SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT	PAGES 82	PAGE 1
ENGINEERING DIVISION	APPL. NO. 432610-15	DATE 11/23/2010
APPLICATION PROCESSING AND CALCULATIONS	PROCESSED BY LI CHEN	CHECKED BY

PERMITS TO CONSTRUCT AND OPERATE

COMPANY NAME AND ADDRESS

Los Angeles Department of Water and Power
111 North Hope Street, Room 1050
Los Angeles, CA 90012

Contact: Bruce Moore (213) 367-0443

EQUIPMENT LOCATION

LA City, DWP Haynes Generation Station
6801 2nd Street
Long Beach, CA 90803
SCAQMD ID #800074

EQUIPMENT DESCRIPTION

Section H of the Facility Permit, ID# 800074, Permit to Construct and Temporary Permit to Operate:

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
Process 1: POWER GENERATION					
TURBINE, UNIT NO. 11, NATURAL GAS, GENERAL ELECTRIC, MODEL: LMS100PA, INTERCOOLED, WITH WATER INJECTION, 906.6 MMBTU/HR, WITH: A/N: 495664	D159	C161	NOx: Major Source	**NOx**: 2.5 PPMV (4) [RULE 2005, RULE 1703]; NOx: 96.94 LB/MMSCF COMMISSIONING (1) [RULE 2012]; NOx: 14.27 LB/MMSCF INTERIM (1) [RULE 2012]; NOx: 25 PPMV (8) NATURAL GAS [40CFR60 SUBPART KKKK]; **CO**: 4.0 PPMV (4) [RULE 1703 BACT]; CO: 2,000 PPMV (5) [RULE 407];	A63.4, A99.4, A99.5, A99.6 A195.8, A195.9, A195.10, A327.1, C1.4, C1.5, D29.6, D29.7, D82.3, D82.4, E193.6, E193.7, E193.8, E193.10, I296.2, K40.5, K67.6
GENERATOR, 102.7 MW @ 65 °F	B160				

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
Process 1: POWER GENERATION					
				VOC: 2 PPMV (4) [RULE 1303-BACT]; **PM**: 5.8 LBS/HR (4) [RULE 1303]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; SO_2: 0.9 lb/MW-hr (8A)[40CFR 60 SUBPART KKKK]; SO_2: (9)[40CFR 72 – ACID RAIN];	
OXIDATION CATALYST, BASF, MODEL: CAMET, 80 MODULES, CATALYST VOLUME: 160 FT^3; WITH: A/N: 495978	C161	D159, C162			
SELECTIVE CATALYTIC REDUCTION, CORMETECH, MODEL: CMHT-27, 12 MODLUES; CATALYST VOLUME: 1,211 FT^3; WITH: AMMONIA INJECTION A/N: 495978	C162 B163	C161, S164		NH_3: 5 PPMV (4) [RULE 1303-BACT]	D12.9, D12.10, D12.11, D29.8, E179.5, E179.6, E193.9
STACK, NO.11, SERVING UNIT 11, DIAMETER: 13.5 FT, HEIGHT: 150 FT, WITH: A/N: 495664	S164	C162			
TURBINE, UNIT NO. 12, NATURAL GAS, GENERAL ELECTRIC, MODEL: LMS100PA, INTERCOOLED, WITH WATER INJECTION, 906.6 MMBTU/HR, WITH: A/N: 495665	D165	C167	NOx: Major Source	**NOx**: 2.5 PPMV (4) [RULE 2005, RULE 1703]; NOx: 96.94 LB/MMSCF COMMISSIONING (1) [RULE 2012]; NOx: 14.27 LB/MMSCF INTERIM (1) [RULE 2012]; NOx: 25 PPMV (8) NATURAL GAS [40CFR60 SUBPART	A63.4, A99.4, A99.5, A99.6 A195.8, A195.9, A195.10, A327.1, C1.4, C1.5, D29.6, D29.7, D82.3, D82.4, E193.6,

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
Process 1: POWER GENERATION					
GENERATOR, 102.7 MW @ 65 °F	B166			KKKK]; **CO**: 4.0 PPMV (4) [RULE 1703 BACT]; CO: 2,000 PPMV (5) [RULE 407]; **VOC**: 2 PPMV (4) [RULE 1303-BACT]; **PM**: 5.8 LBS/HR (4) [RULE 1303]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; SO_2: 0.9 lb/MW-hr (8A)[40CFR 60 SUBPART KKKK]; SO_2: (9)[40CFR 72 – ACID RAIN];	E193.7, E193.8, E193.10, I296.2, K40.5, K67.6
OXIDATION CATALYST, BASF, MODEL: CAMET, 80 MODULES, CATALYST VOLUME: 160 FT^3; WITH: A/N: 495979	C167	D165, C168			
SELECTIVE CATALYTIC REDUCTION, CORMETECH, MODEL: CMHT-27, 12 MODLUES; CATALYST VOLUME: 1,211 FT^3; WITH: AMMONIA INJECTION A/N: 495979	C168 B169	C167, S170		NH3: 5 PPMV (4) [RULE 1303-BACT]	D12.9, D12.10, D12.11, D29.8, E179.5, E179.6, E193.9
STACK, NO.12, SERVING UNIT 12, DIAMETER: 13.5 FT, HEIGHT: 150 FT, WITH: A/N: 495665	S170	C168			
TURBINE, UNIT NO. 13,	D171	C173	NOx:	**NOx**: 2.5 PPMV (4)	A63.4, A99.4,

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
Process 1: POWER GENERATION					
NATURAL GAS, GENERAL ELECTRIC, MODEL: LMS100PA, INTERCOOLED, WITH WATER INJECTION, 906.6 MMBTU/HR, WITH: A/N: 495666 GENERATOR, 102.7 MW @ 65 °F	B172		Major Source	[RULE 2005, RULE 1703]; NOx: 96.94 LB/MMSCF COMMISSIONING (1) [RULE 2012]; NOx: 14.27 LB/MMSCF INTERIM (1) [RULE 2012]; NOx: 25 PPMV (8) NATURAL GAS [40CFR60 SUBPART KKKK]; **CO**: 4.0 PPMV (4) [RULE 1703 BACT]; CO: 2,000 PPMV (5) [RULE 407]; **VOC**: 2 PPMV (4) [RULE 1303-BACT]; **PM**: 5.8 LBS/HR (4) [RULE 1303]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; SO_2: 0.9 lb/MW-hr (8A)[40CFR 60 SUBPART KKKK]; SO_2: (9)[40CFR 72 – ACID RAIN];	A99.5, A99.6 A195.8, A195.9, A195.10, A327.1, C1.4, C1.5, D29.6, D29.7, D82.3, D82.4, E193.6, E193.7, E193.8, E193.10, I296.2, K40.5, K67.6
OXIDATION CATALYST, BASF, MODEL: CAMET, 80 MODULES, CATALYST VOLUME: 160 FT^3; WITH: A/N: 495980	C173	D171, C174			
SELECTIVE CATALYTIC REDUCTION, CORMETECH, MODEL: CMHT-27, 12 MODLUES; CATALYST VOLUME: 1,211 FT^3; WITH: AMMONIA INJECTION	C174 B175	C175, S176		NH3: 5 PPMV (4) [RULE 1303-BACT]	D12.9, D12.10, D12.11, D29.8, E179.5, E179.6, E193.9

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Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
Process 1: POWER GENERATION					
A/N: 495980					
STACK, NO.13, SERVING UNIT 13, DIAMETER: 13.5 FT, HEIGHT: 150 FT, WITH: A/N: 495666	S176	C174			
TURBINE, UNIT NO. 14, NATURAL GAS, GENERAL ELECTRIC, MODEL: LMS100PA, INTERCOOLED, WITH WATER INJECTION, 906.6 MMBTU/HR, WITH: A/N: 495667 GENERATOR, 102.7 MW @ 65 °F	D177 B178	C179	NOx: Major Source	**NOx**: 2.5 PPMV (4) [RULE 2005, RULE 1703]; NOx: 96.94 LB/MMSCF COMMISSIONING (1) [RULE 2012]; NOx: 14.27 LB/MMSCF INTERIM (1) [RULE 2012]; NOx: 25 PPMV (8) NATURAL GAS [40CFR60 SUBPART KKKK]; **CO**: 4.0 PPMV (4) [RULE 1703 BACT]; CO: 2,000 PPMV (5) [RULE 407]; **VOC**: 2 PPMV (4) [RULE 1303-BACT]; **PM**: 5.8 LBS/HR (4) [RULE 1303]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; SO_2: 0.9 lb/MW-hr (8A)[40CFR 60 SUBPART KKKK]; SO_2: (9)[40CFR 72 – ACID RAIN];	A63.4, A99.4, A99.5, A99.6 A195.8, A195.9, A195.10, A327.1, C1.4, C1.5, D29.6, D29.7, D82.3, D82.4, E193.6, E193.7, E193.8, E193.10, I296.2, K40.5, K67.6
OXIDATION CATALYST, BASF, MODEL: CAMET, 80 MODULES, CATALYST VOLUME: 160 FT^3; WITH: A/N: 495981	C179	D177, C180			
SELECTIVE CATALYTIC REDUCTION,	C180	C179, S182		NH3: 5 PPMV (4) [RULE 1303-BACT]	D12.9, D12.10,

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
Process 1: POWER GENERATION					
CORMETECH, MODEL: CMHT-27, 12 MODLUES; CATALYST VOLUME: 1,211 FT^3; WITH: AMMONIA INJECTION A/N: 495981	 B181				D12.11, D29.8, E179.5, E179.6, E193.9
STACK, NO.14, SERVING UNIT 14, DIAMETER: 13.5 FT, HEIGHT: 150 FT, WITH: A/N: 495667	S182	C180			
TURBINE, UNIT NO. 15, NATURAL GAS, GENERAL ELECTRIC, MODEL: LMS100PA, INTERCOOLED, WITH WATER INJECTION, 906.6 MMBTU/HR, WITH: A/N: 495668 GENERATOR, 102.7 MW @ 65 °F	D183 B184	C185	NOx: Major Source	**NOx**: 2.5 PPMV (4) [RULE 2005, RULE 1703]; NOx: 96.94 LB/MMSCF COMMISSIONING (1) [RULE 2012]; NOx: 14.27 LB/MMSCF INTERIM (1) [RULE 2012]; NOx: 25 PPMV (8) NATURAL GAS [40CFR60 SUBPART KKKK]; **CO**: 4.0 PPMV (4) [RULE 1703 BACT]; CO: 2,000 PPMV (5) [RULE 407]; **VOC**: 2 PPMV (4) [RULE 1303-BACT]; **PM**: 5.8 LBS/HR (4) [RULE 1303]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; SO_2: 0.9 lb/MW-hr (8A)[40CFR 60 SUBPART KKKK]; SO_2: (9)[40CFR 72 – ACID RAIN];	A63.4, A99.4, A99.5, A99.6 A195.8, A195.9, A195.10, A327.1, C1.4, C1.5, D29.6, D29.7, D82.3, D82.4, E193.6, E193.7, E193.8, E193.10, I296.2, K40.5, K67.6
OXIDATION CATALYST,	C185	D183,			

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
Process 1: POWER GENERATION					
BASF, MODEL: CAMET, 80 MODULES, CATALYST VOLUME: 160 FT^3; WITH: A/N: 495982		C186			
SELECTIVE CATALYTIC REDUCTION, CORMETECH, MODEL: CMHT-27, 12 MODLUES; CATALYST VOLUME: 1,211 FT^3; WITH: AMMONIA INJECTION A/N: 495982	C186 B187	C185, S188		NH3: 5 PPMV (4) [RULE 1303-BACT]	D12.9, D12.10, D12.11, D29.8, E179.5, E179.6, E193.9
STACK, NO.15, SERVING UNIT 15, DIAMETER: 13.5 FT, HEIGHT: 150 FT, WITH: A/N: 495668	S188	C186			
TURBINE, UNIT NO. 16, NATURAL GAS, GENERAL ELECTRIC, MODEL: LMS100PA, INTERCOOLED, WITH WATER INJECTION, 906.6 MMBTU/HR, WITH: A/N: 495669 GENERATOR, 102.7 MW @ 65 °F	D189 B190	C191	NOx: Major Source	NOx: 2.5 PPMV (4) [RULE 2005, RULE 1703]; NOx: 96.94 LB/MMSCF COMMISSIONING (1) [RULE 2012]; NOx: 14.27 LB/MMSCF INTERIM (1) [RULE 2012]; NOx: 25 PPMV (8) NATURAL GAS [40CFR60 SUBPART KKKK]; CO: 4.0 PPMV (4) [RULE 1703 BACT]; CO: 2,000 PPMV (5) [RULE 407]; VOC: 2 PPMV (4) [RULE 1303-BACT]; PM: 5.8 LBS/HR (4) [RULE 1303]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF	A63.4, A99.4, A99.5, A99.6 A195.8, A195.9, A195.10, A327.1, C1.4, C1.5, D29.6, D29.7, D82.3, D82.4, E193.6, E193.7, E193.8, E193.10, I296.2, K40.5, K67.6

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
Process 1: POWER GENERATION					
				(5A) [RULE 475]; SO_2: 0.9 lb/MW-hr (8A)[40CFR 60 SUBPART KKKK]; SO_2: (9)[40CFR 72 – ACID RAIN];	
OXIDATION CATALYST, BASF, MODEL: CAMET, 80 MODULES, CATALYST VOLUME: 160 FT^3; WITH: A/N: 495983	C191	D189, C192			
SELECTIVE CATALYTIC REDUCTION, CORMETECH, MODEL: CMHT-27, 12 MODLUES; CATALYST VOLUME: 1,211 FT^3; WITH: AMMONIA INJECTION A/N: 495983	C192 B193	C191, S194		NH3: 5 PPMV (4) [RULE 1303-BACT]	D12.9, D12.10, D12.11, D29.8, E179.5, E179.6, E193.9
STACK, NO.16, SERVING UNIT 11, DIAMETER: 13.5 FT, HEIGHT: 150 FT, WITH: A/N: 495669	S194	C192			
IC ENGINE, EMERGENCY #1, CATERPILLAR, DIESEL, MODEL 3516C DITA, 3,622 HP, LEAN BURN, TURBOCHARGED, WITH A JOHNSON MATTHEY CRT PARTICULATE FILTER, WITH: A/N: 495670 GENERATOR: 2.5 MW	D195		NOx: LARGE UNIT	**NOx**: 3.7 G/BHP-HR (4) [RULE 2005, RULE 1703]; NOx: 270 LB/1000 GAL (1) [RULE 2012]; **CO**: 0.67 G/BHP-HR (4) [RULE 1303]; **VOC**: 0.25 G/BHP-HR (4) [RULE 1303] **PM10**: 0.007 G/BHP-HR (4) [RULE 1303]	D12.12, D12.13, E116.2, E448.1, E448.2, I296.3, K67.7
IC ENGINE, EMERGENCY #12, CATERPILLAR,	D196		NOx: LARGE	**NOx**: 3.7 G/BHP-HR (4) [RULE 2005, RULE 1703];	D12.12, D12.13,

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
PROCESS 1: POWER GENERATION					
DIESEL, MODEL 3516C DITA, 3,622 HP, LEAN BURN, TURBOCHARGED, WITH A JOHNSON MATTHEY CRT PARTICULATE FILTER, WITH: A/N: 495671 GENERATOR: 2.5 MW			UNIT	NOx: 270 LB/1000 GAL (1) [RULE 2012]; **CO**: 0.67 G/BHP-HR (4) [RULE 1303]; **VOC**: 0.25 G/BHP-HR (4) [RULE 1303] **PM10**: 0.007 G/BHP-HR (4) [RULE 1303]	E116.2, E448.1, E448.2, I296.3, K67.7
TANK, DIESEL STORAGE, VOLUME: 15,000 GAL; DIA: 10 FT, LEN: 25.5 FT, WITH: A/N:495672	D197				
OIL/WATER SEPARATOR, #1, HIGHLAND, MODEL: HTJ2000, VOL: 2000 GAL, FLOWRATE: 200 GPM, WITH: A/N: 495673	D198				
OIL/WATER SEPARATOR, #1, HIGHLAND, MODEL: HTJ2000, VOL: 2000 GAL, FLOWRATE: 200 GPM, WITH: A/N: 495674	D199				
OIL/WATER SEPARATOR, #1, HIGHLAND, MODEL: HTJ2000, VOL: 2000 GAL, FLOWRATE: 200 GPM, WITH: A/N: 495675	D200				

BACKGROUND

The Los Angeles Department of Water and Power (LADWP) operates the Haynes Generation Station (HnGS) located in Long Beach. The HnGS is a 122-acre electric power generating facility designed to provide electricity to the LADWP distribution grid. The HnGS has been in operation since 1962. In 2000 it had six utility boiler generators with a combined gross output of 1,606 MW and a total net output of 1,570 MW. The boiler generators were capable of firing with both fuel oil and natural gas.

Starting in 2001 the HnGS embarked on a mission to upgrade and re-power the facility. In 2002 and as the first step it installed two combined cycle gas turbine generators and retired Boilers 3 and 4. In addition, as a part of the Settlement Agreement between the LADWP and SCAQMD dated May 28, 2003 the LADWP is required to obsolete the existing Boilers 5 and 6 by December 31, 2013. It was agreed that LADWP is to replace the boiler generators with clean and efficient power generators. In 2006 LADWP had proposed to install new combined cycle gas turbine generators. However, the proposal was withdrawn due to the concerns with cooling tower water issues. The LADWP is now proposing to upgrade the HnGS by replacing Boilers 5 and 6 with a new simple cycle generating system (SCGS). The SCGS will consist of six General Electric (GE) LMS100 combustion turbines, and six electric generators. The combustion turbine and generator are interconnected and are referred to as a combustion turbine generator (CTG) set.

The current maximum combined electric power rating of Boilers 5 and 6 is 604 MW (gross output; 343 MW for Boiler 5 & 261 MW for Boiler 6) while the gross power output of the SCGS will be 616.2 MW at an annual average temperature of 65°F. Thus, there would be an increase of 12.2 MW gross output after the upgrade. The net power output of the SCGS will be 600 MW at an annual average temperature of 65°F. The new units will require connection to the existing liquid discharge system and installation of ancillary equipment such as electric transformers and switching equipment. Since the net increase in megawatts is less than 50 MW LADWP, this project does not require review and approval from the California Energy Commission (CEC).

The SCGS will include air pollution control equipment. On the front end the SCGS will rely on the use of water injection to reduce the NOx emissions to 25 ppmv at 15% O_2, 1 hour average. On the back end a selective catalytic reduction (SCR) system will be used to further reduce NO_X emissions to 2.5 ppmv at 15% O_2, 1 hour average. The SCR injects aqueous ammonia at a given temperature window to react with the combustion exhaust, thus converting NOx to nitrogen. The HnGS has existing ammonia storage tanks and does not plan to build new ammonia storage tanks. The SCGS will also install an oxidation catalyst that reduces CO and VOC emissions. Each CTG will also include a weatherproof, acoustic (i.e., sound-dampening) enclosure with separate compartments for the turbine and generator.

The six new CTGs will be labeled as Units 11 to 16. The replaced boilers will remain in place. However, in accordance with Rules1303 and 1313 LADWP will take the units out of service and surrender the permits within 90 calendar days after the initial startup of the SCGS.

The following table is a summary of the applications submitted by the LADWP.

Table 1 Application Numbers

Applications	Description	Fees
495664	Gas turbine generator Unit 11 - GE	$15,272.72
495665	Gas turbine generator Unit 12 - GE	$7,636.36
495666	Gas turbine generator Unit 13 - GE	$7,636.36
495667	Gas turbine generator Unit 14 - GE	$7,636.36
495668	Gas turbine generator Unit 15 - GE	$7,636.36
495669	Gas turbine generator Unit 16 - GE	$7,636.36
495670	Standby diesel IC engine generator #1	$2,051.52
495671	Standby diesel IC engine generator #2	$1,025.76
495672	Diesel Storage Tank	$1,287.22
495673	Waste oil/water separator #1	$3,244.91
495674	Waste oil/water separator #2	$1,622.46
495675	Waste oil/water separator #3	$1,622.46
495978	SCR for Gas Turbine Generator #11	$3,244.91
495980	SCR for Gas Turbine Generator #12	$1,622.46
495988	SCR for Gas Turbine Generator #13	$1,622.46
495989	SCR for Gas Turbine Generator #14	$1,622.46
495990	SCR for Gas Turbine Generator #15	$1,622.46
495991	SCR for Gas Turbine Generator #16	$1,622.46
Total Base Fee		$75,666.06
50% fee of expedite permit processing		$37,833.03
495663	Facility title V permit significant revision	$1,687.63
Total Permit Processing Fee		$115,186.72

LADWP Haynes Generation Station is a federal Title V and Acid Rain facility. It also participates in the NOx RECLAIM program (Cycle 1). The facility is currently complying with all federal, state, and local rules and regulations.

The applications were received by the AQMD on February 13, 2009. They were deemed complete on March 10, 2009. The applicant requested expedite permit processing of the applications, and paid the 50% additional fee per Rule 301(v).

PROCESS DESCRIPTION

1. COMBUSTION TURBINE GENERATORS (CTG)

As shown in the process schematic of Figure 1 combustion air is supplied to the CTG through an inlet air filter and associated inlet air ductwork. Evaporative coolers are placed at the air inlet and are turned on during hot weather to improve cycle efficiency. Downstream of the air-cooling section, the air will be compressed in the low pressure compressor, sent to the intercooler and then back to the high pressure compressor. The intercooler lowers the air temperature and improves CTG performance. The compressed air joins the pre-heated and compressed natural gas, supplied through the fuel compressor, in the combustor and starts the combustion process. The high-temperature, high-pressure gas mixture produced in the combustor expands through the turbine blades, driving the turbine, the electric generator, and the compressor. The exhaust and the intercooler will be cooled by a dry cooling tower system that will utilize fans to reject the heat to the atmosphere. A closed loop water system will be used to transfer the heat from the intercooler to the dry cooling towers.

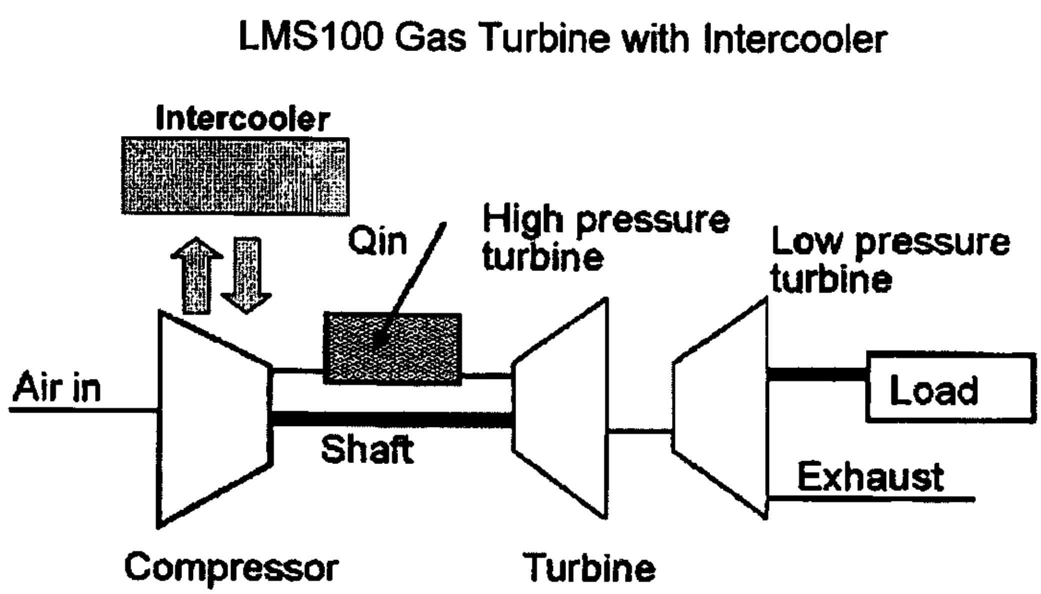

Figure 1 LMS100 Simple Cycle Gas Turbine

Table 2 lists the key parameters of the CTG.

Table 2 Gas Turbine Generators Specifications

PARAMETERS	SPECIFICATIONS
CTG Manufacturer	General Electric
Model	LMS100PA
Fuel Type	Pipeline Natural Gas
Maximum Fuel Consumption, Natural Gas	0.903 MMscf/hr @ 65°F
Combustion Turbine Heat Input	816.8 MMBtu/hr @ 65°F (LHV), 906.6 MMBtu/hr @ 65°F (HHV)
Maximum CTG Output	102.7 MW@ 65°F
Gross CTG Heat Rate, LHV	7,957 Btu/kWh@ 65°F
Gross CTG Heat Rate, HHV	8,832 Btu/kWh @ 65°F
NO_x Combustion Control, Natural Gas	Water Injection
Ammonia Injection Rate	250.6 lb/hr at full load @65°F
Post Combustion Control	SCR and CO Catalyst
SO_2 to SO_3 Conversion Rate (due to SCR and CO catalysts)	48%
Maximum Stack Exhaust Flow	1.72 MMlb/hr @ 65°F
Net Plant Heat Rate, LHV	8,279 Btu/kWh @ 65°F
Net Plant Heat Rate, HHV	9,190Btu/kWh @ 65°F
Net Plant Efficiency	41%@ 65°F (LHV)

2. AUXILIARY DEVICES

Selective Catalytic Reduction (SCR)

SCR is a post-combustion control technology to reduce NOx emissions. At a given temperature window and with the presence of a specific catalyst ammonia reacts with nitride oxides of the combustion flue gas. The reaction converts NOx into nitrogen and lowers NOx emissions. A

SCR system includes ammonia vaporization and injection equipment, a booster fan for the flue gas, an SCR reactor with catalyst, and instrumentation and control equipment. The SCGS will use six SCR systems, one for each CTG. The facility will use the existing ammonia storage tanks to provide aqueous ammonia.

The SCR catalyst will be manufactured by Cormetech, or equivalent. The SCR catalyst will be operating within an optimal temperature window of approximately 740°F to 840°F to facilitate a heterogeneous reaction between NO_X and ammonia (NH_3). The catalyst in each SCR is expected to be vanadium based on a titanium support matrix. The Cormetech SCR will carry a five-year warranty. After that it is anticipated that the SCR catalyst will be returned to the vendor for reprocessing.

The emission guarantee is 2.5 ppmvd NO_X at 15% O_2 when firing natural gas for 20,000 hours operation, with 5 ppmvd NH_3 slip at 15% O_2 at dry conditions. Additional details of the SCR system will be provided after the SCR vendor and specifications are finalized. The LADWP will ensure that the SCR catalyst system meets the NO_X emission guarantee of 2.5 ppmvd at 15% O_2.

The next table is a summary of the SCR specifications.

Table 3 Selective Catalyst Data Summary

PARAMETERS	SPECIFICATIONS
Catalyst Manufacturer	Cormetech, Inc.
Catalyst Description	Titanium-Vanadium-Tungsten (Ti-V-W)
Catalyst Model	CMHT-27
Catalyst Volume	1,211 ft^3
Catalyst Dimension (each module)	1'8" X 10'10" X 5'6"
Number of modules	12
Space Velocity (typical)	31,449 hr^{-1}
Ammonia Injection Rate	164 lb/hr
Ammonia Slip	5 ppmvd NH_3 at 15% O_2 1 hour average
Outlet NOx	2.5 ppmvd NOx at 15% O_2 1 hour average
Catalyst Life	5 years

CO Oxidation Catalyst

The internal combustion control of the CTGs will reduce the carbon monoxide emissions to 93 ppmvd at 15% oxygen and VOC emissions to 4.4 ppmvd at 15% oxygen. The CO oxidation catalyst is a post-combustion control technology to reduce CO and VOC emissions. Each CTG will be equipped with an oxidation catalyst, which will be placed immediately after the CTG. The CO oxidation catalyst will be manufactured by BASF or equivalent. The CO emission guarantee is 4.0 ppmvd at 15% O_2 (1-hr average). The VOC emission guarantee is 2 ppmvd at 15% O_2 (1-hour average). Additional details of the oxidation catalyst system will be provided after the oxidation catalyst vendor has been selected. The LADWP will ensure that the oxidation catalyst system meets the CO and VOC emission guarantees listed above.

Table 4 CO Oxidation Catalyst Data Summary

PARAMETER	SPECIFICATION
Manufacturer	BASF
Catalyst Type	Pt on Al single layer metal monolith
Catalyst Model	Camet
Catalyst Dimension (each module)	3.135" X 2' X 2'1.5"
Number of modules	80
Catalyst Volume (typical)	160 ft^3
Outlet CO (typical)	4 ppmvd (1-hr average) at 15%O_2
Outlet VOC (typical)	2 ppmvd (1-hr average) at 15% O_2
Minimum Operating Temp (typical)	500° F
Maximum Operating Temp (typical)	1250° F
Catalyst Life	5 years

Ammonia Injection Grid and Storage

Aqueous ammonia (ammonium hydroxide at 29.5 percent nominal concentration by weight) is currently used in SCRs to reduce NO_X emissions for HnGS Units 1, 2, 5, 6, 9 and 10 and will also be used for the new units, Unit 11 through 16. The ammonia will continue to be delivered to the site by truck and stored at the site's existing aqueous ammonia tank facility. Existing ammonia storage consists of six cylindrical aboveground storage tanks, with a total capacity of

225,000 gallons (37,500 gallons in each tank). No new ammonia storage is required for the new units.

The vaporized ammonia will be diluted with air and injected into the gas stream through nozzles for NO_X control. The amount of ammonia introduced into the system will vary depending upon NO_X reduction requirements, but will be approximately a 1:1 molar ratio of ammonia to NO_X. Expected maximum ammonia use is about 33.4 gallons per hour (250.6 lbs/hr/7.5 lbs/gal) per CTG system. At an expected average annual CTG capacity factor of 60%, estimated SCGS annual aqueous ammonia use for all six new CTGs would be 1,053,302 gallons (33.4 x 24 x 365 x 0.6 x 6).

Oil Water Separator

Three new oil water separator (OWS) will be installed to serve the new units. The OWS will collect potentially oily wastewater from equipment area wash downs and the boiler feed water pump skid. The only potential oil contaminant is lubricating oil associated with the gas turbines and associated feed water pumps. Oil will collect in the OWS and will be removed by vacuum truck prior to the oil collection section of OWS reaching capacity. The proposed OWS will have a capacity of 2,000 gallons and handle a maximum flow rate of 200 gallons per minute.

Table 5 Oil/Water Separator Information

PARAMETER	SPECIFICATIONS
Make and Model	Highland Model HT 2000 or Equivalent
Capacity	Separator: 2,000 gallons Spill Capacity: 1,000 gallons
Maximum Flow Rate	200 GPM
Dimensions	5-ft 4-in diameter by 15-ft-3-in long
Expected Flow Rates	Normally No Flow
Vapor Pressure of Oil	<0.01 mm Hg at 20°F
Oil Concentration in Wastewater	0-10%
Performance	10 ppm or less free oil effluent

Emergency Generators

Two diesel fuel operated emergency power generators will be installed that would allow the gas turbines to shut down safely and maintain critical systems during emergencies. The power rating of each standby power generator will be 3,622 brake horsepower. Each engine will drive a 2.5 MW electric generator. These engines will be tested for one hour every week. The specifications of this engine are provided in the Table 6.

Table 6 Emergency Generator Specifications

PARAMETER	SPECIFICATIONS
Manufacturer	Caterpillar
Model No.	3516C DITA
Rated Power	3,622 bhp (2,500 kW) at 1,800 rpm
Engine Design	Lean Burn, 4 stroke, water-cooled
Rated Fuel Consumption	173.3 gallons per hour
Number of Cylinders	16
Expected Hours of Operation	12 hr/yr (emission calculations are performed for 50 hrs/yr)
Type of Fuel	No. 2 Diesel, 15 ppmw sulfur content by weight
Stack Temperature	921.9 °F
Stack Flow	19,048.7 ACFM
Stack Height	18 ft
Stack Diameter	20-inch
Aspiration	Turbocharged and aftercooled
Particulate Filter	Johnson Matthey CRT(+)16-BITO-CS-28-RT

Based on the emission characteristics provided in the next table this diesel engine complies with EPA Tier II emission standards. The particulate filter is installed so that the unit will meet the federal LAER requirement. The emission profile of the engine is provided in the next table.

Table 7 Emergency Generator Emissions Specifications

PARAMETER	SPECIFICATIONS (gram/bhp-hr)
NOx	3.7
CO	0.67
Hydrocarbon	0.25
PM10	0.007
SOx	0.2158 lb/1,000 gallons

Diesel Fuel Storage

A fixed roof, above ground, horizontal storage tank will be installed at the SCGS for storing diesel fuel for the standby power generators. The storage capacity of the diesel tank will be 15,000 gallons. The dimensions of the diesel fuel storage tank will be: diameter 10 ft and length 25.5 ft.

Stacks

Each CTG and SCR catalyst group will be equipped with a 150-foot tall, 13.5-foot diameter (inside diameter) stack. In addition to the stack, catalyst frames and ductwork will be required for the simple cycle operation. The base elevation for the stacks is approximately at sea level.

COMPLIANCE HISTORY

A review of the facility's compliance history in the last five years shows the following violations of permit conditions. A review of the facility's compliance history in the last five years shows the following violations of permit conditions. Most of these violations were resulting from the equipment breakdown. However, LADWP did not report the breakdown within the deadlines specified in AQMD rules.

- Notice of Violation (NOV) #P51112 was issued on December 18, 2007 for exceeding the NOx concentration limit of D125, gas turbine Unit 9. The violation occurred on November 29, 2007. The NOV was closed out on July 23, 2008.
- Notice of Violation (NOV) #P51113 was issued on January 3, 2008 for exceeding the NOx and CO concentration limit of D134, gas turbine Unit 10. The violation occurred on December 5, 2007. The NOV is closed on July 23, 2008.

- Notice of Violation (NOV) #P11116 was issued on February 8, 2008 for exceeding the NOx concentration limit of D134, gas turbine Unit 10. The violation occurred on January 9, 2008. The NOV was closed out on July 23, 2008.
- Notice of Violation (NOV) #P11117 was issued on February 13, 2008 for exceeding the NOx concentration limit of D125, gas turbine Unit 9. The violation occurred on January 30, 2008. The NOV was closed out on July 23, 2008.
- Notice of Violation (NOV) #P11124 was issued on September 24, 2009 for failure to conduct a Relative Accuracy Test Audit for D4, boiler #2. The NOV was closed out on April 23, 2010.

EMISSIONS

Emissions from the SCGS comprise primarily emissions from the combustion turbine generators (CTG). The CTGs have several distinct operating modes when the emission characteristics are drastically different. The six operating modes are:

Table 8 Operating Modes of the CTG

Operating Mode	Description
Commissioning	This is the period when the gas turbine conducts test runs in order to reach optimal operating conditions. GE has a specific commissioning sequence that LADWP plans to follow. A detailed description of the step by step process and the emissions calculations are included in Appendix A.
Normal Operating	This is the process designed for power generation. BACT limits apply: NOx < 2.5 ppmv, CO < 4.0 ppmv, and VOC < 2.0 ppmv. Use of natural gas is required for PM10 and SOx control.
Startup	The process of bringing the CTG to designated operating mode. A startup may take up to 25 minutes. Emissions of this process are higher than normal operation and are not expected to meet BACT concentration limits. Startup conditions are placed on the turbine to ensure that emissions are minimized during this period.
Shutdown	The process of turning the CTG off. The process typically takes 10 minutes. During the process ammonia injection to the SCR will be turned off. The oxidation catalyst continues to work. The emissions are not expected to meet the BACT limits.

Emissions from each operating mode are determined in Appendix A. For potential to emit determinations the worst emitting operating conditions are assumed. For the gas turbine generators the worst emitting operating conditions are 100% capacity, 65° F ambient temperature.

1. MONTHLY TOTAL EMISSIONS – NORMAL OPERATION

The monthly total emissions of criteria pollutants NOx, CO, VOC, PM10 and SOx during normal operation are determined by assuming the following monthly operating schedule. One calendar month is assumed to have 31 days.

22 days continuous operation at full load that includes 6 startups and 6 shutdowns per day
9 days operating for 8 hours per day and with 2 startups and 2 shutdowns.

The total emissions are calculated in Appendix A, Table A-4 and are tabulated in the next table:

Table 9 Monthly Total Emissions – Normal Operation Each Turbine

	NOx	CO	VOC	PM10	SOx
Startups– 150 events (lbs)	3,000	2,384	645	275	8
Shutdowns – 150 events (lbs)	450	5,250	450	33	3
Regular Operation – 523 hours (lbs)	4,231	4,121	1,177	3,033	79
Monthly total (lbs)	7,681	11,755	2,272	3,341	90

The monthly total emissions per turbine will be enforced in Condition A63.4.

2. MONTHLY TOTAL EMISSIONS – NORMAL OPERATIONS + COMMISSIONING

During the gas turbine commissioning process the monthly total emissions of criteria pollutants NOx, CO, VOC, PM10 and SOx are determined by assuming the following monthly operating schedule. One calendar month is assumed to have 31 days.

12 days of commissioning process
19 days continuous operation at full load that includes 6 startups and 6 shutdowns per day

The total emissions are calculated in Appendix A, Table A-17 and are tabulated in the next table:

Table 10 Monthly Total Emissions – Normal Operation + Commissioning, Each Turbine

	NOx	CO	VOC	PM10	SOx
Commissioning – 12 days	7,760	16,482	917	549	39
Regular Operation – startups (19 days)	2,280	1,811	490	209	6
Regular Operation – shutdowns (19 days)	342	3,990	342	25	2
Regular Operation – 100% load (19 days)	3,151	3,069	877	2,259	59
Monthly Total	13,533	25,352	2,626	3,042	106

3. NOx ANNUAL EMISSIONS

For RECLAIM purposes it is necessary to determine NOx annual emissions. The first year NOx emissions are different from the following years due to the commissioning process. The first year and the subsequent years have been calculated in Appendix C.4 & C,5. The following is a summary of the emissions:

Each Turbine, first year:	68,120 lbs (from Appendix C.4, Table C-4)
Each Turbine, subsequent year:	61,784 lbs (from Appendix C.4, Table C-5)
Each Diesel Engine:	1,478 lbs (from Appendix C.5)

4. EMISSIONS OF TOXIC AIR CONTAMINANTS

Toxic air contaminants (TAC) are generated primarily from natural gas combustion by the CTGs. TAC emissions from CTG normal operation are determined by using the emission factors of AP-42. Maximum annual emissions are calculated by assuming 8,760 hours of operation per year. The detailed calculations of the TAC are provided by LADWP in Appendix A.11 of the Application for Permit to Construct and Operate Units 11 through 16 Haynes Simple Cycle Generating System. The following table is the summary.

Table 11 TAC emissions from CTG (each unit)

Toxic Air Contaminant(s)	Yearly Emissions (lbs/yr)	Yearly Emissions (tons/yr)
Ammonia	5.26E+04	2.63E+01
1,3-Butadiene	3.50E+00	1.75E-03
Acetaldehyde	3.18E+02	1.59E-01
Acrolein	2.89E+01	1.45E-02
Benzene	2.63E+01	1.31E-02
Ethylbenzene	2.54E+02	1.27E-01
Formaldehyde	2.86E+03	1.43E+00
Propylene Oxide	2.30E+02	1.15E-01
Toluene	1.03E+03	5.16E-01
Xylenes	5.08E+02	2.54E-01
Benzo(a)pyrene	1.10E-01	5.50E-05
Benzo(b)fluoranthene	9.00E-02	4.50E-05
Benzo(k)fluoranthene	9.00E-02	4.50E-05
Chrysene	2.00E-01	1.00E-04
Diebenz(a,h)anthracene	1.90E-01	9.50E-05
Indeno(1,2,3-cd)pyrene	1.90E-01	9.50E-05
Naphthalene	1.31E+01	6.57E-03

TAC emissions from the CTGs will be used in the detailed air quality modeling analysis for determination of compliance with AQMD Rule 1401.

RULES EVALUATION

California Environmental Quality Act (CEQA)
An Environmental Impact Report (EIR) has been prepared for this project. LADWP is the lead agency. The draft EIR was released on January 28, 2010. A copy of the draft was provided to AQMD for comments. AQMD provided written comments on March 12, 2010. AQMD commented on the issues of air quality modeling, health risk assessment, contaminated soils, and emergency diesel IC engines. The comments were addressed by LADWP in the final EIR that was released in April 2010. The state clearinghouse number is 2005061111. The final EIR was certified on May 4, 2010.

As a part of the CEQA certification conditions, the two emergency IC engines shall not be tested at the same time, or during the gas turbine commissioning period. This condition will be added to the diesel engines.

40CFR Part 51 Subpart Z Appendix S – NSR for PM2.5
On May 16, 2008 the USEPA released its final NSR rule for PM2.5 and published it in the Federal Register. The effective date of the Final NSR Rule for PM2.5 is July 15, 2008. The Final Rule specifies that for areas which are non-attainment for PM2.5 NAAQS, the state and local agencies must adopt and submit non-attainment NSR rules to implement the PM2.5 requirements for EPA's approval into the State Implementation Plan no later than July 11, 2011. Since this project is located in the South Coast Air Basin that is designated as non-attainment for PM2.5 and the AQMD has not yet adopted PM2.5 NSR rules, the requirements of NSR for PM2.5 must be implemented through Appendix S. Thus, as of July 15, 2008 all AQMD permit applications for facilities with PM2.5 emissions must be evaluated for compliance with PM2.5 requirements that are included in Appendix S.

Some of the NSR provisions in Appendix S include the major source PM2.5 threshold (100 tons per year) and significant PM2.5 emissions rate (10 tons per year). The requirements of Appendix S will not apply to facilities if the facility emissions, including existing equipment and equipment currently proposed, will result in a potential to emit of less than 100 tons of PM2.5 per year. LADPW has agreed to limit the facility total PM2.5 emissions to less than 100 tons per year. Therefore, the facility and the project will be exempted from the requirements of this rule.

In order to demonstrate compliance with the 100-ton facility wide PM2.5 emission limit the facility will use the following formula to calculate PM2.5 emissions.

$$PM_{2.5} = (FF_1*EF_1+ FF_2*EF_2+ FF_9*EF_9+ FF_{10}*EF_{10}+ FF_{11}*EF_{11}+ FF_{12}*EF_{12}+ FF_{13}*EF_{13}+ FF_{14}*EF_{14}+ FF_{15}*EF_{15}+ FF_{16}*EF_{16})/2000$$

Where

PM2.5 = PM2.5 emissions in tons per year

FF_1= fuel flow for Unit 1 in MMscf, Unit 1 is a boiler generator
FF_2= fuel flow for Unit 2 in MMscf, Unit 2 is a boiler generator
FF_9= fuel flow for Unit 9 in MMscf, Unit 9 is a combined cycle gas turbine generator
FF_{10}= fuel flow for Unit 10 in MMscf, Unit 10 is a combined cycle gas turbine generator
FF_{11} to FF_{16}= fuel flow for Units 11 to 16 in MMscf

EF_1= emission factor for Unit 1 = 7.14 lb/MMscf
EF_2= emission factor for Unit 2 = 6.61 lb/MMscf
EF_9= emission factor for Unit 9 = 1.238 lb/MMscf
EF_{10}= emission factor for Unit 10 = 0.968 lb/MMscf
EF_{11} to EF_{16} = emission factor for Units 11 to 16 = 6.423 lb/MMscf

The emission factors of Units 1, 2, 9, and 10 were determined from the past PM10 source tests. The 6.423 lbs/MMscf emission factor for Units 11 to 16 was derived from 5.8 lbs/hr PM10 emission factor provided and guaranteed by General Electric. All PM10 emissions are assumed to be the same as PM2.5 emissions.

In the event that the facility total PM2.5 emissions exceed 100 tons per year, the facility must provide offset. Offset requirements are calculated in Appendix C.2. Offsets are calculated by determining the net annual emissions increases. As calculated, the project net PM2.5 emission increase is 292 lbs/day. LADWP will be required to provide 292 pounds per day of federally enforceable PM2.5 emission reduction credits unless a different amount associated with the Repower Project modification at this facility as determined to be required according to the federal New Source Review (NSR) requirements (40CFR Part 51 Subpart Z Appendix S), as approved by both AQMD and EPA.

<u>40CFR Part 60 Subpart GG – Standards of Performance for Stationary Gas Turbines</u>
Subpart GG applies to the stationary gas turbines that have a heat input of greater than 10.7 gigajoules per hour. However, gas turbines that are subject to the requirements of Subpart KKKK are exempted from this subpart. The SCGS gas turbines are subject to Subpart KKKK, and are exempted from this subpart.

<u>40CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines</u>
Subpart KKKK applies to gas turbines that are installed after February 18, 2005 and have a heat input greater than 10.7 gigajoules per hour (10 MMBtu/hr). The SCGS gas turbines will be installed after February 18, 2005; and they have a heat rating of 816.8 MMBtu/hr (LHV). Thus the SCGS units are subject to this subpart.

This regulation requires the gas turbines to meet NOx and SO_2 emission limits, which are determined based on the turbine's heat rate and fuel type. NOx limits are provided in Table 1 of the subpart. For new turbines firing natural gas that are less than 850 MMBtu/hr the NOx limit is 25 ppmv. The SO_2 standard is 110 ng/J, or 0.9 lb/MWhr for units located in a continental area. The SCGS units will have a NOx limit of 2.5 ppmv, and a SO_2 limit equivalent to 0.006 lb/MWhr. Compliance with the emission limits are expected.

In addition to the emission limits, Subpart KKKK requires continuous monitoring of the unit operation to ensure compliance. For units that use SCR and water injection to control NOx emissions, it is required to install a CEMS, and to conduct a performance test within 60 days of installation. The operator is required to measure fuel sulfur content unless it can demonstrate that the total sulfur in natural gas is less than 20 grains per 100 standard cubic feet (0.2 grain/scf). LADWP will install a NOx CEMS for each gas turbine in accordance with the SCAQMD rules. The installation of the CEMS satisfies the requirements for NOx monitoring. LADWP will prepare and issue all reports as required and maintain all appropriate records. The pipeline natural gas will have sulfur content below 16 ppmv, which is equivalent to 0.01 grains/scf, as it is subject to Rule 431.1. Thus, compliance with monitoring requirements are expected.

<u>40CFR Part 63 Subpart YYYY – NESHAP for Gas Turbines</u>

EPA has promulgated the National Emission Standards for Hazardous Air Pollutant (NESHAP) for various types of operation. NESHAP applies to facilities that are major sources of hazardous air pollutants. A major source facility is defined as having a single HAP emissions greater than 10 tons/year, or total HAP emissions greater than 25 tons/year. LADWP has determined that, as calculated in Appendix D.3, the facility total formaldehyde emissions will exceed 10 tons per year with the installation of the SCGS. Thus, the Haynes Generation Station will become an major source facility, and be subject to this subpart.

Subpart YYYY sets emission limits and requires notification, source testing, monitoring and recordkeeping for gas turbines. EPA proposed to delist natural gas fired gas turbines from the NESHAP on August 14, 2004, Thus, in accordance with §63.6095(d) of this subpart natural gas fired gas turbines are exempted from all requirements other than the initial notification. LADWP will make the initial notification as required. The notification will be included as a part of the Rules 212, RECLAIM, and 3006 public notice.

<u>40CFR Part 64 – Compliance Assurance Monitoring (CAM)</u>

The CAM regulation applies to major stationary sources, which use control equipment to achieve a specified emission limit. The rule is intended to provide "reasonable assurance" that the control systems are operating properly to maintain compliance with the emission limits. The turbines are major sources for NOx, CO, and VOC emissions, and will be subject to a BACT limit for each of these pollutants.

NOx and CO BACT limits are met with added equipment, i.e., SCR and oxidation catalyst. Thus, this subpart rule applies to NOx and CO emissions. LADWP will install a continuous emission monitoring system (CEMS) for NOx and one for CO. The NOx CEMS will be certified in accordance with Rule 2012 requirements and the CO CEMS will be certified in accordance with Rule 218 requirements. The CEMSs are equivalent to the Acid Rain CEMS and are considered as a continuous compliance determination method, which allows an exemption to the CAM rule per Part 64.2(b)(vi).

This subpart also applies to the VOC emissions because the VOC BACT limit is achieved with the help of the oxidation catalyst. The oxidation catalyst is effective when operating temperature is above 300 F, and its effectiveness is dependent upon the catalyst temperature. There will be a temperature gauge that monitors exhaust temperature continuously and records on the hourly basis. The exhaust temperature is required to be at least 700 F. In addition the operator will conduct periodic source testing. Compliance is expected.

40CFR Part 72 – Acid Rain

The HnGS currently has SO_2 allocations under the acid rain program, allocated to their Boilers 1 through 6. The acid rain program is similar to RECLAIM in that facilities are required to cover SO_2 emissions with "SO_2 Allowances" (similar to RTCs), or purchase of SO_2 on the open market. The facility is also required to monitor SO_2 emissions through use of fuel gas meters and gas constituent analysis (use of emission factors is also acceptable in certain cases) or with the use of exhaust gas CEMS. The LADWP HnGS will comply with the monitoring requirements of the acid rain provisions with the use of gas meters in conjunction with natural gas default sulfur data as allowed by the Acid Rain regulations (Appendix D to 40 CFR Part 75). If additional SO_2 credits are needed, LADWP will obtain the credits from the SO_2 trading market. Based on the above, compliance with this rule is expected.

RULE 212 – Standards for Approving Permits

The facility is not located within 1,000 feet of a school and the MICR for each gas turbine is less than 1 in a million. Thus, this project is not subject to the public notification requirements under Rule 212(c)(1) and (c)(3). However, this project is subject to Rule 212(c)(2) and Rule 212(g) public notice requirements because the increase in NOx emissions from the project will exceed the emission threshold specified in subdivision (g) of this rule, as summarized in the following table:

Table 12 Project Emission Increase and Rule 212 Thresholds (lbs/day)

	NOx	CO	VOC	PM10	SOx
Gas Turbines (6)	54	100	10	12	1
Emergency ICEs (2)	4	1	0	0	0
Project Emission Increase	58	101	10	12	1
Rule 212 Thresholds	40	220	30	30	60

The District will prepare the public notice and it will contain sufficient information to fully describe the project. In accordance with subdivision (d) of this rule, the applicant will be required to distribute the public notice to each address within ¼ mile radius of the project.

Subdivision (g) requires that the public notification and comment process include all applicable provisions of 40 CFR Part 51, Section 51.161(b) and 40 CFR Part 124, Section 124.10. The minimum requirements specified in the above documents are included in paragraphs (g)(1), (g)(2), and (g)(3). In accordance with paragraph (g)(1) of this rule, the District will make the following information available for public inspection at the City of Long Beach Public Library - Bay Shore Neighborhood Branch located at 195 Bay Shore, Long Beach, CA, during the 30-day comment period: public notice, project information submitted by the applicant, and the District's permit to construct evaluation. In accordance with paragraph (g)(2) of this rule, the public notice will be published in a newspaper which serves the area that will be impacted by the project. In accordance with paragraph (g)(3) of this rule, the public notice will be mailed to the following persons: the applicant, the Region IX EPA administrator, the ARB, the chief executives of the city and county where the project will be located, the regional land use planning agency, and the state and federal land managers whose lands may be affected by the emissions from the proposed project. After the public notice is published, there will be a 30-day period for submittal of public comments.

RULE 218 – Continuous Emission Monitoring

This rule applies to the CO CEMS, which is required to verify CO emission levels from each gas turbine. The LADWP is required to submit an "Application for CEMS" for CO CEMS for each turbine and required to adhere to retention of records requirements and reporting requirements once approval to operate CO CEMS is granted. Compliance with this rule is expected.

RULE 401 – Visible Emissions

Visible emissions from the gas turbines are not expected since they will be firing exclusively with natural gas. The standby diesel generators will only be used during an emergency. They will use only low sulfur diesel fuel. Compliance with this rule is expected.

RULE 402 – Nuisance

Nuisance problems are not expected under normal operating conditions. The facility is located in an isolated industrial area, and that the ammonia slip is minimum.

RULE 407 – Liquid and Gaseous Air Contaminants

This rule limits SO_2 emissions to 500 ppm for equipment not subject to the gaseous fuel sulfur emission concentration limits of 431.1. It limits CO emissions to 2,000 ppm. Since gas turbines will be subject to Rule 431.1 and is expected to comply with Rule 431.1, the sulfur limit does not apply. Compliance with the CO limit of this rule is expected since the equipment is subject to the BACT CO emission limit of no more than 4 ppmv. Compliance with CO will also be verified through the CEMS data.

This rule does not apply to the stationary internal combustion engines such as the emergency diesel generators of this project.

RULE 409 – Combustion Contaminants

This rule limits combustion generated PM emissions to 0.1 gr/dscf at 12% CO_2. For the gas turbines the following operation data are used to determine PM loading:

PM = 5.8 lbs/hr (from Appendix A, Table A-2)
CO_2 = 4.43%
Exhaust flow = 23.266 MMscf/hr (from page 60; 1.717 mmlbs/hr)

Thus,

$$PM = \frac{5.8 * 7000 * 12 / 4.43}{23.266 * 10^6} = 0.0047 \text{ grains/scf}$$

Compliance is demonstrated.

This rule does not apply to the stationary internal combustion engines such as the emergency diesel generators of this project.

RULE 431.1 – Sulfur Content of Gaseous Fuel

This rule stipulates that for natural gas the sulfur content as H_2S shall be less than 16 ppmv. The natural gas fuel that LADWP will use is pipeline quality natural gas. Pipeline quality natural gas is certified to has sulfur content less than 1.0 gr/scf, or 16 ppmv. Compliance is expected.

RULE 431.2 – Sulfur Content of Liquid Fuel

Only the standby diesel generators will use liquid fuel that is subject to this rule, which prohibits use of liquid fuel with a sulfur concentration of greater than 15 ppmw. LADWP will use low sulfur diesel fuel that complies with the sulfur limit. Compliance is expected.

RULE 475 –Electric Power Generating Equipment

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. This rule limits combustion contaminants as PM to be either less than 11 lbs/hour, or less than 0.01 gr/dscf. For natural gas fired gas turbine engines almost all PM emissions are PM10 emissions. As calculated in Rule 409 evaluation PM10 emissions from the gas turbines is 0.0047 gr/dscf, less than 0.01 gr/dscf. Therefore, compliance is expected.

Regulation XIII – New Source Review for Non-RECLAIM Pollutants – Gas Turbines
The gas turbine generators are new emissions sources that must be subject to the requirements of new source review (NSR). This regulation applies to non-attainment criteria pollutants including VOC and PM10. NOx is reviewed under RECLAIM. NH_3 is subject to BACT requirement. CO and NO_2 are attainment pollutants that are reviewed under PSD. NSR includes requirements of BACT, modeling, and offset.

1. Best Available Control Technology (BACT)

BACT is defined in AQMD Rule 1301 as follows:

BACT means the most stringent emission limitation or control technique which:

- has been achieved in practice for such category or class of source; or
- is contained in any State Implementation Plan (SIP) approved by the US EPA for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer that such limitations or control technique is not presently achievable; or
- is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board.

This definition of BACT is consistent with the federal LAER definition with the exception of the cost effectiveness clause.

For simple cycle gas turbine generators the BACT for the non-RECLAIM criteria pollutants are determined by following the above BACT definitions:

VOC: The most stringent emission limit, found on a simple cycle gas turbine is 2.0 ppmv, 1-hour average, dry at 15% O_2. The recently permitted simple cycle gas turbines at the city of Anaheim and the city of Riverside are permitted at 2.0 ppmv, 1-hour average. The 2.0 ppmv limit is consistent with AQMD's BACT requirement for simple cycle gas turbine generators.

PM10: Use of natural gas with sulfur content as H_2S less than 1 gr/scf.

As a summary the following is the AQMD determined BACT/LAER limits:

VOC: 2.0 ppmv, dry at 15% O_2, 1-hour average.
PM10: Use of natural gas with sulfur content as H_2S less than 1 gr/scf.

LADWP has proposed to use the same emission limits for the six simple cycle gas turbines. Thus, the BACT/LAER requirement is met. Compliance will be ensured through testing, monitoring and reporting requirements.

The SCR's BACT requirement is to meet the NH_3 slip limit of 5 ppmv. LADWP has proposed to limit the NH_3 slip limit to 5 ppmv. Compliance is expected.

2. Modeling

Modeling is required for CO and PM10 emissions per Rule 1303(b). Rule 1303 requires that through modeling, the applicant must substantiate that the project does not exceed the most stringent ambient air quality standard for attainment pollutants or cause a significant change in air quality concentration for non-attainment pollutants. The Haynes Generation Station is located the area that is PM10 non-attainment, but CO attainment. Therefore, the CO emissions from the proposed project shall not cause a violation of the most stringent air quality standard and the PM10 emissions shall not be greater than the significant change threshold.

Maximum project impacts from CO and PM10 emissions were determined by using the ISCST3 model. The representative meteorological data used in the model are from the Los Alamitos (SCAQMD Station ID 53127). Modeling analysis were performed for startup, shutdown, commissioning, and normal operation. The next two tables show the applicable standards for the subject pollutants and the maximum impacts from the gas turbine generators according to the LADWP modeling analysis.

Table 13 New Source Review Modeling – CO Emissions

Pollutants	Averaging Time	LADWP Model Results (ug/m³)	Background Concentrations (ug/m3)	Total Impact (ug/m3)	Most Stringent Air Quality Standard (ug/m3)
CO	1-hour	471.2(1)	4,600	5,071	23,000
	8-hour	262.6(1)	4,025	4,288	10,000

(1) 2 turbines in commissioning. Simultaneous commissioning of a maximum of two turbines is allowed.

The projected ambient concentrations will be below the most stringent air quality standard. Compliance is demonstrated.

Table 14 New Source Review Modeling – PM10 Emissions[1]

Pollutants	Averaging Time	LADWP Model Results ($\mu g/m^3$)	Significant Change Threshold ($\mu g/m3$)	Significant (Yes/No)
PM10	24-hour	0.95	2.5	No
	Annual	0.25	1.0	No

(1) Modeling analysis of base load operation assumes default PM10 emission factor of 0.0066 lb/MMBtu, which is equivalent to 6.8 lbs/hr and higher than the manufacturer guaranteed rate of 5.8 lbs/hr

The results presented in the above table are the total impacts of six turbines operating simultaneously at the maximum loadings. The total PM10 emissions increase, both the 24-hour average and the annual average, are below the respective significant change thresholds.

LADWP submitted the air quality modeling analysis in March 2009 to the District for review. The District found the analysis acceptable for Rule 1303 requirements.

3. Offset

Rule 1303(b)(2) requires that all increases in emissions be offset unless exempt from offset requirements pursuant to Rule 1304.

Rule 1304(a)(2) - Electric Utility Steam Boiler Replacement states that if the electric utility boilers are replaced by the combined cycle gas turbines, intercooled, or other advanced gas turbines the project will be exempt from emission offsets unless there is a basin-wide electricity generation capacity increase on a per-utility basis. If there is an increase in basin-wide capacity, only the increased capacity must be offset. The GE LMS100 gas turbine is an intercooled gas turbine and is also considered as an advanced gas turbine. Replacing the utility boiler generator with an intercooled/advanced gas turbine is allowed by Rule 1304(a)(2) and qualifies for the exemption.

The language of this exemption allows for offset and modeling exemptions on a MW to MW basis. The purpose is to facilitate the removal of older and less efficient boiler/steam turbine technology with cleaner gas turbine technology at the utilities. Since the advent of RECLAIM, the exemption was expanded to include modifications conducted for compliance with Reg. XX rules. As previously stated the six new turbines replace the existing boiler generators #5 and #6. The combined power generating capacity of the six new turbine generators is 616 MW while the combined power generating capacity of the existing two boiler generators is 604 MW. Thus there is a total increase of 12 MW. Each turbine has an increase of 2 MW. According to the provisions of this rule, LADWP must provide offset for the emissions increases related to the 2 MW capacity increase.

Since NOx is regulated under RECLAIM and CO is an attainment pollutant, only VOC, PM, and SOx offset are required under this regulation. The detailed calculations are provided in Appendix C, Table C-3. The offset requirements are:

VOC: 2 lbs per turbine
VOC: 12 lbs for the SCGS

PM10: 3 lbs for each of the 1st 3 turbines & 2 lbs for the other 3 turbines
PM10: 15 lbs for the SCGS

SOx: Offset not required

Therefore, the applicant shall provide 12 lbs of VOC ERC and 15 lbs of PM10 ERC.

<u>Regulation XIII – New Source Review for Non-RECLAIM Pollutants – Standby Generators</u>

The facility proposes to install two identical diesel fueled emergency IC engine generators. Since the facility is a major source it is subject to BACT and LAER requirements. The minor source BACT requirement is consistent with the requirement of Rule 1470. Based on the rating of 3,622 bhp and the application deemed complete date of March 2009 the engine needs to comply with the EPA Tier II engine emission standards. The LAER requirement includes the use of a diesel particulate filter (DPF) to control PM emissions. An example is the diesel engine at the Mountainview facility in Redlands.

LADWP plans to use the Caterpillar 2516C DITA engine that conforms to the Tier II emissions standards. The engine will be outfitted with a diesel particulate filter. LADWP has identified that the diesel particulate filter will be Johnson Matthey CRT filter or equivalent. The control efficiency is expected to be 90%. The following a comparison of the emission limits.

Table 15 Emergency Diesel Engine Performance

	Proposed Engine	Tier 2 Standard (g/kw-hr)	Tier 4 Interim Standard (g/kw-hr)
NOx	3.7 (g/bhp-hr), 2.76(g/kw-hr)	NOx + HC to be less than 6.4	3.5
HC	0.25 (g/bhp-hr) 0.19 (g/kw-hr)		0.4
CO (g/kw-hr)	0.67 (g/bhp-hr), 0.50(g/kw-hr)	3.5	3.5
PM (g/kw-hr)	0.07 (g/bhp-hr), 0.007 (g/bhp-hr) with DPF 0.05 (g/kw-hr), 0.005 (g/kw-hr) with DPF	0.2	0.1

The engine meets the Tier II standards. Starting in 2011 the engine will need to comply with the Tier 4 interim standard. As shown in the above table the engine also meets the Tier 4 standard.

Standby IC engines are exempted from modeling and offset.

Regulation XIII – New Source Review for Non-RECLAIM Pollutants – Diesel Storage Tank and Oil/Water Separators

VOC emissions from the diesel storage tank and the oil/water separators are negligible (0.015 lbs/day each) and therefore are not subject to BACT or offset requirements. Modeling requirement does not apply to VOC emissions.

RULE 1401 – New Source Review for Toxic Air Contaminants
This rule specifies limits for maximum individual cancer risk(MICR), cancer burden, and acute and chronic hazard index (HI) from new permit units, relocations, or modifications to existing permits which emit toxic air contaminants (TAC).

Rule 1401 requirement levels are as follows:

MICR, without T-BACT:	$\leq$ 1 in 1 million (1.0×10^{-6})
MICR, with T-BACT:	$\leq$ 10 in 1 million (1.0×10^{-5})
Cancer Burden:	≤ 0.5
Maximum Chronic Hazard Index:	≤ 1.0
Maximum Acute Hazard Index:	≤ 1.0

Rule 1401 applies to new or modified permitted units unless those units are exempted by the provisions of Rule 1401(g). The two standby generators are exempted from Rule 1401 per Rule 1401(g)(1)(F). The three oil water separators and the diesel storage tank have minimal VOC emissions and negligible TAC emissions. They are expected to comply with the requirements of this rule.

For the six gas turbines the LADWP performed a detailed health risk analysis (HRA) using CARB's Hotspots Analysis Reporting Program (HARP) model. The HARP model combines the EPA's ISCST3 air dispersion model with a risk assessment model that is based on the AB2588 Air Toxics Hot Spots Program Risk Assessment Guidelines. The Los Alamitos meteorological data is selected as the background data for the air dispersion model. The gas turbines are assumed to operate for 8,760 hours in a year at 100% load. The HRA submitted by LADWP was reviewed by the District and found to be accurate. The modeling results are provided in the next table.

Table 16 Health Risk Assessment from Combustion Turbines

Units	MICR, Resident	MICR, Worker	Chronic Hazard Index	Acute Hazard Index
Turbine Unit 11	0.03 in a million	0.005 in a million	1.59E-03	5.08E-03
Turbine Unit 12	0.03 in a million	0.005 in a million	1.59E-03	5.09E-03
Turbine Unit 13	0.03 in a million	0.005 in a million	1.56E-03	5.06E-03
Turbine Unit 14	0.03 in a million	0.005 in a million	1.56E-03	5.05E-03
Turbine Unit 15	0.03 in a million	0.005 in a million	1.56E-03	5.05E-03
Turbine Unit 16	0.03 in a million	0.005 in a million	1.56E-03	5.05E-03

Results of the analysis show that the highest estimated MICR is 0.03 in a million, which is below the Rule 1401 threshold limits of 1 in a million. The estimated acute hazard index is 5.09E-03, less than the rule limit of 1.0. In addition, the chronic hazard index is 1.59E-03, which is also less than the rule limit of 1.0. Thus, the Haynes SCGS will be in compliance with Rule 1401.

Rule – 1470 Requirements for Stationary Diesel-Fueled Internal Combustion Engines

This rule applies to the two standby diesel fueled IC engine generators. Based on the horsepower rating and the proposed installation date the rule requires that the engine meets the EPA Tier 2 engine emission standards. The proposed Caterpillar engine meets both of the Tier 2 and Tier 4 emission standards based on the comparison presented in the Table 15.

The facility will use only diesel fuel that contains less than 15 ppmw sulfur. This is also required by Rule 431.2. The engine will install a particulate filter that reduces PM emissions by 90%. Based on the PM emission rate the engine is allowed 50 hours per year for maintenance and testing operations.

Regulation XVII – Prevention of Significant Deterioration

The AQMD and the EPA has entered an agreement on July 25, 2007 that AQMD is re-delegated a partial PSD authority. AQMD is authorized to issue new and modified PSD permits in accordance with AQMD's Regulation XVII. Since this is a partial delegation the facilities in the South Coast Air Basin (SCAB) may either apply directly to EPA for the PSD permit in accordance with the current requirements of 40CFR Part 52 Subpart 21, or apply to AQMD in accordance with the current requirements of Regulation XVII. The LADWP has chosen to apply to AQMD.

The SCAB is in attainment for NO_2, SO_2, and CO emissions. Therefore, this regulation applies to NO_2, SO_2, and CO emissions. BACT applies to all projects that have emission increases. BACT requirements for NO_2, CO and SO_2 are evaluated in this section.

- NO_2 – The requirement is consistent with the NOx emission limit of 2.5 ppmv, 15% O_2, 1-hour average. Use of the SCR for control of NOx emissions is considered BACT for simple cycle gas turbines.
- SO_2 – The requirement is to use pipeline quality natural gas. LADWP will use pipeline natural gas for the gas turbines. Compliance is expected.
- CO – The most stringent emission limit, found on simple cycle gas turbines is 4.0 ppmv based on 1-hour average dry at 15% O2. The same limit is also found on the simple cycle gas turbines permitted at the city of Riverside and the city of Anaheim. Therefore, the BACT limit is set at 4 ppmv. LADWP has proposed the 4 ppmv limit for the gas turbines of this project. Compliance is achieved.

In addition to the requirement of BACT, other requirements of this regulation may be triggered based on whether the new or modified source causes a significant increase of emissions. The LADWP HnGS is a major source per PSD definitions. The repower project will be considered a modification to the existing major source. A significant increase, defined as an increase of 40 tons/year of either NO_2 or SO_2 or 100 tons/year of CO emissions, would trigger the PSD analysis requirement. The repower project's potential emissions are compared with the existing emissions in the next table. Based on the NO_2 and CO emissions increases the project triggers PSD analysis.

Table 17 Emission Change Summary

Pollutant	Boiler 5 and Boiler 6 Actual Emissions (tons)[a]	Units 11 through 14 Potential Emissions (tons/yr)	Emission Change (tons/yr)
CO	6.5	419.9	413.4
NO_2	17.5	323.3	305.8
SO_2	1.7	11.2	9.5
a – Boiler emissions are based on actual emissions from September 2006 to August 2008			

The following analyses are required for a facility having a significant emission increase under Rule 1703.

- Use of BACT [1703(a)(3)(B)].
- Modeling to determine impacts of the project on National and State AAQS and increases over the baseline concentration [1703(a)(3)(C)].
- Analysis of ambient air quality in the impact area [1703(a)(3)(D)].
- Analysis of project impacts on visibility, soil, and vegetation [1703(a)(3)(E)].

As required by this regulation, the District sent the PSD analysis and modeling materials to the following affected officials on May 15, 2009:

Gerardo Rios, US EPA, Region IX
Rick Shaw, representative of Mike McCorison, Federal Land Manager

The following methodology was used in performing the PSD analysis.

1. Determine whether pre-construction monitoring is required

Preconstruction monitoring is required if the air quality impacts are greater than the following amounts:

CO: 575 $\mu g/m^3$, 8-hour average
NOx: 14 $\mu g/m^3$, annual average

The application submitted modeling results that showed the maximum NO_2 impact of 0.42 $\mu g/m^3$, ground level annual average and maximum CO impact of 8.3 $\mu g/m^3$, 8-hour average. Since the levels does not exceed the preconstruction monitoring threshold preconstruction monitoring is not required, and that monitoring data from nearby monitoring stations can be used to determine ambient air quality.

2. Assessment of significance under PSD

The air quality impact is considered significant if they exceed the following amounts:

NO_2:	7.5 $\mu g/m^3$, 1-hour average
NO_2:	1.0 $\mu g/m^3$, annual average
CO:	2,000 $\mu g/m^3$, 1-hour average
CO:	500 $\mu g/m^3$, 8-hour average

The 1-hour average significant impact level (SIL) limit is recently suggested by the EPA. The modeled air quality impacts are:

NO_2:	7.2 $\mu g/m^3$, 1-hour average based on three turbines in startups
NO_2:	0.42 $\mu g/m^3$, ground level annual average
CO:	90.5 $\mu g/m^3$, 1-hour average
CO:	8.3 $\mu g/m^3$, 8-hour average

The impacts are below the significance thresholds. Since the project does not exceed the significance thresholds, an increment consumption analysis is not required. However, LADWP reported to AQMD that when more than three units are starting up simultaneously the 1-hour average will exceeds the 7.5 $\mu g/m^3$ SIL. Therefore, the permit will have a condition (E193.7) limiting simultaneous startups to no more than three.

The LADWP conducted an separate modeling analysis specifically to study the 1-hour average NOx impact with the reference to the SIL. It is through the modeling analysis that the facility determined that the impact will exceed the 7.5 μg/m^3 SIL if more than three turbines are starting simultaneously. Simultaneous normal operation of the six units has an impact level of 2.64 μg/m^3 and simultaneous shut down of the six turbines has an impact level of 5.48 μg/m^3. Since both limits are less than the 7.5 μg/m^3 SIL and assuming the facility will not start more than three turbines simultaneously the full impact analysis requirement is not triggered. The modeling analysis was reviewed by AQMD's planning division and was found to be adequate.

3. Determine ambient air quality impacts

The impacts to ambient ground level air quality are analyzed in the air quality modeling analysis. Modeling analysis is required for NO_2 1-hour and annual impacts, and CO 1-hour and 8-hour impacts. After the EPA adopted the new 1-hour NO_2 ambient air quality standard of 100 ppb, 98th percentile of the three years average LADWP provided a supplemental analysis for the NO_2 1-hour impact. The background NO_2 concentration is provided in the next table.

Table 18 Background NO_2 concentrations at South Coastal LA County Station 1 (072)

	1-hr 98th percentile background NO_2 concentration ppb (μg/m3)			
	2006	2007	2008	Average
1-hour 98th percentile	69 (129.7)	77 (144.8)	88 (165.4)	78 (146.6)

The data confirms that NO_2 is an attainment pollutant.

Table 19 Impact to Ambient Air Quality, Entire Facility

Pollutant	Averaging Time	Impacts (μg/m^3)	Background Concentration (μg/m^3)	Total Impact (μg/m^3)	Most Stringent Air Quality Standard (μg/m^3)	Results
NO_2	1-hour	28.2$^{(1)}$	146.6	174.8	188	Acceptable
	Annual	0.42	45.3	45.7	100	Acceptable
CO	1-hour	90.5$^{(2)}$	4,600	4,691	23,000	Acceptable
	8-hour	8.3	4,025	4,033	10,000	Acceptable

(1) Based on the worst scenario of all six turbines in startup simultaneously
(2) Based on the worst scenario of all six turbine in normal operation plus shutdown.

Therefore, the emissions do not cause violation of the most stringent air quality standards.

The modeling analysis was initially submitted to AQMD in March 2009. AQMD reviewed the analysis and determined that the modeling methodology was consistent and acceptable. The results are accurate with one exception of CO 1-hour impact. AQMD's results indicate the worst 1-hour impact is 140.2 $\mu g/m^3$ which is higher than 90.5 μg/m3 calculated by the applicant. However, with the 140.2 $\mu g/m^3$ impact level the total impact is still less than 10,000 $\mu g/m^3$ ambient quality standard.

The supplemental modeling analysis of NO_2 1-hour impact was submitted to AQMD in March 2010. AQMD reviewed the analysis and determined that the modeling was consistent and acceptable. The results of Table 19 are accurate.

4. Determine Visibility and Soil Impacts in Class I areas

The impacts were analyzed on Class I areas that are within 100 kilometers of the project site. The following Class I areas are within 100 km of the LADWP HnGS:

San Gabriel Wilderness Area (54 km)
Cucamonga Wilderness Area (64 km)

The results of the haze analysis were compared to a 5-percent threshold change in background extinction coefficient to determine if the proposed project would significantly contribute to regional haze at the Class I areas. The modeling results showed that the maximum percent change in extinction coefficient for all the Class I areas were satisfactory (less than 5%).

The results of the Class I PSD increment analysis showed that the model predicted concentrations are well below the EPA proposed Class I significance thresholds. Therefore, no further modeling was required for PSD increment analysis.

The results of the acid deposition analysis showed that nitrogen and sulfur deposition impacts are well below the Deposition Analysis Threshold. Therefore, adverse acid deposition impacts attributable to HnGS SCGS emissions are not likely to occur.

The federal land manager of the Class I areas provided comments after reviewing the PSD analysis performed by LADWP. They expressed a concern about the short term impacts due to rapid startups and shutdowns, and proposed the following condition:

> "Within 4 months of permit issuance, the Permittee will sign an existing Collection Agreement with the U.S. Forest Service to participate in a post PSD visibility monitoring project, the results of which will be used to establish a visibility baseline in nearby Class I Areas."

The federal land manager concurs with the issuance of the Title V permit provided that the above condition be included in the Title V permit. The federal land manager has determined that the project will not have adverse impacts to Class I areas. Therefore, the proposed condition will be included as a permit condition.

Regulation XX – NSR for RECLAIM Pollutants
This regulation applies to NOx emissions.

1. BACT

For a simple cycle combustion turbine the most stringent NOx emissions limit is 2.5 ppmv, 15% O_2, dry, 1-hour average. The City of Riverside power plant and the City of Anaheim have four GE LMS6000 simple cycle gas turbines that were permitted at 2.5 ppmv in 2005.

LADWP will use a SCR control system in conjunction with water injection for NOx control. The NOx emissions will meet the 2.5 ppmv 1-hour average emission limit.

2. MODELING

The facility is located in the South Coast air basin, which is in NO_2 attainment. Thus, Rule 2005(c)(1)(B) requires the facility to demonstrate, through modeling, that the proposed NOx emission sources will not cause a violation of the most stringent ambient air quality standard. There are two air quality standards for NO_2, the newly adopted 1-hour federal standard of 100 ppb (188 $\mu g/m^3$) based on 98th percentile of the last three year average, and annual standard of 30 ppb (56 $\mu g/m^3$). The background air quality data from the South Coastal LA County Station 072 are used in the modeling analysis. As determined in Table 18 the 3-year average 98th percentile 1-hour average background is 146.6 $\mu g/m^3$ and the maximum annual average is 45.3 $\mu g/m^3$. The maximum project impacts of NO2 emissions were determined using the AERMOD model. Although the rule requires modeling analysis of each individual permitted unit the LADWP elected to model the six turbines together as a group. This approach is more stringent and it satisfies the requirement of this rule. The modeling analysis indicates that the highest 1-hour impact occurs when two turbines are under commissioning and four others are under startup. The highest annual impact was modeled by assuming all six turbines operating at 100% load for 8,760 hours per year. The LADWP modeled both units operating concurrently instead of one unit at a time. The following table shows the modeling results.

Table 20 NOx Emissions Modeling Results

[illegible]	Background (μg/m^3)$^{(a)}$	Modeling Impacts (μg/m^3)	Total NOx (μg/m^3)	Air Quality Standard (μg/m^3)	Violation
1-hour 98th percentile	146.6	28.2	174.8	188	No
Annual	45.3	0.42$^{(b)}$	45.7	100	No

a – Background concentration was measured at South Coastal Los Angeles County Meteorological Station 072 in 2000.
b – Modeled annual concentration based on modeled result of 1.1 μg/m^3 times the USEPA approved Ambient Ratio Method (ARM) factor of 0.75.

The modeling results are satisfactory.

3. OFFSET (RTC)

The facility is required to demonstrate that it holds sufficient RTCs to offset the annual emission increase for the first year of operation using a 1-to-1 offset ratio. Furthermore, provision (b)(2)(B) states that the RTCs must comply with the zone requirements of Rule 2005(e). The SCGS is expected to undergo commissioning operation in Year 2011. Since the facility is located in Zone 1, RTCs may only be obtained from Zone 1.

As calculated in Appendix C.6 the total NOx RTC requirements of the repower project for the 1st year of operation is 411,676 lbs. This requirement is based on the emissions from the commissioning, and based on a 60% capacity factor projected. After the 1st year the project will require 373,660 lbs of NOx RTC per year. It is lower than the 1st year requirement since the emissions from the commissioning are not included.

LADWP will either purchase the required NOx RTCs from the open market or transfer credits from their other RECLAIM facilities. Compliance with the offset requirement is expected.

4. ADDITIONAL REQUIREMENTS FOR MAJOR SOURCES

Rule 2005 requires that a major source also comply with the following:

A) Certify that all major sources in the state under control of the applicant are in compliance with all applicable federal emissions standards.

B) Submit an analysis of alternative sites, sizes, production processes, and environmental control techniques for the proposed source.

C) Compliance with CEQA

D) Protection of Visibility

The LADWP certifies in the permit application that all major sources under their control in the state currently comply with federal regulations. An alternative analysis under the California Environmental Quality Act (CEQA) process is being performed as part of the EIR. The minimum distance between the SCGS project site and the nearest Class I area (San Gabriel Wilderness Area) is 54 km, which is greater than the maximum distance requirement of 29 kilometers. Thus, no visibility analysis is required for the SCGS project site. Thus, the above three requirements have been met for the SCGS project.

Rule 2012 – Monitoring Recording and Record Keeping for RECLAIM

The Haynes Generation Station is currently in compliance with all monitoring, record-keeping, and reporting requirements of NO_X RECLAIM. The new CTGs will be classified as major sources for RECLAIM purposes. As such each turbine will be provided with a NO_X CEMS and a fuel meter, and emissions will be reported through a remote terminal unit (RTU) on a daily basis. The CEMS will be installed within 12 months from the date of installation of the turbines. Thus, the operation of the SCGS turbines will be in compliance with Rule 2012.

Regulation XXX – Title V Operating Permit

The Haynes Generation Station is a federal Title V facility and is subject to Title V requirements. The addition of the new turbines is considered a Significant Permit Revision as defined in Rule 3000.

The facility is required to provide public notification of the SCGS project. EPA will also be provided with this information for their review comments (45 day review period). The Title V public notice will be combined with Rule 212 notice, which is also required for this project. Rule 3006 requires that the notice contain the following:

(i) The identity and location of the affected facility.

(ii) The name and mailing address of the facility's contact person.

(iii) The identity and address of the SCAQMD as the permitting authority processing the permit.

(iv) The activity or activities involved in the permit action.

(v) The emissions change involved in any permit revision.

(vi) The name, address, and telephone number of a person whom interested persons may contact to review additional information including copies of the proposed permit, the application, all relevant supporting materials, including compliance documents as defined in paragraph (b)(5) of Rule 3000, and all other materials available to the Executive Officer that are relevant to the permit decision.

(vii) A brief description of the public comment procedures provided.

(viii) The time and place of any proposed permit hearing that may be held or a statement of the procedures to request a proposed permit hearing if one has not already been requested.

DISCUSSION

Based on the engineering evaluation, the new equipment is expected to comply with all federal, state, and local rules and regulations. A public notice is required pursuant to Rules 212, 1701, and 3006. The total monthly emissions from the proposed project to be included in the public notice are summarized in the next table.

Table 21 Project Emissions for Rule 212 Public Notice (Normal Operation; lbs/month)

	NOx	CO	VOC	PM10	SOx
Gas Turbines (6)	46,086	70,530	13,632	20,046	540
Emergency ICEs (2)	246	45	17	0	0
Diesel Storage Tank (1)	0	0	0	0	0
Oil/Water Separators (3)	0	0	1	0	0
Total Project Emissions	46,332	70,575	13,650	20,046	540

Since the total electrical generating capacity of the new SCGS is slightly greater than the electrical generating capacity of the existing electric utility boiler generating units, as required by AQMD rules and regulations, the emissions associated with the increase in the electrical generating capacity from the new equipment will be offset through providing emission reduction credits (ERCs) from shut down of other facilities within the air basin that LADWP has acquired. The amounts of ERCs required that is associated with the increase in the electrical generating capacity are 12 pounds per day (or 360 pounds per month) of VOC and 15 pounds per day (or 450 pounds per month) of PM_{10}. There are no emission offsets in the form of ERCs required for SOx and CO, since the SOx increase in emissions is less than 0.5 pound per day and the air basin is considered attainment with CO. Also all of the NOx emissions from this facility has to be offset with emission credits that LADWP either holds or purchases in the form of NOx Trading Credits available in the Regional Clean Air Incentive's Market (RTCs). Finally, the total facility's emissions of $PM_{2.5}$ will be limited to less than 100 tons per year, unless LADWP also provides ERCs for $PM_{2.5}$ in the amount of 292 pounds per day, unless a different amount associated with the Repower Project modification at this facility as determined to be required according to the federal New Source Review (NSR) requirements, as approved by both AQMD and EPA. The VOC and PM_{10} ERCs are required to be provided by LADWP prior to issuance of the final Title V Permits to Construct. The NOx RTCs and $PM_{2.5}$ ERCs (if necessary), are required to be provided by LADWP prior to the Repower Project commencing its operation in accordance with RECLAIM rules (AQMD Rule 2005) and federal NSR rule (40CFR Part 51 Subpart Z Appendix S), respectively.

RECOMMENDATION

It is recommended that the District approve the proposed project after the 30-day public comment period and the 45-day EPA review period are over and issue permits to construct after LADWP has provided the required VOC and PM_{10} ERCs. The permit will be subject to the following conditions.

CONDITIONS

A63.4 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
CO	11,755 LBS IN ANY 1 CALENDAR MONTH
PM10	3,341 LBS IN ANY 1 CALENDAR MONTH
VOC	2,272 LBS IN ANY 1 CALENDAR MONTH
SOx	90 LBS IN ANY 1 CALENDAR MONTH

The above limits apply after the equipment is commissioned. The above limits apply to each turbine.

The operator shall calculate the emission limit(s) by using calendar monthly fuel use data and the following emission factors: VOC: 4.42 lbs/mmscf, PM10: 6.50 lbs/mmscf, SOx: 0.18 lbs/mmscf.

The operator shall calculate the emission limits for CO after the CO CEMS certification based upon readings from the AQMD certified CEMS. In the event the CO CEMS is not operating or the emissions exceed the valid upper range of the analyzer, the emissions shall be calculated by using monthly fuel use data and the following factor: CO: 22.88 lbs/mmscf.

[Rule: 1303(b)(2)-Offset]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

A99.4 The 96.94 lbs/mmscf NOx emission limit(s) shall only apply during the turbine commissioning period to report RECLAIM emissions.

[Rule 2012]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

A99.5 The 14.27 lbs/mmscf NOx emission limit(s) shall only apply during the interim period after commissioning to report RECLAIM emissions.

[Rule 2012]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

A99.6 The 5.8 lbs/hour PM10 emission limit(s) shall not apply to turbine commissioning, startup and shutdown periods.

[Rule: 1303(b)(2)-Offset]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

A195.8 The 2.5 PPMV NOx emission limit is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup and shutdown periods.

[Rule 2005 – BACT, Rule XVII – PSD]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

A195.9 The 4.0 PPMV CO emission limit is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup and shutdown periods.

[Rule XVII – PSD]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

A195.10 The 2.0 PPMV VOC emission limit is averaged over 1 hour, dry basis at 15 percent oxygen. This limit shall not apply to turbine commissioning, startup and shutdown periods.

[Rule 1303 – BACT]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

A327.1 For the purpose of determining compliance with District Rule 475, combustion contaminant emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.

[Rule 475]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

C1.4 The operator shall limit the number of startups to less than 150 in any one calendar month.

Startup time shall not exceed 25 minutes per startup.

NOx emissions shall not exceed 20 lbs per startup.

For this condition startup is defined as the start up process to bring the turbine in full successful operation that complies with the BACT emission limits. If during startup the process is aborted the process will count as one startup.

The operator shall maintain records in a manner approved by the District, for a minimum of five years, to demonstrate compliance with this condition.

[Rule 1703 – PSD, Rule 2005– Offset]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

C1.5 The operator shall limit the number of shutdowns to less than 150 in any one calendar month.

Shutdown time shall not exceed 10 minutes per shutdown.

The operator shall maintain records in a manner approved by the District, for a minimum of five years, to demonstrate compliance with this condition.

[Rule 1703 – PSD, Rule 2005– Offset]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

D12.9 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH3).

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. The ammonia injection rate shall remain between 93 and 146 lbs per hour.

[Rule 2005– BACT, Rule 1703- PSD]

[Devices subject to this condition: C162, C168, C174, C180, C186, C192]

D12.10 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. The temperature shall be between 734 °F and 850 °F.

[Rule 2005– BACT, Rule 1703- PSD]

[Devices subject to this condition: C162, C168, C174, C180, C186, C192]

D12.11 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every twelve months. The pressure differential shall be between 4.0 and 5.8 inches water column.

[Rule 2005– BACT, Rule 1703- PSD]

[Devices subject to this condition: C162, C168, C174, C180, C186, C192]

D12.12 The operator shall install and maintain a non-resettable totalizing time meter to accurately indicate the elapsed operating time of the engine.

[Rule 1304-Excemptions, Rule 1470]

[Devices subject to this condition: D195, D196]

D12.13 The operator shall install and maintain a non-resettable elapsed fuel meter to accurately indicate the engine fuel consumption.

[Rule 1304-Exemptions, Rule 2012]

[Devices subject to this condition: D195, D196]

D29.6 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Avg. Time	Test Location
NOx emissions	District Method 100.1	1 hour	Outlet of the SCR
CO emissions	District Method 100.1	1 hour	Outlet of the SCR
SOx emissions	Approved District Method	District Approved Avg. Time	Fuel Sample
VOC emissions	Approved District method	1 hour	Outlet of the SCR
PM10 emissions	Approved District Method	District Approved Avg. Time	Outlet of the SCR
NH3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	Outlet of the SCR

The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start-up or three hundred hours of operation after startup. The District shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate. The combined gas turbine and steam turbine generating output in MW shall also be recorded if applicable.

The test shall be conducted in accordance with a District approved source test protocol. The protocol shall be submitted to the AQMD engineer no later than 90 days before the proposed test date and shall be approved by the District before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

For gas turbines only the VOC test shall use the following method: a)Stack gas samples are extracted into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute, b)Pressurization of Summa canisters is done with zero gas analyzed/certified to having less than 0.05 ppmv total hydrocarbons as carbon, and c)Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the canisters temperature when extracting samples for analysis is not to be below 70 degrees F.

The use of this alternative VOC test method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The test results must be reported with two significant digits.

The test shall be conducted when this equipment is operating at loads of 100 and 75 percent of maximum load for the NOx, CO, VOC, and ammonia tests.

The PM10 test shall be conducted when this equipment is operating at 100 percent of maximum load.

Test results shall be submitted to AQMD with 90 days of the completion of the tests.

[Rule 1303 – BACT, Rule 1303 – Offsets, Rule 2005 – BACT, Rule 2005 - Offsets, Rule 1401, Rule 1703 – PSD]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

D29.7 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Avg. Time	Test Location
SOx emissions	Approved District Method	District Approved Avg. Time	Fuel Sample
VOC emissions	Approved District method	1 hour	SCR Outlet
PM emissions	Approved District Method	District Approved	SCR Outlet

| | Avg. Time |

The test(s) shall be conducted at least once every three years.

The test shall be conducted and the results submitted to the District within 90 days after the test date. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted when the gas turbine is operating at 100 percent of maximum heat input.

For gas turbines only the VOC test shall use the following method: a) Stack gas samples are extracted into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of Summa canisters is done with zero gas analyzed/certified to having less than 0.05 ppmv total hydrocarbons as carbon, and c) Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the canisters temperature when extracting samples for analysis is not to be below 70 degrees F.

The use of this alternative VOC test method is solely for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines. The test results must be reported with two significant digits.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emissions limit.

[Rule 1303 – BACT, Rule 1303 – Offsets]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

D29.8 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Avg. Time	Test Location
NH3 emissions	District Method 207.1 and 5.3 or EPA Method 17	1 hour	SCR Outlet

The test shall be conducted and the results submitted to the District within 90 days after the test date. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit.

[Rule 1303 – BACT]

[Devices subject to this condition: C162, C168, C174, C180, C186, C192]

D82.3 The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS shall be installed and operated to measure CO concentrations over a 15 minute averaging time period.

The CEMS shall be installed and operated no later than 90 days after initial start-up of the turbine, and in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD. Within two weeks of the turbine start-up, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS would convert the actual CO concentrations to mass emission rates (lbs/hr) using the equation below and record the hourly emission rates on a continuous basis.

CO Emission Rate, lbs/hr = $K*Cco*Fd[20.9/(20.9\% - \%O_2\ d)][(Qg * HHV)/106]$, where

$K = 7.267 * 10^{-8}$ (lb/scf)/ppm

Cco = Average of four consecutive 15 min. average CO concentration, ppm

Fd = 8710 dscf/MMBTU natural gas

$\%O_2$ d = Hourly average % by vol. O_2 dry, corresponding to Cco

Qg = Fuel gas usage during the hour, scf/hr

HHV = Gross high heating value of fuel gas, BTU/scf

[Rule 1703 – PSD]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

D82.4 The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS shall be installed and operated no later than 90 days after initial start-up of the turbine, and in accordance with an approved AQMD REG XX CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD. Within two weeks of the turbine start-up, the operator shall provide written notification to the District of the exact date of start-up.

Rule 2012 provisional RATA testing shall be completed and submitted to the AQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3).

[Rule 2012, Rule 2005-BACT, Rule 1703-PSD]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

E116.2 This engine shall not be used as part of an interruptible service contract in which a facility receives a payment or reduced rates in return for reducing electric load on the grid when requested by the utility or the grid operator.

[Rule 1470, Rule 1304-Excemptions]

[Devices subject to this condition: D195, D196]

E179.1 For the purpose of the following condition number(s) continuously record shall be defined as recording at least once every 15 minutes and shall be calculated based upon the average of the continuous monitoring for that hour.

Condition no. D12.6

[Rule 1303 – BACT, Rule 2005– BACT, Rule 1703-PSD]

[Devices subject to this condition: C162, C168, C174, C180, C186, C192]

E179.2 For the purpose of the following condition number(s) continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that month.

Condition no. D12.7
Condition no. D12.8

[Rule 1303 – BACT, Rule 2005– BACT]

[Devices subject to this condition: C162, C168, C174, C180, C186, C192]

E193.6 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all air quality mitigation measures stipulated in the Draft Environmental Impact Report (EIR), State Clearing House #2005061111.

[CEQA]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

E193.7 The operator shall operate and maintain this equipment according to the following requirements:

The gas turbines shall operate with natural gas exclusively.

The commissioning period shall not exceed 176 hours of operation for each turbine during the first 30 calendar days from the date of initial turbine start-up. During the commissioning process the operator shall calculate the emission limit(s) by using calendar monthly fuel use data and the following emission factors: VOC: 11.46 lbs/mmscf, PM10: 6.86 lbs/mmscf, SOx: 0.49 lbs/mmscf, CO: 205.89 lbs/mmscf.

Within 90 days of the initial startup of the turbines permits for Boiler #5 (D7) and Boiler #6 (D9) shall be surrendered.

The operator shall vent this equipment to the CO oxidation catalyst and SCR control system whenever the turbine is in operation after initial commissioning.

There shall not be more than three gas turbines in the startup mode concurrently.

The operator shall provide the AQMD with written notification of the initial startup date. Written records of commissioning, startups, and shutdowns shall be maintained and made available upon request from AQMD.

[Rule 1303 – BACT, Rule 2005– BACT, Rule 1703-PSD]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

E193.8 The equipment is subject to the applicable requirements of the following rules:

Within 4 months of the issuance of Permit to Construct, the Permittee will sign an existing Collection Agreement with the U.S. Forest Service to participate in a post PSD visibility monitoring project, the results of which will be used to establish a visibility baseline in nearby Class I Areas.

[Rule 1703 – PSD]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

E193.9 The operator shall calculate and continuously record the NH3 slip concentration using the following:

NH_3 (ppmvd) = [a-b*(c*1.2)/1,000,000]*1,000,000/b,

where a=NH_3 injection rate (lb/hr)/17(lb/lb-mol), b= dry exhaust flow rate (scf/hr)/(385.5 scf/lb-mol), c = change in measured NOx across the SCR, ppmvd at 15 percent O_2. The operator shall install a NOx analyzer to measure the SCR inlet NOx ppm accurate to within +/- 5 percent calibrated at least once every 12 months. The operator shall use the method described above or another alternative method approved by the Executive Officer. The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information determination without corroborative data using an approved reference method for the determination of ammonia. The ammonia slip calculation procedure shall be in-effect no later than 90 days after initial startup of the turbine.

[Rule 1303 – BACT]

[Devices subject to this condition: C162, C168, C174, C180, C186, C192]

E193.10 The operator shall not commence operation of any of the new Units 11-16 until the AQMD certifies that one of the following conditions has been satisfied:

The facility has provided 292 lbs/day of federally enforceable $PM_{2.5}$ emission reduction credits unless a different amount associated with the Repower Project modification at this facility as determined to be required according to the federal New Source Review (NSR) requirements (40CFR Part 51 Subpart Z Appendix S), as approved by both AQMD and EPA.

The operator shall comply with a federally enforceable limit of 100 tons per year of $PM_{2.5}$ emissions.

For purposes of demonstrating compliance with the 100 ton per year limit the operator shall determine the $PM_{2.5}$ emissions for each of the major sources at the facility by calculating a 12-month rolling average using the following formula:

$PM_{2.5} = (FF_1*EF_1+ FF_2*EF_2+ FF_9*EF_9+ FF_{10}*EF_{10}+ FF_{11}*EF_{11}+ FF_{12}*EF_{12}+ FF_{13}*EF_{13}+ FF_{14}*EF_{14}+ FF_{15}*EF_{15}+ FF_{16}*EF_{16})/2000$

Where:

PM2.5 = PM2.5 emissions in tons per year

FF_1= fuel flow for Unit 1 in MMscf
FF_2= fuel flow for Unit 2 in MMscf
FF_9= fuel flow for Unit 9 in MMscf
FF_{10}= fuel flow for Unit 10 in MMscf
FF_{11} to FF_{11}= fuel flow for Units 11 to 16 in MMscf

EF_1= emission factor for Unit 1 = 7.14 lb/MMscf
EF_2= emission factor for Unit 2 = 6.61 lb/MMscf
EF_9= emission factor for Unit 9 = 1.238 lb/MMscf
EF_{10}= emission factor for Unit 10 = 0.968 lb/MMscf
EF_{11} to EF_{16} = emission factor for Units 11 to 16 = 6.423 lb/MMscf

Any changes to these emission factors must be approved in advance by the District in writing and be based on unit specific source tests performed using a District approved testing protocol.

[40 CFR, Part 51, Appendix S, September 26, 2008]

[Devices subject to these conditions: D1, D4, D125, D134, D159, D162, D168, D174, D180, D186]

E448.1 This engine shall not be operated more than 200 hours in any one year, which includes no more than 50 hours per year and 1 hour per week for maintenance and testing as required in rule 1470(c)(2)

[Rule 1470, Rule 1304-Excemptions]

[Devices subject to this condition: D195, D196]

E448.2 Operation beyond the allotted time for engine maintenance and testing shall be allowed only in the event of a loss of grid power or up to 30 minutes prior to a rotating outage, provided that the utility distribution company has ordered rotating outages in the control area where the engine is located or has indicated that it expects to issue such an order at a certain time, and the engine is located in a utility service block that is subject to the rotating outage. Engine operation shall be terminated immediately after the utility distribution company advises that a rotating outage is no longer imminent or in effect.

[Rule 1470]

[Devices subject to this condition: D195, D196]

I296.2 This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.

To comply with this condition, the operator shall prior to the 1st compliance year hold a minimum NOx RTCs of 68,120 lbs. This condition shall apply during the 1st 12 months of operation, commencing with the initial operation of the gas turbines.

To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the 1st compliance year, hold a minimum NOx RTCs of 61,784 lbs. In accordance with Rule 2005(f), unused RTC's may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the 1st compliance year.

[Rule 2005 – Offsets]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

I296.3 This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.

To comply with this condition, the operator shall hold a minimum NOx RTCs of 1,478 lbs prior to the beginning of all compliance years. In accordance with Rule 2005(f), unused RTC's may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the 1st compliance year.

[Rule 2005 – Offsets]

[Devices subject to this condition: D195, D196]

K40.5 The operator shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District no later than 90 days after the source test was conducted.

Emission data shall be expressed in terms of concentration (ppmv), corrected to 15 percent oxygen (dry basis), mass rate (lbs/hr), and lbs/MM cubic feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

All exhaust flow rates shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

Source test results shall also include the oxygen levels in the exhaust, the fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.

[Rule 1303 – Offsets, Rule 1303 – BACT, Rule 2005, Rule 1703]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

K67.6 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

Natural gas fuel use during the commissioning period

[Rule 2012]

[Device subject to this condition: D159, D165, D171, D177, D183, D189]

K67.7 The operator shall keep a log of engine operations documenting the total time the engine is operated each month and the specific reason for operation as.

A. Emergency Use
B. Maintenance and Testing
C. Other (be specific)

In addition, for each time the engine is manually started, the log shall include the date of engine operation, the specific reason for operation, and the totalizing hour meter reading (in hours and tenths of hours) at the beginning and the end of the operation.

On or before January 15th of each year the operator shall record in the engine operating log:

A. The total hours of engine operation for the previous calendar year,
B. The total hours of engine operation for maintenance and testing for the previous calendar year

Records shall be kept and maintained on file for a minimum of five years and made available to district personnel upon request.

[Rule 1470, Rule 1304-Exemptions]

[Devices subject to this condition: D195, D196]

APPENDIX A CRITERIA POLLUTANTS EMISSIONS – GAS TURBINES

1. EMISSIONS FROM STARTUPS

The startup process is between when the gas turbine starts and when it reaches the designated operation load and achieves compliance with the emission limits. During this process the SCR and the oxidation catalyst are not fully operational until their temperatures reach the operating temperature windows. LADWP has specified that the startup process will take 25 minutes. During the first eight minutes NOx levels are in the 50-100 ppmvd range and CO levels are in the 100-500 ppmvd levels. Water injection is introduced at the 8th minute and NOx levels reach 25 ppmvd by the 10th minute. From the 10th minutes on and during the next 15 minutes the SCR and the oxidation catalyst become more effective, bringing the NOx levels to 2.5 ppmvd and the CO levels to 4 ppmvd.

To determine the startup emissions LADWP used the manufacturer provided data, and the startup emissions data of a 25-minute startup process (CPV Sentinel Projects). The startup process is divided into a period of the first ten minutes, and another period of the next fifteen minutes.

The turbine manufacturer General Electric has provided an emission factor of 5.8 lbs/hr (6.423 lbs/MMscf or 0.0064 lb/MMBtu) for base load operation. However, it does not provide a specific emission factor for the startup process. Thus, PM10 and SOx emissions are calculated using the default AP-42 emission factors (0.0066 lb/MMBtu for PM10 and 0.6 lb/MMscf for SOx).

PM10 = Heat Input (HHV) * 0.0066 lb/MMBtu
SOx = Fuel Usage * 0.6 lb/MMscf

Heat Input (HHV) = 906.6 MMBtu/hr @ 100% load
Fuel Usage = 0.903 MMscf/hr @ 100% load

The chemical reactions in the SCR and the oxidation catalyst may generate additional PM10 emissions. In the SCR a portion of the SO_2 reacts with ammonia and converts into ammonium sulfate $(NH_4)_2SO_4$, which is considered as PM10. LADWP estimates that an average of 72% of SO_2 is converted to $(NH_4)_2SO_4$. The additional PM10 emissions are:

0.6 lb/MMscf * 72% * 132/64 = 0.891 lbs/MMscf

Total PM10 emission factor for the startup process is then:

0.0066 lbs/MMBtu + 0.891 lbs/MMscf /(1004 MMBtu/MMscf) = 0.0075 lbs/MMBtu

Consequently the SOx emissions are reduced. The net SOx emissions rate is:

Fuel Usage * (1-72%) *0.6 lb/MMscf

The SOx emission factor for the startup is then:

0.168 lbs/MMscf

The emissions of criteria pollutants during the startup are calculated in the following table.

Table A-1 Startup Emissions

Startup Period	Period 1 (first 10 minutes)	Period 2 (next [illegible] minutes)	Total (25 minutes)
Heat Input (MMBtu, LHV)	26	197.5	223.5
Heat Input (MMBtu, HHV)	28.9	219.3	248.2
Fuel Usage (MMscf)	0.029	0.22	0.247
NOx (lbs)	5	15	20
CO (lbs)	13	2.89	15.89
VOC (lbs)	3	1.3	4.3
PM10 (lbs)	0.191	1.645	1.836
SOx (lbs)	0.017	0.037	0.054

2. EMISSIONS FROM NORMAL OPERATION

Normal operation is when the CTG reaches its generating capacity and when the emissions are subject to BACT limits. The emission limits are:

NOx = 2.5 ppmv at 15% O_2, dry
VOC = 2.0 ppmv at 15% O_2, dry (as CH4)
CO = 4.0 ppmv at 15% O_2, dry

As indicated on page 59, the net PM10 and SOx emission factors calculated from default AP-42 are 0.0075 lb/MMBtu for PM10 and 0.168 lb/MMscf for SOx. The gas turbine manufacturer General Electric provides a PM emission factor guarantee of 5.8 lbs/hr (0.0064 lb/MMBtu) at base load. As a result, the net PM10 emission factor of 0.0075 lb/MMBtu from page 59 is not used for emission calculations.

PM10 = 5.8 lbs/hr
PM10 = 5.8 lbs/hr * 1004 Btu/scf / (906.6 MMBtu/hr) = 6.423 lbs/MMscf

For potential to emit (PTE) determinations LADWP calculated emissions generated from operating at three ambient temperatures, 25 °F, 65 °F, and 91 °F. The calculation assumes that at 25 °F the inlet evaporative cooling is off, and on at 65 °F and 91 °F. The results indicate that the highest amount of emissions occur when operating at ambient temperature of 65 °F. Thus, the results of 65 °F are selected for PTE determinations.

At 65 °F the combustion gas turbine has the following fuel parameters:

Heat Input: 906.6 MMBtu/hr, HHV
Fuel Flow: 0.903 MMscf/hr
HHV = 1,004 Btu/scf
LHV = 904 Btu/scf

According to the engine data provided by GE the exhaust characteristics are:

Exhaust flow rate:	1.717 X 10^6 lb/hr
Molecular weight:	28.00 lb/lb-mole
Temperature:	770 °F
Water content:	11.96%
Oxygen content:	11.63%

The above parameters include tempering air flow rate of 34,000 lbs/hr. The following calculations convert the exhaust flow rate to standard condition, i.e., 15% O_2, dry.

$$O_2(dry) = \frac{O_2(wet)}{1 - w\%} = 13.21\%$$

$$Q\ (\text{MMscf}) = M\ (\text{MMlbs}) / MW\ (\text{lb/lb-mole}) * 379.5\ \text{scf/lb-mole} * \frac{20.9\% - O_2(dry)}{20.9\% - 15\%} * (1 - w\%)$$

Exhaust @15% O_2, dry: 26.70 MMscf

Emission factors of NOx, CO, VOC, and PM10 are derived from the manufacturer guaranteed data. Emission factors of SOx are calculated using the net emission factor of 0.168 lb/MMscf.

The following table shows the hourly emissions of one gas turbine corrected to the standard condition, i.e., 15% O_2, dry.

Table A-2 Criteria Pollutants Emissions during Normal Operation, 65 °F

	BACT limits	Emission Factor (lbs/mmscf)	Hourly Emissions (lbs/hour)
NOx	2.5 ppmv	8.96[2]	8.09[1]
CO	4 ppmv	8.84[2]	7.88[1]
VOC	2.0 ppmv	2.80[2]	2.25[1]
PM10	Natural Gas	6.423	5.80[3]
SOx	Natural Gas	0.168	0.15[3]

1. (lbs/hr) = (26.70 mmscf)*(ppmv)/(379.5 scf/lb-mole)*(MW lb/lb-mole)
2. (lbs/mmscf) = (lbs/hr)/(0.903 mmscf/hr)
3. (lbs/hr) = (Emission Factor in lbs/mmscf)*(0.903 mmscf/hr)

3. EMISSIONS FROM SHUT DOWN

Shutdown is the process of bringing down the load of the CTG to zero. It typically takes 10 minutes to conclude the shutdown process for a GE LMS100 gas turbine. LADWP used the same emission factors of the shutdown process of the CPV Sentinel project with one exception of NOx emission rates. According to LADWP, the latest information provided by GE indicate that NOx emissions during a shutdown would be 0.2 lbs. LADWP choose to assume NOx emissions to be 3 lb. The increase of NOx emissions from 0.2 lbs to 3.0 lbs is intended to include a safety margin and to ensure compliance.

Table A-3 Shutdown Emissions

Parameter	Value
Duration (minutes)	10
Heat Input (MMBtu, LHV)	26.0
Heat Input (MMBtu, HHV)	28.9
Fuel Usage (MMscf)	0.029
NOx (lbs)	3.0
CO (lbs)	35.0
VOC (lbs)	3.0
PM10 (lbs)	0.22
SOx (lbs)	0.02

4. MONTHLY TOTAL EMISSIONS – NORMAL OPERATION

Once the gas turbine generators start commercial operation LADWP expects the units may operate continuously at full load in some days and at partial load in other days. A hypothetical monthly operating schedule is presented, assuming that there are 31 days in the month. This schedule is considered for PTE calculations.

Full load continuous operation: 22 days, 24 hours per day that includes 6 startups (150 minutes total), 6 shutdowns (60 minutes total), and 20.5 hour normal operation

Full load partial operation: 9 days, each day includes 2 startups, 2 shutdowns, and 8 hours normal operation

Based on the above schedule there are 150 (6*22+2*9) startups, 150 (6*22+2*9) shutdowns, and 523 (20.5*22+8*9)total hours of normal operation in a calendar month. Using the emission rates calculated in the previous three sections the monthly emissions are calculated and summarized in the next table.

Table A-4 Monthly Total Emissions – Normal Operation

	NOx	CO	VOC	PM10	SOx
Startups– 150 events (lbs)	3,000	2,384	645	275	8
Shutdowns – 150 events (lbs)	450	5,250	450	33	3
Regular Operation – 523 hours (lbs)	4,231	4,121	1,177	3,033	79
Monthly total (lbs)	7,681	11,755	2,272	3,341	90

Total fuel consumption is:

$$150*0.247 + 150*0.029 + 523*0.903 = 513.70 \text{ mmscf/month}$$

The equivalent emission factors are:

Table A-5 Average Emission Factors – Normal Operation

	NOx	CO	VOC	PM10	SOx
Average Emission Factor (lbs/mmscf)	14.95	22.88	4.42	6.50	0.57

5. EMISSIONS FROM NATURAL GAS COMMISSIONING

PROCESS DESCRIPTION

The combustion turbine generators must first be commissioned to the desired performance before they begin regular service. The commissioning is a dedicated process that is generally prescribed by the turbine manufacturer. In the case of the GE LMS100 generators the manufacturer GE provides a 7-step commissioning process. GE estimates that it will take 104 hours to accomplish the commissioning. The LADWP decides to assign 152 hours for the commissioning, which are the same hours as the CPV Sentinel Project GE LMS100 generators. In addition, the LADWP adds 24 hours for SCR system testing and stack/RATA testing to the commissioning schedule. In all the commissioning will be a 9-step process, and will take 176 hours. The commissioning will be concluded in 12 days.

A maximum of three gas turbines will be commissioned during a month. However, only two turbines will be commissioned simultaneously during a month.

The following table describes the commissioning process.

Table A-6 Commissioning Schedule

	Description	Duration
Step 1	Checking and inspection, unfired	Included in Step 2 in Day 1
Step 2	First fire and shutdown to check leaks	23 hours in Day 1
Step 3	Synch and check Emergency-stop	17 hours in Day 2
Step 4	Automatic Voltage Regulator (AVR) commissioning	17 hours in Day 3
Step 5	Break-in run	12 hours in Day 4
Step 6	Dynamic commissioning of AVR	60 hours in Days 5-9
Step 7	Base load AVR commissioning	23 hours in Day 10
Step 8	SCR testing	12 hours in Day 11
Step 9	Stack/RATA testing	12 hours in Day 12

EMISSIONS CALCULATIONS

- Step 1 – Checking and Inspection

As the gas turbine is unfired there will not be any emissions.

- Step 2 – First Fire and Shutdown to Check Leaks

Heat input will be 81.6 MMBtu/hr and the fuel consumption will be 0.081 MMscf/hr. Based on the heat input the gas turbines are running at about 10% load. NOx, CO, and VOC emissions of this step are provided by GE. PM10 and SOx emissions are calculated in the next table.

Table A-7 Step 2 Emissions

	Emission Factors	Fuel/Heat Input	Emissions (lb/hr)	Totals (lbs)
NOx				256.0
CO				1045.0
VOC				27.0
PM10	0.0066 lb/MMBtu	81.6 MMBtu/hr	0.54	12.4
SOx	0.60 lb/MMscf	0.081 MMscf/hr	0.05	1.12

Total emissions of the step are calculated by multiplying the hourly emission rates by 23 hours.

- Step 3 – Synch and Check Emergency-stop

Heat input will be 81.6 MMBtu/hr and the fuel consumption will be 0.081 MMscf/hr. Based on the heat input the gas turbines are running at about 10% load. NOx, CO, and VOC emissions of this step are provided by GE. PM10 and SOx emissions are calculated in the next table.

Table A-8 Step 3 Emissions

	Emission Factors	Fuel/Heat Input	Emissions (lb/hr)	Totals (lbs)
NOx				188.0
CO				772.0
VOC				20.0
PM10	0.0066 lb/MMBtu	81.6 MMBtu/hr	0.54	9.2
SOx	0.60 lb/MMscf	0.081 MMscf/hr	0.05	0.85

Total emissions of the step are calculated by multiplying the hourly emission rates by 17 hours.

- Step 4 – Automatic Voltage Regulator (AVR) Commissioning

Heat input will be 103.0 MMBtu/hr and the fuel consumption will be 0.103 MMscf/hr. Based on the heat input the gas turbines are running at about 15% load. NOx, CO, and VOC emissions of this step are provided by GE. PM10 and SOx emissions are calculated in the next table.

Table A-9 Step 4 Emissions

	Emission Factors	Fuel/Heat Input	Emissions (lb/hr)	Totals (lbs)
NOx				356.0
CO				514.0
VOC				12.0
PM10	0.0066 lb/MMBtu	103.0 MMBtu/hr	0.68	11.56
SOx	0.60 lb/MMscf	0.103 MMscf/hr	0.06	1.02

Total emissions of the step are calculated by multiplying the hourly emission rates by 17 hours.

- Step 5 – Break-in Run

Heat input will be 103.0 MMBtu/hr and the fuel consumption will be 0.103 MMscf/hr. Based on the heat input the gas turbines are running at about 15% load. NOx, CO, and VOC emissions of this step are provided by GE. PM10 and SOx emissions are calculated in the next table.

Table A-10 Step 5 Emissions

	Emission Factors	Fuel/Heat Input	Emissions (lb/hr)	Totals (lbs)
NOx				251.0
CO				363.0
VOC				9.0
PM10	0.0066 lb/MMBtu	103.0 MMBtu/hr	0.68	8.16
SOx	0.60 lb/MMscf	0.103 MMscf/hr	0.06	0.72

Total emissions of the step are calculated by multiplying the hourly emission rates by 12 hours.

- Step 6 – Dynamic commissioning of AVR

This step is divided into 10 separate tasks. Heat input and fuel consumption rate are different for each task. NOx, CO and VOC emissions are provided by GE. PM10 and SOx emissions are calculated by fuel input and AP-42 standard emissions factors.

Table A-11 Step 6 Emissions

[illegible]	Duration (Hour)	Heat Input (MMBtu/hr)	Fuel (MMscf/hr)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 [1] (lbs)	SOx [2] (lbs)
Task #1	6	184.3	0.184	100	416	32.0	7.3	0.7
Task #2	6	273.1	0.272	148	272	16.0	10.8	1.0
Task #3	6	354.1	0.353	192	272	16.0	14.0	1.3
Task #4	6	431.8	0.430	234	240	16.0	17.1	1.5
Task #5	6	507.3	0.506	276	198	17.0	20.1	1.8
Task #6	6	582.8	0.581	317	270	20.0	23.1	2.1
Task #7	6	656.0	0.654	356	371	24.0	26.0	2.4
Task #8	6	731.5	0.729	398	524	31.0	29.0	2.6
Task #9	6	808.1	0.805	438	774	44.0	32.0	2.9
Task #10	6	885.8	0.883	482	1184	72.0	35.1	3.2
Total	60	32,488.8	32.382	2,941	4,521	288.0	214.4	19.4

1. Based on an emission factor of 0.0066 lb/mmBtu
2. Based on an emission factor of 0.60 lb/mmscf

The total emissions of this step are shown in the last row of the above table.

- Step 7 – Base Load AVR Commissioning

Heat input will be 885.8 MMBtu/hr and the fuel consumption will be 0.883 MMscf/hr. Based on the heat input the gas turbines are running at about 100% load. NOx, CO, and VOC emissions of this step are provided by GE. PM10 and SOx emissions are calculated in the next table.

Table A-12 Step 7 Emissions

	Emission Factors	Fuel/Heat Input	Emissions (lb/hr)	Totals (lbs)
NOx				1,844
CO				4,535
VOC				275.0
PM10	0.0066 lb/MMBtu	885.8 MMBtu/hr	5.85	134.5
SOx	0.60 lb/MMscf	0.883 MMscf/hr	0.53	12.2

Total emissions of the step are calculated by multiplying the hourly emission rates by 23 hours.

- Step 8 – SCR Testing

Heat input will be 885.8 MMBtu/hr and the fuel consumption will be 0.883 MMscf/hr. Based on the heat input the gas turbines are running at about 100% load. NOx, CO, and VOC emissions of this step are provided by GE. PM10 and SOx emissions are calculated in the next table.

Table A-13 Step 8 Emissions

	Emission Factor	Fuel/Heat Input	Emissions (lb/hr)	Totals (lbs)
NOx				962
CO				2,366
VOC				143.0
PM10[1]	0.00749 lb/MMBtu	885.8 MMBtu/hr	6.63	79.6
SOx[1]	0.168 lb/MMscf	0.883 MMscf/hr	0.15	1.78

1. Net emission factors with conversion in SCR (see Page59 & 60)

Total emissions of the step are calculated by multiplying the hourly emission rates by 12 hours.

- Step 9 – Stack RATA testing

Heat input will be 885.8 MMBtu/hr and the fuel consumption will be 0.883 MMscf/hr. Based on the heat input the gas turbines are running at about 100% load. NOx, CO, and VOC emissions of this step are provided by GE. PM10 and SOx emissions are calculated in the next table.

Table A-14 Step 9 Emissions

	Emission Factor	Fuel/Heat Input	Emissions (lb/hr)	Totals (lbs)
NOx				962
CO				2,366
VOC				143.0
PM10[1]	0.00749 lb/MMBtu	885.8 MMBtu/hr	6.63	79.6
SOx[1]	0.168 lb/MMscf	0.883 MMscf/hr	0.15	1.78

1. Net emission factors with conversion in SCR (see Page 59 & 60)

Total emissions of the step are calculated by multiplying the hourly emission rates by 12 hours.

- Summary – Natural Gas Commissioning

Total operating hours, total fuel consumption, and total emissions are tabulated in the next table. Average emission rates are also calculated.

Table A-15 Natural Gas Commissioning Summary

	Duration (Hour)	Heat Input (MMBtu)	Fuel (MMscf)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs)
Step #1	0	0	0	0	0	0	0.00	0.00
Step #2	23	1,876.8	1.869	256	1,045	27	12.40	1.12
Step #3	17	1,387.2	1.382	188	772	20	9.20	0.85
Step #4	17	1751	1.744	356	514	12	11.56	1.02
Step #5	12	1236	1.231	251	363	9	8.16	0.72
Step #6	60	32,488.8	32.359	2,941	4,521	288	214.43	19.43
Step #7	23	20,373.4	20.292	1,844	4,535	275	134.50	12.20
Step #8	12	10,629.6	10.587	962	2,366	143	79.60	1.78
Step #9	12	10,629.6	10.587	962	2,366	143	79.60	1.78
Total	176	80,372.4	80.05	**7,760**	**16,482**	**917**	**549.4**	**38.9**

The average emission factors during the commissioning is presented in the next table.

Table A-16 Average Emission Factors of the Commissioning

	NOx	CO	VOC	PM10	SOx
Emission Factor (lb/MMscf)	96.94	205.89	11.46	6.86	0.49

<u>Monthly Averaged Emissions – Normal Operations + Natural Gas Commissioning</u>

The highest monthly total emissions are calculated for the purpose of determining emission increases, which are the total emissions of a calendar month divided by 30. The calendar month that includes the commissioning will have the highest emissions. For calculation purposes it is assumed that the month includes 12 days of the commissioning and 19 days of normal operation. The 19 days of normal operation consists of 6 startups per day, 6 shutdowns per day, and 20.5 hours of full load operation per day.

The next table calculates the monthly total emissions.

Table A-17 Monthly Total Emissions – Normal Operations + Commissioning

	NOx	CO	VOC	PM10	SOx
Commissioning – 12 days (lbs)	7,760	16,482	917	549	39
Startups, 19 days (lbs) – 114 events	2,280	1,811	490	209	6
Shutdowns, 19 days (lbs) – 114 events	342	3,990	342	25	2
Normal Operation, 19 days (lbs) – 389.5 hours	3,151	3,069	877	2,259	59
Monthly total (lbs)	13,533	25,352	2,626	3,042	106
30-Day Average Emissions (lb/day)	451.1	845.1	87.5	101.4	3.5

Monthly fuel usage:

Fuel = 80.05 mmscf + 19*(6*0.247+6*0.029+20.5*0.903)
= 463.26 mmscf/month

The average emission factors during the normal operations with commissioning is presented in the next table.

Table A-18 Average Emission Factors of the Normal Operations + Commissioning

	NOx	CO	VOC	PM10	SOx
Emission Factor (lb/MMscf)	29.21	54.73	5.67	6.57	0.23

6. NOX EMISSIONS OF THE INTERIM PERIOD

The interim period is defined as a period up to one year from the start of operation until the NOx CEMS is certified. Even though the NOx CEMS is not yet certified during the interim period, it is believed that after commissioning the SCR would be operating properly. Therefore, the NOx emissions are calculated based on 2.5 ppmv.

Based on the information provided by LADWP on October 5, 2010 the first year NOx emissions are calculated based on the following operating schedule:

Number of startups:	1,095
Number of shutdowns:	1,095
Normal operation hours:	4,348
Operation capacity factor:	59%

The first year interim period NOx emissions are, not including commissioning:

NOx = 1,095*20.0 + 1,095*3.0 + 4,348*8.09
NOx = 60,360.3 lbs

Total fuel usage (in mmscf):

Natural Gas = 1,095*0.247 +1,095*0.029 + 4,348* 0.903
Natural Gas = 4,228.46 mmscf

Thus, NOx emission factor for the interim period (not including the commissioning) is:

NOx emission factor = 14.27 lbs/mmscf

7. NOX ANNUAL EMISSIONS (after commissioning is completed)

Based on the information provided by LADWP on October 5, 2010 the annual NOx emissions are calculated based on the following operating schedule:

Number of startups:	1,095
Number of shutdowns:	1,095
Normal operation hours:	4,524 (4348+176)
Operation capacity factor:	59%

The number of normal operation hours are higher than the 1st year due to the commissioning activities of the 1st year.

Therefore,

NOx = 1,095*20.0 + 1,095*3.0 + 4,524*8.09
NOx = 61,784.2 lbs

APPENDIX B CRITERIA POLLUTANTS EMISSIONS – AUXILIARY EQUIPMENT

1. Standby Generators

The project includes two diesel fueled standby generator engines. The following specifications are used in emission calculations:

Engine Manufacturer	Caterpillar
Engine Model Number	3516C DITA
Engine brake horsepower (BHP)	3,622
Engine Power Output (KW)	2,500
Fuel:	#2 CARB Diesel (7.5 lbs/gal)
Fuel Usage (Gallons/hour):	173.3
Annual Operation Limit (hours):	200
Annual Maintenance Limit (hours):	50

The following emission factors are proposed by the applicant and warranted by the manufacturer.

NOx (grams/bhp-hr)	3.7	
CO (grams/bhp-hr)	0.67	
VOC (grams/bhp-hr)	0.25	
PM (grams/bhp-hr)	0.07	before the particulate filter
	0.007	after the diesel particulate filter

SOx emission factor is extrapolated by assuming the CARB diesel contains less than 15 ppm sulfur as H_2S. One pound of H_2S would convert to 64/34 pounds of SO_2 or SOx.

SOx (lb/lb diesel)	$28.2 * 10^{-6}$
SOx (lb/Mgal)	$28.2 * 10^{-6} * 1000 * 7.5 = 0.21$

Emission increases are then calculated by assuming 50 hours of annual maintenance, or 4.2 hours per month (1 hour per week).

Table B-1 Emissions of the Standby Generators

[illegible]	NOx	CO	VOC	PM10	SOx
Hourly (lbs/hour)	29.55[1]	5.35[1]	2.0[1]	0.056[1]	0.037[2]
Monthly (lbs/month)[3]	123.1	22.3	8.3	0.2	0.2
Emission Increase (lbs/day, 30-day Avg.)	4.10	0.74	0.28	0.01	0.01

1. (lbs/hr) = (gram/bhp-hr)*(3622 bhp)/(453.4 grams/lb)
2. (lbs/hr) = (173.3 gal/hr)*(0.21 lb/Mgal)
3. (lbs/month) = (lbs/hour)*(50 hours/year)/(12 months/year)

2. Diesel Storage Tank

The project includes one 15,000 gallons diesel storage tank. The specifications of the tank are:

Type:	Horizontally placed cylindrical above ground
Tank diameter:	10 ft
Tank length:	25.5 ft
Volume:	15,000 gallons
Annual turnovers:	5
Vacuum setting:	no vent valve
Pressure setting:	no vent valve

Breathing loss and working loss are expected from the tank. The emissions are considered as VOC, and are calculated by using the EPA's Tank program. The detailed calculation spreadsheets are included in the application folder. The results are:

Annual Breathing Loss:	3.6 lbs
Annual Working Loss:	1.88 lbs
Total Loss:	5.48 lbs/year

The monthly average is 0.46 lbs/month. The 30-day average emissions are 0.015 lbs/day.

3. Oil Water Separators

The project includes three identically sized oil water separators. The specifications of the oil water separators are:

Type:	Horizontally placed cylindrical above ground
Count:	3
Tank diameter:	5 ft
Tank length:	10 ft
Volume:	2,100 gallons
Annual turnovers:	52
Vacuum setting:	no vent valve
Pressure setting:	no vent valve

Working loss and breathing loss are expected from the oil water separators. The emissions are considered as VOC, and are calculated using EPA's Tank program. The detailed calculation spreadsheets are included in the application folder. The results are summarized below:

Annual Breathing Loss:	0 lbs
Annual Working Loss:	5.27 lbs
Total Loss:	5.27 lbs/year

The monthly average is 0.44 lbs/month. The 30-day average emissions are 0.015 lbs/day.

APPENDIX C EMISSION OFFSETS

1. Emission Reduction Credits (ERC) Requirements of the Gas Turbine Generators

In order to determine the offset required for this project the monthly averaged emission increases in terms of potential to emit (PTE) must be calculated.

For PTE determinations only the worst polluting operation scenario is considered. The following monthly operating schedules are considered for PTE determinations:

1. Monthly Operation Schedule #1

Total calendar days:	31
Total days undergoing commissioning:	12
Total days normal operation at 100% load:	19
Each day consists of:	6 startups totaling 150 minutes, 2.5 hours 6 shutdowns totaling 60 minutes, 1.0 hour remaining operating at 100% load, 20.5 hours

The following table contains the emissions associated with each gas turbine as calculated in Appendix A and summarized in Table A-17.

Table C-1 Monthly Total Emissions – Operation Case #1

	NOx	CO	VOC	PM10	SOx
Commissioning – 12 days (lbs/month)	7,760	16,482	917	549	39
Regular Operation – Startups (19 days, 114 events)	2,280	1,811	490	209	6
Regular Operation – Shutdowns (19 days, 114 events)	342	3,990	342	25	2
Regular Operation – 100% load (19 days, 389.5 hours)	3,151	3,069	877	2,259	59
Monthly total (lbs/month)	13,533	25,352	2,626	3,042	106
30-Day Average Emissions (lb/day)	**451.1**	**845.1**	**87.5**	101.4	3.5

2. Monthly Operation Schedule #2

Total calendar days:	31
Total days undergoing commissioning:	12
Total days normal operation at 100% load:	19
Each day consists of:	operating at 100% load, 24 hours

The following table contains the emissions associated with each gas turbine.

Table C-2 Monthly Total Emissions – Operation Case #2

	NOx	CO	VOC	PM10	SOx
Commissioning – 12 days (lbs/month)	7,760	16,482	917	549	39
Regular Operation – 100% load (lbs/month)[1]	3,689	3,593	1,026	2,645	68
Monthly total (lbs/month)	11,449	20,075	1,943	3,194	109
30-Day Average Emissions (lb/day)	381.6	669.2	64.8	**106.5**	**3.6**

1. (lbs/month) = (lbs/hr from Table A-2)*(24 hrs/day)*(19 days/month)

The amounts of required offsets are calculated by using the highest emissions of the above two operating scenarios (worst-case emissions), which are summarized in the following table (Table C-3). This repower project proposed by LADWP will result in an increase of 12.2 MW electrical output (from 604 MW to 616.2 MW). As a result, LADWP needs to provide ERC to comply with the offset requirement for the megawatts exceeding the original capacity (12.2 MW for 6 gas turbines or 2.03 MW per gas turbine). Since the above emissions are calculated for each gas turbine with an electrical output of 102.7 MW, a factor of 0.0198 (2.03/102.7) will be used to calculate the amount of ERC required to comply with the offset requirement. The offset (ERC) calculations are also summarized in the following table (Table C-3):

Table C-3 Worst-Case Emissions and Offset (ERC) Calculations

	NOx	CO	VOC	PM10	SOx
Worst-Case Emission (lbs/day/turbine)	451.1	845.1	87.5	106.5	3.6
Emission Increase [1] (lbs/day/turbine)	8.93	16.73	1.73	2.11	0.07
Emission Increase (lbs/day for 6 turbines)	53.58	100.38	10.38	12.65	0.42
ERC Required @ 1.2-to-1.0 ratio (lbs/day for 6 turbines)	N/A[2]	N/A[3]	12	15	0

1. (Emission Increase) = (Worst-Case Emission)*0.0198
2. NOx is a RECLAIM pollutant (offset by RTC)
3. CO is an attainment pollutant (no offset is required)

2. Emission Reduction Credits (ERC) Requirements of PM2.5

The facility needs to offset the PM2.5 emissions in accordance with 40CFR Subpart Z Appendix S. The repower project has emission increases from the new gas turbine units and emission reductions from shut down of the Units 5 and 6 boiler generators. According to Appendix S the contemporaneous emission reductions is calculated based on the 5-year look back period, and the baseline emissions are the 24-month rolling average in the 5-year period. Therefore, LADWP has compiled the emissions data of the two boilers, Units 5 and 6, of the last five years. The fuel usage data were provided to AQMD on October 29, 2010.

For Unit 5, the highest 24-month rolling average fuel usage is between March 2008 to February 2010. The averaged annual fuel usage is:

Unit 5: 5,401.344 MMscf/year

For Unit 6, the highest 24-month rolling average fuel usage is between February 2006 to January 2008. The averaged annual fuel usage is:

Unit 6: 3,049.592 MMscf/year

The total fuel usage for Units 5 and 6 is 8,450.936 MMscf/year.

Assuming the emission factor of 7.6 lbs/MMscf which is determined from previous PM10 source tests for the boilers (assume PM10 = PM2.5), the baseline emissions are:

8,450.936 * 7.6 / 2000 = 32.11 tons/year (baseline PM2.5 emissions)

The new units PM2.5 emissions are calculated in the next table. The emission factors for PM10 have been calculated in Tables A-1, A-2, and A-3. The annual operation schedule is provided in Appendix A-7. The PM2.5 emissions are assumed to be the same as PM10 emissions for the gas turbines.

Table C-3 PM2.5 Annual Emissions Per Turbine

	Event	Emission Factor	Total (lbs)
Startup	1,095 times	1.836 lbs/time	2,010
Shutdown	1,095 times	0.22 lbs/time	241
Normal Operation	4,524 hours	5.8 lbs/hr	26,239
Total (lbs/year/turbine)			28,490

Therefore, the six units total is:

28,490 * 6 = 170,940 lbs/year

The emergency IC engine annual PM2.5 emissions are calculated based on 50 hours/year.

2 * 50 * 0.056 lbs/hr = 6 lbs/year

Total annual PM2.5 emissions are:

170,940 + 6 = 170,946 lbs = 85.473 tons/year

The net emissions increase is:

85.473 - 32.11 = 53.363 ton/year, 292.4 lbs/day (based on 365 days/year)

LADWP will be required to provide 292 pounds per day of federally enforceable PM2.5 emission reduction credits unless a different amount associated with the Repower Project modification at this facility as determined to be required according to the federal New Source Review (NSR) requirements (40CFR Part 51 Subpart Z Appendix S), as approved by both AQMD and EPA.

3. Emission Reduction Credits (ERC) Requirements of the Standby Generators

Non-RECLAIM pollutants offset are not required for emergency IC engines as per Rule 1304(a)(4).

4. RECLAIM Trading Credits (RTC) Requirements of the Gas Turbines

NOx emissions are to be mitigated through RTC since LADWP Haynes participates in the NOx RECLAIM program. RTC is calculated based the annual NOx emission increases.

The following two scenarios are considered for RTC requirements.

1. First year

The gas turbines are expected to be operating under a load factor of 59%. However for the first year the hours of normal operation are reduced because of commissioning. The gas turbines are to have 6 startups and 6 shutdowns per day. On the annual basis LADWP is proposing to allow 1,095 startups, 1,095 shutdowns, and 4,348 hours of normal operation. The first year includes the initial 12-day commissioning process. The following table determines the anticipated annual NOx emissions from one gas turbine. The emission factors and emission data have been calculated in Appendix A.

Table C-4 First Year RTC Requirement (lbs/gas turbine)

[illegible]	Event	Emission Factor	Total (lbs)
Startup	1,095 times	20.0 lbs/time	21,900
Shutdown	1,095 times	3.0 lbs/time	3,285
Normal Operation	4,348 hours	8.09 lbs/hr	35,175
Commissioning	176 hours		7,760
Total (lbs/year/turbine)			68,120

2. Each year after the 1st year

After the first year the gas turbine generators are expected to assume the same 59% load factor. Commissioning will not be a part of the operation, however. Therefore, annual operation will include 1,095 startups, 1,095 shutdowns, and 4,524 hours of normal operation. The following table provides the annual NOx emissions.

Table C-5 Subsequent Year RTC Requirement (lbs/gas turbine)

	Events	Emission Factor	Total (lbs)
Startup	1,095 times	20.0 lbs/time	21,900
Shutdown	1,095 times	3.0 lbs/time	3,285
Normal Operation	4,524 hours	8.09 lbs/hr	36,599
Total (lbs/year/turbine)			61,784

5. RECLAIM Trading Credits (RTC) Requirements of the Standby Generators

NOx emissions from the standby generators are not exempted from offset under RECLAIM rules. The annual RTC requirements are based on 50 hours operation per year and an hourly NOx emission rate of 29.55 lbs/hr (see Table B-1).

RTC = 29.55 * 50 = 1,478 lbs

As there are two standby generators the total requirements are 2,956 lbs RTC.

6. RECLAIM Trading Credits (RTC) Requirements of the Project

For the 1st year the total requirements are:

68,120 * 6 + 2,956 = 411,676 lbs/year

For the 2nd and subsequent years the total requirements are:

61,784 * 6 + 2,956 = 373,660 lbs/year

APPENDIX D <u>HAZARDOUS AIR POLLUTANT EMISSIONS</u>

1. Gas Turbine Generators

Hazardous air pollutants (HAP) are products of gas turbine combustion. Total emissions are calculated based on the following parameters:

Annual hours of operation:	4,524 hours
Startups per year:	1,095
Shutdowns per year:	1,095
Fuel flow rate, normal operation:	0.903 MMscf/hr
Fuel flow rate, per startup:	0.247 MMscf
Fuel flow rate, per shutdown:	0.029 MMscf
Annual total fuel usage:	4,387.39 MMscf/year

The hazardous air pollutants and the emission factors are listed in the next table.

Table D-1 HAP Emissions from Each Gas Turbine

Hazardous Air Pollutant	Air Toxic Case Number	Emission Factor (lb/MMscf)	Annual Emissions (lb/year)	Annual Emissions (tons/year)
1,3-Butadiene	106990	4.32E-04	1.90E+00	9.48E-04
Acetaldehyde	75070	4.02E-02	1.76E+02	8.82E-02
Acrolein	107028	3.63E-03	1.59E+01	7.96E-03
Benzene	71432	3.27E-03	1.43E+01	7.17E-03
Ethylbenzene	100414	3.21E-02	1.41E+02	7.04E-02
Formaldehyde	50000	3.61E-01	1.58E+03	7.92E-01
Propylene Oxide	75569	2.91E-02	1.28E+02	6.38E-02
Toluene	108883	1.31E-01	5.75E+02	2.87E-01
Xylenes	1330207	6.43E-02	2.82E+02	1.41E-01
Acenaphthene	83329	1.90E-05	8.34E-02	4.17E-05
Acenaphthylene	208968	1.47E-05	6.45E-02	3.22E-05
Anthracene	120127	3.38E-05	1.48E-01	7.42E-05
Benzo(a)anthracene	56556	2.26E-05	9.92E-02	4.96E-05
Benzo(a)pyrene	50328	1.39E-05	6.10E-02	3.05E-05
Benzo(b)fluoranthene	205992	1.13E-05	4.96E-02	2.48E-05

Benzo(e)pyrene	192972	5.44E-07	2.39E-03	1.19E-06
Benzo(g,h,i)perylene	191242	1.37E-05	6.01E-02	3.01E-05
Benzo(k)fluoranthene	207089	1.10E-05	4.83E-02	2.41E-05
Chrysene	218019	2.52E-05	1.11E-01	5.53E-05
Indeno(1,2,3-cd)pyrene	193395	2.35E-05	1.03E-01	5.16E-05
Naphthalene	91203	1.66E-03	7.28E+00	3.64E-03
Diebenz(a,h)anthracene	53703	2.35E-05	1.03E-01	5.16E-05
Fluoranthene	206440	4.32E-05	1.90E-01	9.48E-05
Fluorene	86737	5.80E-05	2.54E-01	1.27E-04
Phenanthrene	85018	3.13E-04	1.37E+00	6.87E-04
Pyrene	129000	2.77E-05	1.22E-01	6.08E-05
Total			2.93E+03	1.46E+00

Thus, the anticipated emissions of HAP are 1.46 tons/year for each gas turbine. For the six turbines the total HAP emissions are 8.784 tons per year.

2. Standby Generators

The two diesel fueled standby generators are expected to emit hazardous air pollutants. The HAP emissions are calculated based on the following parameters:

Annual hours of operation:	50 each engine
Fuel usage:	173.3 gallons/hour
Annual fuel usage:	8.665 Mgal

The hazardous air pollutants and the emission factors are listed in the next table.

Table D-2 HAP Emissions from Each Standby Generator

Hazardous Air Pollutant	Air Toxic Case Number	Emission Factor (lb/Mgal)	Annual Emissions (lb/year)	Annual Emissions (tons/year)
Benzene	71432	0.1862	1.61E+00	8.07E-04
Formaldehyde	50000	1.7261	1.50E+01	7.48E-03
PAHs (including naphthalene)	107028	0.0559	4.84E-01	2.42E-04
Naphthalene	91203	0.0197	1.71E-01	8.54E-05
Acetaldehyde	75070	0.7833	6.79E+00	3.39E-03
Acrolein	1070208	0.0339	2.94E-01	1.47E-04

1,3-Butadiene	106990	0.2174	1.88E+00	9.42E-04
Chlorobenzene	108907	0.0002	1.73E-03	8.67E-07
Propylene	115071	0.4670	4.05E+00	2.02E-03
Hexane	110543	0.0269	2.33E-01	1.17E-04
Toluene	108883	0.1054	9.13E-01	4.57E-04
Xylenes	1330207	0.0424	3.67E-01	1.84E-04
Ethyl Benzene	100414	0.0109	9.44E-02	4.72E-05
Hydrogen Chloride	7647010	0.1863	1.61E+00	8.07E-04
Arsenic	7440382	0.0016	1.39E-02	6.93E-06
Cadmium	7440439	0.0015	1.30E-02	6.50E-06
Total Chromium	7440473	0.0006	5.20E-03	2.60E-06
Hexavalent Chromium	18540299	0.0001	8.67E-04	4.33E-07
Copper	7440508	0.0041	3.55E-02	1.78E-05
Lead	7439921	0.0083	7.19E-02	3.60E-05
Manganese	7439965	0.0031	2.69E-02	1.34E-05
Mercury	7439976	0.0020	1.73E-02	8.67E-06
Nickel	7440020	0.0039	3.38E-02	1.69E-05
Selenium	7782492	0.0022	1.91E-02	9.53E-06
Zinc	7440666	0.0224	1.94E-01	9.70E-05
Diesel Particulates	N/A	0.056	2.80E+00	1.40E-03
Total			3.67E+01	1.83E-02

Note diesel particulates has been classified as a hazardous air pollutant. The emission rate is assumed to the same as the PM, which is 0.056 lbs/hr.

Therefore, the total HAP emissions from the two diesel standby generators are 0.037 tons/year.

3. Facility Total Formaldehyde Emissions

According to the data provided by LADWP, Table 4-29 of the Application for Permit to Construct and Operate Units 11 through 16 Haynes Simple Cycle Generating System, the existing equipment's formaldehyde emissions are:

Combine cycle gas turbine generator Units 9 and 10:	13,694 lbs/year
Boiler generator Units 1 and 2:	141 lbs/year

As calculated in the Table D-1 the SCGS Units 11-16 each has a potential of 1,584 lbs/year. The total of the six unit is 9,504 lbs/year. Thus, including the SCGS the facility total is:

Facility total: 23,339 lbs/year, or 11.7 tons/year