La Jolla Energy Development, Inc.

Baldwin Energy Facility No. 1

PERMIT TO CONSTRUCT APPLICATION

Submitted to:

South Coast Air Quality Management District
21865 East Copley Drive
Diamond Bar, California 91765

Submitted by:

La Jolla Energy Development, Inc.

May 4, 2001
May 10,2001 (Revision 1)
May 21, 2001 (Revision 2)

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WARRANTY DISCLOSURE

This document has been prepared using presently accepted engineering and scientific judgment and a level of care consistent with the standards of practice measured on the date of this document and in the locale of the project site for similar type studies performed by environmental professionals in the State of California. No warranty is made, expressed or implied, in fact or by law, whether of merchantability, fitness for any particular purpose, or otherwise, concerning any information contained in this document, whether caused by error, omission, negligence, or otherwise.

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1.0 INTRODUCTION

This application package is being submitted by La Jolla Energy Development, Inc. (La Jolla) to the South Coast Air Quality Management District (SCAQMD) for a Permit to Construct (PTC) for The Baldwin Energy Facility No.1. This new project will consist of the installation of two (2) General Electric LM 2500 simple cycle turbine units for a total output of approximately 50 MW.
La Jolla proposes to utilize the California Energy Commission (CEC) emergency power plant permitting process for this project. The initial project will consist of a startup scenario of peaking turbine units, operating within parameters of the CEC guidelines. These turbines will operate with water injection emission controls, limiting emissions to 25 ppm NOx, 40 ppm CO, and 4 ppm ROC. The final project will include the installation of the following controls: installation of steam injection utilizing heat recovery steam generators (HSRG), Selective Catalytic Reduction (SCR) system, and an oxidation catalyst. This will provide emission reductions of 5 ppm NOx, 1.4 ppm ROC, and 4 ppm CO. This proposed project has been conceived and designed to minimize new environmental impacts, and thus bring new supplies of electricity to the market in the shortest time possible. The project is to be sited on property that has already been extensively developed for industrial use, thus minimizing new ground disturbance. Existing gas and water supplies are adequate for the project.

The units will be equipped with the lowest achievable emission rate (LAER) control devices for NO_x and CO emissions, and all emissions of non-attainment criteria pollutants will be fully offset from known sources (e.g. RECLAIM, Provisional Bank, State Emergency Bank). The units are sited as far as practical from the property line to minimize noise concerns and offsite consequences of potential release of hazardous materials.

2.0 PROJECT INFORMATION

2.1 Project Location

The Baldwin Energy Facility No.1 will be located at 5640 S. Fairfax Avenue, Los Angeles, CA, 90065. A facility map is provided as Figure 2-1, and a facility plot plan is provided as Figure 2-2 below.

2.2 Background Information

2.2.1 Business Name and Mailing Address

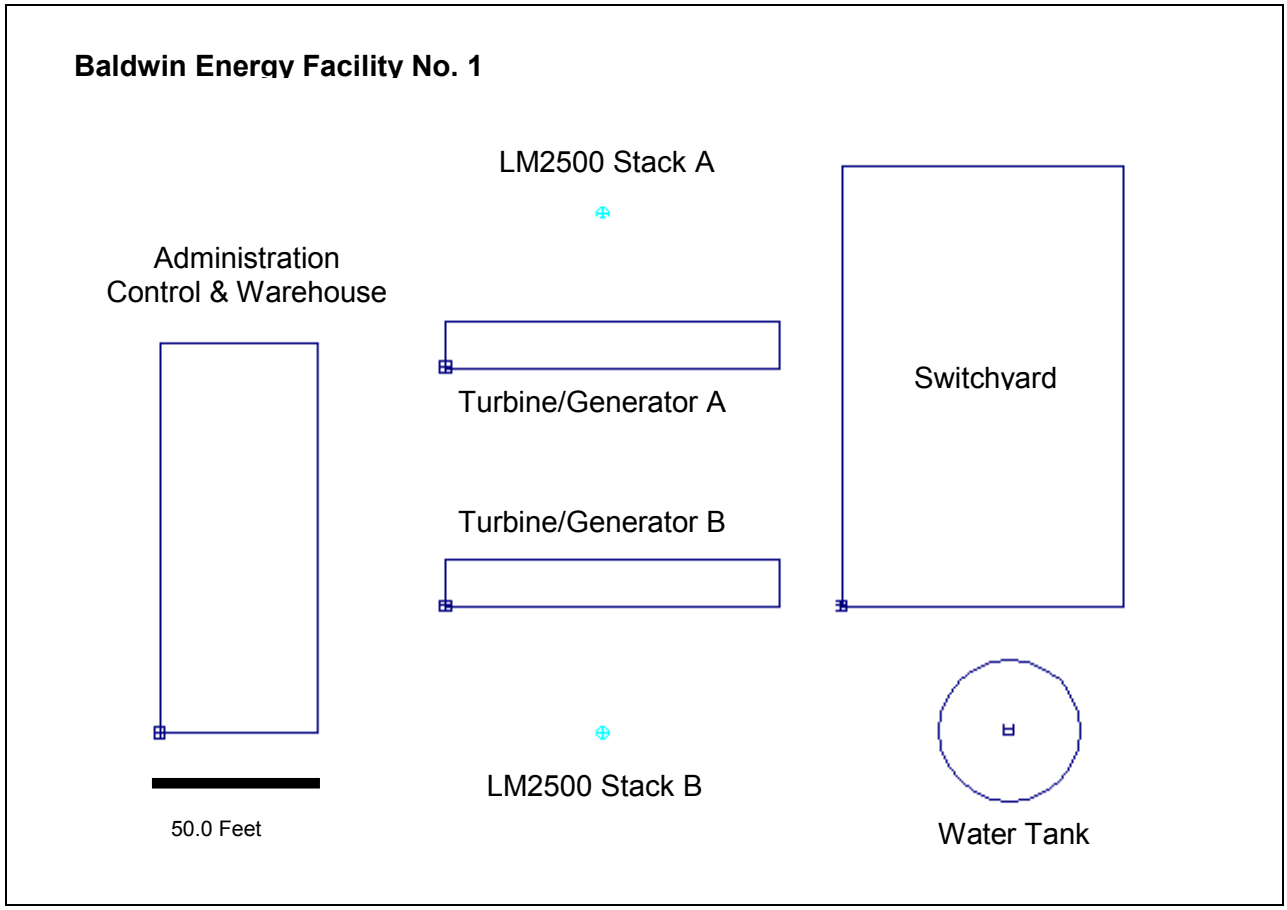
La Jolla Energy Development, Inc.
2882 – C Walnut Ave.
Tustin, CA. 92780

2.2.2 Facility Address

Baldwin Energy Facility No.1
5640 S. Fairfax Avenue
Los Angeles, CA, 90065.

Figure 2-1 Facility Map

Figure 2-2 Facility Plot Plan



2.2.3 IRS Number

IRS No. 522235913

2.2.4 Nature of Business

Power Generation (SIC 4911)

2.2.5 Type of Applications

Permit to Construct / Permit to Operate

2.2.6 Person to Contact Regarding this Application

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2.2.7 Estimated Construction and Completion Dates

Construction will begin upon issuance of PTC. It is anticipated that the project will be completed by September 30, 2001.

2.2.8 Operation Schedule

The Baldwin Energy Facility No.1 is expected to operate 24 hours per day, 7 days per week.

2.2.9 Compliance Certification

La Jolla Energy Development, Inc. certifies to the best of their knowledge, all facilities owned or operated by La Jolla Energy Development, Inc. within the State of California are in compliance or on an approved schedule for compliance with applicable federal and state air quality emission limits and standards.

3.0 EQUIPMENT SPECIFICATIONS AND ESTIMATED EMISSIONS

3.1 Turbine Specifications

La Jolla proposes to initially install two (2) General Electric (GE) LM 2500 simple cycle turbine units for a total electrical power output of 50 MW, followed by modification to combined cycle as soon as the HRSG and SCR systems are available. Table 3-1 below provides the engine specifications for each unit.

Table 3-1 GE LM 2500 Engine Specifications

Output	27.35 MW
Specific Fuel Consumption	0.2844 lb/hp-hr
Thermal Efficiency	38.8 %
Heat Rate	8,804 BTU/kW-hr
Exhaust Gas Flow	228,410 wacf/min
Exhaust gas Temperature	367 ° F
Power Turbine Speed	3,600 rpm
Length	21.4 ft.
Height	6.7 ft.

3.2 Control Equipment and Technologies

3.2.1 NO_x Emissions

Water (or steam) injection is a technology that has been demonstrated to cost-effectively suppress NO_X emission from gas turbines. The effect of water injection is to increase the thermal mass by dilution and thereby reduce peak flame temperatures in the flame zone, thus cutting thermal NO_X formation significantly. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water is typically injected at a water-to-fuel weight ratio of less than one. Depending on initial NO_X levels, the correct rate of water of injection may reduce NO_X by 65 percent or more. NO_X emission levels are estimated at the 25 ppmvd range with the installation of this technology. Steam injection, utilizing a HRSG, will be installed on each turbine unit as a final control technology.

In order to meet BACT /LAER requirements, a Hitachi selective catalytic reduction (SCR) system will be installed with each turbine unit. This SCR system will selectively reduce NO_X emissions by injecting ammonia into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form N_2 and H_2O. NO_x emissions are expected to be reduced to 5 ppm using this control technology. Aqueous ammonia will be stored on a storage skid on site with the injection rate being controlled and monitored by a centralized operating system. The following is a listing of the specifications of the SCR unit:

Catalyst Manufacturer: Engelhard

Catalyst Type: Engelhard VnX Titania/Vanadia

Aqueous Ammonia Injection Rate: 57 lbs / hr

Ammonia Emission Rate: 5 ppmvd @ 15% O_2

Pressure Drop Across SCR Unit: 4 in. w.c.

Pressure Drop Across Aqueous Ammonia Grid: 0.1 in. w.c.

Catalyst Volume: 450 cu. ft.

Gas Flow Rate: 168 lb/sec.

Space Velocity (Gas Flowrate/Catalyst Volume): Based on SCFM is 11,000 lbs/hr, based on ACFM it is 41,000 lbs/hr.

Area Velocity (Gas Flowrate/Wetted Catalyst Surface Area): Not Available

Minimum Temperature for Ammonia Injection: 690º F

Manufacturer Guarantee for Efficiency and Catalyst Life: 90 %, 3 years

NO_x Inlet Concentration: 25 ppmvd @ 15% O_2

NO_x Outlet Concentration: 5 ppmvd @ 15% O_2

CO Inlet Concentration: 40 ppmvd @ 15% O_2

CO Outlet Concentration: 4.0 ppmvd @ 15% O_2

Catalyst Unit Total Cost: $819,000 (Includes SCR and Oxidation Catalyst)

Catalyst Replacement Cost: $238,000

Temperature Range for Optimum Performance: 690 to 720 º F.

Catalyst Layers: Catalyst is 3 x 3 x 2 ft. per block with a total of 25 blocks.
Weight of one block is 800 pounds.

SO_2 Oxidation Rate/SO_3 Emissions: Not applicable, natural gas only.

HSRG System Specifications:

The following is a listing of the specifications of the HRSG:

Manufacturer: Deltak

Full Steam Injection Rate: 71,000 lb/hr @ 850 º F

Flow Rate: 168 lb/sec

Temperature Profile: Imput: 941 º F, Output: 367 º F

Oxidation catalyst equipment specifications:

Catalyst Manufacturer: Engelhard

Catalyst Type: Vandia/Titania

Pressure Drop Across Catalyst: 1.5 in. w.c.

Catalyst Volume: 150 cu. ft.

Space Velocity: Based on SCFM is 11,000 lbs/hr, based on ACFM it is 41,000 lbs/hr.

Linear Velocity: 22fps.

Manufacturer Guarantee for Efficiency and Catalyst Life: 90 %, 3 years

Temperature Range for Optimum Performance: 690 to 860 F.

Effective Temperature for Efficiency: 720 F

CO Inlet Concentration: 40 ppmvd @ 15% O_2

CO Outlet Concentration: 4.0 ppmvd @ 15% O_2

ROC Inlet Concentration: 4.0 ppmvd @ 15% O_2

ROC Outlet Concentration: 1.4 ppmvd @ 15% O_2

CO Conversion Efficiency: 90 %

Unsaturated Hydrocarbon Conversion Efficiency: 60 %

Saturated (Non Methane) Hydrogen Conversion Efficiency: 65 %

Methane Conversion Efficiency: 65 %

Catalyst Unit Total Cost: $819,000 (Includes SCR and Oxidation Catalyst)

Catalyst Replacement Cost: $238,000

Catalyst Layers: Catalyst is 3 X 3 X 2 ft. per block with a total of 25 blocks.
Weight of one block is 800 pounds.

Catalyst Cell Density (Cells/in^2): Range: 100 to 150 cpi.

3.2.2 CO and VOC Emissions

A Deltak oxidation catalyst will be installed on these turbine installations to achieve control of CO emissions. CO catalysts are also used to reduce organic VOC and HAPs emissions. The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (CO_2) and water (H_2O) as the gas stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement for introducing reactants. The performance of these oxidation catalyst systems on combustion turbines results in 90-plus percent control of CO and about 85 to 90 percent control of formaldehyde. Similar emission reductions are expected on other HAP pollutants. VOC emissions are expected to be reduced by 50 to 60 percent with this oxidation catalyst.

3.2.3 SO_X Emissions

In accordance with SCAQMD BACT guidelines, BACT for SO_X in gas turbines is utility-grade natural gas. Since these turbines will operate only on natural gas fuel, BACT for SO_X is achieved.

3.2.4. PM_{10} Emissions

Per South Coast AQMD BACT guidelines, BACT for PM_{10} in gas turbines (any size or application) is PUC-specification natural gas. The USEPA AP-42 PM_{10} emission factor is 6.93 lb/mmcf (see Section 3.4). Since the turbines will operate only on natural gas fuel, BACT for PM_{10} is achieved.

Emissions of criteria pollutants are estimated below using EPA AP-42 emission factors and natural gas usage data.

3.3 Fuel Usage

The subject systems are capable of operating on a 24 hours per day with normal maintenance downtime. The maximum and average fuel consumption of each controlled turbine is estimated as follows:

- Estimated Annual Fuel Usage: 1,949.3 mmcf/yr each unit
- Estimated Maximum Hourly Fuel Usage: 0.2374 mmcf/hr each unit
- Estimated Average Hourly Fuel Usage: 0.2291 mmcf/hr each unit
- Estimated Maximum Daily Fuel Usage: 5.70 mmcf/day each unit
- Estimated Average Daily Fuel Usage: 5.50 mmcf/day each unit

3.4 Criteria Pollutant Emission Factors

The primary criteria pollutant emissions from this facility are nitrogen oxides (NO_x), reactive organic gases (ROG), sulfur dioxide (SO_2), carbon monoxide (CO), and particulate matter (PM_{10}). The SCR unit will control and significantly reduce NO_x emissions. The amount of criteria pollutant emissions are calculated using the emission factors listed in Table 3-2 below.

3-2. Criteria Pollutant Emission Factors

Pollutant Name	Controlled ppmvd	Emission Factor lb/mmcf**
Nitrogen Oxides (as NO_2)	5.00	20.23
Reactive Hydrocarbons (ROG) as CH_4	1.40	1.97
Carbon Monoxide (CO)	4.00	9.85
Sulfur Dioxide (SO_2)	0.11	0.63
Particulates (as PM_{10})*	0.0014	6.93
Ammonia Slip (NH_3)	5.00	7.48

**PM_{10} in grains/dscf*
*** Fd = 9112 dscf/mmBTU from LM2500 turbine performance model*

The criteria pollutant emissions from each turbine are calculated for (1) pre-project (uncontrolled) and (2) post-project (controlled) using the following general equation:

Emissions (lb/period) = (fuel usage, mmcf/period) (emission factor, lb/mmcf)

Maximum and average emission rates are calculated using maximum and average fuel consumption rates, respectively.

3.5 Emissions Summary

Startup/shutdown emissions were not factored into the estimated emission rates calculated for this project. In the original application, hot start, cold start, and startup/shutdown models were included as attachments, but no values were assigned to those scenarios. Project emissions were calculated for base load only. Higher mass emission rates were factored in for cold weather (Cold Max). Following a review of these emission estimates, an error was discovered in the mass emission rate calculation for the permanent project model. This resulted in revised emissions and offset requirements which are reflected in the permanent project description listed below.

During commissioning and startup, emissions of CO, NO_x and ROC are expected to be higher than normal due to the fact that the water injection, SCR, and CO catalyst control systems may not be fully operational. The mass emission rates listed below are expected for the turbine startup and commissioning operations.

Interim Project Models:

Startup Model A:

No water, 70 % Load

0 to 5 minutes: 75 ppm NO_x
12 ppm ROC
120 ppm CO

Startup Model B:

Water on, 100% Load

5 minutes and up: 25 ppm NO_x
2 ppm ROC
40 ppm CO

Permanent Project Models:

Startup Model A:

No steam, 70 % Load

0 to 10 minutes: 75 ppm NO_x
12 ppm ROC
120 ppm CO

Startup Model B:

Steam only, 85 % Load

10 minutes to 20 minutes: 25 ppm NO_x
4 ppm ROC
40 ppm CO

Startup Model C:

Steam and Ammonia Controls, 100 % Load

After 20 Minutes: 5 ppm NO_x
1.4 ppm ROC
4 ppm CO
5 ppm NH_3

The interim project will consist of a startup scenario of peaking turbine units, operating within parameters of the CEC guidelines. These turbines will operate with water injection emission controls, limiting emissions to 25 ppm NOx, 40 ppm CO, and 4 ppm ROC. Table 3.3 below summarizes the emission parameters used to estimate the emissions for the interim project.

Table 3.3: Interim Emission Parameters

PROCESS EQUIPMENT DESCRIPTION	LM2500 Gas Turbine	
FUEL TYPE/PROCESS INFO	Pipeline Natural Gas	
Parameter	**Value**	**Units**
TOTAL YEARLY PROCESS RATE	264.74	Mmcf
AVERAGE HOURLY PROCESS RATE	0.2353	Mmcf
MAXIMUM HOURLY PROCESS RATE	0.2436	Mmcf
FUEL HIGHER HEATING VALUE	1049.99	BTU/scf
ON-LINE TIME	1125	Hrs/yr
AVERAGE UNIT RATING	23.40	MW
AVERAGE HEAT INPUT	247.09	MmBTU/hr
MAX UNIT RATING	24.99	MW
MAX HEAT INPUT	255.73	MmBTU/hr
AVERAGE STACK TEMP	950	Deg F
AVERAGE STACK TEMP	783	Deg K
AVERAGE STACK FLOW	340927	Wacf/min
STACK HYDRAULIC DIAMETER	9.11	Ft
STACK HYDRAULIC DIAMETER	2.78	M
STACK HYDRAULIC AREA	65.18	Sq ft
AVG STACK VELOCITY	5230.40	Ft/min
AVG STACK VELOCITY	26.57	M/sec
STACK HEIGHT AGL	70.00	Ft
STACK HEIGHT AGL	21.34	M
ANNUAL FUEL USAGE	264.74	Mmcf
ANNUAL HEAT INPUT, HHV	277,972	MmBTU
ANNUAL ENERGY CONVERSION, HHV	89,840	MmBTU
ANNUAL WASTE HEAT, HHV	188,132	MmBTU
ANNUAL ENERGY PRODUCTION	26,323	MW-hrs
AVERAGE HEAT RATE, HHV	10,560	BTU/kw-hr
AVERAGE THERMAL EFFICIENCY, HHV	32.32%	

- The emissions estimates for the interim project have been calculated upon the assumptions outlined in Table 3.3 above. These emission estimates for one unit are summarized in Table 3.4 below.

Table 3.4: Interim Uncontrolled/Controlled Emission Rates – Unit 1 or 2

Interim – Each Unit	Control	AHU	AHC	MHU	MHC	MDU	MDC	AA	30-DAY
Emissions without Controls	**Efficiency**	**lb/hr**	**lb/hr**	**Lb/hr**	**lb/hr**	**lb/day**	**lb/day**	**Lb/yr**	**lb/day**
Nitrogen Oxides (as NO_2)	0%	2.97	2.97	24.25	24.25	581.88	581.88	26,002	554.70
Reactive Hydrocarbons (ROC) as CH_4	0%	0.17	0.17	2.02	2.02	48.57	48.57	1,447	30.87
Carbon Monoxide (CO)	0%	2.89	2.89	25.97	25.97	623.37	623.37	25,323	540.23
Sulfur Dioxide (SO_2)	0%	0.02	0.02	0.15	0.15	3.68	3.68	167	3.56
Particulates (as PM_{10})	0%	0.21	0.21	1.69	1.69	40.51	40.51	1,835	39.14

*ROG = reactive organic gases (VOC * 0.83)*
AHC = average hourly controlled emissions
MHC = maximum hourly controlled emissions
MDC = maximum daily controlled emissions
30-DY = 30 day average controlled emissions
AHU = average hourly uncontrolled emissions
MHU = maximum hourly uncontrolled emissions
MDU = maximum daily uncontrolled emissions
AA = average annual controlled emissions

The final project will include the installation of the following controls: installation of steam injection utilizing heat recovery steam generators (HSRG), Selective Catalytic Reduction (SCR) system, and an oxidation catalyst. This will provide emission reductions of 5 ppm NOx, 1.4 ppm ROC, and 4 ppm CO. Table 3.5 below summarizes the emission parameters used to estimate the emissions for the permanent project.

Table 3.5: Permanent Emission Parameters

PROCESS EQPT DESCRIPTION	LM2500 Gas Turbine	
FUEL TYPE/PROCESS INFO	Pipeline Natural Gas	
Parameter	**Values**	**Units**
TOTAL YEARLY PROCESS RATE	1949.43	Mmcf
AVERAGE HOURLY PROCESS RATE	0.2293	Mmcf
MAXIMUM HOURLY PROCESS RATE	0.2374	Mmcf
FUEL HIGHER HEATING VALUE	1049.99	BTU/scf
ON-LINE TIME	8500	hrs/yr
AVERAGE UNIT RATING	27.35	MW
AVERAGE HEAT INPUT	240.81	mmBTU/hr
MAX UNIT RATING	29.21	MW
MAX HEAT INPUT	249.24	mmBTU/hr
AVERAGE STACK TEMP	367	Deg F
AVERAGE STACK TEMP	459	Deg K
AVERAGE STACK FLOW	228410	wacf/min
STACK HYDRAULIC DIAMETER	9.11	ft
STACK HYDRAULIC DIAMETER	2.78	m
STACK HYDRAULIC AREA	65.18	sq ft
AVG STACK VELOCITY	3504.20	ft/min
AVG STACK VELOCITY	17.80	m/sec
STACK HEIGHT AGL	70.00	ft
STACK HEIGHT AGL	21.34	m
ANNUAL FUEL USAGE	1,949.43	mmcf
ANNUAL HEAT INPUT, HHV	2,046,879	mmBTU
ANNUAL ENERGY CONVERSION, HHV	793,524	mmBTU

ANNUAL WASTE HEAT, HHV	1,253,355	mmBTU
ANNUAL ENERGY PRODUCTION	232,501	MW-hrs
AVERAGE HEAT RATE, HHV	8,804	BTU/kw-hr
AVERAGE THERMAL EFFICIENCY, HHV	38.77%	

- The emissions estimates for the permanent project have been calculated upon the assumptions outlined in Table 3.5 above. These emission estimates for one unit's emissions are summarized in Table 3.6 below. Cold Weather Maximum.

Table 3.6: Permanent Uncontrolled/Controlled Emission Rates – Unit 1 or 2

Permanent – Each Unit	**Control**	**AHU**	**AHC**	**MHU**	**MHC**	**MDU**	**MDC**	**AA**	**30-DAY**
Emissions with Controls	**Efficiency**	**lb/hr**	**lb/hr**	**Lb/hr**	**lb/hr**	**lb/day**	**lb/day**	**lb/yr**	**lb/day**
Nitrogen Oxides (as NO_2)	80%	20.73	4.15	22.41	4.48	537.88	107.58	36,320	102.55
Reactive Hydrocarbons (ROC) as $_{CH4}$	65%	1.15	0.40	1.87	0.65	44.90	15.72	3,537	9.99
Carbon Monoxide (CO)	90%	20.19	2.02	24.01	2.40	576.23	57.62	17,686	49.94
Sulfur Dioxide (SO_2)	0%	0.14	0.14	0.15	0.15	3.59	3.59	1,228	3.47
Particulates (as PM_{10})	0%	1.54	1.54	1.64	1.64	39.48	39.48	13,509	38.14
Ammonia Slip (NH_3)		0.00	1.53	0.00	1.66	0.00	39.76	13,423	37.90

*ROG = reactive organic gases (VOC * 0.83)*
AHC = average hourly controlled emissions
MHC = maximum hourly controlled emissions
MDC = maximum daily controlled emissions
30-DY = 30 day average controlled emissions
AHU = average hourly uncontrolled emissions
MHU = maximum hourly uncontrolled emissions
MDU = maximum daily uncontrolled emissions
AA = average annual controlled emissions

Controlled emissions for the total permanent project (two units) is summarized in Table 3.7 below.

Table 3.7: Total Permanent Project Emissions

Permanent Project– Two Units	**Actual**	**Actual**	**Permitted**
Emissions with Controls	**lb/hr**	**lb/day**	**Tons/yr**
Nitrogen Oxides (as NO_2)	8.55	205.10	36.32
Reactive Hydrocarbons (ROC) as CH_4	0.83	19.98	3.54
Carbon Monoxide (CO)	4.16	99.88	17.69
Sulfur Dioxide (SO_2)	0.29	6.94	1.23
Particulates (as PM_{10})	3.18	76.29	13.51
Ammonia Slip (NH_3)	3.16	75.80	13.42

3.6 Emission Offsets

Regulation XIII of the District's rules and regulations requires that the proposed project PM_{10} emissions be offset by a 1.2 to 1 ratio so that this project will represent a net air quality benefit to the air basin. Due to a review and revision of the mass emission rates, the permanent

project emission rates have been revised. This resulted in a revision to the offsets required for the project as follows:

- PM_{10} : 91 lbs/day
- NOx emissions will be offset for the first year of operations using RECLAIM trading credits (RTCs) in the amount of 72,640 lbs/year.

Revision to Form 400 E – 12:

Due to the revision in mass emission rates, please find enclosed a revised Form 400 E-12.

3.7 Emission Calculations

Emission calculations and data for the interim project are enclosed as Attachment 1, and for the permanent project, emission calculations and data are enclosed as Attachment 2. This emissions data is organized as follows for your review:

- *LM 2500 Performance Model*: This spreadsheet lists the following data:
    - Emission calculation parameters, including variable parameters;
    - Molecular weight calculations;
    - Emission factors used for calculations(cold weather maximum and annual average);
    - Mass uncontrolled and controlled emission rates (ppmvd); and
    - Resultant emissions on a lb/hr and lb/day basis.
- *Base Load Report*: This spread sheet shows emission rates for the base load condition of the turbine operations;
- *Composite Emissions Report*: This spreadsheet details emission parameters and resultant emission rates for one turbine unit;
- *Multiple Unit Emissions Report*: This spreadsheet details emission parameters and resultant emission rates for the maximum of two turbines; and
- *Fuel Gas Report*: This spreadsheet provides the fuel constituents for the natural gas fuel.

3.8 Air Quality Modeling

The dispersion modeling was completed using the EPA approved Industrial Source Complex Short-Term 3 (ISCST3), version 99155, dispersion model. ISCST3 calculates downwind concentrations of subject pollutants from single or multiple sources using model control parameters, source data, a receptor grid and meteorological data.

3.8.1 Model Control Parameters

ISCST3 model was run with the following control options:

- regulatory default switch off;
- no calm processing;

- urban dispersion;
- elevated terrain; and,
- concentration mode.

Building Downwash

The EPA approved Building Profile Input Program (BPIP) was utilized to determine if the wake of surrounding structures could effect dispersion of stack emissions. Source and building locations are shown on the plot plan included as Figure 3-1. Table 3-8 lists the structures included as input into the BPIP program. The output of BPIP was included as input into ISCST3 input files.

Table 3-8 Structure Location and Dimensions

Building/ Structure	ISCST3 Name	UTM E (meters)	UTM N (meters)	Height (meters)	E/W Length (meters)	N/S Length (meters)
Administration	Admin	373362.3	3763458	6	15.2	37.5
Turbine- North	GenTurbA	373389.8	3763493.1	6	32	4.6
Turbine-South	GenTurbB	373389.8	3763470.2	6	32	4.6
Switchyard	Swtchyrd	373427.9	3763470.2	6	27.1	42.4
Building/ Structure	**ISCST3 Name**	**UTM E (meters)**	**UTM N (meters)**	**Height (meters)**	**Radius (meters)**	
Water Tank	H20Tank	373444	3763458.3	6.8	6.8	

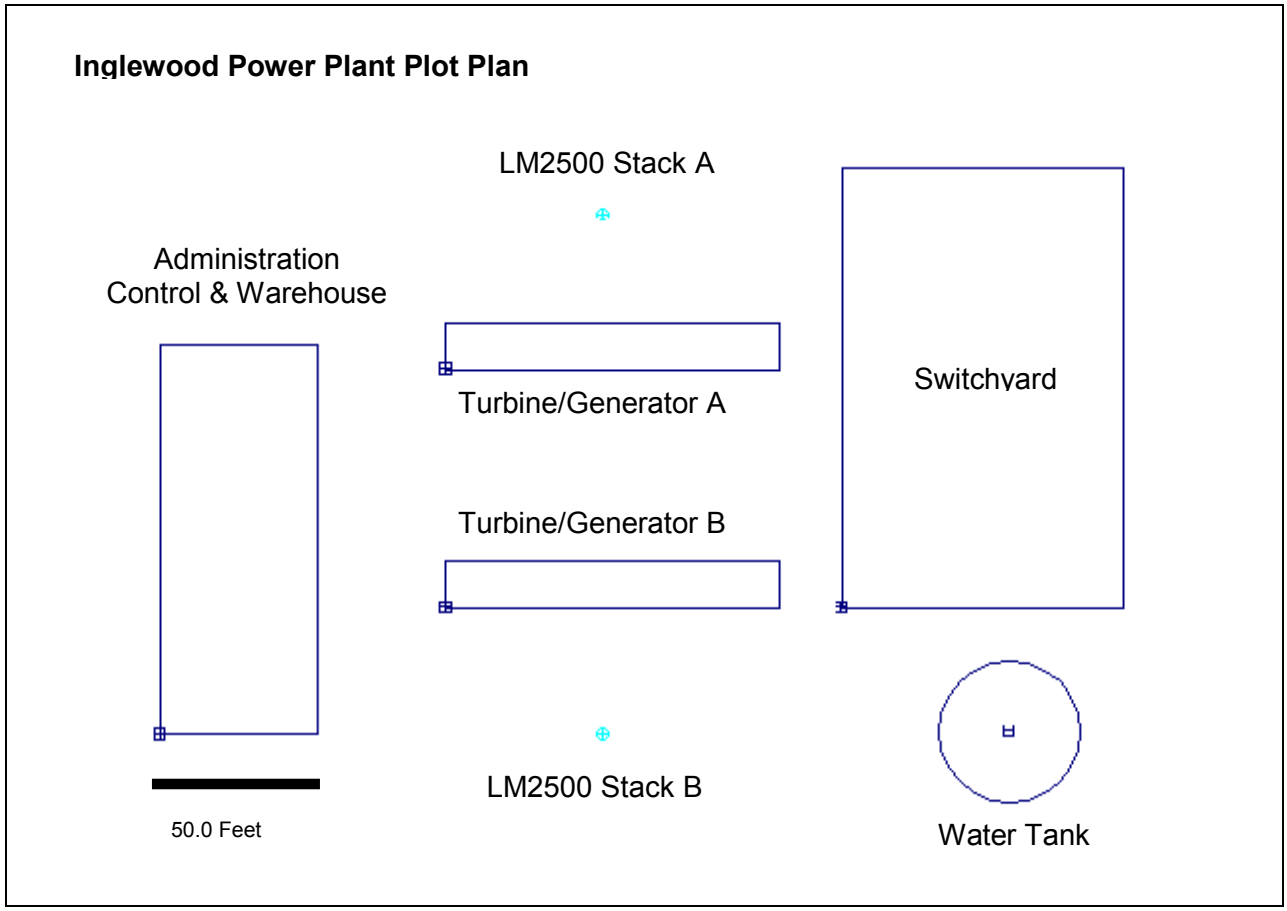

Figure 3-1 Facility Plot Plan

3.8.2 Source Input Parameters

Table 3-9 lists the controlled and uncontrolled release parameters for the two turbines.

Table 3-9 Release Parameters

Uncontrolled

ISCST3 Name	UTM E	UTM N	Stack Height (m)	Temperature (°K)	Exit Velocity (m/s)	Stack Diameter (m)
LM2500A	373405	3763508	21.3	783	26.57	2.7
LM2500B	373405	3763458	21.3	783	26.57	2.7

Controlled

ISCST3 Name	UTM E	UTM N	Stack Height (m)	Temperature (°K)	Exit Velocity (m/s)	Stack Diameter (m)
LM2500A	373405	3763508	21.3	459	17.80	2.7
LM2500B	373405	3763458	21.3	459	17.80	2.7

Table 3-10 lists the modeled controlled and uncontrolled emission rates for the two turbines.

Table 3-10 Modeled Emission Rates

Uncontrolled

ISCST3 Name	NO_x		CO	SO_2		PM_{10}	
	Max g/s	Annual g/s	Max g/s	Max G/s	Annual g/s	Max g/s	Annual g/s
LM2500A	2.47	0.30	2.64	0.029	0.002	0.21	0.03
LM2500B	2.47	0.30	2.64	0.029	0.002	0.21	0.03

Controlled

ISCST3 Name	NO_x		CO	SO_2		PM_{10}	
	Max g/s	Annual g/s	Max g/s	Max G/s	Annual g/s	Max g/s	Annual g/s
LM2500A	0.61	0.55	0.33	0.19	0.02	0.21	0.19
LM2500B	0.61	0.55	0.33	0.19	0.02	0.21	0.19

3.8.3 Receptor Grid

Receptor grid locations were determined based on SCAQMD guidance and screening modeling analysis. Each modeling scenario was completed with 500 meter receptor spacing from the property boundary out to a distance of ten kilometers. The location of maximum impact for each scenario was identified based on the screening model runs. A two kilometer by two kilometer square grid with 100 meter receptor spacing was then centered at the maximum impact point for each scenario. Receptors along the property boundary were placed at 100 meter intervals. Receptor spacing can be summarized as follows:

- 100 meters spacing along the property boundary;
- 100 meter spacing from the maximum impact location out two kilometers; and,
- 500 meter spacing from the property boundary out ten kilometers.

Figure 3-2 shows the facility source location and facility property boundary. Figure 3-3 shows the source location, facility property boundary and coarse (500 meter) receptor grid.

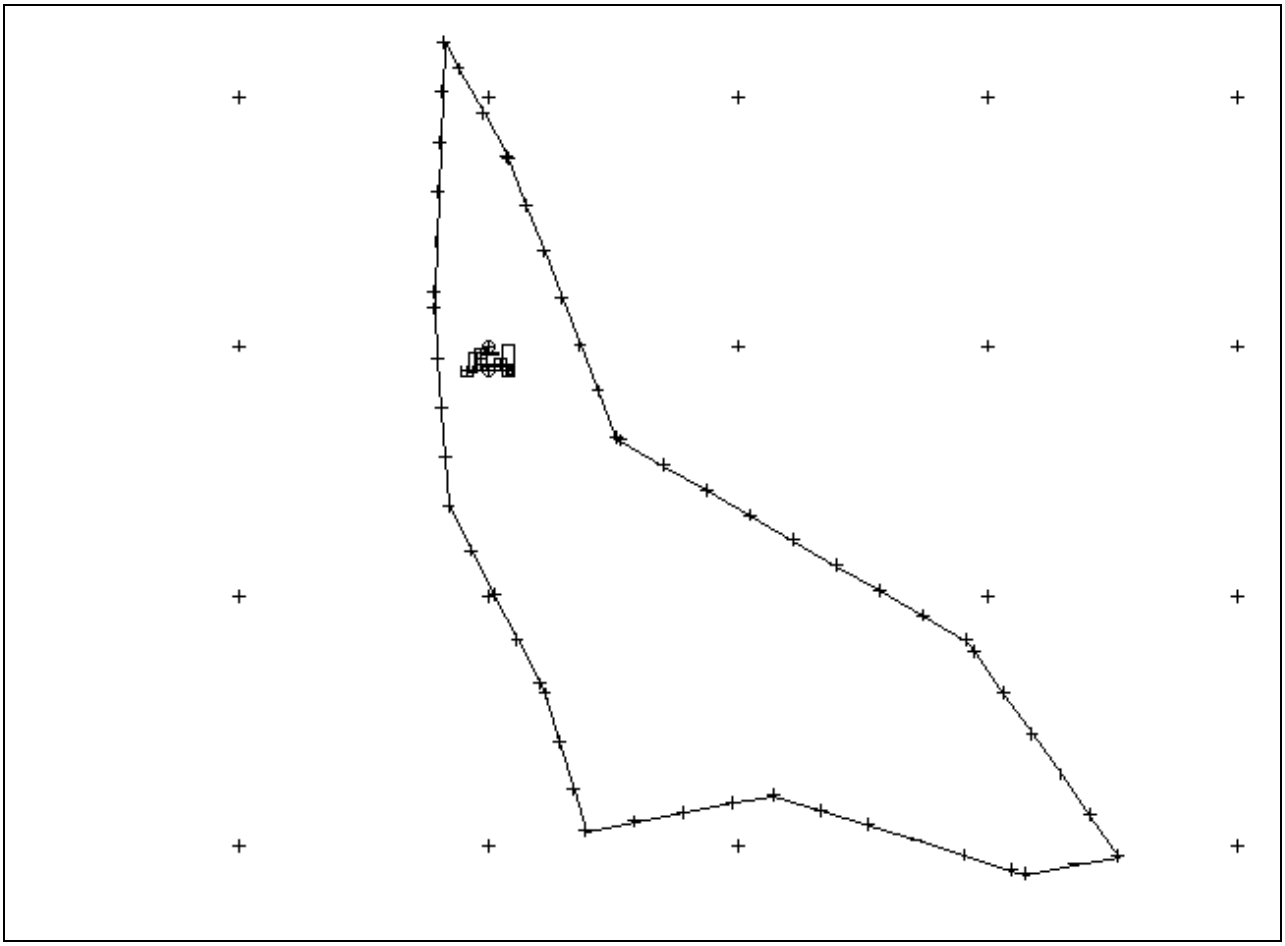

Figure 3-2 Facility and Property Boundary Receptors

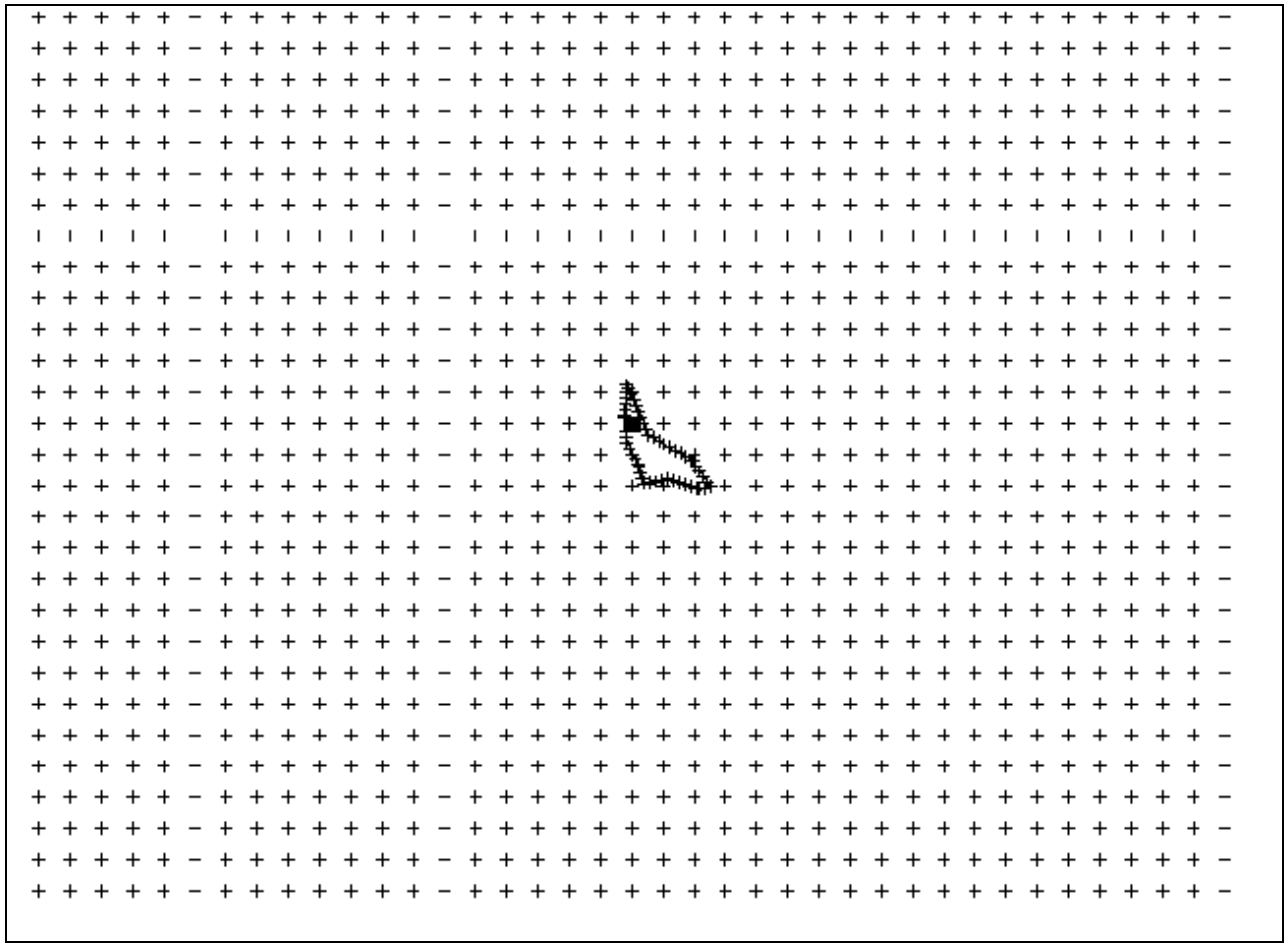

Figure 3-3 Facility Property Boundary and 500 Meter Receptor Grid

3.8.4 Meteorological Data

Meteorological data from the SCAQMD were used for this analysis. SCAQMD provides pre-processed meteorological data sets for dispersion modeling applications. Data from the West LA station (Surface station 52158 upper air station 91919) for the year 1981 were used as input to the ISCST3 model.

3.8.5 Results

Table 3-11 lists the air quality impact analysis results of controlled and uncontrolled emissions by pollutant. Appendix-B contains a zip file on disk of the modeling data.

Table 3-11 Air Quality Impact Analysis Results

Uncontrolled

Pollutant	Averaging Period	Maximum Modeled Concentration (ug/m^3)	SCAQMD Allowable Significance Levels (ug/m^3)	NAAQS (ug/m^3)	CAAQS (ug/m^3)
CO	1-hour	22.5	1100	40,000	23,000
CO	8-hour	15.2	500	10,000	10,000
SO_2	1-hour	0.17	--	--	650
SO_2	3-hour	0.16	--	1,300	--
SO_2	24-hour	0.06	--	365	109
SO_2	Annual	0.001	--	80	--
PM_{10}	24-hour	0.6	2.5	150	50
PM_{10}	Annual	0.02	1.0	50(2)	30(1)
NO_x	1-hour	19.1	20	--	470
NO_x	Annual	0.08(3)	1.0	100	--

1 Annual Arithmetic Mean
2 Annual Geometric Mean
3 NO_x annual average concentration reflects the NO_x/NO_2 conversion factor of 0.42.

Controlled

Pollutant	Averaging Period	Maximum Modeled Concentration (ug/m^3)	SCAQMD Allowable Significance Levels (ug/m^3)	NAAQS (ug/m^3)	CAAQS (ug/m^3)
CO	1-hour	7.2	1100	40,000	23,000
CO	8-hour	4.9	500	10,000	10,000
SO_2	1-hour	0.4	--	--	650
SO_2	3-hour	0.4	--	1,300	--
SO_2	24-hour	0.2	--	365	109
SO_2	Annual	0.04	--	80	--
PM_{10}	24-hour	1.6	2.5	150	50
PM_{10}	Annual	0.4	1.0	50(2)	30(1)
NO_x	1-hour	13.4	20	--	470
NO_x	Annual	0.46(3)	1.0	100	--

1 Annual Arithmetic Mean
2 Annual Geometric Mean
3 NO_x annual average concentration reflects the NO_x/NO_2 conversion factor of 0.42.

3.9 Protection of Visibility

Table 3-12 below lists identified Class I Areas that could be influenced by the proposed facility. These Class I Areas are listed in order of distance from the facility from the closest to the farthest.

Table 6: Class I Areas and Their Distance to the Proposed La Jolla Project

Class I Area	Distance in Kilometers
San Gabriel Wilderness	50
Cucamonga Wilderness	76
San Gorgonio Wilderness	154
Aqua Tibia Wilderness	268
San Jacinto Wilderness	310
Joshua Tree National Monument	352

As indicated in Table 3-12 above, the proposed facility will be located beyond the range of impacts to Federal Class I Areas as listed in Table C-1 of Rule 1303 (b)(5)(C). Therefore, no modeling analysis for plume visibility is required for this proposed project.

4.0 REGULATORY ANALYSIS

SCAQMD and Federal rules and regulations have been examined for relevance/applicability to this application. The following rules were found to have some significance regarding the permit application process of the proposed permit units.

4.1 REGULATION II - PERMITS

4.1.1 Rule 212, Standards For Approving Permits

Rule 212 specifies the standard requirements for a Permit to Construct (PTC) and Permit to Operate (PTO), including public notification requirements.

Analysis: The proposed project will not be located within 1000 feet from the outer boundary of a school, nor do estimated emissions exceed those stated in Rule 212(g). Additionally, the subject system does not potentially expose an individual to a cancer risk greater than, or equal to, one in 10 million for facilities with T-BACT installed. La Jolla in compliance with this rule.

4.2 Regulation III – Fees

4.2.1 Rule 301, Permit Fees

This rule identifies the fees that are applicable to permit modifications, new facilities, and permitted emissions.

Analysis: Review of the fee schedules identifies the fees in the Table 4-1 for processing of this application. La Jolla is in compliance with this rule.

Table 4-1. Permit Fees Payable

Equipment Description	Permit Processing Type	Schedule	Fee Amount
Gas Turbine (Unit 1)	Basic Equipment	D	$4,544.68
Gas Turbine (Unit 2)	Duplicate Equipment	D	$2,272.34
SCR	Control Equipment	C	$2,087.74
1 to 20 Unit Facility	Title V Processing Fee	--	$842.96
Total Permit Processing Fees:			$9,747.72

4.3 Regulation IV - Prohibitions

4.3.1 Rule 401, Visible Emissions

Rule 401 prohibits the discharge of any air contaminant from a single source for more than three (3) minutes in any one hour that produces visible emissions of specified opacity or shade (designated on the Ringlemann Chart).

Analysis: No visible emissions are expected with proper, normal operation of the turbines and the control equipment. La Jolla is in compliance with this rule.

4.3.2 Rule 402, Nuisance

Rule 402 prohibits the discharge from any source of any air contaminant that may cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public, or which endangers such persons or public, or which may cause injury or damage to business or property.

Analysis: No nuisance is expected with proper, normal operation of the turbines and control equipment. La Jolla is in compliance with this rule.

4.3.3 Rule 407, Liquid and Gaseous Air Contaminants

Rule 407 prohibits the discharge of carbon monoxide (CO) and sulfur compounds into the atmosphere at specified concentrations.

Analysis: The turbine installations will meet the CO emission limit of 2,000 ppm. The sulfur emission requirement does not apply per (c)(2) since the fuel complies with the gaseous fuel sulfur content limits of Rule 431.1 (see Section 4.3.5 below). La Jolla is in compliance with this rule.

4.3.4 Rule 409, Combustion Contaminants

Rule 409 specifies emission limits for equipment that is used to combust fuels. The combustion contaminant discharge limit for fuel burning equipment is 0.1 grains per cubic foot of flue gas calculated to 12% of carbon dioxide (CO_2) at standard conditions.

Analysis: Compliance with this rule is expected with proper, normal operation of the turbines. The turbines will fire natural gas exclusively, therefore only trace quantities of particulate matter are expected. La Jolla is in compliance with this rule.

4.3.5 Rule 431.1, Sulfur Content of Gaseous Fuels

Rule 431.1 specifies fuel sulfur content limits applicable to any person who burns gaseous fuels containing sulfur compounds. The rule's limit requirements are based on fuel type. The rule also provides test methods, monitoring, recordkeeping, and reporting requirements.

Analysis: Compliance with this rule is expected with usage of natural gas as fuel. The total sulfur compound concentration of this fuel is less than the rule's 16 ppmv limit for natural gas (calculated as hydrogen sulfide). La Jolla is in compliance with this rule.

4.3.6 Rule 475, Electric Power Generating Equipment

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. Requirements establish a limit for combustion contaminants (particulate matter) of 11

lbs/hr or 0.01 gr/scf. Compliance is achieved if either the mass limit or the concentration limit is met.

Analysis: La Jolla is in compliance with this rule.

4.4 REGULATION IX - STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Regulation IX incorporates and adopts by reference the provisions of 40 CFR 60 NSPS for affected sources where the construction or modification project commenced after the applicability date of each NSPS. Compliance with NSPS does not pre-empt compliance with more stringent local rules applicable to the source. Subpart GG applies to stationary gas turbines rated at 10 mmBTU/hr or larger and constructed, modified, or reconstructed after October 3, 1977 to comply with the provision of the rule unless specifically exempted by the rule. These subparts establish limits of particulate matter, SO_2 and NO_2 emissions from the facility, and their corresponding monitoring and testing requirements.

Analysis: This proposed power generating facility is subject to subpart GG because it was built after 1977. The project will be in compliance with the SO_2 and NO_2 emission limits listed in this subpart. La Jolla will install a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. La Jolla will be in compliance with this rule.

4.5 Regulation XI – Source Specific Standards

Rule 1134 applies to stationary gas turbines, which provide guidelines/requirements for controlling NO_x emissions. However, the proposed system is exempt from the requirements of this rule since this facility will be in the NO_x RECLAIM program under Regulation XX - RECLAIM. The RECLAIM program exempts facilities from complying with the NO_x requirements in certain rules as listed in Rule 2001, Table 1.

4.6 Regulation XIII – New Source Review (NSR)

SCAQMD regulates new sources that emit non-attainment pollutants. Non-attainment pollutants are those air contaminants that do not meet the National Ambient Air Quality Standards (NAAQS) or the California Ambient Air Quality Standards (CAAQS). Requirements for Best Available Control Technology (BACT), Air Quality Impact Analysis (AQIA), and emission offsets for non-attainment pollutants are the primary provisions of the SCAQMD NSR rules and regulations.

The South Coast Air Basin is a nonattainment region for ozone (O_3), carbon monoxide (CO), nitrogen dioxide (NO_2), sulfates, and fine particulate matter (PM_{10}). Precursors to non-attainment pollutants are also considered non-attainment for regulatory purposes of SCAQMD's review. Therefore, SCAQMD considers the following pollutants to be non-attainment:

- Reactive Organic Gases (ROG) as a precursor to O_3 and the organic fraction of suspended particulate matter.

- Oxides of nitrogen (NO_x) as a precursor to O_3, NO_2 and the nitrate fraction of suspended particulate matter.

- Sulfur oxides (SO_x) as a precursor to sulfur dioxide (SO_2), sulfates (SO_4) and the sulfate fraction of suspended particulate matter.

- Inorganic gases such as ammonia (NH_3), hydrogen fluoride (HF), and hydrogen chloride (HCl) as precursors to particulate matter.

Under NSR (Regulation XIII), Rule 1303 (Requirements), there are four specific requirements that apply to an applicable permit unit: 1) Installation of BACT (1303(a)); 2) modeling to substantiate that there will be no significant increase in an air quality concentration (1303(b)(1)); 3) obtaining emission offsets for the proposed increase in facility emissions (1303(b)(2)); and 4) facility compliance verification (1303 (b)(3)).

Analysis: This regulation applies to all new or modified existing permit units which may cause the issuance of any non-attainment air contaminant (or precursor), halogenated hydrocarbon, or ammonia. The proposed project is expected to have emissions of NO_x, CO, SO_x, ROG and PM_{10}. Please note that the RECLAIM program, under Regulation XX – RECLAIM, exempts RECLAIM facilities from complying with the NO_x requirements in Regulation XIII as listed in Rule 2001, Table 1 (see Section 4.9.1 for Rule 2005 RECLAIM NSR). Since the proposed project will be a RECLAIM facility, no Regulation. XIII requirements apply to this project.

La Jolla will comply with the four basic NSR requirements as follows:

- *Modeling:* The modeling results contained in Section 3.7 demonstrates that the facility emission impacts are below allowable significance levels.

- Protection of Visibility: The visibility impact analysis contained in Section 3.9 demonstrates that this project will have no adverse impacts on the protection of visibility.

- *Best Available Control Technology (BACT*): BACT requirements for this project are satisfied by the following:

- The SCR unit and oxidation catalyst installation will achieve NO_x emission level of 5 ppm, a CO emission level of 4 ppm, and a ROG emission level of 1.4 ppm.

- BACT is achieved for SO_X in the gas turbines through the use of utility-grade natural gas. Since these turbines will operate only on natural gas fuel, BACT for SO_X is achieved.

- Per South Coast AQMD BACT guidelines, BACT for PM_{10} in gas turbines (any size or application) is utility-grade natural gas. Since the turbines will operate only on natural gas fuel, BACT for PM_{10} is achieved.

- *Emission Offsets*: Offsets are required for CO, ROG, and PM_{10} and will be provided by emission reduction credits (e.g. RECLAIM, Provisional Bank, State Emergency Bank).

- *Facility Compliance:* Pursuant to Rule 1303 (b)(3) and Regulation II (Permits), La Jolla Energy Development, Inc. certifies to the best of their knowledge, all facilities owned or operated by La Jolla Energy Development, Inc. within the State of California are in compliance or on an approved schedule for compliance with applicable federal and state air quality emission limits and standards. La Jolla is in compliance with this rule.

4.7 Regulation XIV - Toxics

4.7.1 Rule 1401, New Source Review of Carcinogenic Air Contaminants

The SCAQMD regulates air toxic contaminants from new, modified or relocated permit units by specifying limits for the maximum individual cancer risk and excess cancer cases which may result from exposure to carcinogenic air contaminants from these sources.

Requirements for Best Available Control Technology for Toxics (T-BACT), maximum individual cancer risk (MICR), and risk assessment guidelines for toxic pollutants are the primary provisions of SCAQMD Rule 1401.

Analysis: The proposed project will not increase the amount of Rule 1401 toxic emissions. In addition, due to the facility's location and the amount of calculated increase in toxic emissions (rule definition: PTE minus actual reductions), no violation of Rule 1401 is anticipated. The health risk screening analysis presented in Section 5.0 documents this compliance. La Jolla is in compliance with this rule.

4.8 Regulation XVII – Prevention of Significant Deterioration

4.8.1 Rule 1703, PSD Analysis

The SCAQMD regulates in 1703(a)(2) that each permit unit is constructed using BACT for each criteria air contaminant for which there is federally significant net emission increase.

Analysis: SCAQMD is nonattainment for ozone and CO. However, the proposed project will not trigger any federally significant pollutant emission increases for fossil-fueled steam electric utility plants. La Jolla is in compliance with this rule.

4.9 Regulation XX – Regional Clean Air Incentives Market (RECLAIM)

The Regional Clean Air Incentives Market (RECLAIM) is a program designed to distribute emission allocations (or credits) for two primary non-attainment pollutants: oxides of nitrogen (NO_x) and oxides of sulfur (SO_x). A facility under the program may emit NO_x and/or SO_x only according to the amount of credits in the facility's possession. Facilities that emit more than 4 tons per year of NO_x or SO_x are automatically included in the program. Other facilities may opt into the RECLAIM program. Regulation XX sets specific NO_x and/or SO_x requirements for RECLAIM facilities and exempts the facilities from other NO_x and/or SO_x requirements in a number of command and control rules according to Tables 1 and 2 in Rule 2001.

Analysis: La Jolla will obtain a RECLAIM permit for the Baldwin facility as a RECLAIM NO_x facility per Rule 2001. La Jolla will comply with the requirements of Rule 2004 prior to and after the installation and operation of the proposed project. Additionally, La Jolla will comply with the monitoring, recordkeeping and reporting requirements for NO_x per Rule 2012. La Jolla is in compliance with this rule.

4.9.1 Rule 2005 – New Source Review for RECLAIM

Similar to Regulation XIII, Rule 2005 defines the pre-construction review requirements for new RECLAIM facilities and modifications to existing RECLAIM facilities. The requirements of Rule 2005 are virtually identical to Rule 1303, except for different offset NO_x requirements. NO_x emission increases must be below the facility's current RECLAIM Trading Credit (RTC) allocation or additional RTCs must be provided by the applicant. RECLAIM facilities have no Community Bank for NO_x. Compliance certification requirements are identical to Rule 1303.

Analysis: La Jolla will obtain sufficient RECLAIM, State, or Provisional Bank credits to offset the projected emissions from this new project. Therefore, La Jolla is in compliance with this rule.

4.9.2 Rule 2012 - Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NO_x) Emissions

This rule applies to any RECLAIM NO_x source or process unit. This rule requires the installation of a continuous emissions monitoring system (CEMS) with the following variables to be measured:

- Stack NO_x concentration;
- Stack O_2 concentration;
- Fuel flow rate; and
- Status codes.

Analysis: La Jolla will install a CEMS as required by this regulation, will submit a CEMS Plan for review and approval by the District, and will conduct the required initial source testing to certify the CEMS. Therefore, La Jolla is in compliance with this rule.

4.10 Regulation XXX – Federal Operating Permits (Title V, Part 70)

Regulation XXX administers the 40 CFR Part 70 Federal Permitting Program, established by Title V of the Clean Air Act Amendments, within SCAQMD's jurisdiction. This facility will be a Title V major source. Regulation XXX defines the permit application, issuance, and the compliance requirements of the program. This project will require La Jolla to submit a Title V permit application, and EPA Region IX review is required. Regulation XXX integrates the Title V permit with the RECLAIM permit.

Analysis: La Jolla has enclosed a Title V application as Appendix C.

5.0 RISK SCREENING ANALYSIS

5.1 Overview

SCAQMD Rule 1401 requires permit applicants to assess the cancer risks associated with the emissions of select toxic air contaminants (TACs)/carcinogens. The risk assessment procedures for determining the risks under this rule are defined in the July 1995 Version 2.1 "Risk Assessment Procedures for Rule 1401 and Rule 212."

The revised risk assessment procedures specify a top-down four-level tiered approach:

1. Screening Emission Levels;
2. Screening Risk Assessment Procedure;
3. Screening Dispersion Modeling; and
4. Detailed Risk Assessment.

Each of these methods is used to estimate the "worst case" maximum individual cancer risk (MICR) at the nearest residence and commercial/industrial receptor. The methods used to calculate carcinogenic risk are based on a "worst-plausible" situation and are health-conservative in nature. They predict the upper limits of risk, that is to say, the real risks are not expected to be any higher than the predicted numbers and may well be substantially lower, even approaching zero. Conservative estimates and the assumptions used in this risk screening are intended to ensure that the assessment does not underestimate facility impacts on the public.

5.2 Risk Screening Procedures and Results

The emissions from the two turbines are subject to risk screening analysis procedure, the SCAQMD's tiered approach was followed. Step 4, Detailed Risk Assessments was used to determine the maximum individual cancer risk (MCIR). The results of the detailed screening are presented in Appendix B, Air Quality Modeling. The results show that the turbine emissions will result in an estimated maximum individual cancer risk of less than 10 in one million for both residential and commercial/industrial exposures, as allowed by SCAQMD Rule 1401 provisions for T-BACT. For target organ systems, the increase in total chronic hazard index (HIC) and the total acute hazard index do not exceed 1.0 for any target organ system.

The cumulative cancer burden was calculated by multiplying the total population in the zone of impact by the MICR and it was determined to be 0.07. This value is less than the allowed 0.5 contained in Rules 212 and 1401.

Attachment A – Emissions Calculations

Attachment B – Air Quality Modeling

Attachment C – SCAQMD Application Forms

[400-A , 400-E-12, 400-XPP, & 400-CEQA]

ATTACHMENT D – TITLE V PERMIT APPLICATION FORMS