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June 12, 2007

Jack Caswell, Project Manager
California Energy Commission
1516 Ninth Street, MS-15
Sacramento, CA 95814

Dear Mr. Caswell:

This is the Final Determination of Compliance from the Colusa County Air Pollution Control District for the Colusa Generating Station project.

Sincerely,

Harry A. Krug
Director of Air Quality Standards

Hand Delivered

June 11, 2007

FINAL

DETERMINATION OF COMPLIANCE

COLUSA GENERATING STATION

E&L Westcoast, L.L.C.

Application submitted November 22,2006

COLUSA COUNTY
AIR POLLUTION CONTROL DISTRICT

100 Sunrise Blvd, Suite F
Colusa CA 95932

November 28, 2006

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COLUSA GENERATING STATION PROJECT

I APPLICANT

This Authority to Construct/Permit to Operate (ATC/PTO) application is for the construction and operation of a nominally rated 660 megawatt (MW) combined cycle power plant in Colusa County by E&L Westcoast, L.L.C. (E&L Westcoast).

E&L Westcoast, LLC
8403 Colesville, Suite 915
Silver Spring, Maryland 20910

Contact:
Mr. Andrew Welch, P.E.
Project Manager
E&L Westcoast, LLC

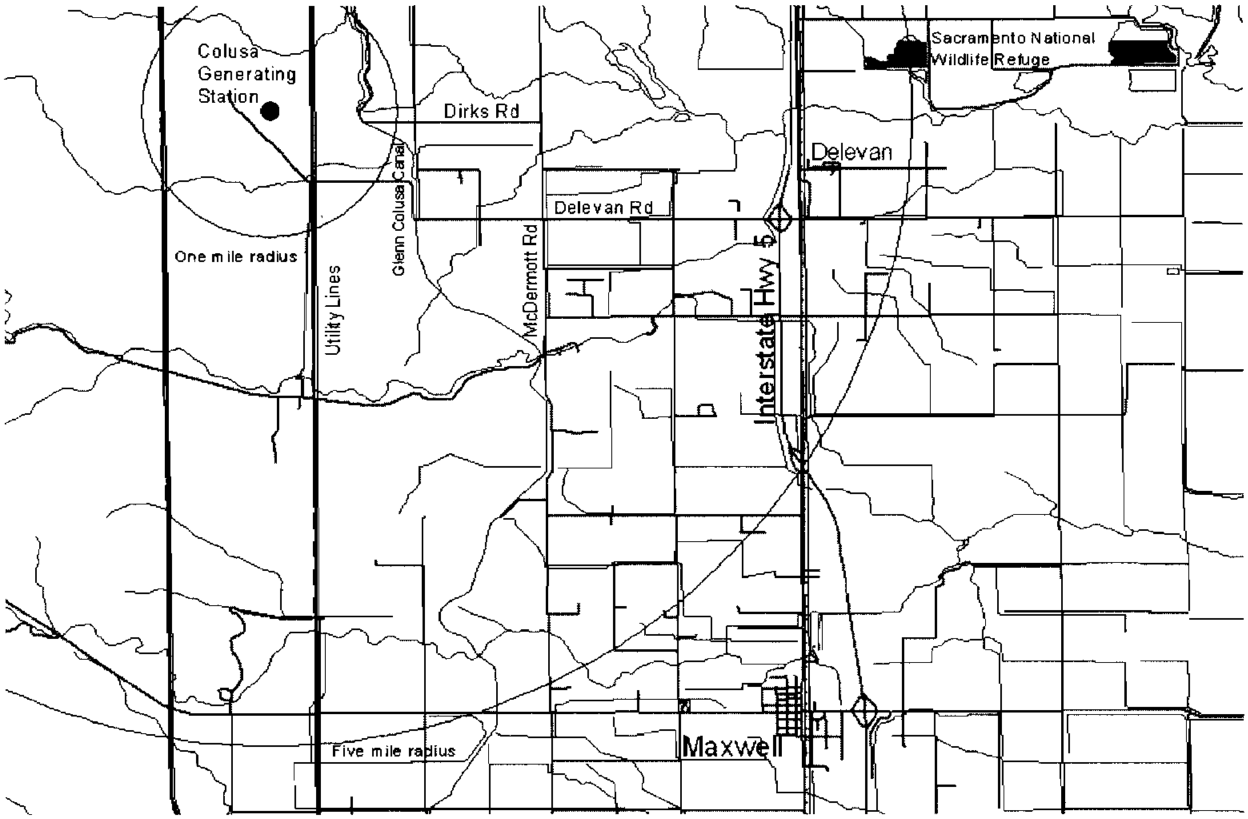
II BACKGROUND INFORMATION

The application was submitted to the Colusa County Air Pollution Control District (CCAPCD) on November 22, 2006 with the intention of obtaining a Determination of Compliance. The submittal was also intended to serve as an application for an Authority to Construct from the District.

The proposed project is sited adjacent to existing industrial facilities in an unincorporated area of Colusa County (Section 35, Township 18N, Range 4W) designated Agricultural-General (A-G) and zoned Exclusive Agriculture (EA). The Colusa Generating Station (CGS) is compatible with these industrial facilities. The closest resident is approximately 1.7 miles southeast of the site. E&L Westcoast has applied to Colusa County for a change in General Plan Land Use Designation and Zoning, and a subdivision of the 100-acre parcel. The application to the County will be processed in conjunction with the California Energy Commission's (CEC) review of this project utilizing the CEC's role as lead agency for the California Environmental Quality Act (CEQA) and its environmental analysis.

III FACILITY LOCATION

The CGS is proposed to be located about 4 miles west of Interstate 5 (I-5) in Colusa County, California on a 100-acre parcel of land. The site is adjacent to the PG&E Delevan Compressor Station near Maxwell. The power plant and switchyard will occupy approximately 26.6 acres within the 100-acre project site. The site is presently undeveloped agricultural land used for grazing cattle. Site topography is rolling hills from 175 to 190 feet above mean sea level. The map below shows the site in relation to nearby roads and the towns of Delevan and Maxwell.



IV FACILITY DESCRIPTION

The proposed CGS power plant will consist of two General Electric (GE) Frame 7-FA combustion gas turbines (CTGs) equipped with dry, low nitrogen oxide (DLN) combustors; two heat recovery steam generators (HRSGs), each equipped with a duct burner, an oxidation catalyst, and an aqueous ammonia selective catalytic reduction (SCR) system; a multistage steam turbine generator (STG); dry cooling tower technology; an auxiliary boiler with ultra low NOx burner; and associated support equipment. Each CTG will generate an average of 172 MW. Up to 320 MW will be produced by the steam turbine.

PROCESS EQUIPMENT

The CGS will include two GE Frame 7-FA combustion gas turbines with electrical generators. They will burn natural gas fuel. Gas purchased from suppliers will be delivered to the project site via a new 8-inch pipeline interconnected to the Pacific Gas Transmission/PG&E gas transmission lines. The CTGs will each be equipped with evaporative inlet air coolers/filters to enhance turbine performance in hot weather. An auxiliary boiler will be installed at the facility. The boiler is used to generate steam that is vented to the CTG trains to preheat the equipment which allows for quicker startup.

Hot exhaust gases from the CTGs will be directed to parallel HRSGs where steam will be generated at three pressures. The steam produced by the HRSGs will be combined to drive a single steam turbine. The HRSGs will include duct burners to increase steam output and achieve higher levels of power output in selected modes of operation. Cooled exhaust gases from each HRSG will be exhausted to the atmosphere through a stack that will be approximately 175 feet in height.

Steam from the HRSGs will be directed to the steam turbine, then exhausted and condensed in an air-cooled condenser. Condensate from the condenser is returned to the steam cycle. The CGS will use "dry" cooling technology for its operation.

Each of the CTGs and the steam turbine are connected to electric generators, which generate electrical energy at 18 kilovolts.

The proposed facility will have a backup emergency generator (1,000 kW) powered by a diesel engine. Also, two emergency firewater pumps are planned, one electric powered and the other by a diesel fired internal combustion engine. The engine will be tested periodically but otherwise only operate to pump water from the firewater storage tank in the event of a fire.

The CGS will have one remote reservoir cold solvent degreasing station. This equipment will employ low VOC solvent used at room temperature. The solvent will be stored within an enclosed remote reservoir and sprayed on parts within a basin that drains back to the solvent reservoir. The degreasing station will be equipped with a lid that will be closed when the degreaser is not in use. No rags or other porous material will be stored in the degreaser. Spent solvent will be recycled or disposed of in an appropriate manner by an approved contractor.

Major Project Equipment

Equipment	Quantity	Make/Model/Size/Capacity
Combustion Turbine Generators	2	General Electric 7-FA 1917.2 MMbtu/hr
Steam Turbine Generator	1	320 MW condensing reheat STG
Heat Recovery Steam Generators	2	Duct burners rated at 688 MMbtu/hr
Auxiliary Boiler	1	NBC or equivalent 44 MMbtu/hr
Firewater Pump Engines	2	One a 300 hp diesel fired
Emergency Generator 1,000 kW	1	1,340 hp diesel engine powered
Aqueous Ammonia Storage Tank	1	20,000 US gal for NOx control
SCR Catalysts	2	NOx control
Oxidation Catalysts	2	VOC and CO control

OPERATING CONDITIONS

The CGS plant will be operated 7 days a week, 24 hours a day. In any given hour, the plant may be operating at peak load, base load, or part load with both CTGs or with one CTG running. Peak load operation will most likely occur during summer on-peak hours, and minimum load operation during non-summer off-peak hours. Shutdown periods for annual maintenance will be scheduled during extended periods of low demand, which typically occur in the winter or early spring.

The CGS facility will burn natural gas fuel in the turbines, duct burners and auxiliary boiler.

Natural Gas Analysis

Constituent	Percent by Volume
Methane	94
Ethane	3
Propane	0.1
n-Butane	0.01
i-Butane	0.01
n-Pentane	0.00
i-Pentane	0.01
Hexane+	0.01
Oxygen	0.00
Nitrogen	2.2
Carbon dioxide	0.66
Total	100.00
Sulfur (grains per 100 scf)	<0.20
Specific Gravity (air = 1.00)	0.59
Higher Heating Value (Btu/scf)	1010

Source: PG&E 2006.
Btu = British thermal unit(s)
scf = standard cubic feet

Heat and material balances are presented in the following table. These are four typical operating cases. Further clarification of the duct burner and evaporative cooler operations is presented as it relates to ambient weather conditions. Prevailing temperature and relative humidity influence the need for operation of these systems.

Case	Description	Ambient Temp, °F	Duct Fire Status	Evaporation Cooler Status	CGT Firing Rate LHV	HRSG Duct Firing Rate LHV	Net Facility Output CGT&STG
1	July Peak	94	On	On	1,558.3	574.2	640.0
2	ISO	59	On	Off	1,601.9	565.6	666.3
3	ISO	59	Off	Off	1,601.9	0.0	519.4
4	ISO, minimum	59	Off	Off	1,045.4	0.0	130.0
Note	Independent System Operator (ISO) – Firing Rates in MM Btu/hr – LHV is 20,300 Btu/lb – Output MW						

Case	Description	Ambient Temp, °F	Duct Fire Status	Evaporation Cooler Status	CGT A Output	CGT B Output	STG Output
1	July Peak	94	On	On	166.4	166.4	327.9
2	ISO	59	On	Off	172.9	172.9	341.3
3	ISO	59	Off	Off	172.9	172.9	188.1
4	ISO, minimum	59	Off	Off	86.4	0.0	55.9
Note	Independent System Operator (ISO) – Output in MW before subtracting the auxiliary load ~ 20-14 MW						

Two CTG operations (base load and cycling load) are described below in terms of the anticipated number of startups per year and annual hours online with and without duct firing.

These definitions apply to the following tables: "Hot Start" means less than 8 hours since time of last firing (Startup time:90 minutes); "Warm Start" means between 8 and 72 hours since time of last firing (Startup time: 180 minutes); and "Cold Start" means more than 72 hours since time of last firing (Startup time: 270 minutes).

Quarterly and Annual Turbine Estimated Operating Conditions (if base load)					
Operating Condition	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Annual
Number of Startups	14	14	14	14	56
Hot Starts	10.5	10.5	10.5	10.5	42
Warm Starts	0	0	0	0	0
Cold Starts	3.5	3.5	3.5	3.5	14
Startup/Shutdown Time (hours)	38.5	38.5	38.5	38.5	154
Turbines w/o Duct Burners (hours)	1,082	1,106	1,129	1,129	4,446
Turbines w/ Duct Burners (hours)	1,040	1,040	1,040	1,040	4,160
Total CTG Operating Hours	2,160	2,184	2,208	2,208	8,760

Quarterly and Annual Turbine Estimated Operating Conditions (if cycling load)					
Operating Condition	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter	Annual
Number of Startups	74	74	74	74	296
Hot Starts	61	61	61	61	244
Warm Starts	12	12	12	12	48
Cold Starts	1	1	1	1	4
Startup/Shutdown Time (hours)	168	168	168	168	672
Turbines w/o Duct Burners (hours)	0	0	0	0	0
Turbines w/ Duct Burners (hours)	1,040	1,040	1,040	1,040	4,160
Total CTG Operating Hours	1,208	1,208	1,208	1,208	4,832

Hourly fuel use rates of the facility's main combustion equipment are indicated in the next table. Natural gas is the primary fuel with diesel being used in the emergency generator and firewater pump engines.

Source	**Fuel – Units/Hr**	**Maximum**
Combustion Gas Turbine, each	Gas MMBtu-HHV	1,917.2
Duct Burner, each	Gas MMBtu-HHV	674.3
Auxiliary Boiler	Gas MMBtu	44
Emergency Generator	Diesel MMBtu	9.9
Firewater Pump Engine	Diesel MMBtu	2.2

For gas turbines "normal" conditions are 100% load and 60F average annual ambient temperature and "maximum" conditions are 100% load and 18F winter minimum temperature. For the duct burners "normal" conditions are 100% load and 60F average annual ambient temperature and "maximum" conditions are full fire and 114F summer maximum temperature. The boiler's "maximum" fuel use rate is at the nameplate rating. The emergency generator's "normal" conditions are weekly testing (one hour) at 50% load and "maximum" conditions are 100% load or 1,340 brake horsepower (bhp). The firewater pump engine's "normal" conditions are weekly testing (one hour) at 50% load and "maximum" conditions are 100% load or 300 brake horsepower (bhp).

AIR POLLUTION CONTROL EQUIPMENT / STRATEGIES

Air pollution emissions from the combustion of natural gas in the CTG and HRSG duct burners are controlled by the best available control technology (BACT) systems. Emissions that are controlled include NO_X, CO, VOCs, PM_{10}, and SO_2. A continuous emissions monitoring system (CEMS) will be installed to monitor NO_X, CO, and oxygen (O_2) concentrations in the stack emissions. The CEMS generates a log of emissions data for compliance documentation and activates an alarm in the plant control room when stack emissions exceed specified limits.

The facility will include selective catalytic reduction (SCR) with ammonia injection emissions control equipment for reduction of nitrogen oxides (NO_x) and an oxidation catalyst for reduction of carbon monoxide (CO) and volatile organic compound (VOC) emissions in the exhaust gas.

NOx Control

Dry low NOx (DLN) combustors in the combustion turbines, low NOx duct burners, and SCR will be used to control NO_x concentrations in the exhaust gas emitted to the atmosphere. DLN combustors in the CTGs followed by SCR in the HRSGs will control stack NO_X emissions to a maximum 2.0 ppmvd corrected to 15 percent oxygen. The DLN combustors control NO_X emissions to approximately 9 ppmvd at the CTG exhausts by pre-mixing fuel and air immediately prior to combustion. The SCRs equipment will include a reactor chamber, catalyst modules, ammonia storage system, ammonia vaporization and injection system, and monitoring equipment and sensors. The SCR process uses aqueous ammonia as a reagent.

The auxiliary boiler will be equipped with an ultra low NOx burner.

CO and VOC Control

An oxidation catalyst installed in the HRSG will control the CO and VOC emissions from the CTG combustors and HRSG duct burners. The HRSG limit for CO emissions will be 3 ppmvd to ensure that VOC emissions are controlled to less than 2 ppmvd at 15 percent oxygen. This catalytic system will promote the oxidation of CO to carbon dioxide (CO_2) and VOCs to CO_2 and water vapor without the need for additional reagents such as ammonia.

PM_{10} Particulate Control

Particulate emissions will be controlled using clean-burning natural gas as the exclusive fuel for the CTGs and duct burners. PM_{10} emissions consist primarily of hydrocarbon particles formed during combustion. In addition, the CTGs will be equipped with high-efficiency inlet air filters.

SOx Control

Sulfur oxides will be controlled using pipeline-quality natural gas as the exclusive fuel for the CTGs and duct burners. The amount of SO_x emissions is dependent upon the amount of sulfur compounds in the natural gas. The Public Utilities Commission has established standards for the sulfur content in natural gas. The level of sulfur will be limited to 1.0 grains per 100 standard cubic feet of gas.

Toxic Control

Use of natural gas and state-of-the-art combustion technology will minimize the quantities of potentially toxic air emissions that will be created. The SCR process will use aqueous ammonia. Ammonia slip will be limited to 5.0 ppmvd corrected to 15 percent oxygen.

Mitigation Measures for Dust Control

Dust emissions from construction activities are expected to be 90 percent with the following measures.

1. Frequent watering of unpaved roads and disturbed areas (at least twice a day).
2. Limit speed of vehicles on the construction areas to no more than 10 miles per hour.
3. Sweep paved internal roads after the evening peak period.
4. Increase frequency of watering when wind speeds exceed 15 miles per hour.
5. Employ tire washing and gravel ramps prior to entering a public roadway to limit accumulated mud and dirt deposited on the roads.
6. Pave the entrance roadways to the construction site.
7. Place sandbags adjacent to roadways to prevent run-off to public roadways.
8. Employ dust sweeping vehicles at least twice a day to sweep public roadways that are used by construction and worker vehicles.
9. Sweep newly paved roads at least twice weekly.
10. Replace ground cover in disturbed areas as quickly as possible.
11. Cover all trucks hauling dirt, sand, soil or other loose materials and maintain a minimum of six inches of freeboard between the top of the load and the top of the trailer.
12. Limit equipment idle times to no more than 15 minutes.
13. Employ electric motors for construction equipment when feasible.
14. Apply covers or dust suppressants to soil storage piles and disturbed areas that remain inactive for over two weeks.
15. Pre-wet the soil to be excavated during construction.

V FACILITY EMISSIONS

Construction Emissions

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

Months 1-2: 73.7 acres
Months 3-5: 35.9 acres
Months 6-20: 38.0 acres
Months 21-24: 2.6 acres

The sites and related preparations include: construction trailer and parking lot, construction laydown area, power block area, switchyard, plant access road, transmission line, water supply pipeline, and Teresa Creek bridge.

Based on the 24-month construction schedule, the worst-case monthly emissions would occur during the first and second months of construction when 73.7 acres of land are disturbed. This would result in uncontrolled emissions of approximately 8.11 tons of PM_{10} per month. Assuming 90 percent control efficiency from the fugitive dust suppression program outlined above to mitigate construction related emissions, the controlled worst-case construction dust emissions are estimated to be 7.4 lb/hour, 74 lb/day, 0.81 tons/month and approximately 5.7 tons/year, based on the average disturbed land acreage listed above for Months 1 through 12.

Estimated Controlled Emissions from Site Preparation			
Scenario	**Time period**	**Units**	**PM_{10}**
Worst case months 1-12	Annual	Tons	5.7
Worst case month 1	Monthly	Tons	0.81
Worst case 24 hours	Daily	Pounds	74.0
Worst case 1 hour	Hourly	Pounds	7.4

Another source of PM_{10} dust emissions from the project construction phase includes earth moving with heavy equipment. Controlled PM_{10} emissions of fugitive dust from this activity come from the several pieces of equipment listed in the table below. A second source of emissions during construction is equipment exhaust. Emissions from equipment would occur over a 24-month construction period.

	Controlled Fugitive Dust as PM_{10} Emissions from Earth Moving					
Construction Equipment	**Source**	**Lbs/Month 1**	**Lbs/Month 2**	**Lbs/Month 3**		
Excavator Loader	Loading trucks	420.9	210.4	210.4		
Excavator Backhoe	Unloading trucks	22.8	11.4	11.4		
Dozer Tractor Crawler	Unpaved roads	766.9	383.5	383.5		
Front End Loader	Bulldozing	224.6	224.6	224.6		
Trenching Machine	TOTAL	1,435.2	829.9	829.9		
Excavator Motor Grader						
Vibrating Plate Compactor	**Estimated Emissions From Construction Equipment Exhaust**					
Roller Vibrator	Worst Case	NOx	CO	VOCs	SOx	PM_{10}
Water Truck	Lbs/Hour	33	19.7	5.8	0.03	2.2
Concrete Mixer	Lbs/Month	6,589.70	3,941.50	1,166.4	6.2	447.6
Concrete Pump, trailer mount	Lbs/Year	66,110.50	39,157.60	11,661.20	61.1	4,624.1
Mortar Mixer	Worst-case hourly emissions estimated by dividing worst-case monthly by 200 hours (20 days of 10 hours)					
Paving Machine	Worst-case annual emissions were estimated by summing emissions for each 12-month period					
Dump Truck						
Cranes (6-500 tons)	**Estimated Peak PM_{10} Emissions During Construction**					
Manlift, telescoping	Worst Case Scenario	Fugitive Dust	Exhaust	Total PM_{10}		
Welder (250 amp)	Lbs/Hour	15.3	1.6	16.9		
AirCompressors(185-750cfm)	Lbs/Day	152.83	16.38	169.2		
Generator (6 kW)	Lbs/Month	3,056.60	327.6	3,384.20		
Forklifts (2-4 tons)	Lbs/Year	14,532	4,624	19,156		
Fuel/Lube Truck	Exhaust PM_{10} peak month does not occur in same month as Fugitive Dust Emissions peak month.					
Pickup Truck (1/2-ton)	Total emissions were based on projected daily hours of equipment operation in a given month.					
Stakebed Truck						
Hydraulic Boom Truck						
Concrete Trowel						
Concrete Floor Saw						
Bobcat Skip Loader						

Hydrotest Pump	

Operational Emissions

Operational equipment emissions covered are from the two turbines, under various operating conditions, the auxiliary boiler, emergency generator engine and firewater pump engine. A description of the various turbine operational scenarios and emissions are included in the following tables.

Gas Turbines

Emissions from the two turbines were estimated for all applicable scenarios using base emission rates and startup/shutdown emissions. The base criteria pollutant emission rates provided by the turbine vendor and the engineer for three load conditions (50 , 75 , and 100 percent) and three ambient temperatures (18°F, 59°F, and 114°F).

Estimated Emission Rates for Gas Turbines and SCR with Ammonia Injection Normal Operation (pounds/hour - two turbines)				
		Ambient Temperature		
Load	**Pollutant**	**18°F**	**59°F**	**114°F**
100%	VOCs	6.8	6.2	6.0
	Ammonia Slip	28.4	26.2	25.0
	CO	28.0	26.0	24.6
	NO_X	30.6	28.4	27.0
	SO_2	12.0	11.0	11.0
	PM_{10}	25.8	25.6	25.6
75%	VOCs	5.4	5.0	5.0
	Ammonia Slip	22.8	21.2	20.4
	CO	22.6	21.0	20.0
	NO_X	24.6	23.0	22.0
	SO_2	10.0	9.0	9.0
	PM_{10}	25.4	25.4	25.2
50%	VOCs	4.4	4.2	4.2
	Ammonia Slip	18.0	16.8	15.8
	CO	17.8	16.6	15.6
	NO_X	19.4	18.2	17.2
	SO_2	8.0	7.0	7.0
	PM_{10}	25.2	25.0	25.0
100% with Duct Burners	VOCs	14.4	13.6	13.2
	Ammonia Slip	38.4	36.4	35.2
	CO	37.8	35.8	34.8
	NO_X	41.4	39.2	38.0
	SO_2	16.0	15.0	15.0
	PM_{10}	40	39.8	40.2

Startup and shutdown events typically have higher emission rates than normal operating conditions.

Estimated Emission Rates for One Gas Turbine During Startup and Shutdown								
	Cold Startup		**Warm Startup**		**Hot Startup**		**Shutdown**	
	270 Minutes		**180 Minutes**		**90 Minutes**		**30 Minutes**	
Pollutant	**Max lb/hour**	**Total lb/270 min**	**Max lb/hour**	**Total lb/180 min**	**Max lb/hour**	**Total lb/90 min**	**Max lb/hour**	**Total lb/30 min**

NO_X	333.3	779.10	152.00	456.20	249.90	259.90	115.00	115.00
CO	373.60	1355.60	370.30	790.50	429.60	679.60	483.50	483.50
VOCs	27.7	106.70	27.7	47.40	27.7	38.00	23.9	23.90
SO_2	2.0	5.05	2.0	2.88	2.0	1.66	1.0	1.0
PM_{10}	12.00	48.80	12.00	30.80	12.00	12.80	6.00	6.00

The number of startups was estimated for each quarter. To calculate quarterly emissions, emissions from these startups were added to operational emissions, assuming 100 percent load and 59°F for the specified number of hours per quarter and duct burner operation at 59°F for the specified number of hours. The analysis is conservative because no credit was taken for downtime associated with each shutdown.

Estimated Quarterly and Annual Emissions for Two Turbines					
Pollutant	**1st Quarter Emissions (tons)**	**2nd Quarter Emissions (tons)**	**3rd Quarter Emissions (tons)**	**4th Quarter Emissions (tons)**	**Annual Emissions (tons)**
NO_X	45.1	43.1	50.9	43.8	182.9
CO	53.4	51.6	106.3	53.1	264.4
VOCs	12.3	11.6	11.8	11.7	47.4
PM_{10}	35.1	35.2	35.4	35.5	141.2
SO_2	4.05	3.83	3.87	3.87	15.62

Worst-case short-term emissions from the turbines were calculated for use in the air quality modeling. For worst 1-hour emissions, the worst-case startup condition was used. Based on the startup information, NO_X, CO, and VOC emissions during a cold startup are the worst-case condition. PM_{10} and SO_X emissions are maximized at peak fuel usage. The maximum amount of fuel is used when the turbines and duct burners are running 100 percent and the ambient temperature is 18°F.

The 24-hour NO_X, CO, and VOC emission rates were calculated assuming six hours of startup (3 hot starts and stops) ~~one cold start, one shutdown~~, and the balance (18 hours) operating at the worst-case operating condition (turbine and duct burners are running 100 percent and the ambient temperature is 18°F). PM_{10} and SO_X worst-case 24-hour emission rates were calculated assuming the turbine and duct burners are running at 100 percent for 24 hours and the ambient temperature is 18°F for SO_X and 114°F for PM_{10}.

Estimated Worst-Case Short-Term Emission (per turbine excluding commissioning)	
1-Hour Emissions (lb/hour)	
NO_X	333.30
CO	483.50
VOCs	27.7
PM_{10}	20.1
SO_2	8.0
24-Hour Emissions (lb/day)	
NO_X	1,497.30
CO	3,829.50
VOCs	315.30
PM_{10}	482.4
SO_2	192.0

The gas turbine commissioning period has a unique emissions profile because the air pollution control equipment is not fully functional. The gas turbine commissioning periods begin when the turbines first burn natural gas. Every reasonable effort will be made to minimize CO, VOC, and NO_x emissions during the commissioning period. Cold, pre-operational equipment checks will be required. However, these checks will not require the equipment to be running or emitting air pollutants. The applicant proposes a commissioning period of approximately 6 months during which all installed equipment will be run and tested. Applicant requests 500 hours maximum of partially abated emissions for each gas turbine train.

Once installed, the oxidation catalyst in each train will abate CO and VOC emissions from the gas turbine and the duct burners because it is essentially a passive device. While the SCR catalyst can in some cases be installed prior to initial startup of the combustion turbines, it may not be installed until later in the commissioning period, after completion of steam blows, which could deposit debris and otherwise damage the catalyst.

The SCR catalyst may not be installed at the same time as the oxidation catalyst. NO_x emissions from the gas turbines and the duct burners may be only partially abated during times that the gas turbine burners are being tuned and the SCR system is being tested. Regardless of the fact that the oxidation catalyst and SCR may not be installed until late in the commissioning process, the inherent low emissions of NO_x, CO, and VOCs associated with the DLN combustors will ensure that the impacts of these emissions are minimized.

The commissioning period will be divided into four phases:

1. Gas combustion turbine 1 (CT#1) duct burner (DB#1);
2. Gas combustion turbine 2 (CT#2) duct burner (DB#2);
3. Commissioning of both HRSGs and the steam turbine; and
4. Performance and reliability testing of the entire plant together

Commissioning emission estimates were conservatively estimated as worst case by assuming that the control efficiency of the applicable abatement systems is essentially zero during significant portions of the commissioning phase. The CEMS will also undergo commissioning at this time. Once the CEMS is commissioned, it will record emissions of NO_x and CO. Emissions of SO_2 and PM_{10} may be quantified by using emission factors based on fuel flow. Peak emission rates of CO and NO_x will only occur from one gas turbine at a time. Where applicable, emission offsets are proposed as mitigation of the emissions.

Commissioning Emissions **Phase Tests**	**Unit**	**Load**	**Time (hrs)**	**SO_X (lb/hr)**	**NO_X (lb/hr)**	**CO (lb/hr)**	**VOC (lb/hr)**	**PM_{10} (lb/hr)**
First fire	CT # 1	10.0%	4.0	0.3	146.0	250.0	24.2	12.0
	CT # 2	10.0%	4.0	0.3	146.0	250.0	24.2	12.0
Green rotor run-in	CT # 1	25.0%	12.0	0.4	217.3	1,287.3	47.1	12.0
	CT # 2	25.0%	12.0	0.4	217.3	1,287.3	47.1	12.0
Steam blows	CT # 1	25.0%	168.0	0.4	217.3	1,287.3	47.1	12.0
	CT # 2	25.0%	168.0	0.4	217.3	1,287.3	47.1	12.0
Restoration	CT # 1	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	CT # 2	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Turbine roll/ overspeed	CT # 1	10.0%	16.0	0.3	146.0	250.0	24.2	12.0
	CT # 2	10.0%	16.0	0.3	146.0	250.0	24.2	12.0
Part load DLN tuning	CT # 1	50.0%	12.0	0.6	475.0	808.0	8.2	12.0
	CT # 1	100.0%	18.0	0.9	58.0	29.0	2.8	12.0
	CT # 2	50.0%	12.0	0.6	475.0	808.0	8.2	12.0

Commissioning Emissions Phase Tests	Unit	Load	Time (hrs)	SO_X (lb/hr)	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)
	CT # 2	100.0%	18.0	0.9	58.0	29.0	2.8	12.0
Outage/ Water Wash	CT # 1	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	CT # 2	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Fine DLN tuning/ Finalize control constants	CT # 1	50.0%	40.0	0.6	475.0	808.0	8.2	12.0
	CT # 1	75.0%	24.0	0.7	58.0	29.0	2.8	12.0
	CT # 1	100.0%	96.0	0.9	58.0	29.0	2.8	12.0
	CT # 2	50.0%	40.0	0.6	475.0	808.0	8.2	12.0
	CT # 2	75.0%	24.0	0.7	58.0	29.0	2.8	12.0
	CT # 2	100.0%	96.0	0.9	58.0	29.0	2.8	12.0
Duct burners and safety valves	CT # 1	100.0%	144.0	0.9	58.0	29.0	2.8	12.0
	CT # 2	100.0%	144.0	0.9	58.0	29.0	2.8	12.0
	DB # 1	50.0%	24.0	0.2	23.9	23.9	3.0	3.0
	DB # 1	100.0%	96.0	0.3	47.9	47.9	6.0	6.0
	DB # 2	50.0%	24.0	0.2	23.9	23.9	3.0	3.0
	DB # 2	100.0%	96.0	0.3	47.9	47.9	6.0	6.0
Outage (strainers/ catalyst, etc.)	CT # 1	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	CT # 2	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	DB # 1	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	DB # 2	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CEMS drift and Source testing	CT # 1	100.0%	64.0	0.9	12.8	11.6	2.0	12.0
	CT # 2	100.0%	64.0	0.9	12.8	11.6	2.0	12.0
	DB # 1	100.0%	64.0	0.3	10.5	19.2	4.2	6.0
	DB # 2	100.0%	64.0	0.3	10.5	19.2	4.2	6.0
Functional tests	CT # 1	100.0%	96.0	0.9	12.8	11.6	2.0	12.0
	CT # 2	100.0%	96.0	0.9	12.8	11.6	2.0	12.0
	DB # 1	100.0%	96.0	0.3	10.5	19.2	4.2	6.0
	DB # 2	100.0%	96.0	0.3	10.5	19.2	4.2	6.0
Outage/ Water Wash	CT # 1	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	CT # 2	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	DB # 1	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	DB # 2	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Performance test	CT # 1	100.0%	24.0	0.9	12.8	11.6	2.0	12.0
	CT # 2	100.0%	24.0	0.9	12.8	11.6	2.0	12.0
	DB # 1	100.0%	24.0	0.3	10.5	19.2	4.2	6.0

Commissioning Emissions Phase Tests	Unit	Load	Time (hrs)	SO_X (lb/hr)	NO_X (lb/hr)	CO (lb/hr)	VOC (lb/hr)	PM_{10} (lb/hr)
	DB # 2	100.0%	24.0	0.3	10.5	19.2	4.2	6.0
Continuous operation test	CT # 1	100.0%	192.0	0.9	12.8	11.6	2.0	12.0
	CT # 2	100.0%	192.0	0.9	12.8	11.6	2.0	12.0
	DB # 1	100.0%	192.0	0.3	10.5	19.2	4.2	6.0
	DB # 2	100.0%	192.0	0.3	10.5	19.2	4.2	6.0

Totals for CGS Commissioning	Oxides of Sulfur	Oxides of Nitrogen	Carbon Monoxide	Volatile Organics	Particulate PM_{10}
Pounds lbs/hour*time	12,000	194,021.2	607,266.1	26,273.3	27,633.6
Tons	6.0	97.0	303.6	13.1	13.8
Tons/CT & DB	3.0	48.5	152	6.75	7

Auxiliary Boiler

Auxiliary boiler emissions are based on 3,744 hours of operation per year. A summary of auxiliary boiler emissions is presented in table below.

Auxiliary Boiler Emissions			
Pollutant	Emission Factors (lb/MMBtu)	Emissions lb/hr	Emissions ton/yr
NO_X	0.018	0.79	1.48
CO	0.037	1.61	3.01
PM_{10}	0.0075	0.33	0.62
SO_2	NA	0.13	0.07
VOC	0.0042	0.18	0.34

Emergency Generator Engine

The project will include one 1,340 brake hp diesel fired engine to power an emergency, backup electrical generator. The applicant proposes a USEPA Tier 2 and CARB-Certified candidate engine for this application. Annual emissions from the engine included in the table are based on a maximum non-emergency use rate of 50 hours of operation per year. SO_2 emissions were estimated using ultra-low sulfur diesel fuel containing 15ppm sulfur. The manufacturer estimated emissions for NO_X, CO, PM_{10}, and VOCs.

Non-Emergency Emissions	Generator
Estimated brake horsepower	1,340
Hourly Emissions (pounds)	
NO_X	13.88

CO	0.32
VOCs	0.15
PM_{10}	0.09
SO_2	0.01
Annual Emissions (tons)	
NO_X	0.347
CO	0.008
VOCs	0.004
PM_{10}	0.002
SO_2	0.0003

Firewater Pump Engine

One 300 brake hp diesel engine will be purchased to power a firewater pump. The applicant also proposes a USEPA Tier 3 and CARB-Certified candidate engine for this application. SO_2 emissions were estimated using ultra-low sulfur diesel fuel containing 15 ppm sulfur. Emissions were estimated based on hourly emission rates provided by the manufacturer for NO_X, CO, PM_{10}, and VOCs. Annual emissions from these engines included in the table are based on a maximum non-emergency use rate of 50 hours of operation per year.

Non-Emergency Emissions	Firewater Pump
Estimated brake horsepower	300
Hourly Emissions (pounds)	
NO_X	1.98
CO	1.72
VOCs	Included in NOx
PM_{10}	0.10
SO_2	<0.01
Annual Emissions (tons)	
NO_X	0.05
CO	0.04
VOCs	Included in NOx
PM_{10}	0.0025
SO_2	0.0003

Combined Emissions

Total combined annual emissions are shown below. The table includes emissions from two gas turbines, duct burners, auxiliary boiler, and emergency generator and emergency firewater pump engines.

Quarterly and Annual Estimated Combustion Emissions from CGS Facility					
Pollutant	**1st Quarter Emissions (tons)**	**2nd Quarter Emissions (tons)**	**3rd Quarter Emissions (tons)**	**4th Quarter Emissions (tons)**	**Annual Emissions (tons)**
NO_X	45.77	43.77	51.57	44.47	185.58
CO	55.35	53.55	108.25	55.05	272.20
VOCs	12.51	11.81	12.01	11.91	48.24
PM_{10}	35.36	35.46	35.66	35.76	142.24
SO_2	4.05	3.83	3.87	3.87	15.62

Toxic Air Contaminant Emissions

Facility operations at the proposed Colusa Generating Station were evaluated to determine whether toxic substances would be used or generated that may cause adverse health effects if released to the air. The primary sources of potential emissions from facility operations are the natural gas fired CTGs and the aqueous ammonia used in the SCR control system located in the HRSGs. Natural gas combustion in the auxiliary boiler is also a source of potential emissions. The diesel fuel combusted in the two emergency engines (i.e., generator and fire pump) produces air toxic contaminants. Ammonia emissions associated with potential ammonia slip from the SCR system were also included as well as all air toxics associated with the auxiliary boiler, diesel generator, and the diesel firewater pump.

Gas Turbines

Conservative assumptions were made for estimating air toxic emissions. These assumptions may not be consistent in all cases with the assumptions made for estimating emissions of criteria pollutants. However, they result in higher estimated emissions than the assumptions used in the air quality section. Worst-case estimates of annual turbine emissions were made by assuming that both turbines would operate simultaneously under full load conditions (100 percent load at 59°F annual average) for 8,760 hours per year with full duct burner firing. The exit temperature and velocity for each turbine stack used in the model represented the 100 percent load, with duct firing, at 59°F ambient temperature operating mode. Ammonia slip emissions were estimated to be 5 ppmvd at 15% oxygen. For maximum hourly emissions, the maximum natural gas consumption rate of about 2,452 MMBtu (higher heating value) per hour per combustion turbine including duct burners was used represented the 100 percent load, with duct firing, at 59°F ambient temperature operating mode. Estimated emissions shown below:

Emissions from CTG/HRSG with SCR and Oxidation Catalyst

Chemical Species	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMcf)	Maximum Hourly Emissions per CTG (lb/hour)	Annual Emissions Per CTG (lb/year)
Ammonia	5 ppm[c]	5 ppm[c]	18.2	1.59E+05
1,3-Butadiene	1.24E-07	1.27E-04	3.04E-04	2.66E+00
Acetaldehyde	1.34E-04	1.37E-01	3.28E-01	2.87E+03
Acrolein	1.85E-05	1.89E-02	4.53E-02	3.96E+02
Benzene	1.30E-05	1.33E-02	3.18E-02	2.79E+02
Ethylbenzene	1.75E-05	1.79E-02	4.29E-02	3.75E+02
Formaldehyde	8.96E-04	9.17E-01	2.20E+00	1.92E+04
Hexane	2.53E-04	2.59E-01	6.20E-01	5.43E+03
Propylene	7.53E-04	7.71E-01	1.85E+00	1.62E+04
Propylene oxide	4.67E-05	4.78E-02	1.14E-01	1.00E+03
Toluene	6.93E-05	7.10E-02	1.70E-01	1.49E+03
Xylenes	2.55E-05	2.61E-02	6.25E-02	5.47E+02
Polycyclic Aromatic Hydrocarbons				
Benzo(a)anthracene	2.21E-08	2.26E-05	5.41E-05	4.74E-01
Benzo(a)pyrene	1.36E-08	1.39E-05	3.98E-05	1.32E-01
Benzo(b)fluoranthene	1.10E-08	1.13E-05	2.71E-05	2.37E-01
Benzo(k)fluoranthene	1.07E-08	1.10E-05	2.63E-05	2.31E-01
Chrysene	2.46E-08	2.52E-05	6.03E-05	5.29E-01
Dibenz(a,h)anthracene	2.29E-08	2.35E-05	5.63E-05	4.93E-01

Emissions from CTG/HRSG with SCR and Oxidation Catalyst

Chemical Species	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMcf)	Maximum Hourly Emissions per CTG (lb/hour)	Annual Emissions Per CTG (lb/year)
Indeno(1,2,3-cd)pyrene	2.29E-08	2.35E-05	5.63E-05	4.93E-01
Naphthalene	1.62E-06	1.66E-03	3.97E-03	3.48E+01

Auxiliary Boiler

Emission factors for the natural gas fired auxiliary boiler were obtained from the CATEF Database (CARB 2001). Annual emissions were calculated based on 3,744 hours per year. Emission factors and estimated maximum hourly and annual auxiliary boiler emissions are summarized in the following table.

Emissions from Auxiliary Boiler				
Chemical Species	Emission Factor (lb/MMBtu)	Emission Factor (lb/MMcf)	Maximum Hourly Emissions (lb/hour)	Annual Emissions (lb/year)
Acetaldehyde	8.66E-06	8.87E-03	3.81E-04	1.43E+00
Benzene	4.21E-06	4.31E-03	1.85E-04	6.94E-01
Formaldehyde	2.16E-04	2.21E-01	9.50E-03	3.56E+01

Emergency Generator Engine

Toxic emissions from the diesel generator engine were estimated using the PM_{10} emissions as a surrogate for the toxic compound, diesel exhaust. Emergency diesel generator emissions were estimated assuming it would run at its full rated capacity (1,340 hp) for 1 hour per week for emergency preparedness. Emissions are summarized in the table.

Emissions from Emergency Generator				
Source	Chemical Species	Emission Factor (grams/hp-hour)	Maximum Hourly Emissions (lb/hour)	Annual Emissions (lb/year)
Emergency Generator	Diesel particulate (PM_{10})	0.13	3.84E-01	1.92E+01

Firewater Pump Engine

Toxic emissions from the diesel firewater pump engine were estimated using the PM_{10} emissions as a surrogate for the toxic compound, diesel exhaust. Emergency diesel firewater pump emissions were estimated assuming it would run at its full rated capacity (300 hp) for 1 hour per week for emergency preparedness. Emissions are summarized in the table.

Emissions from Emergency Firewater Pump				
Source	Chemical Species	Emission Factor (grams/hp-hour)	Maximum Hourly Emissions (lb/hour)	Annual Emissions (lb/year)
Emergency Firewater Pump	Diesel particulate (PM_{10})	0.13	8.59E-02	4.30E+00

The air toxic emissions presented in the above tables were used in estimating the potential public health risks due to operation of the proposed equipment and the results of the Health Risk Assessment (HRA). Significant impacts are defined as a maximum incremental cancer risk greater than ten in one million population, a chronic Threshold Hazard Index (THI) over one, or an acute THI over one.

VI AIR QUALITY CONCENTRATIONS

The US Environmental Protection Agency (EPA), in response to the federal Clean Air Act of 1970, established federal Ambient Air Quality Standards (AAQS) in Title 40 Code of Federal Regulations (CFR) Part 50. The federal AAQS include both primary and secondary standards for six "criteria" pollutants. These criteria pollutants are ozone, carbon monoxide (CO), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), ten micron particulate (PM_{10}), and lead. Primary standards were established to protect human health, and secondary standards were designed to protect property and natural ecosystems from the effects of air pollution.

The 1990 Clean Air Act Amendments established attainment deadlines for all designated areas that were not in attainment with the federal AAQS. In addition to the federal EPA AAQS described above, a new federal standard for $PM_{2.5}$ and a revised ozone standard were promulgated in July 1997. In a court case filed in1998 these new AAQS issues were resolved and the 1-hour ozone standard was revoked in 2005 while the revised $PM_{2.5}$ standard was made effective in 2006. The State of California Air Resources Board (ARB) has adopted AAQS that are in some cases more stringent than the federal AAQS. The state and federal AAQS relevant to the CGS are summarized in the table.

Federal and California Ambient Air Quality Standards

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

Federal and California Ambient Air Quality Standards
Notes: [a] Title 17, California Code of Regulations, California AAQS for ozone (as VOCs), CO, SO_2 (1-hour), NO_2, and (PM_{10} are values that are not to be exceeded. The visibility standard is not to be equaled or exceeded. [b] 40 CFR 50. National AAQS, other than those for ozone and based on annual averages, are not to be exceeded more than once a year. The ozone standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than 1. [c] Concentrations are expressed first in units in which they were promulgated. Equivalent units are given in parentheses and based on a reference temperature of 25°C and a reference pressure of 760 mm of mercury. All measurements of air quality area to be corrected to a reference temperature of 25°C and a reference pressure of 760 mm of mercury (1,013.2 millibar); ppm in this table refers to ppm by volume, or micromoles of pollutant per mole of gas. [d] USEPA promulgated new federal 8-hour ozone and $PM_{2.5}$ standards on July 18, 1997. The federal 1-hour ozone standard continues to apply in areas that violated the standard. [e] NO_2 is the compound regulated as a criteria pollutant; however, emissions are usually based on the sum of all NO_X. [f] At locations where the state standards for ozone and/or PM_{10} are violated. National standards apply elsewhere. [g] The federal (PM_{10} standard was revoked on September 22, 2006. The $PM_{2.5}$ standard was modified on September 22, 2006. The California PM_{10} standard was modified and a new $PM_{2.5}$ standard promulgated on July 5, 2003. [h] Insufficient amount to reduce the prevailing visibility to less than 10 miles when the relative humidity is less than 70 percent. "Prevailing visibility" is defined as the greatest visibility, which is attained or surpassed around at least half of the horizon circle, but not necessarily in continuous sectors. NA = not applicable mg/m^3 = milligram(s) per cubic meter $\mu g/m^3$ = microgram(s) per cubic meter ppm = part(s) per million

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

Federal and State Air Quality Status for Colusa County*

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

Notes:
* Attainment status obtained from 40 CFR 81.
** Proposed designations for 2006.

California Designations:

Unclassified: a pollutant is designated unclassified if the data are incomplete and do not support a designation of attainment or non-attainment.

Attainment: a pollutant is designated attainment if the state standard for that pollutant was not violated at any site in the area during a three year period.

Non-attainment: a pollutant is designated non-attainment if there was at least one violation of a State standard for that pollutant in the area.

Non-attainment/Transitional: is a subcategory of the non-attainment designation. An area is designated non-attainment/transitional to signify that the area is close to attaining the standard for that pollutant.

Federal EPA Designations:

Non-attainment: any area that does not meet (or that contributes to ambient air quality in a nearby area that does not meet) the national primary or secondary ambient air quality standard for the pollutant.

Attainment: any area (other than an area identified in clause (i)) that meets the national primary or secondary ambient air quality standard for the pollutant.

Unclassifiable: any area that cannot be classified on the basis of available information as meeting or not meeting the national primary or secondary ambient air quality standard for the pollutant.

Background Ambient Air Quality Data Used in Modeling Analyses				
Pollutant	**Site**	**Year**	**Averaging Time**	**Concentration**
Nitrogen Dioxide	Yuba City – Almond Street Station	2003	Annual average	0.014 ppm
Nitrogen Dioxide	Yuba City – Almond Street Station	2004-2005 average	Max 1 hour average	0.064 ppm
Sulfur Dioxide	Sacramento – Del Paso Manor Station	2003	Annual average	0.001 ppm
Sulfur Dioxide	Sacramento – Del Paso Manor Station	2003	Max 24 hour average	0.003 ppm
Carbon Monoxide	Yuba City – Almond Street Station	2005	Max 8 hour average	3.39 ppm
Carbon Monoxide	Yuba City – Almond Street Station	2004	Max 1 hour average	5.8 ppm
Particulate $Matter_{10}$	Colusa – Sunrise Boulevard Station	2005	Annual Arithmetic Mean	25.5 $\mu g/m^3$
Particulate $Matter_{10}$	Colusa – Sunrise Boulevard Station	2005	Max 24 hour average	92 $\mu g/m^3$
Particulate $Matter_{2.5}$	Colusa – Sunrise Boulevard Station	2005	3-Year Maximum Annual Arithmetic Mean	11 $\mu g/m^3$
Particulate $Matter_{2.5}$	Colusa – Sunrise Boulevard Station	2005	3-yr Ave. 98^{th} Percentile, Max 24 hour average	26 $\mu g/m^3$

Air Dispersion Modeling

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

The modeling was conducted using the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) (USEPA 2004). For this analysis, AERMOD was selected, because it is consistent with the most recent USEPA policy and the data needed to support its application are available in Colusa County. AERMOD was run with the following additional options: Final plume rise at all receptors, Stack-tip downwash, Buoyancy-induced dispersion, Calms processing, Default wind profile exponents, Default vertical potential temperature gradients, and Rural dispersion coefficients. The effect of building wakes (i.e., downwash) on the stack plumes was evaluated for the routine plant operating emissions (downwash is not applicable to area sources, i.e., construction activities) in accordance with USEPA guidance (USEPA 1985).

Meteorological data suitable for input to AERMOD were obtained from a meteorological observation station, outside the town of Maxwell (population about 1,300), located approximately 8 miles south of the CGS project site. The 5 years of meteorological data to be used in this modeling analysis include data from 2001 through 2005. Supplemental cloud cover data from Red Bluff were also used.
AERMOD used the following receptor spacing:

25-meter spacing along the property line and extending from the property line out to 100 meters
100-meter spacing within 1 km of project sources for any locations not covered by the 25-meter grid
500-meter spacing within 1 to 5 km of project sources
1,000-meter spacing within 5 to 10 km of project sources

If maximum concentrations are predicted where the grid spacing is less dense than 25 meter, a 25-meter spaced nested grid of receptors was placed surrounding the receptor where the maximum concentration was predicted. This nested grid extended out 500 m in all directions or until the next regular grid receptors was encountered. The receptor locations were designated using Universal Transverse Mercator (UTM) coordinates. Receptor elevations were obtained from U.S. Geological Survey 7.5-minute electronic data.

The modeling for the CGS required the determination of worst-case emissions scenarios for the following averaging periods and pollutants to demonstrate compliance with AAQS:
1-hour for CO, NO2, and SO2
3-hour for SO2
8-hour for CO
24-hour for PM10, PM2.5 and SO2
Annual for PM10, PM2.5, NO2, and SO2

Site Construction Modeling

For construction activities at the project site, it was assumed that the equipment exhaust emissions would be emitted from two volume sources within the construction zone. PM_{10} emissions from fugitive dust were modeled using two area sources. The area sources were placed to include the construction, laydown, and contractor parking areas. The worst-case hourly and annual emission rates were used to model short-term and annual emissions, respectively. Fugitive dust emissions were included for both annual and 24-hour PM_{10} impacts. The modeling parameters are shown below:

Construction Emissions Release Parameters for the Proposed Project	
	Stack Characteristics (for the Construction Zone)

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

The modeling results are presented in the top half of the second table below.

Turbine Impact Screening Modeling

Screening modeling was performed to determine which turbine operating modes (i.e., load level, duct burner firing, ambient temperature) produced "worst-case" impacts for each pollutant and averaging time.

The model simulated natural gas combustion emissions from two 19-foot-diameter 175-foot-tall stacks. The stacks were modeled as point sources at their proposed locations. The stack parameters for each of the 12 operating modes are shown in the table as well as the AERMOD modeling results.

Turbine Impact Screening Results												
	Winter Minimum (18°F)				**Yearly Average (59°F)**				**Summer Maximum (114°F)**			
CTG Load	**100%**	**100%**	**75%**	**50%**	**100%**	**100%**	**75%**	**50%**	**100%**	**100%**	**75%**	**50%**
Duct Burner Status	On	Off	Off	Off	On	Off	Off	Off	On	Off	Off	Off
Stack Velocity (ft/sec)	68.6	71	55.1	44.3	63.7	66	52.3	42.8	63.1	63.7	51.5	42
Stack Temperature (°F)	162	193	181	175	161	193	181	175	186	202	188	167
AERMOD Results (μg/m³/grams per second)												
1-hour	14.54	12.46	15.29	22.37	15.38	12.69	16.62	23.24	13.61	12.65	15.85	**25.21**
3-hour	7.92	5.87	8.48	10.22	8.58	6.37	8.88	10.52	7.10	6.21	8.63	**11.37**
8-hour	4.70	4.46	5.26	7.63	5.29	4.58	5.70	7.98	4.67	4.55	5.44	**8.80**
24-hour	1.55	1.43	1.76	2.43	1.69	1.46	1.84	2.54	1.51	1.46	1.81	**2.80**
Annual	0.22	0.17	0.25	0.33	0.25	0.19	0.26	0.34	0.21	0.18	0.25	**0.37**
Bolded screening result represent maximum.												

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

Based on the screening results, stack parameters from the 50 percent load, with no duct firing, at 114°F ambient temperature simulate worst-case 1-hour dispersion. These parameters were used in the modeling to provide a conservative value for the pollutant dispersion. Pollutant emission rates for warm startups and cold startups were applied to these dispersion impacts to represent worst-case, short-term impacts of CO (1-hour) and NO_2 (1-hour), respectively. The SO_2 1-hour impact was estimated using the actual emission rate and stack parameters for the 100 percent load, with duct firing, at 18°F ambient temperature operating mode. Annual average impacts were estimated using the stack parameters for the 100 percent load, with duct firing, at 59F ambient temperature operating mode. Annual emission rates for NO_2, PM_{10}, and SO_2, were used in the analysis. PM_{10} 24-hour impacts were based on the actual emission rate and stack parameters for the 100 percent load, with duct firing, at 114°F ambient temperature operating mode. Short-term, worst-case emission rates are summarized in the table below.

Proposed Colusa Generating Station Project AERMOD Modeling Results ($\mu g/m^3$)

Pollutant	Averaging Period	Max Modeled Impact	PSDLevel[a] Significant Impact	Background[b] Concentration	Total Predicted Concentration	AAQS	UTM Coordinates East (m)	UTM Coordinates North (m)
Construction Impacts								
CO	1-hour	1,354.7	NA	6,444	7,799	23,000	562,750	4,357,230
	8-hour	190.0	NA	3,768	3,958	10,000	563,060	4,357,131
NO_2	1-hour[c]	230.81	NA	120.3	351.1	470	562,750	4,357,230
	Annual[c]	8.40	NA	26.3	34.7	100	562,750	4,357,523
PM_{10}	24-hour	332.60	NA	92	424.6	50	563,060	4,357,131
	Annual	3.33	NA	25.5	28.8	20	562,750	4,357,523
$PM_{2.5}$	24-hour	26.61	NA	26	52.6	35	562,750	4,357,500
	Annual[d]	0.69	NA	11	11.7	12	562,750	4,357,523
SO_2	1-hour	2.06	NA	15.6	17.7	655	562,750	4,357,230
	3-hour[e]	0.69	NA	15.6	16.3	1,300	562,750	4,357,230
	24-hour	0.100	NA	7.8	7.9	105	563,060	4,357,131
	Annual	.0083	NA	2.6	2.6	80	562,750	4,357,523
Routine Plant Operation Impacts								
CO	1-hour	1,396	2,000	6,444	7,840	23,000	558,375	4,359,450
	8-hour	293	500	3768	4,061	10,000	558,325	4,359,325
NO_2	1-hour[c]	336.3	NA	120.3	456.6	470	558,800	4,353,925
	Annual[e]	0.64	1	26.3	27.0	100	562,750.2	4,357,572
PM_{10}	24-hour	4.35	5	92	96.4	50	562,600	4,357,800
	Annual	0.5	1	25.5	26.0	30	562,425	4,358,075
$PM_{2.5}$	24-hour[d]	2.73	NA	26	28.6	35	562,325	4,358,200
	Annual	0.51	NA	11	11.5	12	562,425	4,358,075
SO_2	1-hour	22.00	NA	15.6	37.6	655	558,350	4,359,500
	3-hour[e]	9.25	NA	15.6	24.9	1,300	559,025	4,355,700
	24-hour	1.75	NA	7.8	9.6	105	562,600	4,357,800
	Annual	0.06	NA	2.6	2.7	80	562,425	4,358,075

Proposed Colusa Generating Station Project AERMOD Modeling Results (µg/m³)								
Pollutant	Averaging Period	Max Modeled Impact	PSDLevel[a] Significant Impact	Background[b] Concentration	Total Predicted Concentration	AAQS	UTM Coordinates	
							East (m)	North (m)

Notes:

[a] Source: 40 CFR 52.21.
[b] Background represents the maximum value measured at various air monitoring stations around the CGS site, 2003-2005 (except for 1-hour NO_2 which uses the arithmetic average of 2004-2005 measurements).
[c] Results used OLM to estimate NO_2 impacts.
[d] $PM_{2.5}$ results are 98th percentile and background is 3-year average, 98th percentile
[e] Background 3-hour SO_2 not reported, used 1-hr background
AAQS = Most stringent ambient air quality standard for the averaging period
NA = Not applicable
NR = Not reported
m = meters
OLM = ozone limiting method
µg/m³ = micrograms per cubic meter
CO = carbon monoxide
NO_2 = nitrogen dioxide
PM_{10}= particulate matter less than or equal to 10 microns in diameter
SO_2 = sulfur dioxide

Fumigation occurs when a plume with pollution emissions that was originally emitted into a stable layer of air is mixed rapidly to ground level when unstable air below the plume reaches plume level. Fumigation can cause very high ground-level pollution concentrations. Fumigation can occur during the break up of the nocturnal radiation inversion by daytime solar warming of the ground surface. Such conditions are short-lived and are typically compared only with 1-hour standards. A fumigation analysis was performed using the USEPA SCREEN3 model. Fumigation impacts are summarized in the table.

Proposed Project Operations Fumigation Impact Results			
Pollutant	Source	Inversion Impact (µg/m³)	Distance to Max. Impact (m)
NO_2 1 hour	Normal Operation Turbine	3.09	15,953
NO_2 1 hour	Turbine Startup	52.45	15,953
CO 1 hour	Normal Operation Turbine	76.09	15,953
CO 1 hour	Turbine Startup	2.82	15,953
SO_2 1 hour	Turbine – Normal Operations or Startup	1.25	15,953
SO_2 3 hour	Turbine – Normal Operations or Startup	1.25	15,953
Note: 1-hour SCREEN3 results multiplied by 0.9 to convert to 3-hour and 0.7 to convert to 8-hour.			

Fumigation impacts were estimated and summarized above. Fumigation impacts are all below PSD significance thresholds. Predicted Class 1 Area pollutant concentrations from the CGS project are compared to proposed and adopted significant impact levels (SILs) listed in the table. The maximum, modeled impacts are below applicable federal PSD SILs for all criteria pollutants.

Predicted Class I Area Pollutant Concentrations from CGS Compared to Proposed and Adopted Significant Impact Levels (µg/m3)						
Class I and Other Areas of Interest	Maximum Predicted Concentration					
	NO_2[a]	PM_{10}		SO_2		
	Annual Average	24-Hour Average	Annual Average	3-Hour Average	24-Hour Average	Annual Average

Predicted Class I Area Pollutant Concentrations from CGS Compared to Proposed and Adopted Significant Impact Levels (μg/m3)						
	Maximum Predicted Concentration					
	NO_2[a]	PM_{10}		SO_2		
Class I and Other Areas of Interest	**Annual Average**	**24-Hour Average**	**Annual Average**	**3-Hour Average**	**24-Hour Average**	**Annual Average**
USEPA Proposed SIL[b]	0.1	0.3	0.2	1	0.2	0.1
Federal Land Manager - Recommended SIL[b]	0.03	0.27	0.08	0.48	0.07	0.03
Class I Area PSD Increment[c]	2.5	8	4	25	5	2
CGS Maximum Impact	0.008	0.198	0.018	0.16	0.045	0.0015

Notes:

[a]NO was conservatively assumed to be 100 percent converted to NO_2.

[b]USEPA proposed and Federal Land Manager recommended from Federal Register, Vol. 61, No. 142, p. 38292, July 23, 1996.

[c]Adopted PSD level from 40 CFR 52.21(c).

VII COMPLIANCE ANALYSES

The Colusa County Air Pollution Control District Rules and Regulations contain various requirements that must be met by this proposed project. The rules are grouped into six basic categories 1) General requirements; 2) Authority to Construct; 3) Prohibitory Rules; 4) Air Toxics; 5) New Source Performance Standards; and 6) Title V Federal Operating Permit.

The District expects all general requirements, prohibitory rules, new source performance standards, air toxic policies and the Title V provisions to be met by the proposed facility.

GENERAL REQUIREMENTS

Regulation 1 – General Provisions, Rule 1.11 “Field Inspection” - Each source of air pollution subject to permit or registration shall be inspected or tested at such intervals of time so that no extended periods of violations will occur. *FINDING - this will be a permit condition*

Regulation 1 – General Provisions, Rule 1.12 “Air Pollution Equipment, Scheduled Maintenance” - In the case of shut-down or re-start of air pollution control equipment for necessary scheduled maintenance, the intent to shut down such equipment shall be reported to the Air Pollution Control Officer at least twenty-four (24) hours prior to the planned shutdown. *FINDING - this will be a permit condition*

Regulation 1 – General Provisions, Rule 1.13 “Equipment Breakdown” - In the event that any emission source, air pollution control equipment, or related facility breaks down in such a manner which may cause the emission of air contaminants in violation of this article, the person responsible for such equipment shall immediately notify the Air Pollution Control Officer of such failure or breakdown and subsequently a written statement giving all pertinent facts, including the estimated duration of the breakdown. The Air Pollution Control Officer shall be notified when the condition causing the failure or breakdown has been corrected and the equipment is again in operation. *FINDING - this will be a permit condition*

AUTHORITY TO CONSTRUCT

Regulation 3 – Permits, Rule 3.0 "General Requirements" - No person shall cause or permit the construction or modification of any new source of air contaminants without first obtaining an Authority to Construct from the Air Pollution Control Officer so as to comply with applicable regulations and rules and ambient air quality standards of the District. The Control Officer shall not approve such construction or modification unless the applicant demonstrates to the satisfaction of the Air Pollution Control Officer that the new source can be expected to comply with all the applicable state laws and District regulations and rules. *FINDING - this is being done.*

Regulation 3 – Permits, Rule 3.1 "Permits Required" - Any person building, erecting, altering or replacing any article, machine, equipment or other contrivance, the use of which may cause the issuance of air contaminants or the use of which may eliminate or reduce or control the issuance of air contaminants, shall first obtain written authorization for such construction from the Air Pollution Control Officer. *FINDING - this is being done.*

NEW SOURCE REVIEW RULE

Regulation 3 – Permits, Rule 3.6 "Standards for Authority to Construct (New Source Review)"

The federal Clean Air Act, U.S. EPA regulations, California Clean Air Act and the Colusa County APCD establish the criteria for siting new and modified emission sources. The federally mandated process for permitting new or modified sources in federal non-attainment areas is referred to as Non-attainment New Source Review (NNSR). The Colusa District is responsible for NSR rule enforcement for sources in Colusa County. The District's NSR rules are contained in Regulation 3, Rule 3.6. The rule requires that Best Available Control Technology (BACT) be applied to any new or modified emissions unit that emits above a specified level. The rule requires all potential emission increases of non-attainment pollutants or their precursors above specified thresholds be offset by real, quantifiable, surplus, permanent, and enforceable emission decreases in the form of emission reduction credits. An ambient air quality impact assessment must be conducted to confirm that the proposed project does not cause or contribute to a violation of a federal or California ambient air quality standard (AAQS) or jeopardize public health. Finally, the project proponent must certify that all major sources owned or operated in the State of California are either in compliance or on an approved schedule for compliance with applicable air quality regulations.

BEST AVAILABLE CONTROL TECHNOLOGY

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

Pollutant	**BACT Rule Limit**	**CGS Project Emissions - (hours)**		
	Pounds/Day	1 Turbine (24)	Boiler (24)	Generator (1)
Volatile organic compounds	25	315.3	4.32	0.15
Nitrogen oxides	25	1,497.3	11.52	13.88
Sulfur oxides	80	96.0	1.58	0.01
Particulate matter (PM_{10})	80	482.4	5.28	0.09
Carbon monoxide	500	3,829.5	39.12	0.32

As indicated by the data presented in the table above the gas turbines with associated duct burners must have BACT installed for all pollutants. The auxiliary boiler nitrogen oxides number represents controlled emissions with a low NOx burner. This would be considered BACT. The emergency generator engine operates only one hour per week and does not exceed the BACT thresholds.

FINDING - The CTGs will meet the following BACT emission limits: VOC of 2.0, NOx of 2.0 and CO of 3.0. All limits are ppmvd at 15 percent oxygen. BACT for SOx and PM_{10} is the use of natural gas as fuel.

OFFSET REQUIREMENTS

Offsets are required for a new stationary source with a potential to emit non-attainment pollutants or their precursors equal to or exceeding 25 tons per year. The amount of offsets required shall be at least equal to that portion of the potential to emit that exceeds 25 tons per year. Location of offsets and offsets ratios by corresponding distances from the proposed source shall be:

Onsite, at a ratio of	1:1
Within 20 miles, at a ratio of	1.2:1
20 to 50 miles, at a ratio of	1.5:1
Over 50 miles, at a ratio of	2:1

The Air Pollution Control Officer may approve interpollutant offsets on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the Air Pollution Control Officer, through the use of an impact analysis, that the emission increases from the new or modified source will result in a net air quality benefit and will not cause or contribute to a violation of any air quality standard.

The applicant proposed a 1.4:1 ratio as a VOC for NOx interpollutant offset ratio based upon the two nearest relevant studies: the Sacramento Area Ozone Study (CARB, 1995) and the San Francisco Bay Area Ozone Attainment Plan (OAP) (ABAG, BAAQMD, and MTC, 2001). The rate of ozone formation is heavily dependent on initial NO_X and VOC concentrations, as well as local meteorological conditions. The relationship between ozone formation and the initial concentrations of NO_X and VOC has been the subject of many studies and is often depicted graphically through ozone isopleth diagrams. Ozone isopleth diagrams illustrate the dependence of ozone production on the initial amounts of VOC and NO_X. The total 2005 VOC and NO_X emissions for Colusa County were 6.81 tons per day VOC and 10.12 tons per day NO_X. The peak 1-hour ozone level, used as the background in the AFC was 89 ppb. There is consistency between the peak ozone reading predicted by the Colusa isopleth and the actual peak ozone concentration measured in Colusa. Because ozone is a regional pollutant, the applicant also evaluated the Sacramento Valley Air Basin precursor emission inventory and found that reducing more VOC is beneficial to lowering ozone concentrations. Although theoretically the ratio predicted is 1.4:1 NOx to VOC the applicant is proposing to reverse the ratio and provide 1.4 tons of VOC emission reductions to offset a 1.0 ton increase in NOx emissions.

E&L Westcoast needs to offset emissions increases of the following amounts:

NO_x : 160.55 tpy
VOC : 23.24 tpy
PM_{10} : 117.24 tpy

The applicant has prepared the following tables (with distance factor adjustments from the project site) describing available stationary and area source emission reduction credits that could be used as offsets for the project's emissions increase. Two stationary sources are located in the Sacramento Valley Air Basin in adjacent air districts. The Colusa County Air District consultant inspected both sources while they were still in operation. The stationary sources are located northeast of the proposed CGS facility.

Highway 70 Industrial Park, LP // Oroville, CA // Butte County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 08-05-36, 08-05-37)	NO_X	23,333.3	23,333.3	23,333.3	23,333.3	93,333.3
(Cert.08-05-39)	VOC	58,333.3	58,333.3	58,333.3	58,333.3	233,333.3
> 20 < 50 miles	PM_{10}	22,333.3	22,333.3	22,333.3	22,333.3	89,333.3

Jack W. Baber // Sierra Mountain Mills, Camptonville, CA // Yuba County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. ERC-9937006-00T)	NO_X	210.0	353.5	320.5	250.5	1,134.5
	VOC	99.5	167.5	152.0	119.0	538.0
	PM_{10}	3,017.0	5,078.0	4,609.0	3,600.5	16,304.5
> 50 miles	SO_2	83.0	139.5	127.0	99.0	448.5

Emissions will also be offset through the purchase of ERCs generated by the cessation of agricultural burning. Colusa County is an agricultural county. The primary crop is rice, with additional acres of wheat, corn, safflower and other crops also under cultivation. ERCs generated by elimination of agricultural burning are calculated by a methodology that takes into account the following factors:

Historical burn fraction (*i.e.,* what percentage of the crop land is actually burned in a given year), or HBF; Quarterly burn fraction (how much of the total annual burning takes place in a given quarter), or QBF; Fuel loading factor (how many tons of crop residue there are per acre), or FL; and Emission factors (pounds of emissions per ton of crop residue burned), or EF. Proposed agricultural burning ERCs are:

Baber Family Trust // Colusa, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-01-02-03)	NO_X	837.3	675.3	270.1	918.3	2,701.0
	VOC	756.8	610.3	244.1	830.0	2,441.2
	PM_{10}	1,014.4	818.1	327.3	1,112.6	3,272.3
< 20 miles	SO_2	177.1	142.8	57.2	194.3	571.3

Jack W. Baber and Judith S. Baber // Colusa, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-01-02-04)	NO_X	2,001.5	1,614.1	645.7	2,195.2	6,456.4
	VOC	1,809.0	1,458.9	583.6	1,984.1	5,835.6
	PM_{10}	2,424.8	1,955.5	782.3	2,659.5	7,822.1
< 20 miles	SO_2	423.4	341.4	136.6	464.3	1,365.8

Estate of Jack W. Baber Jr. // Colusa, CA // Colusa County

Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-01-02-05)	NO_X	707.1	570.3	228.1	775.6	2,281.0
	VOC	639.2	515.4	206.2	701.0	2,061.8
	PM_{10}	856.7	690.9	276.3	939.6	2,763.5
< 20 miles	SO_2	149.6	120.7	48.3	164.1	482.6

Pixie E. Baber // Colusa, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-01-02-05.2)	NO_X	674.2	521.3	217.5	739.4	2,152.3
	VOC	609.3	491.4	196.6	668.3	1,965.7
	PM_{10}	816.8	658.8	263.5	895.8	2,634.9
< 20 miles	SO_2	142.6	115.0	46.0	156.4	460.0

Jack W. Baber and Judith S. Baber // Colusa, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-01-02-06)	NO_X	489.8	395.1	158.0	537.3	1,580.2
	VOC	442.8	357.1	142.8	485.6	1,428.3
	PM_{10}	593.5	478.6	191.4	650.9	1,914.4
< 20 miles	SO_2	103.6	83.6	33.4	113.7	334.3

Inez Garrette // Colusa, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-01-02-07)	NO_X	163.3	131.7	52.7	179.1	526.7
	VOC	147.6	119.0	47.6	161.8	476.0
	PM_{10}	197.8	159.5	63.8	217.0	638.2
< 20 miles	SO_2	34.5	27.8	11.2	37.9	111.4

Jack W. Baber and Judith S. Baber // Colusa, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-01-02-08)	NO_X	1,736.3	1,400.2	560.1	1,904.3	5,600.8
	VOC	1,569.3	1,265.6	506.3	1,721.2	5,062.3
	PM_{10}	2,103.5	1,696.3	678.6	2,307.1	6,785.5
< 20 miles	SO_2	367.3	296.2	118.5	402.8	1,184.8

Jack W. Baber Jr. // Colusa, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)

Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-01-02-09)	NO_X	1,314.3	1,059.9	424.0	1,441.5	4,239.8
	VOC	1,187.9	958.0	383.3	1,302.9	3,832.1
	PM_{10}	1,592.3	1,284.2	513.7	1,746.4	5,136.6
< 20 miles	SO_2	278.0	224.3	89.7	304.9	896.8

Jon B. Chaney // Maxwell, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-01-02-01)	NO_X	1,753.4	1,414.1	565.4	1,923.2	5,656.1
	VOC	1,584.8	1,278.1	511.3	1,738.3	5,112.4
	PM_{10}	2,124.4	1,713.2	685.3	2,330.0	6,852.8
< 20 miles	SO_2	370.9	299.2	119.7	406.8	1,196.6

Gunnersfield Ent., Inc. // Maxwell, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-01-02-02)	NO_X	4,680.0	3,774.2	1,509.7	5,132.8	15,096.7
	VOC	4,230.0	3,411.3	1,364.5	4,639.3	13,645.1
	PM_{10}	5,669.9	4,572.5	1,829.0	6,218.7	18,290.1
< 20 miles	SO_2	990.0	798.4	319.3	1,085.8	3,193.6

Jerry Maltby et. al. // Williams, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-06-11-01)	NO_X	3,768.8	3,039.3	1,215.8	4,133.5	12,157.3
	VOC	3,406.4	2,747.1	1,098.8	3,736.1	10,988.4
	PM_{10}	4,566.0	3,682.3	1,472.9	5,007.9	14,729.1
< 20 miles	SO_2	797.3	642.9	257.2	874.4	2,571.8

Keeley Family Limited Partnership // Colusa, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-07-06-01)	NO_X	1,404.3	1,132.5	453.0	1,540.2	4,530.0
	VOC	1,269.3	1,023.6	409.4	1,392.1	4,094.4
	PM_{10}	1,701.4	1,372.1	548.8	1,866.0	5,488.2
< 20 miles	SO_2	297.1	239.6	95.8	325.8	958.3

Jim Lagrande // Colusa, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-01-03-01)	NO_X	1,099.2	956.8	472.5	1,207.4	3,735.9

	VOC	993.5	925.6	528.9	1,092.9	3,540.9
	PM_{10}	1,331.7	1,247.4	720.3	1,465.3	4,764.7
< 20 miles	SO_2	232.5	202.3	99.7	255.4	789.8

Charles Tuttle, Gordon Ranch // Maxwell, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-07-02-01)	NO_X	1,327.0	1,207.0	657.6	1,459.0	4,650.6
	VOC	1,199.4	1,209.2	792.5	1,321.9	4,522.9
	PM_{10}	1,607.7	1,634.1	1,084.3	1,772.3	6,098.3
< 20 miles	SO_2	280.7	255.0	138.5	308.6	982.9

Charles Tuttle, Helphenstine Ranch // Maxwell, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-07-02-02)	NO_X	0.0	71.5	119.8	1.9	193.3
	VOC	0.0	126.4	211.8	3.4	341.6
	PM_{10}	0.0	176.3	295.4	4.8	476.5
< 20 miles	SO_2	0.0	15.0	25.1	0.4	40.5

Charles Tuttle, Tenant Ranch // Maxwell, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-07-02-03)	NO_X	1.3	99.0	294.0	2.7	397.0
	VOC	4.3	175.0	714.6	4.8	898.6
	PM_{10}	4.3	244.1	912.9	6.6	1,167.8
< 20 miles	SO_2	0.2	20.8	51.8	0.6	73.3

Charles Tuttle, Williams Ranch // Maxwell, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-07-02-04)	NO_X	0.0	50.8	85.1	1.4	137.2
	VOC	0.0	89.7	150.4	2.4	242.5
	PM_{10}	0.0	125.2	209.7	3.4	338.3
< 20 miles	SO_2	0.0	10.6	17.8	0.3	28.7

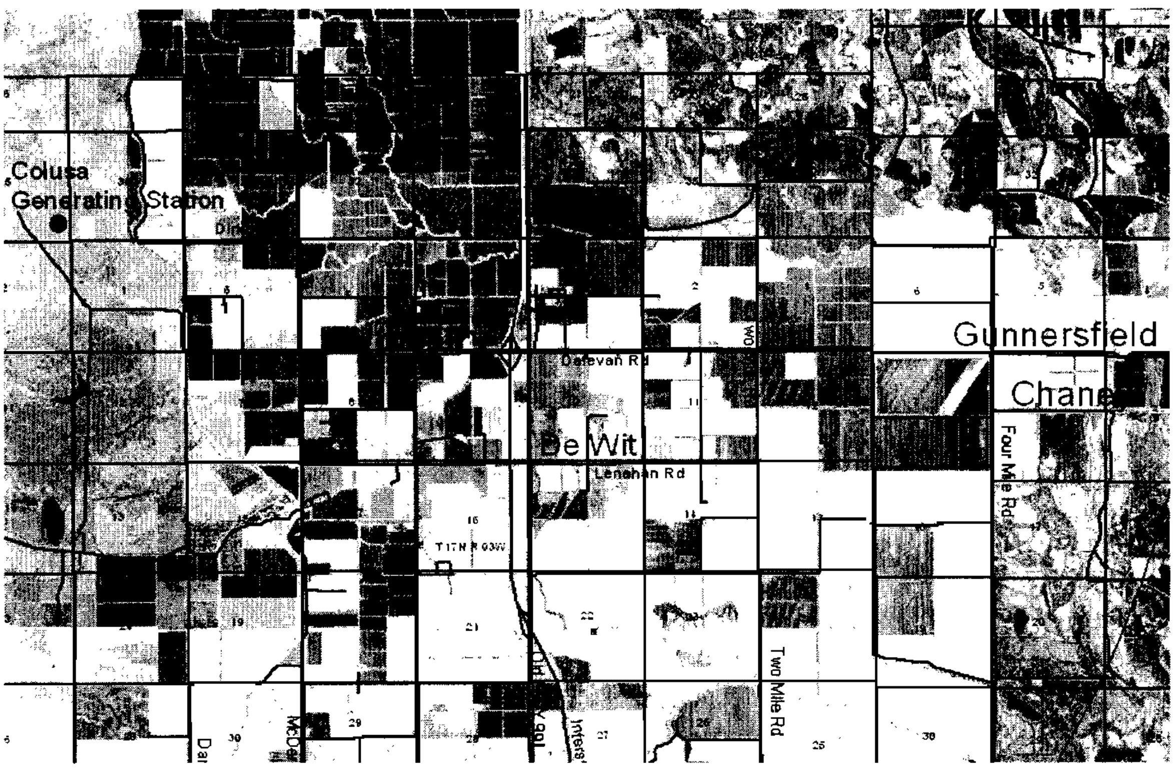
Jack DeWit // Maxwell, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-07-02-05)	NO_X	952.5	768.2	307.3	1,044.8	3,072.7
	VOC	860.9	694.3	277.8	944.3	2,777.3

	PM_{10}	1,154.0	930.7	372.3	1,265.7	3,722.6
< 20 miles	SO_2	201.5	162.5	65.0	221.0	650.0

Davis Ranches // Colusa, CA // Colusa County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. 06-7-2001-1)	NO_X	8,689.5	7,007.7	2,803.1	9,530.4	28,030.6
	VOC	7,853.9	6,333.8	2,533.5	8,614.0	25,335.3
	PM_{10}	10,527.6	8,490.0	3,396.0	11,546.4	33,960.0
> 20 miles < 50 miles	SO_2	1,834.8	1,482.4	592.9	2,016.1	5,926.2

William Payne // Woodland, CA // Sutter County						
Certificate(s) and Distance	Pollutant	1st Quarter (lbs)	2nd Quarter (lbs)	3rd Quarter (lbs)	4th Quarter (lbs)	Annual (lbs)
(Cert. ERC 2001-26)	NO_X	1,134.0	1,249.3	2,022.0	1,267.3	5,672.7
	VOC	1,025.3	1,574.7	5,356.0	1,145.3	9,101.3
	PM_{10}	1,374.0	2,160.0	6,620.7	1,535.3	11,690.0
> 20 miles < 50 miles	SO_2	240.0	263.3	326.0	268.0	1,097.3

The map presented below is a portion of Colusa County with sections, township and range outlined, the CGS site identified and surrounding rice fields (highlighted in yellow crosshatching). Three nearby grower fields are noted that are part of the agricultural ERCs proposed as offsets.



FINDING - the ERC offset information and quarterly pollutant amounts will need to be verified by District analyses. Applicant will be required to have the ERC certificate ownerships transferred to them from the current owners and then surrender the certificates to the Colusa County Air Pollution Control District. Offsets coming from other air districts will need to have a signed MOU between the Colusa County Air Pollution Control District and those districts approving the transfer of emission reduction credits. All of these actions must take place before the facility is allowed to operate.

AIR QUALITY IMPACT ANALYSES

One provision of the NSR Rule regards analyzing project emissions as they might affect ambient air quality levels. The rule states, "In no case shall the emissions from the new or modified stationary source cause or make worse the violation of an Ambient Air Quality Standard." An impact analysis shall be used to estimate the effects of a new or modified source. In considering the project's emission impacts, the Air Pollution Control Officer will take into account the mitigation of emissions through offsets and determine that there is a net air quality benefit. **"Net air quality benefit" means a net improvement in air quality resulting from actual emission reductions impacting the same general area affected by the new or modified source.** The Colusa County Air Pollution Control District has conducted analyses of the emission reduction credits proposed by the applicant. The analyses describe the burning management program, impacts from burning on non-attainment pollutants, how agricultural ERCs are calculated, enforcing agricultural ERCs and modeling of pollution emissions from agricultural burning in Colusa County. The analyses are covered in appendices A through E.

1) Appendix A – Agricultural Burning in Colusa County
2) Appendix B – Impact of Agricultural Burning on Particulate Matter and Ozone Concentrations
3) Appendix C – Emission Reduction Credits and Offsets
4) Appendix D – Enforcement of Emission Reduction Credits and Offsets
5) Appendix E – Modeling of Emissions from Agricultural Burning ERC Fields

The Colusa County Air Pollution Control District analyzed the impact of agricultural burning emissions on air quality levels in the County. Analyses included impacts from combustion of agricultural residues on both particulate matter and ozone concentrations. Agricultural burning emissions include particulate emissions less than ten microns in size as-well-as precursors to ozone (i.e., oxides of nitrogen and volatile organic compounds).

Several air quality studies were reviewed that addressed the impact of agricultural (vegetative) burning on particulate levels. All of the studies concluded that potassium is a strong indicator of vegetative burning sources and is linked to agricultural burns. The Air District reviewed particulate PM_{10} data from the Colusa air monitoring site operated by the California Air Resources Board at Sunrise Blvd. During the years of 1991 through 1995, for September, October and November, the Board's monitoring laboratory analyzed the particulate for various chemical species including potassium. The correlation between the total PM_{10} data and potassium values clearly confirmed the contribution from agricultural burning (see appendix B).

Many studies have been conducted showing the relationship of vegetative burning to ozone formation. Some of the air quality studies have occurred in the United States while others were in foreign countries. One study from the National Center for Atmospheric Research in Boulder, Colorado stated "Although the ingredients for ozone can be found in urban pollution, pollutants from fires might cause a significant increase in ozone levels, even far downwind from the fires."

District staff collected hourly data for $PM_{2.5}$ from the ARB realtime Beta Attenuation Monitor (BAM) located at the Colusa Sunrise Blvd site. Also we obtained the corresponding hourly ozone data from the same site. Hourly data that we analyzed were from 2005 for the months of June through October (the ozone season). These data, for each month, show a parallel in terms of particulate and ozone values for almost every hour (see appendix B).

The proposed project offsets come from emission reductions at stationary sources and area sources (i.e., agricultural burning). Emission reductions in NOx, VOC, PM_{10} and SO_2 will, at a minimum, be at a ratio of 1.2:1 tons reduced emissions to new project emissions. This means the emission reductions occurred within 20 miles of the project site. Some of the emission reductions were between 20 and 50 miles distance and a very small amount were greater than 50 miles. The following percentage of offsets were less than 20 miles from the project site and within Colusa County respectively: NOx 36.9 and 50.7%, VOC 20.5 and 28%, PM_{10} 38 and 51.9%, and SO_2 68 and 93.4%. Although the third quarter has the fewest offset tons of ozone precursors the ratio of ERC offsets to new project emissions is 1.28:1 which is sufficient mitigation.

Transfer of emission reduction credits from Butte, Yuba and Sutter counties have been approved by the Butte County Air Quality Management District and the Feather River Air Quality Management District (Yuba and Sutter counties). Appendix F is Resolution 2007-10 from the Board of the Butte County AQMD authorizing the transfer emission credits. Appendix G is Resolution 2007-02 from the Board of the Feather River Air Quality Management District authorizing the transfer of credits.

Therefore, based on the offset quantities, distances, studies reviewed and air quality data that were collected and analyzed we conclude that the offsets, including agricultural burning emission reductions, will produce a net a quality benefit.

E&L Westcoast's consultant has performed air quality modeling using the AERMOD model. This model is EPA recognized and approved. Ozone modeling was not done although the precursor emissions of NOx and VOC will exacerbate current levels. The PM_{10} and $PM_{2.5}$ emissions from both construction activities and routine plant operations showed levels above the California Ambient Air Quality Standards. *FINDING - the offsets provided for the facility will mitigate all of the air quality impacts.*

Colusa Generating Station Project Modeling Results – Routine Plant Operations

Pollutant	Averaging Period	Maximum modeled	Background ug/m3	Total	CA&EPA AAQS ug/m3
NO_2	1-hour	336.3	120.3	456.6	470
NO_2	Annual	0.64	26.3	26.9	100
PM_{10}	24-hour	4.35	92	96.4	50
PM_{10}	Annual	0.5	25.5	26.0	20
$PM_{2.5}$	24-hour	2.73	26	28.7	35
$PM_{2.5}$	Annual	0.51	11	11.5	12

PROHIBITORY RULES

Regulation 2 – Prohibitions, Rule 2.10 "Nuisance" - In accordance with Section 41700 of the California Health and Safety Code a person shall not discharge from any source whatsoever such quantities of air contaminants or other materials which cause injury, detriment, nuisance or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health or safety of any such person or the public or which cause or have a natural tendency to cause injury or damage to business or property. *FINDING - this facility is not expected to cause a nuisance.*

Regulation 2 – Prohibitions, Rule 2.13 "Visible Emissions" - As provided by Section 41701 of the California Health and Safety Code, a person shall not discharge into the atmosphere from any single source of emissions whatsoever, any air contaminants for a period or periods aggregating more than three minutes in any one hour which is: as dark or darker in shade as that designated as No. 2 on the Ringelmann Chart, as published by the United States Bureau of Mines; or of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in the phrase above. *FINDING - because of the use of natural gas this facility is expected to meet these rule limits.*

Regulation 2 – Prohibitions, Rule 2.15 "Particulate Matter Concentration" - A person shall not discharge into the atmosphere from any source, particulate matter in excess of 0.3 grains per standard dry cubic foot of gas. *FINDING - because of the use of natural gas this facility is expected to meet this limit.*

Regulation 2 – Prohibitions, Rule 2.16 "Dust and Fumes" - A person shall not discharge in any one hour from any source whatsoever, dust or fumes in total quantities in excess of the amounts shown in the table. To use the table, take the process weight per hour as such is defined in Rule 1.2 Definitions.

"Process Weight Per Hour" means the total weight excluding water added for processing or air used in processing introduced into any specific process may cause and discharge into the atmosphere. Solid fuels charged will be considered as part of the process weight, but liquid and gaseous fuels and combustion air will not. The "process weight per hour" will be derived by dividing the total process weight by the number of hours in one complete operation from the beginning of any given process to the completion thereof, excluding any time during which the equipment is idle."

Then find this figure on the table opposite, which is the maximum number of pounds of contaminants that may be discharged into the atmosphere in any one hour. *FINDING - this rule will be met.*

Regulation 2 – Prohibitions, Rule 2.22 "Sulfur Oxides" - A person shall not discharge into the atmosphere from any single source of emission whatsoever, any sulfur oxides in excess of 0.2 percent by volume (2,000 ppm) collectively calculated as sulfur dioxide (SO_2). *FINDING - this rule will be met.*

Regulation 2 – Prohibitions, Rule 2.23 "Reduced Sulfur Compounds" - It shall be unlawful for any person to permit the emissions of air contaminants from any premises that will result in ground level concentrations of total reduced sulfur compounds, expressed as hydrogen sulfide, in excess of 0.03 ppm for a period of sixty (60) minutes. *FINDING - this rule will be met.*

Regulation 2 – Prohibitions, Rule 2.36 "Stationary Internal Combustion Engines" - To limit emissions of nitrogen oxides (NOx) and carbon monoxide (CO) from stationary internal combustion engines. The provisions of this rule apply to any gaseous, diesel, or any other liquid-fueled stationary internal combustion engine within the boundaries of the District. Except for the administrative requirements of Section f.3. the provisions of this rule shall not apply to the following engines: Engines operated exclusively for fire fighting or flood control. *FINDING - this rule will be met because the emergency firewater pump engine is exempt.*

Regulation 2 – Prohibitions, Rule 2.39 "Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters Oxides of Nitrogen Control Measure" - To reduce Oxides of Nitrogen emissions during the operations of Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters to levels consistent with reasonably available control technology (RACT). This rule applies to all boilers, steam generators, and process heaters used in industrial, institutional, and commercial operations that exist within the boundaries of the Colusa County Air Pollution Control District on the date of adoption of this Rule.

No later than one year following District adoption of this Rule, all existing units with a rated heat input capacity greater than or equal to 5 million BTU per hour shall demonstrate final compliance with the following Reasonably Available Control Technology (RACT) emission limitations dependent upon the specific fuel fired in the unit and based upon a three-hour averaging period.

RACT: Gaseous only fuel firing: 0.084 lbs/MMBtu of heat input or 70 ppmv

FINDING - the new auxiliary boiler will comply with the requirements of District Rule 3.6 - Standards for Authority to Construct (New Source Review - BACT) and thereby also meet this rule.

Regulation 2 – Prohibitions, Rule 2.41 "Determination of Reasonably Available Control Technology for the Control of Oxides of Nitrogen from Stationary Gas Turbines" - To limit the emissions of nitrogen oxides (NOx) to the atmosphere from the operation of stationary gas turbines. Except as provided in Section c., this determination shall apply to all existing stationary gas turbines rated by the manufacturer as 0.3 megawatt (MW) power output and larger.

Unless opting for the alternative compliance strategy, the owner or operator of any stationary gas turbine unit subject to the provisions of this rule shall not operate such unit under load conditions, excluding the thermal stabilization period, which results in the measured NOx emissions concentration exceeding the emissions limit listed below averaged over three (3) hours.

		Gas	Oil
RACT:	0.3 MW and Greater	42	65 ppmvd @ 15%O_2

FINDING - the new gas turbine units will comply with the requirements of District Rule 3.6 - Standards for Authority to Construct (New Source Review - BACT) and thereby also meet this rule.

AIR TOXICS

Facility operations were evaluated to determine whether certain substances would be used or generated that may cause adverse health effects if released into the air. The primary sources of potential emissions from facility operations are the natural gas–fired combustion turbine generators (and duct burners) and the aqueous ammonia slipstream from the selective catalytic reduction control system. Toxic emissions from the auxiliary boiler were also evaluated. Emissions from the emergency generator and fire pump engines were estimated using PM_{10} emissions as a surrogate for the toxic compound, diesel exhaust.

The potential human health risks posed by the Project's emissions were assessed using procedures consistent with the Air Toxics Hot Spots Program Risk Assessment Guidelines – The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments (Cal-EPA and OEHHA 2003). The OEHHA guidelines were developed to provide health risk assessment (HRA) procedures as required under the Air Toxics Hot Spots Information and Assessment Act of 1987. The HRA was conducted in four steps using the Hotspots Analysis and Reporting Program (HARP [CARB 2005]):

1. Hazard Identification and Emission Quantification
2. Exposure Assessment

3. Dose-Response Assessment
4. Risk Characterization

First, hazard identification was performed to determine the potential health effects that may be associated with project emissions. Second, an exposure assessment was conducted to estimate the extent of public exposure to the CGS project emissions. Third, a dose-response assessment was performed in HARP to characterize the relationship between pollutant exposure and the incidence of an adverse health effect in exposed populations. Fourth, risk characterization was performed to integrate the health effects and public exposure information and provide qualitative estimates of health risks from project emissions. Risk modeling was performed using HARP to estimate cancer and non-cancer health risks for the project. From the OEHHA guidelines a list of pollutants with potential cancer and non-cancer health effects associated with the emissions from the project are presented in the following table. Unit risk factors for cancer and both chronic (long term) and acute (short term) reference exposure levels (REL) are indicated.

Toxicity Values Used To Characterize Health Risks				
Compound	**Sources of Emissions**	**Inhalation Cancer Potency Factor $(mg/kg\text{-}day)^{-1}$**	**Chronic REL ($\mu g/m^3$)**	**Acute REL ($\mu g/m^3$)**
Diesel particulate (PM_{10})	Two diesel engines	1.1E+00	5.0E+00	--
Ammonia	Gas turbine stacks	--	2.0E+02	3.2E+03
1,3-Butadiene	Gas turbine stacks	6.0E-01	2.0E+01	--
Acetaldehyde	Gas turbine stacks/aux boiler	1.0E-02	9.0E+00	--
Acrolein	Gas turbine stacks	--	6.0E-02	1.9E-01
Benzene	Gas turbine stacks/aux boiler	1.0E-01	6.0E+01	1.3E+03
Ethylbenzene	Gas turbine stacks/	--	2.0E+03	--
Formaldehyde	Gas turbine stacks/aux boiler	2.1E-02	3.0E+00	9.4E+01
Hexane	Gas turbine stacks	--	7.0E+03	--
Propylene	Gas turbine stacks	--	3.0E+03	--
Propylene oxide	Gas turbine stacks	1.3E-02	3.0E+01	3.1E+03
Toluene	Gas turbine stacks	--	3.0E+02	3.7E+04
Xylenes	Gas turbine stacks	--	7.0E+02	2.2E+04
Polycyclic Aromatic Hydrocarbons				
Benzo(a)anthracene	Gas turbine stacks	3.9E-01	--	--
Benzo(a)pyrene	Gas turbine stacks	3.9E+00	--	--
Benzo(b)fluoranthene	Gas turbine stacks	3.9E-01	--	--
Benzo(k)fluoranthene	Gas turbine stacks	3.9E-01	--	--
Chrysene	Gas turbine stacks	3.9E-02	--	--
Dibenz(a,h)anthracene	Gas turbine stacks	3.9E-01	--	--
Indeno(1,2,3-cd)pyrene	Gas turbine stacks	3.9E-01	--	--
Naphthalene	Gas turbine stacks	1.2E-01	9.0E+00	--
Source: Cal-EPA/OEHHA 2005 -- = not applicable [1]mg/kg-day = milligram(s) per kilogram per day				

RISK ASSESSMENT

The HRA was conducted using worst-case turbine, auxiliary boiler, and emergency diesel engine emissions. Cancer and chronic non-cancer health effects were estimated using the annual turbine and other source emission estimates. Acute non-cancer health effects were estimated using the worst-case maximum hourly emissions for the turbines and other sources. The maximum hourly emissions in lb/hour were used as input to the HARP model. Toxicological data, unit risk factors and RELs are built into the CARB's HARP model. Risk values were modeled for all sensitive receptors within 3 miles of the CGS project and all grid, boundary and census receptors within 6 miles of the CGS project.

Adverse health effects are expressed as cancer or non-cancer health risks. Cancer risk is typically reported as "lifetime cancer risk," which is the estimated maximum increase of risk of developing cancer caused by long-term exposure to a pollutant suspected of being a carcinogen. The calculation of cancer risk assumes an individual is exposed continuously to pollutants for 24 hours per day for 70 years. For carcinogenic health effects, an exposure is considered potentially significant when the predicted lifetime cancer risk exceeds 10 in 1 million (1.0×10^{-5}).

Non-cancer risk is reported as a "total hazard index" (THI). The THI is calculated for each target organ as a fraction based on the maximum acceptable exposure level to a pollutant. The acceptable exposure level is generally the level at (or below) which no adverse health effects are expected. The THI is calculated for short-term (acute) and long-term (chronic) exposures. For non-carcinogenic health effects, an exposure that affects each target organ is considered potentially significant when the THI exceeds a value of 1.

Results of the emission modeling and risk assessment analyses are shown in the table below.

Cancer Risk at Maximum Point of Impact	Chronic Risk at Maximum Point of Impact	Acute Risk at Maximum Point of Impact
1.194 Excess risk in 1 million	0.03055 THI	0.4205 THI

The estimated cancer risks at all locations are well below the significance criteria of 10 in 1 million. The estimated chronic and acute THIs are well below the significance criterion of 1. *FINDING - the proposed project emissions pose no significant health effects relative to the criteria established for carcinogenic and non-carcinogenic health effects.*

NEW SOURCE PERFORMANCE STANDARDS

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

The Colusa County Air District BACT requirements are more restrictive than the NSPS requirements. For example, the controlled NOx emissions from the CGS's gas turbines will be controlled to 2.0 parts per million by volume dry (ppmvd) at 15 percent oxygen, significantly less than the NSPS limit of 75 ppmvd at 15 percent oxygen.

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

TITLE V FEDERAL OPERATING PERMIT

Title V of the federal Clean Air Act requires U.S. EPA to develop a federal operating permit program that is implemented under 40 CFR 70. This program is administered by CCAPCD under Regulation 3, rule 3-17. Permits must contain emission estimates based on potential-to-emit, identification of all emission sources and controls, a compliance plan, and a statement indicating each source's compliance status. The permits must also incorporate all applicable federal, state, or District orders, rules and regulations.

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

VIII PERMIT CONDITIONS

1) All facility operating staff shall be advised of and familiar with these permit conditions.

2) The "Right of Entry", as provided by the California Health and Safety Code Section 41510 of Division 26, shall apply at all times.

3) In the case of shut-down or re-start of air pollution control equipment for necessary scheduled maintenance, the intent to shut down such equipment shall be reported to the Air Pollution Control Officer at least twenty-four (24) hours prior to the planned shutdown. Such notification does not exempt the facility from complying with all permit limits and requirements.

4) If any upset or breakdown occurs with equipment under permit in such a manner that may cause excess emissions of air contaminants, the APCO shall be notified of such failure or breakdown within twenty-four (24) hours or by 9:00 a.m. by the following working day. The person responsible shall also submit a written statement of full disclosure of the upset/breakdown to the District within 72 hours. The report shall contain the date, time, duration, estimated emissions, cause, and remedy.

5) Fugitive emissions, including dust and odors shall be controlled at all times such that a nuisance is not created at any point beyond the facility's property lines.

6) A person shall be designated to oversee the fugitive dust control program described in the application and this document. Entry roads to the proposed facility site will be paved prior to commencing construction. During construction, the people onsite shall access real-time weather information from the Western Weather Group to determine the prevailing local wind speed. If wind gusts at the Maxwell weather station exceed 15 mph construction personnel shall increase the frequency of watering the exposed soil. All of the mitigation measures will be implemented.

7) The placement of the source testing ports shall be as specified in 40 CFR Part 60, Appendix A, Method 1. A source test protocol shall be submitted to the District, for approval by the Air Pollution Control Officer (APCO), at least 45 days prior to conducting the annual source tests. The District shall be notified at least 10 days prior to actual source testing.

8) Stack gas testing, using EPA, ARB or other APCO approved methods, shall be required on an annual basis for NOx, VOC and CO on the HRSG stacks and the auxiliary boiler stack. The HRSG stacks and the auxiliary boiler stack shall also be tested for SOx and PM_{10} emissions during the first year and if requested by the APCO in subsequent years. The emergency generator and firewater pump engines shall be tested for NOx, SOx, VOC, CO, and PM_{10} during the first year and thereafter only as requested by the APCO.

9) Annual testing of the HRSG stacks shall include quantification of formaldehyde and ammonia (NH_3) emissions for compliance with permit limits. The facility owner/operator shall verify, by continuous recording, the ammonia injection rate to the system. The ammonia source test shall be conducted over the expected operating range of the turbine (including, but not limited to 50%, 75%, and 100% load) to establish the range of ammonia injection rates necessary to achieve NOx emission reductions while maintaining ammonia slip levels. The source test shall also determine the correlation between the heat input rates of each gas turbine and ammonia mass emissions.

10) The gas turbines, duct burners, and auxiliary boiler shall be fired exclusively on pipeline quality natural gas.

11) The annual average sulfur content in the natural gas used at the facility shall be less than or equal to 0.3 grains per 100 scf. Monthly testing, at the site, using approved methods (i.e., EPA 19 and ASTM D-3246) is required to determine the sulfur content of the natural gas. Pacific Gas and Electric natural gas testing data from Burney shall also be reviewed and provided to the District.

12) The sulfur content limit in diesel fuel used in the construction equipment and emergency generator and firewater pump engines shall be no more than 15 ppm. Emissions from the two stationary engines mentioned above shall not exceed Ringelmann 0.5 or 10 percent opacity for an aggregate of three minutes in a one hour period.

13) All applicable federal standards and test procedures of Subpart KKKK--Standards of Performance for Stationary Combustion Turbines shall be met.

14) The CTGs shall meet a VOC limit of 2.0 ppmvd with duct burner firing and 1.38 ppmvd without duct burner firing @ 15% O_2 averaged over one hour. Maximum hourly steady state emission limits for each CTG are:

Pounds VOC with Duct Firing	Pounds VOC without Duct Firing
7.2	3.4

15) The CTGs shall meet a NOx limit of 2.0 ppmvd @ 15% O_2 averaged over one hour except during commissioning. Maximum hourly steady state emission limits for each CTG are:

Pounds NOx with Duct Firing	Pounds NOx without Duct Firing
20.7	15.3

16) The CTGs shall meet a CO limit of 3.0 ppmvd @ 15% O_2 over a three-hour rolling average except during commissioning. Maximum hourly steady state emission limits for each CTG are:

Pounds CO with Duct Firing	Pounds CO without Duct Firing
18.9	14.0

17) The auxiliary boiler shall meet a NOx limit of 15.0 ppmvd @ 3% O_2 averaged over one hour.

18) Ammonia slip shall be limited to 5.0 ppmvd @ 15% O_2 averaged over one hour. Formaldehyde emissions will be limited to 0.917 lbs per MMscf of natural gas. Maximum hourly steady state emission limits for each CTG are:

Pounds NH_3 with Duct Firing	Pounds NH_3 without Duct Firing
19.2	14.2

19) Continuous emission monitoring (CEM) systems shall be installed to sample, analyze, and record NO_x, CO, O_2 concentration in the exhaust gas of both HRSG stacks. This system will generate reports of emissions data in accordance with permit requirements and will send alarm signals to the plant distributed control system (DCS) control room when the level of emissions approaches

or exceeds pre-selected limits. Relative accuracy test audits shall be conducted annually to verify performance of the CEM system.

20) The Colusa County APCD shall have remote access to the data logger at the facility to enable District staff to monitor realtime emissions as recorded by the CEMs.

21) The CEMs shall be installed, calibrated and operational prior to the first firing of the gas turbines. The commissioning phase of the turbines and heat recovery steam generators without abatement of emissions shall not exceed 500 total hours. All reasonable efforts will be made to shorten the length of time of the commissioning phase. Only one gas turbine may be commissioned at a time. Emissions from the commissioning phase of the turbines and heat recovery steam generators shall accrue toward the quarterly and annual emission limits specified in these conditions.

22) Quarterly reports of CEM and process data, including startup information, shall be submitted to the District within 10 days after the end of each quarter. Format of the data submission will be determined by the District and may include both electronic spreadsheet and hard copy files.

23) The emissions from the emergency generator and firewater pump engines shall not exceed the hourly limits established in the table below. Total annual operating hours shall not exceed 50 per engine. Testing of these two engines shall not be allowed during gas turbine commissioning and facility startup operations. The generator and firewater pump engines must comply with the Tier rating emissions for their model years.

One Hour Maximum Emissions (lbs)		
Source	**Generator**	**Fire Pump**
NO_X	13.88	1.98
CO	0.32	1.72
VOC	0.15	Incl. in NO_X
PM_{10}	0.09	0.10
SO_2	0.01	<0.01

24) The emission rates from the auxiliary boiler shall not exceed the hourly limits established in the table below. The boiler shall not operate more than 3,744 hours per year.

One Hour Maximum Emissions (lbs)		
Source		**Auxiliary Boiler**
NO_X		0.79
CO		1.61
VOC		0.18
PM_{10}		0.33
SO_2		0.13

25) The total emissions from the CTGs and HRSGs shall not exceed those established below for hourly and daily operations.

Maximum Emissions Both Turbines (lbs)		
Pollutant	**1-Hour Emissions**	**24-Hour Emissions**
NO_X	666.60	2,994.60

Maximum Emissions Both Turbines (lbs)		
CO	967.00	7,659.00
VOC	55.40	630.60
PM_{10}	40.20	964.80
SO_2	8.00	192.00

2) The total emissions from the Colusa Power Plant shall not exceed the limits established below.

Quarterly and Annual Estimated Combustion Emissions from CGS Facility					
Pollutant	**1st Quarter Emissions (tons)**	**2nd Quarter Emissions (tons)**	**3rd Quarter Emissions (tons)**	**4th Quarter Emissions (tons)**	**Annual Emissions (tons)**
NO_x	45.77	43.77	51.57	44.47	185.58
CO	55.35	53.55	108.25	55.05	272.20
VOCs	12.51	11.81	12.01	11.91	48.24
PM_{10}	35.36	35.46	35.66	35.76	142.24
SO_2	4.05	3.83	3.87	3.87	15.62

3) Offsets for the Colusa Generating Station power plant shall be in effect prior to operation of the facility and will not be less than the following amounts at any time. The offsets presented in the table below reflect distance factors and the VOC:NOx interpollutant ratio. All ERCs for PM_{10} will be provided prior to start of construction activities to offset construction PM_{10} emissions.

Emission Offsets by Calendar Quarter				
Pollutant in tons	**Quarter 1**	**Quarter 2**	**Quarter 3**	**Quarter 4**
Oxides of nitrogen (NO_2)	48.70	44.97	34.97	51.60
Volatile organic compounds (CH_4)	12.51	11.81	12.01	11.91
Particulate Matter PM_{10}	31.08	29.17	22.66	33.17
Oxides of sulfur (SO_2)	3.25	2.70	1.24	3.58

28) The construction of the facility cannot commence until all construction permits, including the USEPA PSD permit are obtained.

29) Total facility emissions of Hazardous Air Pollutants (HAP) shall not exceed 10 tons per year for any single pollutant except ammonia and formaldehyde.

IX APPENDICES

Appendix A – Agricultural Burning in Colusa County
Appendix B – Impact of Agricultural Burning on Particulate Matter and Ozone Concentrations
Appendix C – Emission Reduction Credits and Offsets
Appendix D – Enforcement of Emission Reduction Credits and Offsets
Appendix E – Modeling of Emissions from Agricultural Burning ERC Fields
Appendix F – Resolution regarding ERC transfer from the Butte County AQMD
Appendix G - Resolution regarding ERC transfer from the Feather River AQMD

RESOLUTION 2007-10
BEFORE THE BOARD OF DIRECTORS OF
BUTTE COUNTY AIR QUALITY MANAGEMENT DISTRICT
STATE OF CALIFORNIA
HIGHWAY 70 INDUSTRIAL PARK, LP REQUEST TO TRANSFER
EMISSION REDUCTION CREDITS FROM BUTTE COUNTY TO COLUSA COUNTY

Resolution 2007-10...................................)
Approval of a request from Highway 70................)
Industrial Park, LP to transfer Emission................)
Reduction Credits from Butte County....................)
to Colusa County...)

WHEREAS, on May 24, 2007 the Governing Board met in regular session;

AND WHEREAS, the Highway 70 Industrial Park, LP has entered into an Option-to-purchase agreement with E&L Westcoast, LLC to purchase Emission Reduction Credits originally generated in Butte County with the closure of Louisiana Pacific Corporation's fiberboard manufacturing plant in Oroville, CA and transfer those emission reduction credits from Butte County to Colusa County;

AND WHEREAS, E&L Westcoast, LLC has filed an Application for Certification with the California Energy Commission Requesting approval to construct and operate the Colusa Generating Station (Project), a nominal 660-megawatt combined-cycle electric power generating facility and related facilities in Colusa County;

AND WHEREAS, Emission Reduction Credits are required by State law and Colusa County Air Pollution Control District Rules and Regulations (Rule 3.6) to offset emissions increases at the proposed Project;

AND WHEREAS, Section 40709.6(a) of the California Health and Safety Code states:

> *"Increases in emissions of air pollutants at a stationary source located in a district may be offset by emission reductions credited to a stationary source located in another district if both stationary sources are located in the same air basin or..."*

AND WHEREAS, Butte County and Colusa County are located in the same air basin;

AND WHEREAS, Section 40709.6(d) of the California Health and Safety Code states:

> *"Any offset credited pursuant to subdivision (a) shall be approved by a resolution adopted by the governing board of the upwind district and the governing board of the downwind district, after taking into consideration the impact of the offset on air quality, public health, and the regional economy."*

AND WHEREAS, E&L Westcoast, LLC has completed an evaluation of the impact of the proposed Project and use of the Emission Reduction Credits on air quality, public health, and the regional quality;

AND WHEREAS, the Project will not have an adverse impact on any of the State or federal air quality standards;

AND WHEREAS, the Project will not have a significant adverse impact on public health;

AND WHEREAS, the Project will not adversely impact the regional economy and will provide power to the region;

AND WHEREAS, the Governing Board has considered the impact of approving the transfer of Emission Reduction Credits to Colusa County to offset the emissions from the Project on air quality, public health, and the regional economy as required by Section 40709.6(d) of the California Health and Safety Code;

THEREFORE, BE IT RESOLVED, that the Governing Board hereby approves inter-district transfer of 69.0 Tons per year of Carbon Monoxide, 70.0 Tons per year of Oxides of Nitrogen, 67.0 Tons per year of Particulate Matter (PM10), and 175.0 Tons per year of Reactive Organic Gases Emission Reduction Credits from Butte County to Colusa County for the Project;

On Motion of Supervisor Yamaguchi, Seconded by Supervisor Josiassen, the foregoing resolution is hereby PASSED AND ADOPTED by the Air Quality Management District Board of Directors on this 24th day of May, 2007 by the following:

AYES: Supervisor Connelly, Supervisor Dolan, Supervisor Josiassen, Supervisor Yamaguchi, Vice Mayor Johansson, Councilmember Arnold, Councilmember Gruendl, Councilmember Huffman.
NOES: Supervisor Kirk
ABSTAIN: None
ABSENT: Mayor Fichter

THEREFORE, BE IT FURTHER RESOLVED, that the Governing Board authorizes the Air Pollution Control Officer to execute the Memorandum of Understanding with Colusa County.

On Motion of Supervisor Yamaguchi, Seconded by Supervisor Josiassen, the foregoing resolution is hereby PASSED AND ADOPTED by the Air Quality Management District Board of Directors on this 24th day of May, 2007 by the following:

AYES: Supervisor Connelly, Supervisor Kirk, Supervisor Dolan, Supervisor Josiassen, Supervisor Yamaguchi, Vice Mayor Johansson, Councilmember Arnold, Councilmember Gruendl, Councilmember Huffman.
NOES: None
ABSTAIN: None
ABSENT: Mayor Fichter

W. J. Wagoner
W. James Wagoner, Air Pollution Control Officer
Butte County Air Quality Management District

[illegible]
ATTEST: Patricia J Cummings
Patricia J Cummings, Clerk of the Governing Board

FEATHER RIVER AIR QUALITY MANAGEMENT DISTRICT

IN RE:

RESOLUTION NO **2007-02**

RESOLUTION TO APPROVE TRANSFER OF EMISSION REDUCTION CREDITS FROM FEATHER RIVER AQMD TO COLUSA COUNTY APCD TO PARTIALLY OFFSET EMISSION INCREASES FROM E&L WESTCOAST, LLC'S COLUSA GENERATING STATION AND AUTHORIZE THE CHAIRMAN TO EXECUTE RELATED DOCUMENTS

WHEREAS, California Health & Safety Code Section 40709.6(a) allows increases in emissions of air pollutants at a stationary source located in one district to be offset by emission reductions credited to a stationary source located in another district if both stationary sources are located in the same air basin;

WHEREAS, California Health & Safety Code Section 40709.6(d) requires any offset credited pursuant to Section 40709.6(a) to be approved by a resolution adopted by the governing boards of both districts after taking into consideration the impact of the offset on air quality, public health, and the regional economy;

WHEREAS, CCAPCD Rule 3.6(c)(3) allows offsets that are obtained from a source located in another district to be used if the provisions of Section 40709.6 are met and if the involved districts enter into an agreement formalized by a memorandum of understanding;

WHEREAS, Section 40709.6(d) allows the governing board of any district to delegate the authority to approve offsets pursuant to Section 40709.6(a) to its Air Pollution Control Officer ("APCO") of the District;

WHEREAS, the Colusa County Air Pollution Control District ("CCAPCD") Governing Board delegated its approval authority under Section 40709.6(d) to its APCO;

WHEREAS, the Governing Board of the Feather River Air Quality Management District ("FRAQMD") has not delegated its approval authority under Section 40709.6(d) to its APCO;

WHEREAS, E&L Westcoast LLC ("E&L Westcoast") has filed an Application for Certification with the California Energy Commission requesting approval to construct and operate the Colusa Generating Station, a nominal 660-megawatt combined-cycle electric power generating facility and related facilities in Colusa County in the Sacramento Valley Air Basin (the "Project");

WHEREAS, pursuant to CCAPCD Rule 3.6(g)(3), the APCO of the CCAPCD has been requested to issue a Determination of Compliance for the Project;

WHEREAS, one of the requirements with which the Project must comply is the provision of offsets pursuant to CCAPCD Rule 3.6;

WHEREAS, the Project intends to acquire for use as offsets for the Project ERCs generated in the Sacramento Valley Air Basin and banked by the FRAQMD;

WHEREAS, E&L Westcoast has entered into binding agreements with two holders of ERCs certified by the FRAQMD, one that grants the Project an option to purchase up to 1,076 pounds (lbs) per year of reactive organic gas ("ROG") ERCs, 2,269 pounds per year of nitrogen oxide ("NOx") ERCs, 32,609 lbs per year of particulate matter ("PM10") ERCs, and 897 lbs per year of sulfur oxide ("SOx") ERCs from FRAQMD ERC certificate 9937006-00T and the other that grants the Project an option to purchase up to 13,652 lbs ROG, 8,509 lbs NOx, 17,535 lbs PM10, and 1,646 lbs SOx (collectively, the "Option Agreements");

WHEREAS, the Project will be a state-of-the-art facility employing the latest in air pollution control equipment;

WHEREAS, the Project will meet all applicable federal, state, and local air quality statutes, rules, and regulations;

WHEREAS, the Project will not cause or contribute to an exceedance of an applicable air quality standard;

WHEREAS, the Project will cause a net decrease in air emissions in the Sacramento Valley Air Basin;

WHEREAS, a health risk assessment prepared for the Project demonstrates no significant risk to human health from the Project;

WHEREAS, the extensive air quality analysis that has been completed for the Project demonstrates that the transfer of ERCs and their use as offsets by the Project will not have a detrimental impact on air quality or public health;

WHEREAS, the transfer of ERCs and their use as offsets by the Project will have a positive impact on the regional economy by allowing the development of the Project, which represents a significant investment in the regional economy;

NOW THEREFORE, BE IT RESOLVED; the Governing Board of the FRAQMD, after consideration of the air quality, public health, and regional economy impacts of the proposed offsets, hereby directs the Air Pollution Control Officer to negotiate with the CCAPCD a memorandum of understanding that covers the use of emission reductions from the FRAQMD to partially offset emission increases from E&L Westcoast, LLC's Colusa Generating Station, as required by section E.2.c.2 of FRAQMD rule 10.1, and to present the memorandum to the chairman of this board.

BE IT FURTHER RESOLVED; The board authorizes the chairman to sign the memorandum of understanding described in paragraph 3 on behalf of the Feather River AQMD.

PASSED AND ADOPTED by the Feather River Air Quality Management District at its regular meeting of June 4, 2007, by the following vote:

AYES:

NOES:

ABSENT:

ABSTAIN:

____

Chairman

ATTEST
CLERK OF THE DISTRICT BOARD

____

APPROVED FOR LEGAL FORM

____

William Vanesek, District Legal Advisor