}) mass emissions (including condensable particulate matter), and Sulfur Dioxide (SO_2) mass emissions from each power train and the auxiliary boilers. The owner/operator shall use the actual Heat Input Rates calculated pursuant to condition 51, actual Gas Turbine Start-up Times, actual Gas Turbine Shutdown Times, and CEC and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

(a) For each calendar day, POC, PM_{10}, and SO_2 Emissions shall be summarized for: each power train (Gas Turbine and its respective HRSG combined); the Auxiliary Boilers; and all eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8) combined.

(b) on a daily basis, the cumulative total POC, PM_{10}, and SO_2 mass emissions, for each year for all eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8) combined.

(Offsets, PSD, Cumulative Increase)

Verification: As part of the annual Air Quality Reports, the owner/operator shall indicate the date of any violation of this Condition including quantitative information on the severity of the violation.

53. To demonstrate compliance with Condition 50, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAH's. Maximum projected annual emissions shall be calculated using the maximum Heat Input Rate of 32,912,920 MM BTU/year and the highest emission factor (pounds of pollutant per MM BTU of Heat Input) determined by any source test at the Gas Turbine, HRSG, or Auxiliary Boilers. (TRMP)

Verification: As part of the annual Air Quality Reports, the owner/operator shall indicate the date of any violation of this Condition including quantitative information on the severity of the violation

54. Within 60 days of start-up of the DEC, the owner/operator shall conduct a District-approved source test on exhaust point P-1, P-2, or P-3 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 27(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-1, A-2, or A-3 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-1, P-2, or P-3. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to minimum, 70%, 85%, and 100% load) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. Continuing compliance with condition 27(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (TRMP)

Verification: Approval of the source test protocols and the source test reports shall be deemed as verification for this condition. The owner/operator shall notify the District and the CEC CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CEC CPM within 30 days of the date of the tests.

Verification:

55. Within 60 days of start-up of the DEC and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1, P-2, and P-3 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load (including steam injection power augmentation mode) to determine compliance with Conditions 27(a), (b), (c), (d), (f), (g), and (h), while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 27(c) and (d), and to verify the accuracy of the continuous emission monitors required in condition 50. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO_2), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter (PM_{10}) emissions including condensable particulate matter. (BACT, offsets)

Verification: Approval of the source test protocols, as required in condition 58, and the source test reports shall be deemed as verification for this condition. The owner/operator shall notify the District and the CEC CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CEC CPM within 30 days of the date of the tests.

56. Within 60 days of start-up of the DEC, the owner/operator shall conduct a District-approved source test on exhaust point P-4 or P-5 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 37(e). The source test shall determine the correlation between the heat input rates of an auxiliary boilers and the A-4 or A-5 SCR System ammonia injection rate, and the corresponding

NH_3 emission concentration at emission point P-4, or P-5. The source testing shall be conducted over the expected operating range of the auxiliary boiler (including, but not limited to 10%, 50%, and 100% load) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. Continuing compliance with condition 37(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (TRMP)

Verification: Approval of the source test protocols, as required in condition 58, and the source test reports shall be deemed as verification for this condition. The owner/operator shall notify the District and the CEC CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CEC CPM within 30 days of the date of the tests.

57. Within 60 days of start-up of the DEC and on an annual basis thereafter, the owner/operator shall conduct a District approved source test on exhaust point P-4 and P-5 while each Auxiliary Boiler (S-7 and S-8) is operating at maximum load to determine compliance with the emission limitations of Condition 37, parts (a) through (e), (g), & (h), while each Auxiliary Boiler (S-7 and S-8) is operating at minimum load to determine compliance with Condition 37, parts (c), (d), & (f), and to verify the accuracy of the continuous emission monitors required in condition 51. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO_2), carbon monoxide concentration and mass emissions, and particulate matter (PM_{10}) emissions including condensable particulate matter. (BACT, offsets)

Verification: Approval of the source test protocols, as required in condition 58, and the source test reports shall be deemed as verification for this condition. The owner/operator shall notify the District and the CEC CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CEC CPM within 30 days of the date of the tests.

58. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM_{10} emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

Verification: Approval of the source test procedures and receipt of source test results will be deemed as verification of this condition.

59. Within 60 days of start-up of the DEC and on an biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-1, P-2, or P-3 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 50. Unless the requirements of condition 59(b) have been met, the owner/operator shall determine the formaldehyde, benzene, and Specified PAH emission rates (in pounds/MM BTU). If any of the above pollutants are not detected (below the analytical detection limit), the emission concentration for that pollutant shall be deemed to be one half (50%) of the detection limit concentration. (TRMP)

    (a) The owner/operator shall calculate the maximum projected annual emission rate for each pollutant by multiplying the pollutant emission rate (in pounds/MM BTU; determined by source testing) by 53,770,760 MM BTU/year.

    (b) If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to part (a) for any of the compounds listed below are less than the BAAQMD Toxic Risk Management Policy trigger levels shown, then the owner/operator may discontinue future testing for that pollutant:

Benzene	≤	221 pounds/year	
Formaldehyde	≤	1,834 pounds/year	
Specified PAH’s	≤	38 pounds/year	(TRMP)

Verification: The owner/operator shall notify the District and the CEC CPM within seven (7) working days before the owner/operator plans to conduct source testing as required by this condition. Source test results shall be submitted to the District and the CEC CPM within thirty (30) days of conducting the test.

60. The owner/operator of the DEC shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)

Verification: Submittal of the reports to the CEC CPM constitutes verification of compliance with this condition. All reports shall be submitted to the CEC CPM within thirty (30) days after they are due according to District Rules and Regulations.

61. The owner/operator of the DEC shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related

incidents. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)

Verification: During site inspection, the owner/operator shall make all records and reports available to the District, California Air Resources Board, and CEC staffs.

62. The owner/operator of the DEC shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)

Verification: Submittal of these notifications as required by this condition is the verification of these permit conditions. In addition, as part of the Air Quality Reports, the owner/operator shall include information on the dates when these violations occurred and when the owner/operator notified the District and the CEC CPM.

63. The stack height of emission points P-1, P-2, and P-3 shall each be at least 144 feet above grade level at the stack base. The stack height of emission points P-4 and P-5 shall each be at least 115 feet above grade level at the stack base. (PSD, TRMP)

Verification: 45 days prior to the release to the manufacturer of the emission stack's "approved for construction" drawings, the Owner/Operator shall submit the drawings to the CEC CPM for review and approval.

64. The Owner/Operator of DEC shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall be subject to BAAQMD review and approval. (Regulation 1-501)

Verification: One hundred and twenty (120) days before initial operation, the Owner/Operator shall submit to the BAAQMD and the CEC CPM a plan for the installation of stack sampling ports and platforms. Within sixty (60) days of receipt of the plant, the BAAQMD will advise the Owner/Operator and the CEC CPM of the acceptability of the plan; otherwise the plan shall be deemed approved.

65. Within 180 days of the issuance of the Authority to Construct for the DEC, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous monitors, sampling ports, platforms, and source tests required by conditions 54 through 57, and 59. All source testing and monitoring shall be conducted in accordance with the BAAQMD Manual of Procedures. (Regulation 1-501)

Verification: The owner/operator shall notify the CEC CPM at least seven (7) working days before these contacts are made.

66. Prior to the issuance of the BAAQMD Authority to Construct for the Delta Energy Center, the Owner/Operator shall demonstrate that valid emission reduction credits in the amount of 235.62 tons/year of Nitrogen Oxides, 75.3 tons/year of Precursor Organic Compounds, and 127.37 tons/year of PM_{10} or equivalent as defined by District Regulations 2-2-302.1, 2-2-302.2, and 2-2-303.1 are under their control through enforceable contract or option to purchase agreements or equivalent binding legal documents. (Offsets)

Verification: No more than 30 days after the issuance of an Authority to Construct, the Owner/Operator shall provide a copy of the ATC to the CEC CPM for review.

67. Prior to the start of construction of the Delta Energy Center, the Owner/Operator shall provide to the District valid emission reduction credit banking certificates in the amount of 235.62 tons/year of Nitrogen Oxides, 75.3 tons/year of Precursor Organic Compounds, and 127.37 tons/year of PM_{10} or equivalent as defined by District Regulations 2-2-302.1, 2-2-302.2, and 2-2-303.1. (Offsets)

Verification: At least 30 days prior to the start of construction, the owner/operator must submit a copy of the required offset or emission reduction credit (ERCs) certificates to the CEC CPM.

68. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.3, the owner/operator of DEC shall submit an application to the District for a significant modification to the DEC's Federal (Title V) Operating Permit within 12 months of the initial operation of the gas turbines (S-1, S-3, & S-5), HRSGs (S-2, S-4, & S-6), or Auxiliary Boilers (S-7 & S-8). (Regulation 2-6-404.3)

Verification: The owner/operator shall notify the CEC CPM of the submittal of this application. In addition, the owner/operator shall submit to the CPM a copy of the Federal (Title V) Operating Permit within 30 days after it is issue by the District.

69. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the Delta Energy Center shall submit an application for a Title IV operating permit at least 24 months prior to the initial operation of any of the gas turbines (S-1, S-3, & S-5) or HRSGs (S-2, S-4, & S-6). (Regulation 2, Rule 7)

Verification: At least 60 days before the initial operation, the owner/operator shall submit to the CEC CPM a plan on how this condition will be satisfied.

70 The Delta Energy Center shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

Verification: At least 60 days before the initial operation, the owner/operator shall submit to the CEC CPM a plan on how the measurements and recordings required by this condition will be performed. Submittal of the reports will also provide verification of compliance with this condition.

71 The owner/operator shall take monthly samples of the natural gas combusted at the DEC. The samples shall be analyzed for sulfur content using District-approved laboratory methods. The sulfur content test results shall be retained on site for a minimum of five years from the test date and shall be utilized to satisfy the requirements of 40 CFR Part 60, Subpart GG. (cumulative increase).

Verification: The owner/operator shall maintain on site the records of all the guarantees received from its natural gas suppliers indicating that the fuel delivered to DEC complies with the 40 CFR Part 60, Subpart GG. These records shall be made available to the District or the CEC CPM upon request during on-site compliance inspections.

72. The cooling towers shall be properly installed and maintained to minimize drift losses. The cooling towers shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0006%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 5,233 ppmw (mg/l). The owner/operator shall sample the water at least once per day. (PSD)

Verification: The owner/operator shall submit to the CEC CPM a performance guarantee letter from the cooling tower manufacturer prior to its installation. As part of the compliance record, the owner/operator shall keep records on-site on the TSC content of water in the cooling tower.

73. The owner/operator shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to initial operation of the Delta Energy Center, the owner/operator shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminators and certify that the installation was performed in a satisfactory manner. The CPM may, in years 5 and 15 of cooling tower operation, require the owner/operator to perform a source test to determine the PM_{10} emission rate from the cooling tower to verify continued compliance with the vendor-guaranteed drift rate specified in condition #71. (PSD)

Staff proposes conditions of certification for construction activities, at this time. Conditions of Certification for the operation of the facility will be included in staff's final testimony, following the issuance of the FDOC.

Verification: As part of the monthly Air Quality Reports, the owner/operator shall indicate the date of any violation of this Condition including quantitative information on the severity of the violation.

For the purposes of the following conditions, the following definitions apply:

(1) ACTIVE OPERATIONS shall mean any activity capable of generating fugitive dust, including, but not limited to, earth-moving activities, construction/demolition activities, or heavy- and light-duty vehicular movement.

(2) CHEMICAL STABILIZERS mean any non-toxic chemical dust suppressant which must not be used if prohibited for use by the Regional Water Quality Control Boards, the California Air Resources Board, the U.S. Environmental Protection Agency (U.S. EPA), or any applicable law, rule or regulation; and should meet any specifications, criteria, or tests required by any federal, state, or local water agency. Unless otherwise indicated, the use of a non-toxic chemical stabilizer shall be of sufficient concentration and application frequency to maintain a stabilized surface.

(3) CONSTRUCTION/DEMOLITION ACTIVITIES are any on-site mechanical activities preparatory to or related to the building, alteration, rehabilitation, demolition or improvement of property, including, but not limited to the following activities; grading, excavation, loading, crushing, cutting, planing, shaping or ground breaking.

(4) DISTURBED SURFACE AREA means a portion of the earth's surface which has been physically moved, uncovered, destabilized, or otherwise modified from its undisturbed natural soil condition, thereby increasing the potential for emission of fugitive dust.

(5) DUST SUPPRESSANTS are water, hygroscopic materials, or non-toxic chemical stabilizers used as a treatment material to reduce fugitive dust emissions.

(6) EARTH-MOVING ACTIVITIES shall include, but not be limited to, grading, earth cutting and filling operations, loading or unloading of dirt or bulk materials, adding to or removing from open storage piles of bulk materials, landfill operations, or soil mulching.

(7) FUGITIVE DUST means any solid particulate matter that becomes airborne, other than that emitted from an exhaust stack, directly or indirectly as a result of the activities of man.

(8) INACTIVE DISTURBED SURFACE AREA means any disturbed surface area upon which active operations have not occurred or are not expected to occur for a period of ten consecutive days.

(9) STABILIZED SURFACE means:
(A) any disturbed surface area or open storage pile which is resistant to wind-driven fugitive dust;
(B) any unpaved road surface in which any fugitive dust plume emanating from vehicular traffic does not exceed 20 percent opacity.

(10) VISIBLE ROADWAY DUST means any sand, soil, dirt, or other solid particulate matter which is visible upon paved road surfaces and which can be removed by a vacuum sweeper or a broom sweeper under normal operating conditions.

74 The project owner shall implement a CEC CPM approved fugitive Dust Control Plan during the construction phase of the project.

Protocol: The plan shall include the following:

1. A description of each of the active operation(s) which may result in the generation of fugitive dust;

2. an identification of all sources of fugitive dust (e.g., earth-moving, storage piles, vehicular traffic, etc.

3. A description of the Best Available Fugitive Dust Control Measures (see Table 1 attached) to be applied to each of the sources of dust emissions identified above (including those required in AQ-2 below). The description must be sufficiently detailed to demonstrate that the applicable best available control measure(s) will be utilized and/or installed during all periods of active operations;

4. In the event that there are special technical (e.g., non-economic) circumstances, including safety, which prevent the use of at least one of the required control measures for any of the sources identified, a justification statement must be provided to explain the reason(s) why the required control measures cannot be implemented.

Verification: Not later than sixty (60) days prior to the commencement of construction, the project owner shall submit the plan to the CEC CPM for review and approval. The project owner shall maintain daily records to document the specific actions taken pursuant to the plan. A summary of the monthly activities shall be submitted to the CPM via the Monthly Compliance Report.

75 During the construction phase of the project, the project owner shall:

1. Prevent or remove within one hour the track-out of bulk material onto public paved roadways as a result of their operations, or take at least one of the actions listed in Table 2 (attached) to prevent the track-out of bulk material onto public paved roadways as a result of their operations and remove such material at anytime track-out extends for a cumulative distance of greater than 50 feet on to any paved public road during active operations;

2. Install and use a track-out control device to prevent the track-out of bulk material from areas containing soils requiring corrective action (as currently identified in drawing no. 5-1 of the addendum dated February 12, 1999 to the Corrective Measures Study performed by the Mark Group for USS-POSCO Industries) to other areas within the project construction site and lay-down area;

3. Minimize fugitive particulate emissions from vehicular traffic on paved roads and paved parking lots on the construction site by vacuum mechanical sweeping or water flushing of the road surface to remove buildup of loose material. The project owner shall inspect on a daily basis the conditions of the paved roads and parking lots to determine the need for mechanical sweeping or water flushing.

Verification: The project owner shall maintain a daily log during the construction phase of the project indicating: 1) the manner in which compliance with AQ-2 is achieved and 2) the date and time when the inspection of paved roads and parking lots occurs and the date and time(s) when the cleaning operation occurs. The logs shall be made available to the CEC CPM upon request.

76 At any time when fugitive dust from Delta Energy Center project construction is visible in the atmosphere beyond the property line, the project owner will identify the source of the fugitive dust and implement one or more of the appropriate control measures specified in Table 3 (attached)

Verification: The project owner will maintain a daily log recording the dates and times that measures in Table 3 (attached) have been implemented and make them available to the CEC CPM upon request.

TABLE 1
BEST AVAILABLE FUGITIVE DUST CONTROL MEASURES

FUGITIVE DUST SOURCE CATEGORY	**CONTROL ACTIONS**
Earth-moving (except construction cutting and filling areas, and mining operations)	Maintain soil moisture content at a minimum of 12 percent, as determined by ASTM method D-2216, or other equivalent method approved by the CEC CPM. Two soil moisture evaluations must be conducted during the first three hours of active operations during a calendar day, and two such evaluations each subsequent four-hour period of active operations; OR
	For any earth-moving which is more than 100 feet from all property lines, conduct watering as necessary to prevent visible dust emissions from exceeding 100 feet in length in any direction.
Earth-moving: Construction fill areas:	Maintain soil moisture content at a minimum of 12 percent, as determined by ASTM method D-2216, or other equivalent method approved by the CEC CPM. For areas which have an optimum moisture content for compaction of less than 12 percent, as determined by ASTM Method 1557 or other equivalent method approved by the CEC CPM, complete the compaction process as expeditiously as possible after achieving at least 70 percent of the optimum soil moisture content. Two soil moisture evaluations must be conducted during the first three hours of active operations during a calendar day, and two such evaluations during each subsequent four-hour period of active operations.

TABLE 1 (Continued)

FUGITIVE DUST SOURCE CATEGORY	**CONTROL ACTIONS**
Earth-moving: Construction cut areas and mining operations:	Conduct watering as necessary to prevent visible emissions from extending more than 100 feet beyond the active cut or mining area unless the area is inaccessible to watering vehicles due to slope conditions or other safety factors.
Disturbed surface areas (except completed grading areas)	Apply dust suppression in sufficient quantity and frequency to maintain a stabilized surface. Any areas which cannot be stabilized, as evidenced by wind driven fugitive dust must have an application of water at least twice per day to at least 80 percent of the unstabilized area.
Disturbed surface areas: Completed grading areas	Apply chemical stabilizers within five working days of grading completion; OR
	Take actions (3a) or (3c) specified for inactive disturbed surface areas.
Inactive disturbed surface areas	Apply water to at least 80 percent of all inactive disturbed surface areas on a daily basis when there is evidence of wind driven fugitive dust, excluding any areas which are inaccessible to watering vehicles due to excessive slope or other safety conditions; OR
	Apply dust suppressants in sufficient quantity and frequency to maintain a stabilized surface; OR
	Establish a vegetative ground cover within 21 days after active operations have ceased. Ground cover must be of sufficient density to expose less than 30 percent of unstabilized ground within 90 days of planting, and at all times thereafter; OR
	Utilize any combination of control actions (3a), (3b), and (3c) such that, in total, these actions apply to all inactive disturbed surface areas.

TABLE 1 (Continued)

FUGITIVE DUST SOURCE CATEGORY	**CONTROL ACTIONS**
Unpaved Roads	Water all roads used for any vehicular traffic at least once per every two hours of active operations; OR
	Water all roads used for any vehicular traffic once daily and restrict vehicle speeds to 15 miles per hour; OR
	Apply a chemical stabilizer to all unpaved road surfaces in sufficient quantity and frequency to maintain a stabilized surface.
Open storage piles	Apply chemical stabilizers; OR
	Apply water to at least 80 percent of the surface area of all open storage piles on a daily basis when there is evidence of wind driven fugitive dust; OR
	Install temporary coverings; OR
	Install a three-sided enclosure with walls with no more than 50 percent porosity which extend, at a minimum, to the top of the pile.
All Categories	Any other control measures approved by the CEC CPM as equivalent to the methods specified in Table 1 may be used.

TABLE 2
TRACK-OUT CONTROL OPTIONS

(1)	Pave or apply chemical stabilization at sufficient concentration and frequency to maintain a stabilized surface starting from the point of intersection with the public paved surface, and extending for a centerline distance of at least 100 feet and a width of at least 20 feet.
(2)	Pave from the point of intersection with the public paved road surface, and extending for a centerline distance of at least 25 feet and a width of at least 20 feet, and install a track-out control device immediately adjacent to the paved surface such that exiting vehicles do not travel on any unpaved road surface after passing through the track-out control device.
(3)	Any other control measures approved by the CEC CPM as equivalent to the methods specified in Table 2 may be used.

TABLE 3
CONTROL MEASURES FOR WIND CONDITIONS EXCEEDING 25 MPH

FUGITIVE DUST SOURCE CATEGORY	**CONTROL MEASURES**
Earth-moving	Cease all active operations; OR
	Apply water to soil not more than 15 minutes prior to moving such soil.
Disturbed surface areas	On the last day of active operations prior to a weekend, holiday, or any other period when active operations will not occur for not more than four consecutive days: apply water with a mixture of chemical stabilizer diluted to not less than 1/20 of the concentration required to maintain a stabilized surface for a period of six months; OR
	Apply chemical stabilizers prior to wind event; OR
	Apply water to all unstabilized disturbed areas 3 times per day. If there is any evidence of wind driven fugitive dust, watering frequency is increased to a minimum of four times per day; OR
	Take the actions specified in Table 1, Item (3c); OR
	Utilize any combination of control actions (1B), (2B), and (3B) such that, in total, these actions apply to all disturbed surface areas.
Unpaved roads	Apply chemical stabilizers prior to wind event; OR
	Apply water twice [once] per hour during active operation; OR
	Stop all vehicular traffic.
Open storage piles	Apply water twice [once] per hour; OR
	Install temporary coverings.
Paved road track-out	Cover all haul vehicles; OR
	Comply with the vehicle freeboard requirements of Section 23114 of the California Vehicle Code for both public and private roads.
All Categories	Any other control measures approved by the Executive Officer and the U.S. EPA as equivalent to the methods specified in Table 3 may be used.

77. Prior to the start of construction, the Delta Energy Center owner/operator must provide the District with valid ERC certificates for PM10 for the amount of 21.15 tons from Spreckels facility located in Clarksburg in Yolo-Solano Air Quality Management District. This portion of required PM10 ERCs and offsets are to be provided in addition to the requirements of condition 67.

Verification: At least 30 days prior to the start of construction, the project owner must submit a copy of the required ERC certificates to the CPM and the District.

REFERENCES

DEC (Delta Energy Center). 1998a. Application for Certification, Delta Energy Center (98-AFC-3). Submitted to the California Energy Commission, December 18, 1998.

CEC (California Energy Commission). 1999b. CEC second set of data requests, data requests #62-86.

DEC (Delta Energy Center). 1998d. Confidential filing—Air Quality. Submitted to the California Energy Commission, December 18, 1998.

DEC (Delta Energy Center). 1999a. PG&E Detailed Facilities Study for DEC, submitted to the California Energy Commission on March 25, 1999.

DEC (Delta Energy Center). 1999f. Response to CEC data requests #62-75 submitted to the California Energy Commission on April 20, 1999.

DEC (Delta Energy Center). 1999h. Response to data requests made at the workshops and submitted to the California Energy Commission on May 7, 1999.

DEC (Delta Energy Center). 1999i. Response to CEC data requests made at the workshops and submitted to the California Energy Commission on May 14, 1999.

DEC (Delta Energy Center). 1999d. Supplemental filing--reduction in length of the gas pipeline and inclusion of an additional outfall for wastewater discharge, dated June 11,1999 and docketed June 16, 1999.

California Air Resources Board, Guidance for Power Plant Siting and Best Available Control Technology, Stationary Source Division, June 1999.

BAAQMD, 1997b. Bay Area 1997 Clean Air Plan. Volume IV. Appendix G. Source Inventory Description. Bay Area Air Quality Management District. December 17.

APPENDIX A

ENGELHARD ANALYSIS OF THE CO CATALYST

APPENDIX B

Copy of the BAAQMD's best Available Control Technology (BACT) Guideline