South Coast
Air Quality Management District
South Coast AQMD
21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 · www.aqmd.gov

April 30, 2013

Mr. Gerardo Rios
Chief, Permits Office
U.S. EPA, Region IX
75 Hawthorne Street
San Francisco, CA 94105-3901

SUBJECT: Pasadena City, Department of Water & Power
Facility ID No. 800168,
Facility Location: 72 E Glenarm St., Pasadena, CA 91105

Gerardo
Dear ~~Mr.~~ Rios:

The South Coast Air Quality Management District (SCAQMD) has received and reviewed permit applications for the subject power plant repowering project. Pasadena City, Department of Water & Power is proposing to add a combined cycle gas turbine located at 72 E Glenarm St., in the City of Pasadena. The new combined cycle gas turbine will replace an existing utility boiler at the facility. The City proposed two gas turbine options, General Electric or Rolls Royce, but will only be selecting one option at a later date.

Based on the emission potential, this project is subject to the public notice requirements of SCAQMD Rules 212 (Standards for Approving Permits) and 3006 (Title V), and has applied for a significant permit revision under the Title V regulation. Therefore, this project is subject to a 45-day EPA review and a 30-day public notice period under SCAQMD Rules 212, 3003, and 3006.

The SCAQMD has evaluated the subject permit applications and made a preliminary determination that the equipment will comply with all of the applicable requirements of our rules and regulations. We intend to take final action on the permit at (1) the end of the 30-day public comment and review period and after all pertinent comments have been considered, and (2) upon receiving and consideration of EPA comments on the Title V significant permit revision.

Please find enclosed SCAQMD's analyses, the draft Title V permits and the public notice for the subject project issued in accordance with SCAQMD Rules 212, 1714, and 3006. The public notice provides for a 30-day public comment period and a 45-day EPA review period prior to making a final decision on issuance of the permit. The public notice is also being published in a newspaper of general circulation in the vicinity of the project, and it is also being forwarded to other interested parties.

If you wish to provide comments or have any questions regarding this project, please contact Mr. Marcel Saulis at (909) 396-3093/ msaulis@aqmd.gov or Mr. John Yee at (909) 396-2531/ jyee@aqmd.gov.

Sincerely,

Mohsen Nazemi, P.E.
Deputy Executive Officer
Engineering and Compliance

MN
Enclosures
(usepa)

ENGINEERING EVALUATION

COMPANY NAME AND ADDRESS

City of Pasadena, Department of Water and Power
85 E State St.
Pasadena, CA 91105

CONTACT(S): Dan B. Angeles, Principal Engineer, (626) 744-6240

EQUIPMENT LOCATION

AQMD ID 800 168
72 E Glenarm St.
Pasadena, CA 91105-3418

EQUIPMENT DESCRIPTION

Section H of the facility permit: Permit to Construct

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
Process 2: INTERNAL COMBUSTION					
System 1: TURBINES					
GAS TURBINE, GT-5, NATURAL GAS, GENERAL ELECTRIC, MODEL LM6000 PG SPRINT, COMBINED CYCLE, WITH WATER INJECTION, 547.5 MMBTU/HR @ 64°F WITH A/N 538115	D56	C66	NOX: MAJOR SOURCE	**CO:** 2000 PPMV (5) [RULE 407]; CO: 2 PPMV NATURAL GAS (4) [RULE 1303 – BACT], [RULE 1703 – BACT] **NOX:** 2.0 PPMV NATURAL GAS (4) [RULE 2005], [RULE 1703 – BACT]; NOX: 42.83 LBS/MMSCF NATURAL GAS (1) [RULE 2012]; NOX: 18.79 LBS/MMSCF NATURAL GAS (1) [RULE 2012]; NOX: 25 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK]	A63.3, A99.8, A99.9, A99.10, A99.11, A195.8, A195.9, A195.10, A195.11, A327.1, A433.1, A433.2, D29.6, D29.7, D29.8, D82.4, D82.5, E193.2, E193.3, H23.5, I297.1, K40.3, K67.6
GENERATOR, SERVING GT-5, 56.1 GROSS MW @ 64°F	B57				
STEAM TURBINE, ST-5, TBD, MODEL TBD	B64				
GENERATOR, SERVING ST-5, 14.7 GROSS MW @ 64°F	B65				

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
				PM: 11 LBS/HR (5B) [RULE 475]; PM: 0.01 GRAINS/SCF (5) [RULE 475]; PM: 0.1 GRAINS/SCF (5A) [RULE 409] **SO2**: (9) [40 CFR 72 – ACID RAIN; SO2: 0.060 LB/MMBTU NATURAL GAS (8) [40 CFR 60 SUBPART KKKK] **VOC:** 2 PPMV NATURAL GAS (4) [RULE 1303 – BACT]	
CO OXIDATION CATALYST, NO. 5, EMERACHEM, MODEL TBD, FIXED BED PLATINUM, VOLUME 100 CU FT; WITH A/N: 538120	C66	D56 C67			
SELECTIVE CATALYTIC REDUCTION, NO. 5, HALDOR TOPSOE, MODEL TBD, CATALYST VOLUME 848 CU FT; WITH A/N: 538120 AMMONIA INJECTION GRID, AQUEOUS AMMONIA	C67 B68	C66 S69		**NH3:** 5 PPMV (4) [RULE 1303 – BACT]	A195.11, D12.9, D12.10, D12.13, E179.6, E179.4, E193.2
STACK, SERVING GT-5, HEIGHT: 125 FT; DIAMETER: 10.17 FT A/N 538115	S69	C67			

SUMMARY

City of Pasadena, Department of Water and Power (PDWP) operates the Glenarm power plant which has a Title V permit and is in the NOx RECLAIM program. PDWP submitted applications for Permits to Construct a combined cycle power generating unit, to be identified as GT-5, along with associated air pollution control equipment that is a significant revision to the Title V permit. The project involves the repowering the power plant by replacing an existing utility boiler (B-3) that is exempt from offsets per Rule 1304(a)(2) – Electric Utility Boiler Replacement.

The construction schedule is expected to be 23 months from when the project permitting and CEQA has been approved. The first 5 months will include demolition, asbestos abatement, site clearing, grading and excavation. The remaining 18 months will include construction. The decommissioning process for the boiler will be within 90 days from the first fire of the gas turbine commissioning process which will likely be sometime in late 2014 or early 2015.

The combined cycle equipment will either include one General Electric (GE) LM6000 SPRINT PG combustion turbine generator or alternatively one Rolls Royce Trent 60 WLE unit. PDWP will make a determination at a later date as to which option it will pursue. ***This evaluation is for the GE Option.*** The applications that were submitted are summarized in Table 1.

Table 1 Application Summary

Option	A/N	Equipment	Submittal Date	Deemed Complete	BCAT/ CCAT	Schedule	Base Fee[a]	XPP Fee	Total Filing Fees
General Electric (GE)	538115	GE LM6000 SPRINT PG Gas Turbine, 56.1 MW	6/7/12	7/2/12	033709	G	$15,811.76	$7,905.88	$23,717.64
	538120	SCR/CO Catalyst	6/7/12	7/2/12	81	C	$3,359.43	$1,679.72	$5,039.15
	538118	TV/RECLAIM Amendment	6/7/12	7/2/12	555009	-	$1,747.19	-	$1,747.19
Rolls Royce (RR)	538672	Rolls Royce Trent 60 WLE Gas Turbine, 59.2 MW	6/7/12	7/2/12	033709	G	$15,811.76	$7,905.88	$23,717.64
	538673	SCR/CO Catalyst	6/7/12	7/2/12	81	C	$3,359.43	$1,679.72	$5,039.15
	538671	TV/RECLAIM Amendment	6/7/12	7/2/12	033709	-	$1,747.19	-	$1,747.19
								Total	**$61,007.96**

There will also be an additional fee for the hours of work completed for the air quality analysis. In addition, the project triggers a school notice per Rule 212(c)(1), a public notice per Rule 212(g), and a significant modification per Rule 3006. Therefore, additional fees will be billed to the facility in accordance with Rule 301.

BACKGROUND

The City of Pasadena constructed the Glenarm power plant in 1907 and later expanded to the adjacent Broadway location, which currently consists of three steam generating units; two decommissioned boilers (B1 and B2) and one active unit (B-3). The facility currently has four natural gas fired combustion turbine generators (GT-1, GT-2, GT-3 and GT-4) which are located at the Glenarm site. The total capacity of the facility (Glenarm and Broadway) is 227 MW. The boiler (B-3) has a gross capacity of 71 MW and a net capacity of 65 MW. PDWP are proposing either a GE or RR turbine that will have a gross rating less than 71 MW, which will allow them to acquire the Rule 1304 offset exemption. The new unit, to be identified as GT-5, and a new cooling tower will be located south of the Glenarm Building. The concept plan is shown in Figure 1.

The new turbine will be configured one-on-one with a Once-Through-Steam-Generator (OTSG) prior to the post-combustion emission control equipment, which will include an oxidation catalyst, for CO and VOC reduction, and selective catalytic reduction system, for NOx reduction. In addition, the turbine will have water injection to reduce NOx levels in the exhaust prior to the control equipment. Following the installation and commissioning of the new equipment, unit B-3 will be de-commissioned and removed from service. Simultaneous operation of the new turbine and boiler is allowed up to 90 days per Rule 1313(d). The 90 day clock commences from when the gas turbine is first fired. PDWP will be required to submit a detailed retirement plan for the boiler.

The project triggers a 30 day public notice per Rule 212(c)(2). Since the new unit will be located within 1,000 ft. from an existing K-12 school, it triggers a 30 day school notice. The noticing period for Rule 212 and for the significant revision per Rule 3006 will run concurrently along with the 45 day EPA review period.

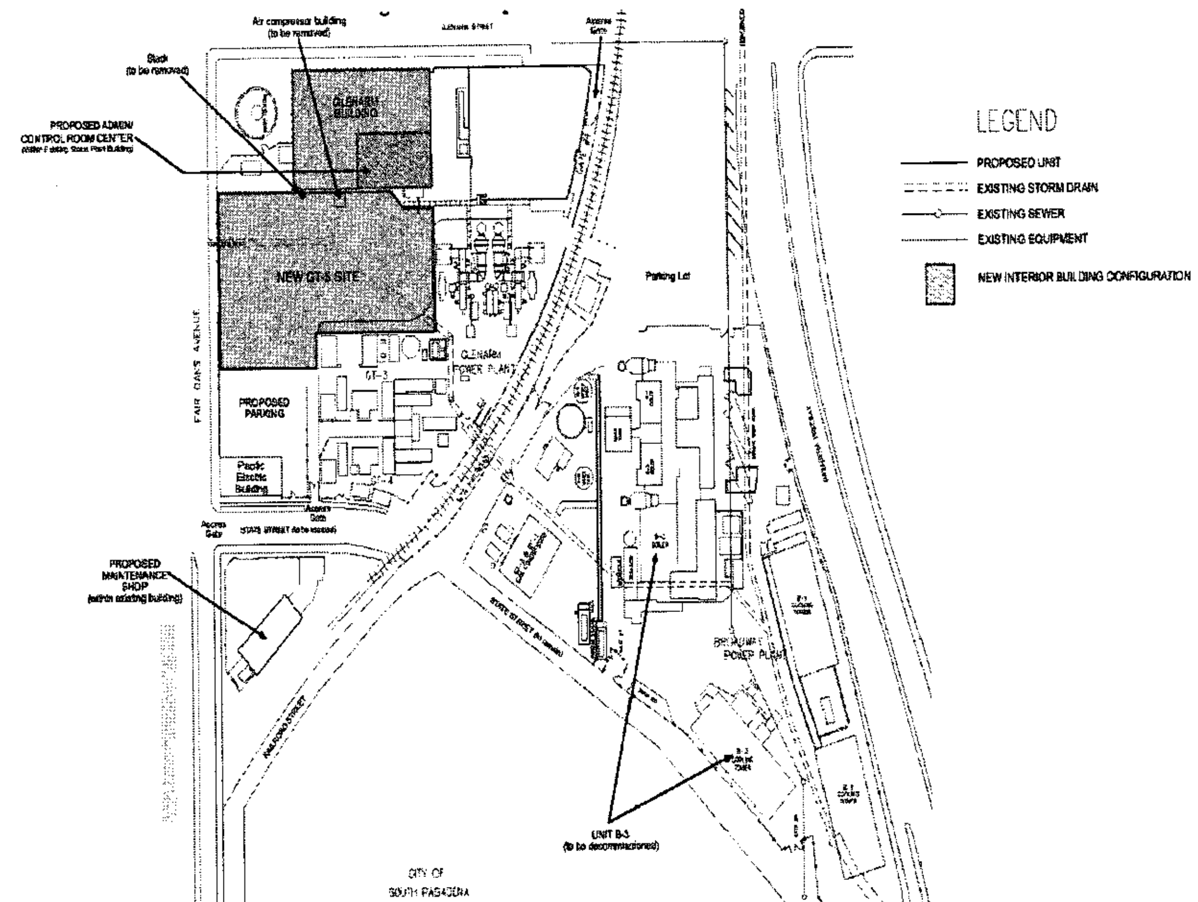

Figure 1 Proposed Location of the New GT-5 Site.

COMPLIANCE REVIEW

A review of the District Compliance database reveals that the facility received two Notices to Comply (NC) and three Notices of Violation (NOV) within the last two year period. The Notices are summarized below:

- NC D20376 was issued on 6/29/11 to the facility to provide emission records, start-up and shutdown records, CEMS calibration dates and monthly emissions. The NC was closed on 7/6/11.
- NC D20377 was issued on 7/14/11 to report records and to submit Title V for 500-ACC on time and calculate total monthly emissions. The NC was closed on 8/11/11.
- NOV P37217 was issued on 6/22/11 for unit GT-4 exceeding the 6.0 ppmv CO emission concentration as listed on the permit. The NOV was closed on 5/29/12.
- NOV P51970 was issued on 3/15/11 for device D36 exceeding the permitted shutdown period. The NOV was closed on 5/29/12.
- NOV P55663 was issued on 8/7/12 to the facility for failing to report total quarterly emissions for process units D11 and D12.

As a RECLAIM and Title V facility, inspections are conducted at this site on an annual basis.

PROCESS DESCRIPTION

GAS TURBINE GENERATOR (GTG) A/N 538118

One of the options that the city is proposing is a General Electric (GE) LM6000 SPRINT PG, which will be set-up in a combined cycle configuration with a Once-Through-Steam-Generator (OTSG) and a steam turbine. The LM6000 is an aeroderivative turbine, meaning that it is a gas turbine derived from an aircraft engine. The LM6000 PC was derived from the high bypass, turbofan CF6-80C2. The LM6000 PG is based on the GE CF6-80E aircraft engine common on many Airbus A330 fleets. The "PG" is denoted for its Standard Annular Combustor. It uses an updated High Pressure Turbine (HPT) rotor design that includes higher temperature alloys and improved cooling patterns. This raises the pounds of thrust from 60,000 to 70,000 that allows the LP compressor to operate at higher speeds to increase flow and increase pressure ratio. The combination of better materials, manufacturing process and the improvement in cooling allows the PG to operate at higher firing temperatures. The result is a 25 percent increase in simple cycle power compared to the PC as well a power increase for combined cycle operation with an increase in exhaust energy.

For a Singular Annular Combustor model, water is used for NOx abatement and for power augmentation. The water will be demineralized by reverse osmosis and an ion exchange system and will be stored in demineralized storage tanks. Approximately 2/3 of water consumption is used for NOx abatement and the remainder is used for SPRINT (spray intercooled) technology to enhance the power output of the turbines and thereby creating a more efficient engine. Essentially this is achieved through the introduction of water into the turbines' working medium. The added water reduces compressor power consumption and allows for higher firing of the turbine unit as well as due to the increased mass flow passing through the turbine blades. Water droplets are injected into the air stream entering the compressors, also known as "over-fogging" or "wet compression", which allows an increase to the power available due to the reduction of work required for compression of inlet air, as latent heat for evaporation of this water cools the inlet air stream when it passes the compressor stages. The advantage of this system is more pronounced at hotter days since the higher ambient temperature has a negative impact on heat rate.

The GE combined cycle power plant is a factory packaged modular design that has the advantage of rapid field installation with maximum flexibility with fast start time, part power efficiency, and cyclic capabilities. Design improvements from previous generations include reductions in wiring and piping as well as a smaller footprint and a reduction in concrete usage. Table 2 summarizes the specifications for the turbine.

Table 2 LM6000 PG SPRINT® Gas Turbine Specifications[a]

Parameter	Value
Manufacturer	General Electric
Fuel Type	California Public Utilities Commission Quality Natural Gas
Maximum Fuel Consumption	0.541 MMscf/hr @64°F
Maximum Exhaust Flow	1,144,200 lb/hr @64°F
Heat Input (LHV)	493.4 MMBtu/hr @64°F
Maximum Output (Gross)	56.1 MW @64°F
Gross Heat Rate (LHV)	8,797 Btu/kWh @64°F
Gross Heat Rate (HHV)	9,762 Btu/kWh @64°F
Ammonia Injection Rate	23 lb/hr NH3 (100%) @64°F
SO_2 to SO_3 Conversion Rate (%)	54
Steam Turbine Output (Gross)	14.7 MW @64°F
Plant Output (Gross)	70.8 MW @64°F
Plant Output (Net)	67.8 MW @64°F
Net Plant Heat Rate (LHV)	7,205 Btu/kWh @64°F
Net Plant Heat Rate (HHV)	7,993 Btu/kWh @64°F
Net Plant Efficiency	47.4% (LHV), 42.7% (HHV) @64°F with Chiller on
GTG Exhaust Temperature	881°F
Stack Outlet Temperature	376°F

[a] 64°F ambient temperature and 61% relative humidity represents the average conditions for Pasadena, California.

The turbine will be configured with a Once-Through-Steam-Generator (OTSG), which is a continuous-tube heat exchanger in which preheating, evaporation, and superheating of the feedwater takes place in series. Water is forced through tubes by a feedwater pump, entering at the cold end (top). It changes phase along the circuit and exits as steam at the hot end (bottom). Exhaust gas flows in a direction opposite to that of water and steam. The feedwater control valve is the single point of control for the OTSG. The feedwater flow is regulated using a feedforward and feedback algorithm programmed into the plant's distributed control system. These units require the use of demineralized water to prevent the build-up of solids deposition in the tube bundles. The tube materials are constructed of premium high nickel steel tubing which allows the OTSG to start-up, shutdown, and respond to load changes rapidly without exceeding material stress limits. The material also enables the OTSG to run dry, unaffected by the hot GTG exhaust.

CO OXIDATION CATALYST & SCR – A/N 538120

A carbon monoxide (CO) oxidation catalyst is located downstream of the gas turbine where it is used to control CO, VOC and HAP emissions. The catalyst is located within a structural catalyst frame integral to the housing, with room for additional layers of catalyst. Table 3 summarizes the specifications for the oxidation catalyst.

NOx emissions are controlled with a SCR catalyst which will be located within a structural catalyst frame downstream of the CO oxidation catalyst. Aqueous ammonia will be provided by an existing permitted ammonia tank located on site. The ammonia is vaporized at the vaporization skid and diluted with air dilution fans and injected into the exhaust gas stream via a grid of nozzles located upstream of the SCR of the catalyst and downstream of the CO Oxidation catalyst. Table 4 summarizes the specifications for the SCR.

Table 3 CO Oxidation Catalyst Specifications

Parameter	Value
Make	EmeraChem
Model	TBD
Catalyst Type	Fixed Bed Platinum
Number of Layers or Modules	1
Size of Each Layer or Module (HxWxD)	19.25" x 20.125" x 2.875"
Total Catalyst Volume	100.6 ft^3
Total Weight	4,525 lbs
Space Velocity	98,677 – 155,956 hr^{-1}
Catalyst Life	36 months/25,000 hrs
Operating Temperature	Minimum Design: 633°F; Maximum Operating: 1,150°F
Operating Schedule	8,760 hrs/yr
Maximum Outlet CO	2 ppmvd @ 15% O2
Maximum Outlet VOC	2 ppmvd @ 15% O2
VOC Control Efficiencies	33.3% Design; 50% Maximum
CO Control Efficiencies	92.3% Design; 94.6% Maximum

Table 4 SCR Catalyst Specifications

Parameter	Value
Make	Haldor Topsoe
Model	TBD
Type	Corrugated DNX-629
Number of Layers or Modules	1 layer, 13 modules per layer
Size of Each Layer or Module (LxWxH)	7.75 ft. x 42 ft. x 3.82 ft.
Catalyst Volume	24 m^3
Catalyst Weight	25,100 lbs
Reducing Agent	Aqueous Ammonia, 19wt%
Space Velocity	12,059 – 18,926 hr^{-1}
Area Velocity	85.83 – 135.4 ft/hr
Catalyst Life	36 months/25,000 hours
Operating Temperature	Minimum Inlet: 600°F; Maximum: 900°F
Ammonia Injection Temperature	450°F
Ammonia Injection Rate	107 lb/hr, 19wt%
Pressure Drop across Catalyst	6.5 in. w.c.
Maximum Outlet NH3 Slip	5 ppmvd @ 15% O2
Operating Schedule	8,760 hrs
Maximum Outlet NOx	2 ppmvd @ 15% O2
NOx Control Efficiency	92%

<u>WET COOLING TOWER – RULE 219(d)(3) EXEMPT</u>

The excess heat from the combined cycle generating unit will be handled with a new wet cooling tower, which will be rated at 14,260 gallons per minute (gpm), with potable water as make-up, and will consist of two cells. The cooling tower will re-circulate the cooling water in a closed system, with limited amounts of make-up water to offset the blowdown and drift. The drift factor for the cooling tower will be 0.0005% of the circulation or 0.071 gpm. The specifications for the cooling tower and the data used to determine the PM10 emissions and toxic emissions for the maximum individual cancer risk (MICR) as well as the calculations are shown below:

Parameter	Value
Manufacturer	TBD
Circulation Rate	14,260 gpm
Make-up Rate of Cooling Water	221.7 gpm
Drift Eliminator Efficiency	0.0005 %
Cooling Tower Cycles of Concentration	6
Cooling Tower Length	64.67 ft
Cooling Tower	30.67 ft
Height to Fan Deck	20.59 ft
Height to Fan Exit	30.59 ft
Cooling Tower Air Exit Velocity	1,727 ft/min
Cooling Tower Hot Water Temperature	88°F @ Ambient Temperature of 64°F
Number of Cells	2
Cooling Tower Fan Shroud Diameter	18 ft
Maximum total dissolved solids (TDS)	660 mg/l or ppm

Cooling Tower PM10 Emissions

PM10 (lbs/day) = circulation rate (gpm) x drift%/100 x density (lb/gal) x TDS (ppm)/1E06 x no. cycles x 1440 min/day

= 14,260 x 0.0005/100 x 8.34 x 1440 x 660/1E06 x 6

= **3.39**

Cooling Tower Toxic Air Contaminant (TAC) Emissions

Pollutant	CAS no.	Conc. in Water[a] (ppb)	Drift[b] (gpm)	Make-up Water (gpm)	Emissions[c] (lb/hr)	Emissions[d] (lb/yr)
Arsenic	7440382	15	0.071	-	5.33E-07	4.67E-03
Fluoride	1101	6000	0.071	-	2.13E-04	1.87+00
Chromium VI	18540299	0.78	0.071	-	2.77E-08	2.43E-04
Chlorine	7782505	0.03	-	221.7	3.33E-06	2.92E-02

(a) PDWP water quality report.
(b) Drift (gpm) = 14,260 gpm x 0.0005/100
(c) Inorganic compounds (Arsenic, Fluoride, and Chromium VI) calculated on drift only (lb/hr) = Drift (gpm) x 8.34 lb/gal x concentration (ppb)/1E09 x 60 min/hr; Organic compound (Chlorine) assumed to be removed in make-up water (lb/hr) = Make-up water (gpm) x 8.34 lb/gal x concentration (ppb)/1E09 x 60 min/hr
(d) Emissions (lb/yr) = Emissions (lb/hr) x 8760 hrs/yr

The cooling tower TAC emissions were used for the Health Risk Assessment (HRA) to determine the MICR and Rule 219 applicability of the cooling tower. The SCAQMD Rule 1401 Risk Assessment Calculator Excel program from the District website was used to conduct a Tier 2 analysis. The inputs to the program were the estimated TACs (table above), distance to the nearest receptors (65 meters at fence line for worker and 150 meters for resident), stack height (30.59 ft for fan exit), operating schedule (8760 hours per year), and the nearest meteorological station (Pasadena Station).

The MICR for the resident and worker were determined to be 1.80E-07 and 8.27E-08, respectively. Because MICR is less than the Rule 1401 significance threshold of 1 in a million, the cooling tower is exempt per Rule 219(d)(3).

The process flow diagram below shows the GE GTG, OTSG, air pollution control equipment and auxiliary equipment for this proposal.

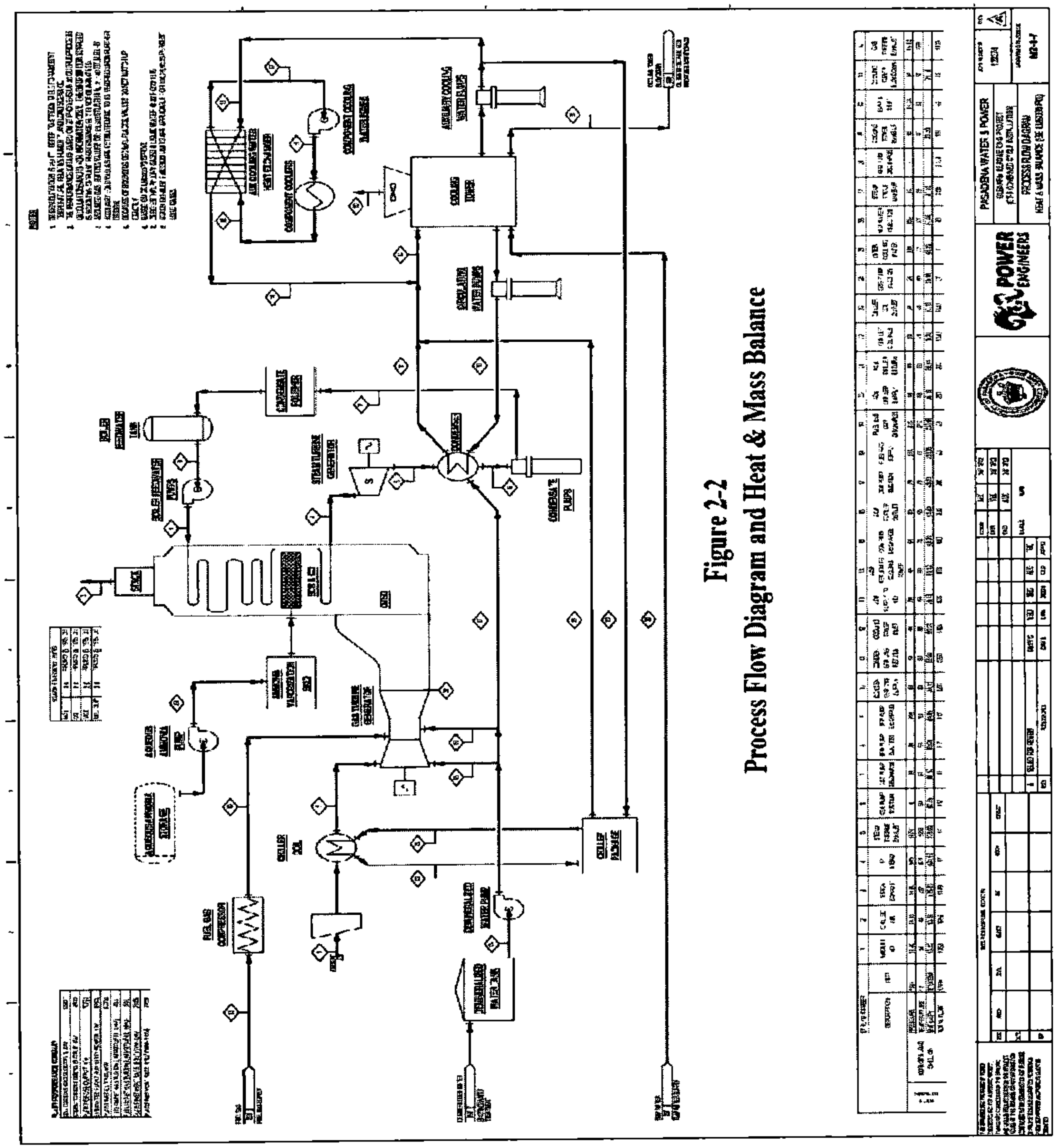

Figure 2 Process Flow Diagram for the General Electric Turbine and Associated Equipment Referenced at 64°F and 61% RH (as provided in the Applicant's Permit Package).

EMISSION CALCULATIONS

The operation of the new turbine will result in emissions of criteria pollutants, toxic air contaminants (TACs), and greenhouse gases (GHGs). Emission of criteria pollutants will be described and calculated in this section and the TACs and GHGs will be described and calculated in the applicable sections to follow.

The turbine's modes of operation are described below.

START-UP

This is the period of time that begins with the introduction of fuel into the combustion turbine that result in a rise in temperature to the normal operating temperature where exhaust enters the air pollution control equipment and exits the stack. It commences with ignition of the combustion turbine through the full operation of the steam turbine generator. The CO, VOC and NOx concentrations during this mode of operation are high due to the phased effectiveness of the oxidation catalyst and SCR that gradually come online as the operating temperatures are being reached.

The turbine can reach full load in approximately 8 minutes from turbine ignition. Water injection commences after 5 minutes and ammonia injection is initiated after 11 minutes from ignition. Prior to water injection, NOx emissions reach a concentration as high as 87 ppm. Following water injection, NOx emissions drop to 25 ppm; however, the CO and VOC emissions rise with the introduction of water. From 11 minutes onward, as the catalysts warm up to operating temperature, the NOx emissions are being controlled from 25 to 2 ppm.

The facility is proposing a 120 minute start-up time for the combined cycle power plant. The NOx emissions during the first hour of operation are expected to be 20.78 lbs and 7.90 lbs for the second hour. The start-up emissions are summarized in Table 5.

The facility requested a 2 hour start-up period for a total of 5 per day, 155 per month and 750 per year. The evaluation is based on their requested amounts. The start-up mass emission rates will be placed on the permit to ensure the facility complies with the emission rates proposed for the equipment.

SHUTDOWN

Shutdown is the period of time from initiation of the shutdown sequence to cessation of firing. During the shutdown operation, all the emission controls may not be operating at full control efficiency; thus emissions will be higher than normal operation. The shutdown emissions are summarized in Table 5.

Table 5 Start-up and Shutdown Emissions

Event	Time Period (min)		NOx (lb)		CO (lb)		VOC (lb)		PM10 (lb)		SOx (lb)
Start-up (full load)	10		5.39		7.39		0.89		0.80		0.06
Start-up (first hour)	60		20.78		18.81		2.47		4.22		0.70
Start-up (second hour)	60 to 120		7.90		4.80		2.74		4.00		0.75
Start-up (total)	**120**	a	**28.68**	b	**23.61**	c	**5.21**	d	**8.22**	e	**1.45**
Shutdown	**60**	f	**11.78**	g	**9.90**	h	**1.59**	i	**4.00**	j	**0.79**

The facility is proposing a 60 minute shutdown period duration and 5 per day, 155 per month, and 750 per year. The shutdown mass emission rates will be placed on the permit to ensure the facility complies with the emission rates proposed for the equipment.

NORMAL OPERATION

Normal operation is achieved when the gas turbine and associated air pollution control equipment are operating at design levels. Although mass emissions will vary depending on ambient conditions, they will remain below guaranteed levels of 2.0 ppmvd-NOx, 2.0 ppmvd-CO and 2.0 ppmvd-VOC at 15% O2 with the aid of the CO catalyst and SCR. GE provided performance data for ambient conditions at 17°F, 64°F, and 97°F for the LM6000 SPRINT PG shown in the table below.

Ambient Temperature (°F)	Relative Humidity (%)	Chiller Status	Turbine Load (%)	Gross Power (kW)	Gross Heat Rate (LHV) (Btu/kWh)	Heat Input (LHV) (MMBtu/hr)
17	71	Off	100	56,425	8,957	505.4
64	61	On	100	56,088	8,797	493.4
97	42	On	100	56,088	8,797	493.4

The temperatures represent the range of conditions in Pasadena; 17°F is the minimum temperature reported and 97°F represents the maximum monthly average temperature. The annual average for Pasadena is 64°F. The maximum firing rate at 17°F is used for determining the worst case emissions for the Rule 1401 analysis and for worst-case normal operation. The emissions during normal operation are shown in Table 6. *Note that the SOx emissions are higher during normal operation than during start-up and shutdown.*

Table 6 Normal Operation Emissions (lb/hr) and Emission Factors (lb/MMscf)

Gas Turbine Data: 100% Load, 17°F, 71%RH				
	Parameter	**Unit**	**Value**	**Reference**
a	Power at Terminals, Gross	kW	56,425	Vendor Data
b	Heat Rate, LHV	Btu/kW-hr	8,957	Vendor Data
c	Fuel Input, LHV	MMBtu/hr	505.4	= a x b/1E06
d	Fuel Input, HHV	MMBtu/hr	560.8	= c x 1012/912
Stack Exhaust Parameters				
	Parameter	**Unit**	**Value**	**Reference**
e	Stack Diameter	ft	10.17	Vendor Data
f	Volumetric Flow Rate, wet	acfm	416,995	Vendor Data
g	Exhaust Temperature	°F	375	Vendor Data
h	Water Content	%	11.84	Vendor Data
i	Oxygen Content, dry	%	13.91	Vendor Data
j	Exhaust Rate, dry, 15% O2	MMscf/hr	16.27	= f x 60/1E06 x [(460+60)/(460+ g)] x [1- (h/100)] x [(20.9- i)/(20.9-15)]
Emission Limits				
	Parameter	**Unit**	**Value**	**Reference**
k	NOx	ppmvd, dry, 15% O2	2.0	Vendor Guarantee
l	CO	ppmvd, dry, 15% O2	2.0	Vendor Guarantee
m	VOC	ppmvd, dry, 15% O2	2.0	Vendor Guarantee
n	PM10	lb/hr	4.0	Vendor Guarantee
o	SOx	gr/100 scf	0.5	Vendor Data
p	NH3	ppmvd, dry, 15% O2	5.0	Vendor Guarantee
Emission Rates				
	Parameter	**Unit**	**Value**	**Reference**
q	NOx	lb/hr	**3.95**	= k x j x 46/379
r	CO	lb/hr	**2.40**	= l x j x 28/379
s	VOC	lb/hr	**1.37**	= m x j x 16/379
t	PM10	lb/hr	**4.00**	Vendor Guarantee
u	SOx	lb/hr	**0.79**	= [o x 1E06 x 64/32] / [100 x 7000 x 1012] x d
v	NH3	lb/hr	**3.65**	= p x j x 17/379
Emission Factors				
	Parameter	**Unit**	**Value**	**Reference**
w	NOx	lb/MMscf	**7.13**	= q / d x 1012
x	CO	lb/MMscf	**4.33**	= r / d x 1012
y	VOC	lb/MMscf	**2.47**	= s / d x 1012
z	PM10	lb/MMscf	**7.22**	= t / d x 1012
aa	SOx	lb/MMscf	**1.43**	= u / d x 1012

COMMISSIONING

Commissioning is the process of fine-tuning the equipment to ensure the proper performance of the turbine and associated control equipment following initial installation. Emissions are expected to be greater during commissioning than during normal operation as air pollution control equipment may only be partially operational or not operational at all. PDWP is proposing to commission the equipment in 12 phases over 12 days summarized in Table 7 below.

Table 7 Equipment Commissioning Emission Rates and Emission Factors

Event	Day – Phase	Load (%)	Runtime (hrs)	SCR (Y/N)	Rate LHV (MMBtu/hr)	Fuel Used LHV (MMBtu)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs)
First Fire/Core Idle Mode	1 - P1	0	16	N	91	1,462	192	784	142	10.7	2.29
Initial Tuning + Run/Synch Idle	2 – P2	0	16	N	91	1,462	192	784	142	10.7	2.29
Integrated Tuning/SPRINT start-up	3 – P3	25	16	N	190	3,045	304	118	9	22.3	4.76
Steam Blow Cleaning	4 – P4	25	12	N	190	2,284	228	89	7	16.7	3.57
OTSG Commissioning	5 – P5	100	24	N	486	11,666	1176	519	34	69.3	18.24
Steam Turbine Commissioning	6 – P6	25	24	N	190	4,567	456	177	13	33.4	7.14
SCR/CO System Commissioning	7 – P7	25	16	Y	190	3,045	49	19	9	27.7	4.76
Emissions Tuning	8 – P8	25	16	Y	190	3,045	49	19	9	27.7	4.76
RATA Test	9 – P9	100	16	Y	486	7,778	63	28	22	61.6	12.16
Performance Test	10 – P10	100	16	Y	486	7,778	63	28	22	61.6	12.16
24-hr Reliability Test	11 – P11	100	24	Y	486	11,666	94	41	33	92.3	18.24
24-hr Reliability Test Continued	12 – P12	100	8	Y	486	3,889	31	14	11	30.8	6.08
TOTAL			**204**			**61,687**	**2,897**	**2,620**	**453**	**465**	**96**
Emission Factors[a] (lb/MMscf)							**42.83**	**38.73**	**6.70**	**6.87**	**1.42**

[a] Emission Factor (lb/MMscf) = Commissioning Pollutant (lbs) / (Fuel Used LHV (MMBtu) / 912 (Btu/scf))

MAINTENANCE

The equipment must undergo periodic maintenance to ensure it operates as intended. In particular, the water injection and intercooler system as well as the ammonia injection grid require regular tuning. Each maintenance operation is discussed in further detail below.

Water Injection and Intercooler Tuning (WIIT)

Tuning of the water injection and intercooler system will involve setting the turbine at a 25 MW load and varying the water injection rate between 15% below and 15% above normal injection rate. The procedure will involve the incremental increase of load in steps of 5 MW and the variation of water injection at each step until the turbine reaches full load. Operation at each step will take about an hour and the total time for the tuning procedure will be 12 hours. The turbine will be required to undergo this procedure **twice per year**. During this tuning process, ammonia injection will be operational as well as the steam turbine. The emissions are shown in Table 8. *Note that on a pound per hour basis, the mass emission rates for SOx and VOC are less than the emission rates during normal operation in Table 6.*

Table 8 Water Injection and Intercooler Tuning (WIIT) Emissions

Event	Load (MW)	Runtime (mins)	Fuel LHV (MMBtu)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs)
Bring SCR online	0							
Stabilize temperature	25	15	65.7	3.2	0.38	0.13	1.0	0.10
Increase water injection rate from normal rate to 15%	25	30	132.1	6.4	1.69	0.48	2.0	0.21
Decrease water injection rate from normal rate to 15%	25	30	130.6	6.2	0.35	0.26	2.0	0.20
Stabilize temperature	30	15	74.3	3.6	0.45	0.15	1.0	0.12
Increase water injection rate from normal rate to 15%	30	30	149.5	7.2	2.11	0.61	2.0	0.23
Decrease water injection rate from normal rate to 15%	30	30	147.7	7.1	0.38	0.29	2.0	0.23
Increase and stabilize load to 35 MW	35	15	83.2	4.0	0.50	0.16	1.0	0.13
Increase water injection rate from normal rate to 15%	35	30	167.5	7.9	2.54	0.77	2.0	0.26
Decrease water injection rate from normal rate to 15%	35	30	165.4	8.1	0.39	0.32	2.0	0.26
Increase and stabilize load to 40 MW	40	15	91.6	4.4	0.56	0.18	1.0	0.14
Increase water injection rate from normal rate to 15%	40	30	184.5	9.0	3.02	1.00	2.0	0.29
Decrease water injection rate from normal rate to 15%	40	30	181.9	8.7	0.41	0.36	2.0	0.29
Allow SPRINT to initiate and stabilize	45	15	100.3	4.8	0.46	0.20	1.0	0.16
Block load and adjust NOx and SPRINT	45	40	267.3	12.9	1.23	0.52	2.7	0.42
Increase water injection/SPRINT rate up to 15%	45	40	269.1	12.7	3.03	0.85	2.7	0.42
Decrease water injection/SPRINT rate up to 15%	45	40	265.7	12.9	0.50	0.52	2.7	0.42
Increase and stabilize load at 50 MW	50	15	108.8	5.3	0.50	0.21	1.0	0.17
Increase water injection/SPRINT rate up to 15%	50	40	292.1	14.4	3.48	0.99	2.7	0.46
Decrease water injection/SPRINT rate up to 15%	50	40	288.2	14.0	0.51	0.56	2.7	0.45
Increase and stabilize load at 53 MW	53	15	115.0	5.6	0.54	0.23	1.0	0.18
Increase water injection/SPRINT rate up to 15%	53	40	309.8	15.2	3.71	1.05	2.7	0.49
Decrease water injection/SPRINT rate up to 15%	53	40	302.5	14.6	0.57	0.59	2.7	0.47
Increase and stabilize load at 56 MW	56	15	121.3	5.9	0.72	0.24	1.0	0.19
Increase water injection/SPRINT rate up to 15%	56	40	328.7	15.7	4.61	1.33	2.7	0.52
Decrease water injection/SPRINT rate up to 15%	56	40	317.5	15.2	0.80	0.62	2.7	0.50
TOTAL (12 hrs)		**720**	**4660**	**225.00**	**33.44**	**12.62**	**48.30**	**7.31**
TOTAL (24 hrs)		**1440**	**9320**	**450.00**	**66.88**	**25.24**	**96.60**	**14.62**

Ammonia Injection Grid Tuning (AIGT)

The ammonia injection tuning process will involve the operation of the turbine at 50 MW for up to 10 hours. This procedure is only required once per year. During this tuning process, ammonia injection will be operational as well as the steam turbine. The emissions are shown in Table 9. *Note that on a pound per hour* *basis, the mass emission rates for SOx and VOC are less than the emission rates during normal operation in Table 6.*

Table 9 Ammonia Injection Grid Tuning (AIGT) Emissions

Event	Load (MW)	Runtime (mins)	Fuel LHV (MMBtu)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs)	NH3 (lbs)
Ramp-up, start Water Injection and SCR, stabilize to 28 MW	28								
Tune the AIG with NH3 injection in service to adjust NOx outlet distribution	Increase to 56	600	4850	234.3	28.9	9.47	40.0	7.6	36.1
TOTAL (10 hrs)		**600**	**4850**	**234.30**	**28.9**	**9.47**	**40.00**	**7.60**	**36.1**

PROJECT EMISSIONS

The emissions for the project are shown for both commissioning and non-commissioning years and are determined based on a maximum operating capacity of **8760** hours per year. As mentioned in the Start-up and Shutdown section, the facility is proposing 750 per year, 155 per month, and 5 per day with two hour duration for start-ups and one hour duration for shutdowns. For estimating the number of start-ups and shutdowns during the commissioning year, it was assumed that there will be 60 start-ups and 60 shutdowns during the 12 day of commissioning operation (5 startups and 5 shutdowns per day). Thus, there will be only 690 start-ups and 690 shutdowns during the commissioning year.

The annual, monthly, and daily hours for each mode of operation are shown in Table 10 for the commissioning and non-commissioning years. The commissioning period will be limited to 204 hours of runtime operation; however, the schedule presented in Table 7 shows the phases of commissioning to occur over a 12 day period, with the turbine operating between 8 to 16 hours and up to 24 hours in a day. Thus the total hours will be 288 but the actual runtime will only be 204 hours.

Table 10 Schedule of Hours for Each Mode of Operation

Commissioning Year							
	Annual	**Hours**	**Reference**		**Monthly**	**Hours**	**Reference**
a	Total	8760	Applicant	h	Total	744	31 days x 24 hrs
b	Commissioning	288	12 days x 24 hrs	i	Commissioning	288	12 days x 24 hrs
c	Start-ups	1380	[750 – 60 (commissioning)] x 2 hrs	j	Start-ups	190	(31 days – 12 days) x 5 starts x 2 hrs
d	Shutdowns	690	[750 – 60 (commissioning)] x 1 hr	k	Shutdowns	95	(31 days – 12 days) x 5 starts x 1 hr
e	WIIT	24	2 events x 12 hrs	l	Normal Operations	171	h – (i + j + k)
f	AIGT	10	1 event x 10 hrs				
g	Normal Operations	6368	a – (b + c + d + e + f)				
Non-Commissioning Year							
	Annual	**Hours**	**Reference**		**Monthly**	**Hours**	**Reference**
m	Total	8760	Applicant	s	Total	744	31 days x 24 hrs
n	Start-ups	1500	750 x 2 hrs	t	Start-ups	310	155 x 2 hrs
o	Shutdowns	750	750 x 1 hr	u	Shutdowns	155	155 x 1 h
p	WIIT	24	2 events x 12 hrs	v	WIIT	12	1 event x 12 hrs
q	AIGT	10	1 event x 10 hrs	w	AIGT	10	1 event x 10 hrs
r	Normal Operations	6476	m– (n + o + p + q)	x	Normal Operations	257	s – (t + u + v + w)
Daily Operating Schedule							
y	Total	24	Applicant				
z	Start-ups	10	5 events x 2 hrs				
aa	Shutdowns	5	5 events x 1 hr				
bb	Normal Operations	9	y – (z + aa)				

The turbine will be conditioned not to exceed 5 start-ups per day and 155 start-ups per month (31 days/month x 5 starts/day); therefore, the number hours of start-ups, and shutdowns, are less than a non-commissioning month. In addition, it is assumed that the worst-case non-commissioning month will include maintenance operations (WIIT and AIGT).

The annual commissioning year emissions in Table 11 are calculated using the hours of operation for the annual commissioning year from Table 10 (b to g) along with the start-up and shutdown rates (lb/hr) in Table 5 (a to j), normal operation rates (lb/hr) in Table 6 (q to u), commissioning emissions from Table 7, and the maintenance operations from Tables 8 and 10.

Table 11 Commissioning Year Emissions (lbs/year)

Pollutant	Normal Operations[a]	Start-up[b]	Shutdown[c]	WIIT[d]	AIGT[e]	Commission[f]	Total[g]	Tons per year[h]
NOx	25,154	19,789	8,128	450	234	2,897	56,652	28
SOx	5,031	1,001	545	15	8	96	6,695	3
PM10	25,472	5,672	2,760	96	40	465	34,505	17
CO	15,283	16,291	6,831	67	29	2,620	41,121	21
VOC	8,724	3,595	1,097	25	10	453	13,904	7

[a] Normal Operation Emissions (lb/hr) *{q to u from Table 6}* x Normal Operations (hrs/yr) *{ g from Table 10}*
[b] Start-up (lb) *{a to e from Table 5}* x 690 start-ups/yr
[c] Shutdown (lb) *{f to j from Table 6}* x 690 shutdowns/yr
[d] WIIT Emissions (lb) *{Total (24 hrs) from Table 8}*
[e] AIGT Emissions (lb) *{Table 10}*
[f] Commission Emissions (lb) *{Table 7}*
[g] (a) + (b) + (c) + (d) + (e) + (f)
[h] (g) / 2000

The commissioning month emissions in Table 12 is based on the month that commissioning is occurring, with the remainder of time for normal operation and the maximum number of start-ups and shutdown possible for the remainder of the month.

Table 12 Commissioning Month Emissions (lbs/month)

Pollutant	Normal Operations[a]	Start-up[b]	Shutdown[c]	Commission[d]	Total[e]	30-DA[f]
NOx	675	2,725	1,119	2,897	7,416	**247**
SOx	135	138	75	96	444	**15**
PM10	684	781	380	465	2,310	**77**
CO	410	2,243	941	2,620	6,214	**207**
VOC	234	495	151	453	1,333	**44**

[a] Normal Operation Emissions (lb/hr) *{q to u from Table 6}* x Normal Operations (hrs/mo) *{ l from Table 10}*
[b] Start-up (lb) *{a to e from Table 5}* x 95 start-ups/mo
[c] Shutdown (lb) *{f to j from Table 6}* x 95 shutdowns/mo
[d] Commission Emissions (lb) *{Table 7}*
[e] (a) + (b) + (c) + (d) *{Table 12}*
[f] (e) / 30 *{Table 12}*

There are more hours available for normal operation and for start-ups and shutdowns for the non-commissioning year shown in Table 13 since the 12 days of commissioning is available for regular operations.

Table 13 Non-Commissioning Year Emissions (lbs/year)

Pollutant	Normal Operations(a)	Start-up(b)	Shutdown(c)	WIIT(d)	AIGT(e)	Total(f)	Tons per year(g)
NOx	25,580	21,510	8,835	450	234	56,609	28
SOx	5,116	1,088	593	15	8	6,818	3
PM10	25,904	6,165	3,000	96	40	35,205	18
CO	15,542	17,708	7,425	67	29	40,771	20
VOC	8,872	3,908	1,193	25	10	14,007	7

(a) Normal Operation Emissions (lb/hr) *{q to u from Table 6}* x Normal Operations (hrs/yr) *{ r from Table 10}*
(b) Start-up (lb) *{a to e from Table 5}* x 750 start-ups/yr
(c) Shutdown (lb) *{f to j from Table 6}* x 750 shutdowns/yr
(d) WIIT Emissions (lb) *{Total (24 hrs) from Table 8}*
(e) AIGT Emissions (lb) *{Table 10}*
(f) (a) + (b) + (c) + (d) + (e) *{Table 13}*
(g) (f) / 2000 *{Table 13}*

The monthly emissions for the non-commissioning year, in Table 14, depict the worst-case scenario, which include the 155 start-ups and shutdowns, as well as all the maintenance operations.

Table 14 Non-Commissioning Month Emissions (lbs/month)

Pollutant	Normal Operations(a)	Start-up(b)	Shutdown(c)	WIIT(d)	AIGT(e)	Total(f)	30-DA(g)
NOx	1,015	4,445	1,826	225	234	7,746	258
SOx(h)	588	0	0	0	0	588	20
PM10	1,028	1,274	620	48	40	3,010	100
CO	617	3,660	1,535	33	29	5,873	196
VOC(i)	382	808	246	0	0	1,436	48

(a) Normal Operation Emissions (lb/hr) *{q to u from Table 6}* x Normal Operations (hrs/mo) *{x from Table 10}*
(b) Start-up (lb) *{a to e from Table 5}* x 155 start-ups/mo
(c) Shutdown (lb) *{f to j from Table 6}* x 155 shutdowns/mo
(d) WIIT Emissions (lb) *{Total (12 hrs) from Table 8}*
(e) AIGT Emissions (lb) *{Table 10}*
(f) (a) + (b) + (c) + (d) + (e) *{Table 14}*
(g) (f) / 30 *{Table 14}*
(h) The SOx emission rate is higher during normal operation than the other modes of operation; therefore, the highest emissions will occur if the turbine operates during normal mode as 744 hrs/mo x 0.79 lb-SOx/hr.
(i) The VOC emission rates are higher during normal operation than during the tuning periods; therefore, the highest emissions for VOC will occur in a non-tuning month. The 22 (12 + 10) hours for tuning will be in the form of normal operations.

The daily emissions shown in Table 15 will be the general day to day operations for the equipment, taking into account the maximum allowable start-ups and shutdowns for the day.

Table 15 Daily Operating Emissions (Non-tuning day) (lbs/day)

Pollutant	Normal Operations[a]	Start-up[b]	Shutdown[c]	Total[d]
NOx	36	143	59	238
SOx[e]	19	0	0	19
PM10	36	41	20	97
CO	22	118	50	190
VOC	12	26	8	46

(a) Normal Operation Emissions (lb/hr) *{q to u from Table 6}* x Normal Operations (hrs/day) *{bb from Table 10}*
(b) Start-up (lb) *{a to e from Table 5}* x 5 start-ups/mo
(c) Shutdown (lb) *{f to j from Table 6}* x 5 shutdowns/mo
(d) (a) + (b) + (c) *{Table 15}*
(e) *Maximum daily SOx emissions will occur with only Normal Operations*

The maximum 30-day emissions for the project are shown in Table 16 taken from Tables 12 and 14. Generally the NOx emissions are higher during a commissioning month; however, as previously discussed, maintenance operations were assumed to occur in the same month for a non-commissioning year to demonstrate worst-case. Commissioning will occur over a 12 day period leaving 95 start-ups and shutdowns for the remainder of the month, whereas the worst-case non-commissioning month will include the maximum 155 start-ups and shutdowns.

Table 16 Maximum 30-DA Emissions

Pollutant	30-DA	Reference
NOx[a]	**258**	Non-commissioning month Table 14
SOx	**20**	Non-commissioning month Table 14
PM10	**100**	Non-commissioning month Table 14
CO	**207**	Commissioning month Table 12
VOC	**48**	Non-commissioning month Table 14

(a) The facility is in the RECLAIM program, so the NOx is shown for informational purposes

RULES EVALUATION

RULE 212-STANDARDS FOR APPROVING PERMITS AND ISSUING PUBLIC NOTICES

Rule 212 requires that a person shall not build, erect, install, alter, or replace any equipment, the use of which may cause the issuance of air contaminants or the use of which may eliminate, reduce, or control the issuance of air contaminants without first obtaining written authorization for such construction from the Executive Officer. Rule 212(c) states that a project requires written notification if there is an emission increase for ANY criteria pollutant in excess of the daily maximums specified in Rule 212(g), if the equipment is located within 1,000 feet of the outer boundary of a school, or if the MICR is equal to or greater than one in a million ($1x10^6$) during a lifetime (70 years) for facilities with more than one permitted unit, source under Regulation XX, or equipment under Regulation XXX, unless the applicant demonstrates to the satisfaction of the Executive Officer that the total facility-wide maximum individual cancer risk is below ten in a million ($10x10^6$) using the risk assessment procedures and toxic air contaminants specified under Rule 1402; or, ten in a million ($10x10^6$) during a lifetime (70 years) for facilities with a single permitted unit, source under Regulation XX, or equipment under Regulation XXX.

FACILITY / EQUIPMENT AND SCHOOL LOCATIONS

The closest kindergarten to grade 12 school is located within 1,000 feet as stated by the applicant and as determined by Greatschools (http://www.greatschools.org). Table 17 summarizes the name, location and proximity of nearby schools. A public notice will be required per section (c)(1).

Table 17 K-12 Schools Near Facility

Name of School	Address	Distance in miles
Blair High School	1201 South Marengo Ave., Pasadena, CA	0.2 (<1000 feet)
Pacific Clinics	66 Hurlbut St., Pasadena, CA	0.3
Aria Montessori School	693 S. Euclid Ave., Pasadena, CA	0.4
Sequoyah School	535 S. Pasadena Ave., CA	0.7
McKinley School	325 S. Oak Knoll Ave., Pasadena, CA	1.1
San Rafael Elementary School	1090 Nithsdale Rd., Pasadena, CA	1.6
Roosevelt School	315 North Pasadena, St., Pasadena, CA	1.7

DAILY EMISSIONS

As shown in table 18, the daily emissions from this project exceed the daily thresholds of Rule 212(g) for NOx, PM10 and VOC; therefore, the project triggers a public notice for section (c)(2).

Table 18 Daily Emissions

Pollutant	Project	R212(g) Daily Threshold	Public Notice triggered?
NOx	258	40	**Yes**
SOx	20	60	No
PM10	100	30	**Yes**
CO	207	220	No
VOC	48	30	**Yes**

MAXIMUM INDIVIDUAL CANCER RISK (MICR)

The total facility wide MICR is less than $1x10^6$, as shown in the discussion under the Regulation XIV section; therefore, a public notice is not required for section (c)(3).

RULE 218 – CONTINUOUS EMISSION MONITORING

The turbine will be required to have CEMS to monitor both CO and NOx to verify compliance with hourly concentrations and monthly emission limits. The CO CEMS will need to comply with the requirements of Rule 218. As a result, a CEMS application for AQMD source testing staff review and approval is required prior to the installation of the CEMS for the turbine. The NOx CEMS must meet the requirements of Regulation XX and will be discussed under the RECLAIM rules section.

RULE 219 – EQUIPMENT NOT REQUIRING A WRITTEN PERMIT PURSUANT TO REGULATION II

PDWP will be installing a wet cooling tower with the project which is exempt from AQMD permit per section (d)(3). Therefore, an application for this equipment is not required.

RULE 401 - VISIBLE EMISSIONS
This rule limits visible emissions to an opacity of less than 20 percent (Ringlemann No.1), as published by the United States Bureau of Mines. It is unlikely, with the use of the SCR /CO catalyst configuration on a natural gas turbine that there will be visible emissions. However, in the unlikely event that visible emissions do occur, anything greater than 20 percent opacity is not expected to last for greater than 3 minutes. During normal operation, no visible emissions are expected. Therefore, based on the above and on experience with other natural gas fired turbines, compliance with this rule is expected.

RULE 402 - NUISANCE
This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. The new turbine is not expected to create a public nuisance based on experience with identical natural gas fired turbines. Therefore, compliance with Rule 402 is expected.

RULE 403 - FUGITIVE DUST
The purpose of this rule is to reduce the amount of particulate matter entrained in the ambient air as a result of man-made fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. This rule prohibits emissions of fugitive dust beyond the property line of the emission source. The installation and operation of the natural gas fired turbine is expected to comply with this rule.

RULE 407 – LIQUID AND GASEOUS AIR CONTAMINANTS
This rule limits CO emissions to 2,000 ppmvd and SO_2 emissions to 500 ppmvd, averaged over 15 minutes. For CO, the natural gas fired turbine will meet the BACT limit of 2.0 ppmvd @ 15% O_2, 1-hr average, and the turbine will be conditioned as such and will be required to verify compliance through CEMS data. For SO_2, equipment which complies with Rule 431.1 is exempt from the SO_2 limit in Rule 407. The applicant will be required to comply with Rule 431.1 and thus the SO_2 limit in Rule 407 will not apply.

RULE 409 – COMBUSTION CONTAMINANTS
This rule restricts the discharge of contaminants from the combustion of fuel to 0.1 grain per cubic foot of gas, calculated to 12% CO_2, averaged over 15 minutes. The equipment is expected to meet this limit based on the calculations shown in table 19.

Table 19 Particulate Matter Concentration in Exhaust Gas

	Parameter	Unit	Value	Reference
a	Volumetric Flow Rate, wet	acfm	416,398	Vendor Data
b	Exhaust Temperature	°F	376	Vendor Data
d	CO2 Content	%	3.53	Vendor Data
e	PM Emission Rate	lb/hr	4.00	Vendor Guarantee
f	Exhaust Rate	scf/hr	15,540,212	a x [(460+60)/(460+375)] x 60
g	Grain Loading	**0.006**	gr/dscf	e x 7000 x 12/ (d x f)

As shown in table 19, the grain loading is less than the 0.1 gr/dscf required by Rule 409. Compliance will be verified through source testing.

RULE 431.1-SULFUR CONTENT OF GASEOUS FUELS

The turbines will use pipeline quality natural gas which will comply with the 16 ppm sulfur limit, calculated as H2S, specified in this rule. Natural gas will be supplied by the Southern California Gas Company. The facility proposed an H2S content of 0.5 gr/100scf, which is equivalent to a concentration of about 8 ppm. It is also much less than the 1 gr/100scf limit typical of pipeline quality natural gas. Compliance is expected. The applicant will comply with the reporting and record keeping requirements as outlined in subdivision (e) of this Rule.

RULE 475-ELECTRIC POWER GENERATING EQUIPMENT

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. Requirements are that the equipment meet a limit for combustion contaminants of 11 lbs/hr or 0.01 gr/scf. Compliance is achieved if either the mass limit or the concentration limit is met. Emissions from the turbine will be 4.0 lb/hr and 0.005 gr/scf [(4 lb/hr x 7000 gr/lb)/(8710 dscf/MMBtu x (20.9/(20.9-3)) x 547.5 MMBtu/hr] during natural gas firing at maximum load. Therefore, compliance is expected and will be verified through source testing.

RULE 1134 – EMISSIONS OF OXIDES OF NITROGEN FROM GAS TURBINES

This rule applies to gas turbines, 0.3 MW and larger, installed on or before August 4, 1989. Therefore, as a new installation, the proposed turbine is not subject to this Rule.

RULE 1135 – EMISSIONS OF OXIDES OF NITROGEN FROM ELECTRIC POWER GENERATING SYSTEMS

This rule applies to the electric power generating systems of several of the major utility companies in the basin. The plants which are included in the RECLAIM program are no longer subject to the requirements of this rule. Therefore, the NOx requirements of this rule are not applicable to the proposed turbine.

REGULATION XIII – NEW SOURCE REVIEW (NSR)

The following section describes the NSR analysis for this project and it will be evaluated for compliance with the rules in the table below.

RULE 1303(a) & RULE 2005(b)(1)(A) – BACT FOR GAS TURBINES

These rules state that the Executive Officer shall deny the Permit to Construct for any new source which results in an emission increase of any non-attainment air contaminant, any ozone depleting compound, or ammonia unless the applicant can demonstrate that BACT is employed for the new source. The addition of the new equipment at this existing facility will result in an increase in emissions; therefore, BACT requirements are applicable.

Emission limits for combined cycle turbines can be found in the EPA RACT/BACT/LAER Clearinghouse (RLBC) database, CARB database, AQMD BACT Guidelines database, and from the most recent power plant projects in California. The most stringent determination found was in the AQMD database for Vernon City Light and Power dated January 30, 2004 for a similar size Alstom combined cycle turbine (A/N 394164)[1]. The limits are shown in Table 20.

[1] The EPA RLBC had a listing for a power plant in Massachusetts, IDC Bellingham, with a NOx limit of 1.5 ppm permitted in 2000; however, the project was cancelled and the proposed limit was never demonstrated as achievable. For CO, the Kleen power plant in Connecticut has limit of 0.9 ppm based on 1-hr average. The facility has only begun operation and source test data is currently unavailable. The Avenal Energy Project has a CO limit of 1.5 ppm. Construction of the Avenal Energy Project has not yet commenced.

Table 20 BACT Requirements for Combined Cycle Gas Turbines

Pollutant	BACT	PDWP Proposal	Complies?
NOx	2.0 ppmvd, @ 15% O_2, 1-hour average	2.0 ppmvd, @ 15% O_2, 1-hour average	Yes
CO	2.0 ppmvd, @ 15% O_2, 1-hour average	2.0 ppmvd, @ 15% O_2, 1-hour average	Yes
VOC	2.0 ppmvd, @ 15% O_2, 1-hour average	2.0 ppmvd, @ 15% O_2, 1-hour average	Yes
PM_{10}/SOx	PUC quality natural gas w/ S content ≤ 1 grain/100 scf	PUC quality natural gas w/ H2S content ≤ 0. 5 grain/100 scf	Yes
NH_3	5.0 ppmvd @ 15% O_2, 1-hour average	5.0 ppmvd @ 15% O_2, 1-hour average	Yes

A NOx CEMS will be used to verify compliance with the NOx concentration limit and a CO CEMS will be used to verify compliance with the CO limit. The proposed levels in the table above will meet current BACT requirements for all criteria pollutants including NH_3. It should be noted that the EPA re-designated the South Coast air basin on June 11, 2007 as attainment for CO. However, the District continues to require CO BACT for combustion sources since the control equipment for CO is the same as for VOC. The two pollutants generally change in the same direction; therefore, since no continuous monitoring is available for VOC, compliance can be tracked through CO with a CO limit and continuous monitoring of CO.

NOx control technologies include water injection and XONON™, water injection and EMx™ (formerly known as SCONOx), and water injection and SCR with ammonia injection. However at this time, only water injection with SCR and ammonia injection has been demonstrated to achieve 2 ppm on a 1-hr average. Oxidation catalyst will be used to control CO and VOC and natural gas as the primary fuel will be used for PM10 and SOx. BACT is satisfied for the turbine during base load operation. The turbine will be required to perform source testing to verify compliance with the BACT limits.

In order to meet the BACT concentration limits for NOx and CO, as well as VOC, shown in table 21, the CO oxidation catalyst and SCR are required to be in full operation. However, during the start-up phase the turbine is going from a cold/ambient temperature to operating temperatures; therefore, the control system is not effective when the temperatures are less than the minimum temperatures specified in tables 3 & 4.

Water injection commences before the SCR comes online during start-up and ends several minutes after ammonia injection is shut off. Water injection allows NOx emissions to be reduced when the SCR catalyst has minimum effectiveness. The start-up and shutdown mass emission rates proposed for this project take into account water injection and phased SCR and CO oxidation catalyst control.

Two recently approved power plant projects in California, Hanford and Henrietta combined cycle power plants, are also proposing to use the LM6000 GTG and the OTSG. The systems are similar to the system proposed by PDWP. The data presented for these power plants reveals that start-up will be completed in 70 minutes that will result in 13.8 lbs of NOx. However, these new plants have not been constructed yet, thus there is no operational data available. In addition, PDWP is proposing a new version of the LM6000 with the OTSG and no source test data is available. The equipment vendor provided emission estimates for the first 60 minutes as well as the total 120 minutes of start-up; 20.78 lbs of NOx for the first hour and 3.8 lbs for the second hour. PDWP is conservatively proposing twice the normal operation rate for NOx, CO and VOC (at ambient temperature of 17°F). The PM10 and SOx emissions were assumed to be equivalent to normal operations.

Proposed shutdown emission data for the Hanford and Henrietta plants reveals that the duration to be 30 minutes and NOx emissions at 9.8 lbs, which at present have not been achieved in practice. The equipment vendor provided emission estimates during the shutdown mode of operation which is expected to be completed in 60 minutes resulting in 11.78 lbs of NOx. The mass emission rates for both start-up and shutdown modes of operation are shown in Table 5. NOx and CO mass emission rate limits will be placed on the permit for start-up and shutdown.

RULE 1303(b)(1) – MODELING

Rule 1303(b)(1) requires air dispersion modeling for CO and PM10. The facility is located within a non-attainment area for PM10 and in an attainment area for CO. Compliance is demonstrated for PM10 through project modeling that will not cause exceedances of the significant change threshold concentrations specified in Table A-2, Appendix A of Rule 1303. For CO, the project concentrations plus the background concentrations should not create a violation of the ambient air quality standard. Thus for CO, the significance threshold would be the CO ambient air quality standard.

PDWP provided modeling evaluations using the AERMOD dispersion model, version 12060 and five years of meteorological data from 2005 through to 2009 from the District's Azusa Station and air data from Miramar NAS Station. Analyses were performed for the turbine's different modes of operation described under the Emission Calculations Section of this evaluation. The CO 1-hr and 8-hr, and the PM10 24-hr modeling analyses for normal operating modes were conducted using stack velocity and temperature that resulted in the lowest source release parameters along with the ambient conditions that resulted in the highest emission rates. Although PDWP conducted modeling at various operating scenarios, the worst case project impacts are shown in Table 21.

Table 21 Rule 1303(b)(1) Modeling Results

Pollutant	Averaging Time	Max Impact (ug/m3)	Background Concentration (ug/m3)	Total Impact (ug/m3)	Most Stringent Air Quality Standard (ug/m3)	Allowable Significant Change (ug/m3)
CO	1-hour	25.7	4,580.8	4,607	23,000	-
	8-hour	11.9	2,404.9	2,417	10,000	-
PM10	24-hour	0.50	-	-	-	2.5
	Ann Geo Mean	0.12	-	-	-	1.0

The maximum emission rate for CO is during Day 1 of commissioning. The maximum concentration for 24-hour PM10 is during Water Injection (WI) and Ammonia Injection Grid (AIG) tuning. The annual geometric mean is based on 8760 hours of operation with 750 start-ups and 750 shutdowns, along with 24 hours of WI tuning and 10 hours of AIG tuning with the remaining time at normal operation.

AQMD modeling staff reviewed the analyses for both air quality modeling and health risk assessment (HRA) – to be discussed under the Rule 1401 – New Source Review for Toxics section of this evaluation. Modeling staff provided their comments in a memorandum from Mr. Philip Fine to Mr. Brian Yeh dated January 4, 2013. A copy of this memorandum is contained in the project file. Staff's review of the modeling and HRA analyses concluded that the applicant used appropriate EPA AERMOD model along with the appropriate model options in the analysis. The memorandum states that the modeling as performed by the applicant conforms to the District's dispersion modeling requirements. No significant deficiencies in methodology were noted. Therefore compliance with modeling requirements is expected.

RULE 1303(b)(2) – OFFSETS

Emission offsets are required for all projects where there is an increase in emissions unless there is an exemption identified in Rule 1304.

Rule 1304(a)(2) - Modeling and Offset Exemptions: Electric Boiler Steam Boiler Replacement

Combined cycle gas turbines, intercooled, chemically recuperated gas turbines, other advanced gas turbines, or other equipment, to the extent that allow compliance with Rule 1135 or Regulation XX rules that replace electric utility steam boilers are exempt from emission offsets provided that the new equipment has a maximum electrical power rating that does not allow basinwide electricity generation capacity on a per-utility basis to increase. If there is an increase in basin wide capacity, only the increased capacity must be offset.

The project involves the replacement of an existing electric steam utility boiler, rated at 71 MW gross, with a new natural gas fired **combined cycle** generating system rated at 70.8 MW gross (gas turbine – 56.1 MW and steam turbine – 14.7 MW), with a OTSG and associated air pollution control equipment. The OTSG allows the system to start-up in 10 minutes, without having to wait for the steam turbine, which will eventually come online to provide the required MW. There will be no increase in capacity, thus the repowering project is exempt from having to provide external emission offsets.

RULE 1303(b)(4) – FACILITY COMPLIANCE

PDWP submitted a Form 500-A2 stating that the facility is in compliance with all applicable Rules and Regulations of the AQMD.

RULE 1303(b)(5) – MAJOR POLLUTING FACILITIES

RULE 1303(b)(5)(A) – ALTERNATIVE ANALYSIS

The applicant is required to conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for the facility and to demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with this project. The analysis was conducted as a part of the CEQA process under the Environmental Impact Report prepared by the City of Pasadena. It was determined that the proposed project is the most beneficial option.

RULE 1303(b)(5)(B) – STATEWIDE COMPLIANCE

The applicant certifies compliance with all applicable emission limitations and standards under the Clean Air Act.

RULE 1303(b)(5)(C) – PROTECTION OF VISIBILITY

Modeling analysis for plume visibility in accordance with Appendix B of Rule 1303 is required if the net increase in emissions from the new or modified source exceeds 15 tons per year of PM10 or 40 tons per year of NOx (NOx is covered under Rule 2005(g)(4)) and if it is within the distance specified in Table C-1, of the rule, from a specified Federal Class I area. The nearest Class I area (San Gabriel Wilderness Area) is 25 km away, which is less than the maximum distance requirement of 29 km and the net increase in PM10 emissions is 15.8 tons per year as shown in Table 22. Therefore, the project triggers a visibility screening analysis.

Table 22 Net Increase in PM10 and NOx Emissions in tons per year (tpy)

Parameter	PM10	NOx	Reference
Project PTE (tpy)	17.6	28.3	Table 13 of this Evaluation
Boiler B-3 (2010 and 2011 avg.) (tpy)	1.8	4.7	Applicant's Data
Net Increase (tpy)	**15.8**	**23.6**	

PDWP performed the visibility screening analysis to assess potential visibility impacts on the San Gabriel Wilderness Area following the procedures in US EPA's Workbook for Plume Visual Impacts Screening and Analysis (Revised). The facility used 5 years (2005 to 2009) of meteorological data from Asuza, CA along with the maximum hourly emissions for NOx and PM10, which occur during WIIT for NOx and during the first hour of start-up for PM10. The results of the visibility analysis are shown in Table 23.

Table 23 VISCREEN Modeling Results

Background	Meteorological Condition	Plume Perceptibility (ΔE)			Plume Contrast (C_p)		
		VISCREEN		Screening Criteria	VISCREEN		Screening Criteria
		Theta 10	Theta 140		Theta 10	Theta 140	
Sky	Level 1: F Stability, 1 m/sec	2.06	1.06	2.00	0.017	-0.019	0.05
	Level 2: E Stability, 1 m/sec	0.56	0.29	2.00	0.005	-0.005	0.05
Terrain	Level 1: F Stability, 1 m/sec	3.39	0.90	2.00	0.032	0.010	0.05
	Level 2: E Stability, 1 m/sec	0.95	0.25	2.00	0.009	0.003	0.05

As shown in Table 23, the initial Level 1 analysis exceeded the threshold for Plume Perceptibility; however, the Level 2 screening analysis was less than the threshold criteria of 2.00 for color contrast and 0.05 for plume contrast.

AQMD modeling staff reviewed the analysis and provided their comments in a memorandum from Mr. Philip Fine to Mr. Brian Yeh dated January 4, 2013. A copy of this memorandum is contained in the project file. Staff's review concluded that the applicant used appropriate model options in the analysis. The memorandum states that the modeling as performed by the applicant conforms to the District's modeling requirements. Therefore compliance is expected.

RULE 1303(b)(5)(D) – COMPLIANCE THROUGH CEQA

An Environmental Impact Report was prepared by the City of Pasadena, Lead Agency for CEQA. Compliance is expected. The document is currently in the draft stage out for public review and comment. Compliance through CEQA will be fulfilled with a final document.

<u>RULE 1325 – FEDERAL PM2.5 NEW SOURCE REVIEW PROGRAM</u>

This rule applies to any new major polluting facility, major modifications to a major polluting facility, and any modification to an existing facility that would constitute a major polluting facility in and of itself; located in areas federally designated pursuant to Title 40 of the Code of Federal Regulations (40 CFR) 81.305 as non-attainment for PM2.5.

With respect to major modifications, this rule applies on a pollutant-specific basis to those pollutants for which (1) the source is major, (2) the modification results in a significant increase, and (3) the modification results in a significant net emissions increase.

Paragraph (d)(5) defines Major Polluting Facility, on a pollutant specific basis, as any emissions source located in areas federally designated pursuant to 40 CFR 81.305 as non-attainment for the South Coast Air Basin (SOCAB) which has actual emissions of, or the potential to emit, 100 tons or more per year of PM2.5, or its precursors. A facility is considered to be a major polluting facility only for the specific pollutant(s) with a potential to emit of 100 tons or more per year. Table 24 shows the facility emissions for NOx, PM2.5 (assumed to be equivalent to PM10), and SOx. The facility is a Major Polluting Facility for NOx.

Table 24 Existing Facility NOx, PM2.5 and SOx Emissions in tons per year (tpy)

Equipment	Pollutant	Calculation[a]	tpy
Turbine GT1	NOx	(9.3 lb/hr x 149000 MWh)/(30.58 MW x 2000)	22.7
	PM2.5	(298 MMBtu/hr x 149000 MWh x 7.37 lb/MMscf)/(1012 x 30.58 MW x 2000)	5.3
	SOx	298 MMBtu/hr x 149000 MWh/30.58 x 0.00141 lb/MMBtu/2000	1.0
Turbine GT2	NOx	(9.3 lb/hr x 149000 MWh)/(30.58 MW x 2000)	22.7
	PM2.5	(298 MMBtu/hr x 149000 MWh x 7.37 lb/MMscf)/(1012 x 30.58 MW x 2000)	5.3
	SOx	298 MMBtu/hr x 149000 MWh/30.58 x 0.00141 lb/MMBtu/2000	1.0
Turbine GT3	NOx	(8.15 lb/hr x 8760)/(2000)	35.7
	PM2.5	(448 MMbtu/hr x 8760 x 7.37 lb/MMscf)/(1012 x 2000)	14.3
	SOx	448 MMBtu/hr x 8760 x 0.00141 lb/MMBtu/2000	2.8
Turbine GT4	NOx	(8.15 lb/hr x 8760)/(2000)	35.7
	PM2.5	(448 MMbtu/hr x 8760 x 7.37 lb/MMscf)/(1012 x 2000)	14.3
	SOx	448 MMBtu/hr x 8760 x 0.00141 lb/MMBtu/2000	2.8
Boiler B-3	NOx	(30 ppm x 8710 x 46 x (20.9/(20.9-3))/(379 x 1E06 x 2000) x 646 MMBtu/hr x 8760	104.8
	PM2.5	(646 MMBtu/hr x 8760 x 7.6 lb/MMscf)/(1012 x 2000)	21.2
	SOx	646 MMBtu/hr x 8760 x 0.00141 lb/MMBtu/2000	4.0
Engine D11	NOx	(5.39 gal/hr x 200 hrs x 469 lb/1000 gal)/(2000)	0.3
	PM2.5	(5.39 gal/hr x 200 hrs x 33.5 lb/1000 gal)/(2000)	0.02
	SOx	96 bhp x 0.0049 g/bhp-hr/453.6 g/lb x 200 hrs	0.0
Engine D12	NOx	(26.6 gal/hr x 200 hrs x 469 lb/1000 gal)/(2000)	1.3
	PM2.5	(26.6 gal/hr x 200 hrs x 33.5 lb/1000 gal)/(2000)	0.09
	SOx	519 bhp x 0.0049 g/bhp-hr/453.6 g/lb x 200 hrs	0.0
TOTAL	**NOx**	**GT1 + GT2 + GT3 + GT4 + B-3 + D11 + D12**	**223.2**
	PM2.5	**GT1 + GT2 + GT3 + GT4 + B-3 + D11 + D13**	**60.5**
	SOx	**GT1 + GT2 + GT3 + GT4 + B-3 + D11 + D14**	**11.6**

[a] Information from applicant's data and Facility Permit

Paragraph (d)(4)(A) identifies Major Modification as any physical change in or change in the method of operation of a major polluting facility that would result in: a significant emissions increase of a regulated NSR pollutant; and a significant net emissions increase of that pollutant from the major polluting facility. Significant as defined in (d)(13), in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates: Nitrogen oxides: 40 tons per year, Sulfur dioxide: 40 tons per year, and PM2.5: 10 tons per year. The project emission increases are shown in Table 25.

Table 25 Rule 1325 Applicability

Pollutant	Baseline PTE	Reference	Major Polluting Facility?	Net Increase	Reference	Triggers Rule 1325?
NOx	223.2	Table 24 of this evaluation	Yes	28.3	Table 13 of this evaluation	No
PM2.5[a]	60.5	Table 24 of this evaluation	No	17.6	Table 13 of this evaluation	No
SOx	11.6	Table 24 of this evaluation	No	3	Table 13 of this evaluation	No

Table 25 summarizes the facility's NOx, PM2.5, and SOx emissions and the project net increase in emissions. The facility is a Major Polluting Facility for NOx, but the net increase is below the 40 tpy threshold. The facility is not a Major Polluting Facility for PM2.5 or SOx; therefore, this project does not trigger the requirements of Rule 1325.

RULE 1401 – NEW SOURCE REVIEW OF TOXIC AIR CONTAMINANTS

This rule is applicable to applications deemed complete on or after June 1, 1990 and it imposes specific limits for maximum individual cancer risk (MICR), cancer burden, and non-cancer acute and chronic hazard indices from new permit units, relocations, or modifications to existing permit units which emit toxic air contaminants (TAC) listed in Table I of Rule 1401. The rule establishes allowable risks for permit units requiring new permit pursuant to Rules 201 or 203. The proposed gas turbine and associated control equipment is a new construction with an increase in TAC emissions shown in Table 26, thus Rule 1401 applies to this project.

Table 26 Turbine Toxic Air Contaminant (TAC) Emissions

TAC[a]	CAS No.	EF (lb/MMscf)	EF (lb/MMBtu)	Maximum Hourly (lb/hr)[b]	Maximum Annual (lb/yr)[c]
Ammonia	7664417	NA	NA	3.65E+00	3.16E+04
1,3-Butadiene	106990	4.35E-04	4.30E-07	2.41E-04	2.06E+00
Acetaldehyde	75070	4.05E-04	4.00E-07	2.24E-04	1.92E+00
Acrolein	107028	3.66E-03	3.62E-06	2.03E-03	1.73E+01
Benzene	71432	3.30E-03	3.26E-06	1.83E-03	1.56E+01
Ethylbenzene	100414	3.24E-02	3.20E-05	1.80E-02	1.54E+02
Formaldehyde	50000	3.64E-01	3.60E-04	2.02E-01	1.73E+03
Propylene Oxide	75569	2.93E-02	2.90E-05	1.62E-02	1.39E+02
Toluene	108883	1.32E-01	1.30E-04	7.31E-02	6.26E+02
Xylenes	1330207	6.48E-02	6.40E-05	3.59E-02	3.07E+02
Benzo(a)anthracene	56556	2.26E-05	2.23E-08	1.25E-05	1.07E-01
Benzo(a)pyrene	50328	1.39E-05	1.37E-08	7.70E-06	6.59E-02
Benzo(b)fluoranthene	205992	1.13E-05	1.12E-08	6.26E-06	5.36E-02
Benzo(k)fluoranthene	207089	1.10E-05	1.09E-08	6.10E-06	5.21E-02
Chrysene	218019	2.52E-05	2.49E-08	1.40E-05	1.19E-01
Diebenz(a,h)anthracene	53703	2.35E-05	2.32E-08	1.30E-05	1.11E-01
Indeno(1,2,3-cd)pyrene	193395	2.35E-05	2.32E-08	1.30E-05	1.11E-01
Naphthalene	91203	1.66E-03	1.64E-06	9.20E-04	7.87E+00

(a) TAC emission factors from AP-42, 3.1 Stationary Gas Turbines and CARB's California Air Toxics Emission Factors (CATEF) database.

(b) Hourly emissions were determined at an ambient temperature of 17°F and 100% Load at 560.8 MMBtu/hr.

(c) Annual emissions were determined at 8,760 hours of operation per year at an ambient temperature of 64°F and 100% Load at 547.5 MMBtu/hr.

The facility provided a health risk assessment (HRA) that was prepared using the guidelines under the District's Risk Assessment Procedures for Rules 1401 and 212 Version 7, July 2005, and the procedures outlined in the Supplemental Guidelines for Preparing Risk Assessments for the Air Toxics "Hot Spots"

Information and Assessment Act (AB2588), June 2011, which supplement the Air Toxics Hotspots Program Guidance Manual for Preparation of Health Risk Assessments (OEHHA, 2003) and the CARB Recommended Interim Risk Management Policy for Inhalation-based Residential Cancer Risk (CARB, 2003). The HRA was prepared using CARB Hotspots Analysis Reporting Program (HARP) model which includes EPA's AERMOD model as well as the risk assessment calculation model based on the Air Toxics Hot Spots Risk Assessment Guidelines. The TACS from Table 26 were used in the assessment.

The modeling results are shown in Table 26, which show MICR less than 1 in a million, chronic and acute hazard indices less than 1.0 for the gas turbine. District staff reviewed the methodology and procedures of the modeling runs submitted by PDWP and it was determined that the results shown in table 26 were appropriately estimated. Please refer to internal memorandum in the project file from Mr. Philip Fine to Mr. Brian Yeh dated January 4, 2013. Therefore, compliance with Rule 1401 is expected.

Table 26 Turbine Toxic Air Contaminant (TAC) Emissions

Parameter	Workplace Receptor	Residential Receptor	Rule 1401 Limits	Complies
Maximum Individual Cancer Risk (MICR)	1.49E-08	6.90E-08	T-BACT: ≤ 1.00E-06 No T-BACT: 1.00E-05	**Yes**
Chronic Hazard Index	1.78E-03	1.59E-03	≤ 1.0	**Yes**
Acute Hazard Index	2.03E-03	3.08E-03	≤ 1.0	**Yes**

RULE 1401.1 – REQUIREMENTS FOR NEW AND RELOCATED FACILITIES NEAR SCHOOLS

The purpose of this rule is to provide additional health protection to children at schools or schools under construction from new or relocated facilities emitting toxic air contaminants. This rule applies to new and relocated, but not to existing facilities. Applications for Permit to Construct/Operate from such new or relocated facilities shall be evaluated under this rule using the list of toxic air contaminants in the version of Rule 1401 that is in effect at the time the application is deemed complete. The PDWP facility is an existing facility that is not new or relocated; therefore, the requirements of this rule are not applicable.

REGULATION XVII – PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

Rule 1703 – PSD Analysis

The AQMD and EPA entered into 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. Sine 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 40 CFR Part 52 Subpart 21, or apply to AQMD in accordance with the current requirements of Regulation XVII.

The PDWP has requested to determine PSD applicability under AQMD Regulation XVII opting for the emissions methodology outlined in Rule 1706(c)(1)(A) – the actual to potential test. PSD analysis applies to new major stationary sources and major modifications to existing stationary sources located in attainment areas. A major source is a listed facility that emits at least 100 tons per year of a listed PSD pollutant or any other facility that emits at least 250 tons per year of a listed PSD pollutant. The PDWP facility is located in an attainment area for CO, SO2, and NO2 and it is an existing major source under PSD definitions. A significant increase in emissions is defined as an increase in 40 tons per year of either NOx or SOx, or 100 tons per year of CO emissions over the emissions before the modifications of the stationary source per Rule 1706(c)(1)(B)(i).

The actual emissions from PDWP prior to the modification will be determined with data from the two-year period preceding the date of the permit application. The application was received in 2012, so the two year preceding period will be 2010 to 2011. The actual boiler emissions compared to the project PTE and the PSD applicability are shown in Table 28.

Table 28 Determination of Project PSD Applicability

Pollutant	Actual Boiler B-3 Emissions (tpy)[(a)]	GT-5 PTE (tpy)[(b)]	Emission Change (tpy)[(c)]	Triggers PSD Analysis?
NO2	4.7	28.3	23.6	N
SO2	0.1	3.4	3.3	N
CO	20.0	20.6	0.6	N

[(a)] Actual boiler emissions from January 2010 through December 2011.
[(b)] Taken from Tables 12 and 13 of this evaluation.
[(c)] (b) – (c)

As shown in Table 28, the increase in emissions is less than 40 tons per year for NO2 and SO2 and the increase in CO emissions are less than 100 tons per year. Therefore, PSD analysis is not triggered for this re-powering project.

Rule 1714 – PSD for Greenhouse Gases

This rule sets forth preconstruction review requirements for greenhouse gases (GHG). The provisions of this rule apply only to GHGs as defined by EPA to mean the air pollutant as an aggregate group of six GHGs: carbon dioxide (CO2), nitrous oxide (N2O), methane (CH4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). All other attainment air contaminants, as defined in Rule 1702 subdivision (a), shall be regulated for the purpose of Prevention of Significant Deterioration (PSD) requirements pursuant to Regulation XVII, excluding Rule 1714. The provisions of this rule shall apply to any source and the owner or operator of any source subject to any GHG requirements under 40 Code of Federal Regulations Part 52.21 as incorporated into this rule. The rule specifies what portions of 40 CFR, Part 52.21 do not apply to GHG emissions, which are identified in Rule 1714(c)(1) as exclusions.

The GHG pollutants of CO2, N2O and CH4 are products of combustion. The use of HFCs, PFCs, and SF6 are associated with equipment that are used for the operation of the facility, such as: HFCs used as heat transfer medium in air condition control equipment, PFCs used as an agent in fire suppression equipment, and SF6 as gas used to insulate transformers as well as in circuit breakers. The facility is expected to follow appropriate procedures to minimize any release of GHGs during installation, operation, and maintenance activities. The purchase of equipment that meet applicable standards and the practice of proper maintenance will ensure compliance for the non-combustion GHG products.

A PSD permit is required, prior to actual construction, of a new major stationary source or major modification to an existing major source as defined in 40 CFR 52.21(b)(1) and (b)(2), respectively. The rule incorporates the EPA rule by reference, so determination of PSD applicability for GHG is done using the EPA's document PSD and Title V Permitting Guidance for Greenhouse Gases, March 2010. The GHG emissions calculated in Table 30, using the heat input data and emission factors from Tables 29 and 30, respectively, were used for the project GHG PSD applicability determination in Table 32.

Table 29 Maximum Fuel and Heat Input for Potential to Emit

Equipment		Parameter	Unit	Value	Reference
Boiler B-3	a	Rating	MMBtu/hr	646	Applicant's data and Facility Permit
	b	Hours	hrs/yr	8,760	Maximum allowable
	c	Annual Heat Input	MMBtu/yr	5,658,960	a x b
	d	Annual Fuel Use	MMscf/yr	5,592	c / 1012
GT-1/GT-2[(a)]	e	Rating	MMBtu/hr	298	Applicant's data and Facility Permit
	f	Annual Limit	MW-hr	149,000	Applicant's data and Facility Permit
	g	Output	MW	30.58	Applicant's data and Facility Permit
	h	Annual Heat Input	MMBtu/yr	1,451,995	e x f / g
	i	Annual Fuel Use	MMscf/yr	1,435	h / 1012
GT-3/GT-4[(b)]	j	Rating	MMBtu/hr	448	Applicant's data and Facility Permit
	k	Hours	hrs/yr	8,760	Maximum allowable
	l	Annual Heat Input	MMBtu/yr	3,924,480	j x k
	m	Annual Fuel Use	MMscf/yr	3,878	l /1012
ICE D11	n	Fuel Rate	gal/hr	5.39	Applicant's data
	o	Hours	hrs/yr	200	Applicant's data and Facility Permit
	p	Annual Fuel Use	gal/yr	1,078	n x o
	q	Annual Heat Input	MMBtu/yr	149	p x 0.138 MMBtu/gal
ICE D12	r	Fuel Rate	gal/hr	26.6	Applicant's data
	s	Hours	hrs/yr	200	Applicant's data and Facility Permit
	t	Annual Fuel Use	gal/yr	5,320	r x s
	u	Annual Heat Input	MMBtu/yr	734	t x 0.138 MMBtu/gal
GT-5 (new)	v	Rating	MMBtu/hr	547.5	d in Table 6 of this evaluation
	w	Hours	hrs/yr	8,760	Maximum allowable
	x	Annual Heat Input	MMBtu/yr	4,796,100	v x w
	y	Annual Fuel Use	MMscf/yr	4,739	x / 1012

(a) Turbines GT-1 and GT-2 are identical units with the same permit conditions, thus the maximum potential fuel use is identical.

(b) Turbines GT-3 and GT-4 are identical units with the same permit conditions, thus the maximum potential fuel use is identical.

Table 30 GHG Emission Factors for Mass and Carbon Dioxide Equivalent (CO2E)

Fuel		GHG	kg/MMBtu[(a)]	ton/MMBtu (Mass)[(b)]	GWP[(c)]	ton/MMBtu (CO2E)[(d)]
Natural Gas	a	CO2	53.02	5.84E-02	1	5.84E-02
	b	CH4	0.001	1.102E-06	21	2.31E-05
	c	N2O	0.0001	1.102E-07	310	3.42E-05
Diesel	d	CO2	73.96	8.15E-02	1	8.15E-02
	e	CH4	0.003	3.306E-06	21	6.94E-05
	f	N2O	0.0006	6.612E-07	310	2.05E-04

(a) Emission Factors from EPA's Emission Factors for Greenhouse Inventories, November 2011

(b) kg/MMBtu x 1.102E-03 ton/kg

(c) Global Warming Potential (GWP) taken from EPA's Emission Factors for Greenhouse Inventories, November 2011

(d) ton/MMBtu (Mass) x GWP

Table 31 GHG Emission Rates for Mass and CO2E

Equipment	Mass (tpy)				CO2E (tpy)			
	CO2[(a)]	CH4[(b)]	N2O[(c)]	Total	CO2[(d)]	CH4[(e)]	N2O[(f)]	Total
Boiler B-3	330,642	6	1	330,649	330,642	131	193	330,966
GT-1	84,837	2	0	84,839	84,837	34	50	84,920
GT-2	84,837	2	0	84,839	84,837	34	50	84,920
GT-3	229,300	4	0	229,304	229,300	91	134	229,525
GT-4	229,300	4	0	229,304	229,300	91	134	229,525
ICE D11	12	0	0	12	12	0	0	12
ICE D12	60	0	0	60	60	0	0	60
			Existing Total	**959,008**			**Existing Total**	**959,928**
GT-5 (new)	280,227	5	1	280,233	280,227	111	164	280,502
			Project Total	**280,233**			**Project Total**	**280,502**

(a) Annual Heat Input MMBtu/hr *{from Table 29}* x CO2 ton/MMBtu (Mass) *{from Table 30}*
(b) Annual Heat Input MMBtu/hr *{from Table 29}* x CH4 ton/MMBtu (Mass) *{from Table 30}*
(c) Annual Heat Input MMBtu/hr *{from Table 29}* x N2O ton/MMBtu (Mass) *{from Table 30}*
(d) Annual Heat Input MMBtu/hr *{from Table 29}* x CO2 ton/MMBtu (CO2E) *{from Table 30}*
(e) Annual Heat Input MMBtu/hr *{from Table 29}* x CH4 ton/MMBtu (CO2E) *{from Table 30}*
(f) Annual Heat Input MMBtu/hr *{from Table 29}* x N2O ton/MMBtu (CO2E) *{from Table 30}*

Table 32 GHG PSD Applicability Flowchart for Project[(a)]

Step	GHG PSD Applicability Step	Result	Response
1	Will the permit be issued on or after July 1, 2011	Yes	Go to Step 2
2	Is this modification subject to PSD permitting for a regulated NSR pollutant other than GHGs?	No	Go to Step 3
3	Determine PTE for existing stationary source, before modification, for each of the 6 GHG pollutants. Determine the mass sum and the CO2e sum (using GWP equivalent).	Mass Sum: 959,008 tpy *{Table 31}* CO2E Sum: 959,928 tpy *{Table 31}*	Go to Step 4
4	Are the PTE for GHG emissions equal or greater than both 100,000 tons per year CO2e and 100 tons per year on mass basis?	Yes	Go to Step 5
5	Determine past actual (baseline) in tons per year for units that are a part of the modification for each of the 6 GHG pollutants. (For new units, the past GHG emissions are zero)	The turbine, GT-5, will be a new unit; therefore, the past actual emissions are zero.	Go to Step 7
6	NA	NA	NA
7	For units that are part of the modification, determine the future projected actual emissions (or PTE) in tons per year for each of the 6 GHG pollutants.	Mass Sum: 280,233 tpy *{Table 31}* CO2E Sum: 280,502 tpy *{Table 31}*	Go to Step 8
8	For each unit, determine the increase or decrease in mass emissions of each of the 6 GHG pollutants by subtracting past actual emissions from future actual emissions. Note: For new units that are not "replacement units", future actual emissions are equal to the PTE.	**Boiler B-3** ***Past Actual*** Average fuel use for 2011 and 2012 was 476.43 MMscf/yr; thus, annual capacity factor is 0.0852 calculated as 476.43/5,592 *{Item d from Table 29}* Mass Sum: 28,171 tpy calculated as 0.0852 x 330,649 tpy *{Table 31}* CO2E Sum: 28,198 tpy calculated as 0.0852 x 330,642 *{Table 31}* ***Future Actual*** Mass Sum: 0 CO2E Sum: 0	Go to Step 9

		GT-5 ***Past Actual*** Mass Sum: 0 CO2E Sum: 0 ***Future Actual*** Mass Sum: 280,233 tpy *{Table 31}* CO2E Sum: 280,502 tpy *{Table 31}*	
9	For each unit, sum any increase or decrease in GHG emissions on a mass basis.	***Decrease*** 28,171 tpy – 0 = 28,171 tpy ***Increase*** 280,233 tpy – 0 = 280,233 tpy	Go to Step 10
10	For all units that have mass emission increase, sum the GHG emissions on a mass basis.	***Increase*** 287,040 tpy – 28,171 tpy = 258,869 tpy	Go to Step 11
11	Is the sum of GHG emissions over zero tons per year?	Yes	Go to Step 12
12	For each unit, convert any increase or decrease in emissions of each of the 6 GHG pollutants to their CO2e using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them for each unit to arrive at one GHG CO2e number for each unit.	***Increase*** 280,502 tpy	Go to Step 13
13	Sum the GHG emissions on a CO2e basis for all units that have an emissions increase. (Emission decreases are not considered in this step).	***Increase*** 280,502 tpy	Go to Step 14
14	Is the CO2e sum of the increase equal or greater than 75,000 tons per year CO2e?	Yes	Go to Step 15
15	Contemporaneous netting is required. Identify all contemporaneous creditable increases and decreases in emissions for each of the 6 GHG pollutants on a mass basis. Note: Creditable decreases are only those that have not been relied upon in prior PSD review and will be practically enforceable by the time construction begins.	The existing boiler B-3 will b e decommissioned as a part of this project.	Go to Step 16
16	For each credible activity, determine the increase or decrease in emissions for each of the 6 GHG pollutants.	***Decrease*** 28,171 tpy	Go to Step 17
17	Sum the increases and decreases, including the increases and decreases from the proposed modifications, for each of the 6 pollutants on a mass basis.	***Increase*** 280,233 tpy ***Decrease*** 28,171 tpy	Go to Step 18
18	Calculate the net GHG emissions on a mass basis.	***Net Increase*** 280,233 tpy – 28,171 tpy = 252,062 tpy	Go to Step 19
19	Are the net GHG emissions on a mass basis over zero tons per year?	Yes	Go to Step 20
20	Convert any contemporaneous, creditable increase or decrease in emissions of each of the 6 GHG pollutants and sum them.	***Increase*** 280,502 tpy ***Decrease*** 28,198 tpy	Go to Step 21
21	Calculate the net GHG emissions on a CO2e basis	***Net*** 280,502 tpy – 28,198 tpy = 252,304 tpy	Go to Step 22
22	Are the net GHG emissions on a CO2e basis equal to or greater than 75,000 tons per year CO2e?	Yes	**GHG emissions subject to PSD Review**

(a) Flowchart from Appendix D. GHG Applicability Flowchart – Modified Sources (On or after July 1, 2011) of EPA's document PSD and Title V Permitting Guidance for Greenhouse Gases, March 2010.

Table 32 identifies that this project is subject to PSD analysis for GHG Emissions. Therefore, BACT is required for GHG. The applicable BACT is Federal BACT, which includes consideration of such factors as energy and cost. The District follows the federal guidelines on BACT for GHGs as outlined in the EPA's document PSD and Title V Permitting Guidance for Greenhouse Gases, March 2010. The EPA recommends that permitting authorities use the five-step "top-down" BACT analysis outlined in Table 33 to determine BACT for GHGs.

Table 33 EPA's 5-Step Top-Down BACT Analysis Methodology

	Step	Description
1	Identify all available control technologies	All available control options for the emissions unit analyzed are identified. Identifying all potential available control options consists of those air pollution control technologies or control techniques with a practical potential for application to the emissions unit and the regulated pollutant being evaluated.
2	Eliminate technically infeasible options	The technical feasibility of the control options identified in Step 1 are evaluated and the control options that are determined to be technically infeasible are eliminated. Technically infeasible is defined where a control option, based on physical, chemical, and engineering principles, would preclude the successful use of the control option due to technical difficulties.
3	Rank remaining control technologies	All control options that were not eliminated in Step 2 are ranked based on effectiveness.
4	Evaluate most effective controls and document results	Additional evaluation is conducted on the technologies presented in Step 3 based on environmental, energy, and economic impacts are all considered for the final BACT evaluation.
5	Select the BACT	BACT is selected as the highest ranked control technology not eliminated in Step 4.

GHG Top-Down BACT Analysis

Step 1: Identify all available control technologies.

A review was conducted on the AQMD BACT/LAER Guidelines, the Bay Area Air Quality Management District (BAAQMD) BACT Guidelines, EPA's RACT/BACT/LAER Clearinghouse (RBLC), pending projects in the California Energy Commission (CEC) Database, as well as information provided by the EPA on BACT limits for combine cycle natural gas turbines. A summary of the GHG BACT Assessments are listed in Table 34.

Table 34 GHG BACT Assessments

	Source	Location	GHG BACT
1	Palmdale Hybrid Power Project (PHPP) (570 MW)	Palmdale, California	1. Thermal efficiency limit of 774 lbs-CO2E/MWh (365 day rolling average) 2. Heat rate limit of 7,319 Btu/kWh (12 month rolling average) 3. Annual facility CO2E limit of 1,913,000 tpy
2	Lower Colorado River Authority (LCRA) Thomas C. Ferguson Power Plant (420 MW)	Marble Falls, Texas	1. Thermal efficiency limit of 0.459 tons-CO2E/MWh (net) (365 day rolling average) 2. Heat rate limit of 7,720 Btu/kWh (365 day rolling average) 3. Annual facility CO2E limit of 1,821,241.5 tpy
3	Portland General Electric Company's Carty Power Plant (415 MW)	Boardman, Oregon	Thermal Efficiency due to natural gas fueled combined cycle power plant
4	Russell City Energy Center (600 MW)	Hayward, California	Thermal Efficiency due to natural gas fueled combined cycle power plant
5	Hyperion Energy Center (532 MW)	Elk Point, South Dakota	Use of Integrated Gasification Combined Cycle (IGCC)
6	Pioneer Valley (400 MW)	Westfield, Massachusetts	1. 825 lbs-CO2E MWh (Initial Test) 2. 895 lbs-CO2E/MWh (365 day rolling average) (thereafter)

7	Woodbridge Energy (CPV Valley) (663 MW)	Woodbridge, New Jersey	925 lb-CO2/MWh
8	Newark Energy Center (655 MW)	Newark, New Jersey	879 lb-CO2/MWh
9	CPV Valley (650 MW)	Wawayanda, New York	925 lb-CO2/MWh
10	Cricket Valley Energy (1,000 MW)	Dover, New York	1. Thermal Efficiency 57.4% 2. Heat Rate ≤ 7,605 Btu/kWh
11	CPV St. Charles (640 MW)	Charles County, Maryland	1. Thermal Efficiency of 57.4% 2. Heat rate limit of 7,605 Btu/kWh (LHV) 3. Annual facility CO2E limit of 2,244,881 tpy
12	Gateway Cogen (168 MW)	Prince George County, Virginia	1. Thermal Efficiency 1050 lb-CO2/MWh 2. Heat Rate 8,983 Btu/kWh (HHV gross)
13	Pacific Corp Lakeside Phase II (637 MW)	Vineyard, Utah	950 lb-CO2E/MWh (gross) (12 month rolling average)

A list of CO2 control technologies were developed and discussed for the BACT analysis.

1. Carbon Capture and Sequestration
2. Lower Emitting Technology
3. Thermal Efficiency

Each of the technologies is discussed in detail in the following subsections.

1. Carbon Capture and Sequestration (CCS)
The most comprehensive information available is on the Department of Energy (DOE) website, which contains information regarding the Carbon Sequestration Program. A number of steps are involved in the process of CCS. First the CO2 emissions must be captured and separated from the streams to be treated, and it must be transported to the site of sequestration, and finally there is the sequestration site that will store the CO2.

A. Capture of CO2 Emissions
The process begins with the capture of CO2 from the flue gas stream. The type of post-combustion capture systems include: amine based solvent systems, which are already in use for removing CO2 from process gas, solid sorbents can be used to remove CO2 from flue gas through chemical adsorption, physical adsorption, or a combination of both; possible configuration include fluidized beds or membrane based technology.

B. Transportation of CO2
Once the CO2 is separated from the flue gas stream it must be transported to the site of sequestration. Large volumes of CO2 from a power plant require the use of a pipeline. At present, there are no pipelines in operation or under construction in California.

C. Sequestration
Sequestration may be accomplished through geologic storage, ocean storage, or mineral carbonation. Geologic sequestration involves the identification of a suitable geological formation within close proximity to the site of the proposed project where the compressed CO2 is delivered under high pressure via pipeline and injected into the formation at depths greater than 800 meters. Below this depth the pressurized CO2 remains supercritical and behaves like a liquid and occupies pore spaces in the surrounding rock displacing saline water. Over time solid carbonate minerals form as a result of reactions between dissolved CO2 in water and the surrounding rock.

A number of geological formations in California have been identified that may be suitable for sequestration. The Department of Energy Carbon Sequestration Atlas for the United States and Canada shows the nearest potential sequestration basins to the project site are north in the Lower San Joaquin Valley and west in Ventura County. The sites may prove to be suitable candidates for CO2 sequestration; however, geological technical analyses have not been conducted to date to verify that possibility. The major obstacle to the viability of using these sites for sequestration is the mountain range between the Pasadena project site and the location in south San Joaquin and Ventura County. Potential sites within the oil production fields of the Long Beach area would require the construction of a CO2 pipeline through the urban Los Angeles area, which would prove to be difficult to construct in regards to cost and environmental approval.

Ocean storage would involve the injection of CO2 into the ocean at depths below 1,000 meters via pipeline or ship. It is expected that the CO2 would dissolve or form a horizontal lens, which would delay the dissolution of CO2 into the surrounding environment. The depth of the water and the CO2 lensing would form an obstacle to the vertical migration of the injected CO2.

Mineral carbonation is the reaction of the CO2 with metal oxides forming metal carbonates that are stable. The natural reaction between metal oxides, which are abundant in silicate minerals and in waste streams, is a slow process. However, reaction time may be increased through enhancing the purity of the metal oxides. The large-scale production of the metal oxides to meet the demand required through electrical generation would be costly and energy intensive.

2. Lower Emitting Technology
Power production technology that is commercially available and low or non-GHG emitting is solar power, wind, geothermal, hydroelectric, nuclear, and biomass fueled facilities. These technologies were examined and considered as a part of the Alternatives Analysis in the Environmental Impact report.

The CEC identified locations in the state that have a high potential for viable solar, wind, and geothermal energy production. They rated California's solar potential by county and although Los Angeles as a county has a relatively high photovoltaic potential, most of the high potential areas are concentrated in the northeastern corner of the county around Lancaster, which is approximately 40 miles away from Pasadena. Large scale solar energy generation is not viable for the city; however, PDWP's Integrated Resource Plan (IRP) has proposed to increase local solar production by 3 MW in 2010, 10 MW by 2015, 15 MW by 2020, and 19 MW by 2024.
The CEC also studied the States' high wind resource potential and areas with winds above 11 mph within Los Angeles County are located at remote regions in the northwestern portion. In addition, transmission of either solar or wind-generated energy to Pasadena is limited to transmission capacity as PDWP has only a single point of connection with SCE at the TM Goodrich substation at the eastern border of Pasadena, limiting electricity at 215 MW.

There are no known geothermal resources located within Los Angeles County. The nearest geothermal resource is Sespe Hot Springs in Ventura County, which is approximately 60 miles away.

The IRP has identified targets to achieve reductions in electricity usage through reducing energy sales by 12.5% below business as usual levels by 2016, reducing peak load by 10% below business as usual levels by 2012, further reducing peak load by an additional 5 MW through education and economic incentives to customers. A number of residential energy programs and incentives are already offered to residents to improve energy and water usage. PDWP has also initiated the Advanced Meter Pilot Program, which is an

American Public Power Association grant funded project to replace 200 existing electric meters with more advanced meter technology that combines a digital meter platform with wireless technology. These meters are able to detect power outages and abnormal voltage on power lines and alert PDWP staff who are than able to activate or deactivate electric service remotely. The meters may play an integral role in improving system reliability.

The lower GHG emitting technologies would fundamentally redefine the project and alter the business purpose. The EPA does not require a BACT analysis to redefine the applicants' project (EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, 2010). As a result, no additional lower emitting alternative technologies are feasible to incorporate into the project without changing the business purpose of the project.

3. Thermal Efficiency
The thermal efficiency of CO2 formation through combustion is governed by the thermodynamics of the system and is defined as the dimensionless ratio of the useful work obtained from the process and the heat input to the process. The reduction of CO2 from fossil fuel combustion is achieved by the use of less fuel through a more thermally efficient process or the use of a lower GHG emitting fuel.

PDWP is proposing to combust natural gas, which is the lowest emitting fossil fuel available, in a one by one combined cycle configuration; gas turbine generator, once-through-steam-generator (OTSG), and a steam turbine. The use of the OTSG, as described in the process description section, allows the gas turbine to operate without water in the tubes as opposed to a traditional heat recovery steam generator (HRSG). The OTSG can operate from a dry state to steam operation without any changes to turbine load. This set-up allows a faster start-up without the restrictions of conventional HRSGs thus minimizing emissions.

PDWP had established a number of minimum operating requirements that the new unit was to meet when they put the proposal out to bid. The new unit was required to meet the following requirements:

- 10 minute start for the gas turbine
- Once Through Steam Generator (OTSG) – dry run capable
- Gross output not more than 71 MW
- Guaranteed BACT emission levels
- Noise guarantee in accordance with the City of Pasadena's noise ordinance

The City of Pasadena issued a Request for Proposal (RFP) for the design and supply of equipment for their repowering project. The RFP was publicly circulated and available on the City of Pasadena's website as well as on www.planetbids.com, which as described on their website is:

> *"...a leading provider of web based modular procurement solutions designed to automate the procurement process thus improving communication between buyers and suppliers cost effectively and efficiently. Our leading web based solutions include supplier management, bid management, insurance certificate management, emergency operations management and contract management"*

This allowed the RFP to be accessed by vendors all across the United States, as well in Canada and the Republic of Korea. The RFP required vendors to perform process design and encouraged them to package the most efficient system possible. PDWP had 31 potential bidders that attended the on-site pre-bid meeting. Eventually, the city received 5 bids, of which all 5 had either the GE LM6000 PG or the Rolls Royce Trent 60 gas turbines as a part of their proposal. Based on the proposals received for this repowering project, the two turbines represent the most efficient units available capable of meeting the city's requirements for the combined cycle repower project.

In comparison to the existing boiler B-3, which will be removed and replaced with the modern high efficiency combined cycle system, the result will be an improvement in PDWP's generation system efficiency, reliability and flexibility. The new combined cycle system will have lower GHG emissions per MWh than the existing boiler and will result in a net reduction of GHG emissions.

Step 2: Eliminate Technically Infeasible Options
Technology identified in the previous steps is only feasible if they are available and applicable to the scope of the project. Any technology that is not commercially available for the scale of the project is also considered infeasible.

1. Carbon Capture and Sequestration (CCS)
The technical feasibility of each step of the CCS process is discussed below.

A. Carbon Capture

a. Solvent-based process

An amine system, developed by Fluor Corp. called Econamine FG Plus (EFG+), has been demonstrated at the 320 MW Bellingham Power Plant in Massachusetts, which has been able to capture 365 short tons per day from the exhaust of natural gas. The CO2 that was captured was sold to the food industry. The CO2 capture plant operated from 1991 to 2005. It closed due to the price of natural gas.

Amines are able to capture CO2 from streams with low CO2 partial pressure, such as flue gas, through reactions that form water soluble compounds as demonstrated with EFG+ process. These solvent based amine (pure or blended) systems require regeneration with steam that results in a loss of power production, when combined with compression, results in a parasitic load of 20 to 30%. The PDWP proposal has a current parasitic load of approximately 4%, a 20 to 30% parasitic load would greatly impact the amount of power that would be available to the residents of Pasadena since the current proposal is only for 71 MW.

Potassium carbonate may also be used to capture CO2. The process converts carbonate to bicarbonate in the presence of CO2, which is then converted back to carbonate through heating and the subsequent release of the absorbed CO2. Carbonate systems have an advantage over amine systems because much less energy is required for regeneration. The demonstration on large scale power plants has yet to be shown.

There are other processes such as aqueous ammonia, ionic liquids and hydrates, as well as physical solvents that rely on the partial pressure of CO2 in the waste stream, that are being investigated; however, these processes have not been demonstrated on a large scale power plant.

b. Membrane-based process

The process of separating CO2 from flue gas is dependent on the CO2 partial pressure to move the CO2 across the membrane. A vacuum or a sweep gas would be needed to aid the transfer of CO2 across the membrane requiring additional energy. Compressing the CO2 to the high operating pressures needed for pipeline transportation would require significant amounts of energy.

Demonstration at the commercial large scale level has not been achieved. The use of membranes as carbon capture is infeasible.

c. Solid Sorbents
Solid sorbent systems present more design and operating difficulties than other systems because the handling of solids is more problematic. Large volumes of CO2 from a power plant would require large scale equipment. As with the other technologies discussed previously, the demonstration of the technology on a commercial power plant has not been achieved.

d. Oxy-combustion
A high pressure combustor is used to ignite natural gas and oxygen to form approximately 10% CO2 and 90% steam, by volume. CO2 may be removed from the stream with the previously mentioned technology. Clean Energy Systems, Inc. (CES) operates a 5 MW oxy-fuel combustor powering a steam turbine in the San Joaquin Valley under a research permit. However, CES has not built a large scale power plant using oxy-fuel combustion.

B. CO2 Transportation
The large volumes of CO2 generated from a commercial power plant would require a pipeline as the only practical option to handle the high volume. Large pipelines are already in existence for carrying CO2 to enhanced oil recovery (EOR) operations, where the CO2 is injected into the formation to lower oil viscosity and promote its movement into the production wells.

C. Sequestration
a. Geologic Sequestration
Injection of CO2 into geological formations has been shown to be effective, especially in the case of EOR operations in which CO2 flooding has shown to revitalize mature oil fields. However, there are still a number of technical issues that need to be resolved before this can be applied to a large commercial power plant.

- The existence of a suitable repository for the injection of the recovered CO2, which should have one or more injection zones that can accept and store large volumes of CO2.
- The repository must be able of sequestering the CO2 for the period of time determined to be the time required to be sequestered. The seismicity of Southern California works against long-term sequestration.
- The repository is located within close proximity to the power plant to allow efficient transportation of the CO2.
- Standards for measuring, monitoring, and verification of containment will be required to be established to allow confidence that long term storage will occur.

b. Ocean Storage
The concept of using the ocean as a CO2 sink and any resulting ecological impacts are still in the research phase. Possible acidification and the resultant negative biological impacts may prove that ocean storage would never be viable for CO2 sequestration. Further research is required to determine this option as being technically feasible.

c. Mineral Carbonation
The chemistry of the formation of metal carbonates is understood and technically feasible; however, sequestration has not been demonstrated for large scale power production activities.

Summary of CCS Feasibility
The post-combustion carbon capture technologies are still in development and are not considered to be commercially available for a large, full-size commercial power plant.

2. Lower Emitting Technology
The lower emitting technology that was presented earlier was determined to be infeasible for the site and would fundamentally alter the business purpose of the source. Thus the alternative technology was not considered as part of the BACT analysis.

3. Thermal Efficiency
The California State Senate Bill (SB) 1368 requires the California Public Utilities Commission (CPUC) to establish a GHG emission performance standard for all baseload utilities by February 1, 2007. The California Energy Commission (CEC) was required to establish a similar standard for local publicly owned utilities by June 30, 2007. The CEC established a GHG performance standard of 1,100 pounds of CO2E per net MWh for baseload publicly owned electrical utilities. The California Legislature in Assembly Bill (AB) 1613 (2007), as amended by AB 2791 (2008), established a CO2 Emission Performance Standard (EPS) for combined heat and power facilities of 1,100 lbs CO2E/MWh. In 2010, the CEC promulgated its regulation to implement AB 1613 in its Guidelines for Certification of Combined Heat and Power Systems pursuant to the Waste Heat and Carbon Emissions Reduction Act.

The EPA released a prepublication version of a proposed rule on March 27, 2012 to establish, a new source performance standard (NSPS) for GHG emissions from fossil fuel-fired electric generating units. The standard, to be published in the Federal Register as Subpart TTTT, will require new fossil fuel-fired power plants to meet an output based standard (based on gross power) of 1,000 lb CO2/MWh on an average annual basis applicable to combined cycle generating systems. At this moment the proposed rule has not been finalized by the EPA.

The combined cycle generating system is already a highly efficient unit that will replace an inefficient steam boiler, which will result in an increase in GHG emissions efficiency over the existing baseline. The project will lower the GHG emissions and the GHG emission performance metric. The thermal efficiency achieved and proposed is a technically feasible alternative for reducing GHG emissions from a fossil fuel fired power plant. This combustion process inherent to the combined cycle system is achieved in practice and eligible for consideration under step 3 of the BACT analysis.

Step 3: Rank Remaining Control Technologies
CCS has been determined to be technically infeasible for the project; however, the option will be carried forward for further discussion and consideration. The control options are ranked below from most effective to least effective.

1. Carbon Capture and Sequestration
2. Thermal Efficiency

The effectiveness of each option is discussed below.

1. Carbon Capture and Sequestration (CCS)
The capture efficiency of post-combustion systems that are being developed are expected to control at least 90% of CO2. This places CCS as the top ranked control technology.

2. Thermal Efficiency
Thermal efficiency will lower the GHG emissions, but not as much as CCS. As previously presented, the proposed system already incorporates an increased thermal efficiency in design with the inclusion of a OTSG and combined cycle configuration. The system parasitic load is already low, at about 3 MW, and any further increases to thermal efficiency are not achievable without changing the objectives of the power plant.

Step 4: Evaluate the Most Effective Controls and Document Results
This step involves the consideration of energy, environmental, and economic impacts associated with each control technology beginning with the most effective technology.

1. Carbon Capture and Sequestration (CCS)
It was outlined earlier that CCS, at present, is not technically feasible for the PDWP but has been carried forward in the BACT evaluation anyway to determine the energy, environmental, and economic impacts.

The aspect of economic impacts was discussed in the EPA's PSD BACT Guidance document.

> *EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated from Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even if in some cases where underground storage of the captured CO2 near the power plant is feasible. However, there may be cases at present where the economics of CCS are more favorable (for example, where the captured CO2 could be readily sold for enhanced oil recovery), making CCS a more viable option under Step 4.*

It is recognized that CO2 capture from the power plant may represent up to 75% of the total cost of CCS, there is also costs associated with the geologic or terrestrial sequestration of the CO2 for long term storage, which are also site-specific. Costs of geotechnical studies for sufficient repositories, pipeline construction, pumping, drilling, well construction, and monitoring represent higher substantial costs that would add to the project. Since CCS has been determined to be unfeasible for this particular project, a quantitative cost analysis was not conducted. Data on capture and control efficiency from a commercial sized power plant already in operation, as well as technical data from drilling studies, pilot studies, and geotechnical studies are unavailable to make any accurate estimates. Therefore, CCS will be analyzed qualitatively for this project.

The Hyperion Energy Center, GHG BACT determination number 5 in Table 33, is an IGCC project that conducted an extensive analysis on CCS. The South Dakota Department of Environment and Natural Resources (SD-DENR) determined that the implementation of CCS would require an additional 400 MW of power generation capacity for gas drying and boosting. The additional power capacity would significantly increase the amount of conventional pollutants, increase energy demands, and emit 23% of the GHG emissions that the CCS was designed to capture. SD-DENR rejected CCS as BACT for these factors and for the high costs and concluded that Hyperion's proposed measures of good combustion practices and energy efficiency measures incorporated into the plant design as GHG BACT.

There are no CO2 pipelines in operation or under construction in the State of California. CCS for this project would require the construction of a new pipeline from Pasadena to any potential sequestration locations. This would involve the construction of a new pipeline through the city of Los Angeles or through the Los Angeles and Los Padres National Forests to reach potential sequestration locations.

The information presented on CCS demonstrates that it is not technically feasible for this project and is eliminated from further consideration.

2. Thermal Efficiency

Table 34 identifies thirteen (13) GHG BACT analyses for combined cycle turbine power plants from 168 to 1,000 MW capacities. The generation capacity for the PDWP project, at 71 MW, will be significantly lower than capacities of the facilities in Table 34. Large capacity combined cycle power plants are expected to have higher thermal efficiencies in comparison to smaller capacity systems due to economies of scale. The heat rates and the calculated CO2E emissions in lbs/MWh (net) are shown in tables 35 and 36.

Table 35 PDWP Power Plant Data

DATA			
Total Operating Hours	8760		
Degradation	3.20%		
Load	50%	75%	100%
Starts	750	750	750
Shutdown	750	750	750
Normal Hours	6510	6510	6510
Heat Input (MMBtu/hr) LHV	286.0	386.4	493.4
Heating Value of Natural Gas			
Natural Gas Heating Value, LHV	912	Btu/scf	
Natural Gas Heating Value, HHV	1012	Btu/scf	
NET Power Data			
CTG power (kW)	27075	40372	53701
STG power (kW)	9983	11274	14316
CCGS power (kW)	37058	51646	67800
CTG heat rate (Btu/kWh)	10563	9571	9188
CCGS heat rate (Btu/kWh)	7718	7482	7254

Table 36 PDWP CO2E Emissions with Degradation

NET Power			
START-UP (does not include Steam Turbine)			
Fuel per SU (MMBtu)	922.02		
Fuel per no electricity (MMBtu)	12		
Fuel Use for Power Generation (MMBtu)	910.02		
Load	50%	75%	100%
Fuel Use (MMBtu)	910.02	910.02	910.02
GTG Heat Rate (Btu/kWh)	10563	9571	9188
Power per SU (kWh)	86152	95081	99044
Total Power during Start-ups (MWh)	64614	71311	74283
Annual Heat (degraded) (MMBtu) LHV	713643	713643	713643
SHUTDOWN (includes Steam Turbine)			
Fuel per SD (MMBtu)	431.41		
Fuel per no electricity (MMBtu)	7.57		
Fuel Use for Power Generation (MMBtu)	423.84		
Load	50%	75%	100%
Fuel Use (MMBtu)	423.84	423.84	423.84
CCGS Heat Rate (Btu/kWh)	7718	7482	7277
Power per SD (kWh)	54916	56648	58244
Total Power during Shutdowns (MWh)	41187	42486	43683
Annual Heat (degraded) (MMBtu) LHV	333911	333911	333911
BASE LOAD			
Load	50%	75%	100%
Power per Normal Operation, NO (kWh)	37058	51646	67800
Total Power Base Load (MWh)	241248	336215	441378
Annual Heat (degraded) (MMBtu) LHV	1921440	2595959	3314819
TOTAL POWER SU + SD + NO (MWh)	347,049	450,012	559,344
CO2E EMISSIONS			
Load	50%	75%	100%
Annual Heat Input (MMBtu) HHV (degraded)	3,294,542	4,043,022	4,840,704
CO2E Emission Factor (ton/MMBtu)	0.05849	0.05849	0.05849
Annual CO2E (lb/yr)	385,395,523	472,952,714	566,265,554
CO2E (lbs/MWh)	**1110**	**1051**	**1012**

As previously discussed, the State standard is 1,100 lbs-CO2E/MWh, which shall be measured over a 12 month rolling average from the annual CO2E emissions from fuel use and the measured MWh. The values calculated for the loads in Table 36 are conservatively based on no steam turbine contribution for each start-up and unit degradation that will result in an increased in fuel use. However, the steam turbine will come online and contribute power. Although the values in Table 36 are theoretical, PDWP has proposed a more stringent value of 1050 lb-CO2E/MWh determined over a 12 month rolling average.

Step 5: Select BACT
Based on the Top-Down BACT Analysis, thermal efficiency is the only technical and economical option that is feasible for this facility. The current design of the facility and the proposal of a stringent CO2E emission rate per useful energy generated meets the BACT requirement for GHG reductions. A BACT limit of 280,502 tons of CO2E per year (from Table 31 for GT-5) will be added as a permit condition, which will be determined by monitoring fuel use and calculating it with an emission factor of 59.187 tons-CO2E/MMscf[2]. A permit condition of 1,050 lb-CO2E/MWh will also be placed on the permit to ensure compliance with PSD BACT.

<u>RULE 1714 – PSD FOR GHG, CIRCUIT BREAKERS</u>
There will be no new circuit breakers installed at the facility. The existing SF6 containing circuit breakers will continue to be maintained and will be used to protect the new generating unit. No change in the amount of SF6 that will be used or stored at the facility is proposed. Therefore, BACT is not triggered for SF6 containing equipment.

REGULATION XX – REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)
The PDWP facility is in the NOx RECLAIM program and is subject to the requirements of this regulation.

<u>RULE 2005(b)(1)(A) – BACT</u>
The NOx BACT limit for natural gas fired combined cycle turbines were discussed in the Regulation XIII NSR section. A concentration of 2.0 ppmv, corrected to 15% O2 dry, and averaged over 1 hour is BACT. Permit conditions and verification through CEMS and source testing will ensure compliance.

<u>RULE 2005(c)(1)(B) – MODELING</u>
This section of the rule requires a facility that is located in an attainment area for nitrogen dioxide (NO2) to demonstrate through modeling analysis that the proposed NOx emission sources will not cause a violation of the most stringent ambient air quality standards. PDWP conducted dispersion modeling using the AERMOD model for the maximum project impacts of NO2 emissions. The results of the analysis are shown in Table 37.

Table 37 Rule 2005(c)(1)(B) Modeling Results

Criteria	Operation with maximum impact	Impact (ug/m3)	Background (ug/m3)	Total Impact (ug/m3)	Most Stringent AQ Standard (ug/m3)
NOx, 1-hour (CAAQS)	Commissioning, Phase 5, Day 5	14.12	207.0	221.1	339
NOx, 1-hour (NAAQS)	WIIT	6.59	127.9	134.5	188
NOx, annual	Maximum operation with 750 start-ups, 750 shutdowns, 24 hours of WI and IT Tuning	0.15	44.2	44.4	57

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[2] Calculated as [(53.02 kg-CO2/MMBtu)(1 CO2E/CO2) + (0.001 kg-CH4/MMBtu)(21 CO2E/CH4) + (0.0001 kg-N2O/MMBtu) (310 CO2E/N2O)] x 0.001102 ton/kg x 1012 MMBtu/MMscf

Modeling staff provided their comments in a memorandum from Mr. Philip Fine to Mr. Brian Yeh dated January 4, 2013. A copy of this memorandum is contained in the project file. Staff's review of the modeling analysis concluded that the applicant used appropriate EPA AERMOD model along with the appropriate model options in the analysis. The memorandum states that the modeling as performed by the applicant conforms to the District's dispersion modeling requirements and no significant deficiencies in methodology were noted. Therefore compliance with modeling requirements is expected.

RULE 2005(b)(2)(A) – 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, paragraph (b)(2)(B) states that the RTCs must comply with the zone requirements of Rule 2005(e). The repower project is expected to undergo commissioning in Year 2015. Since the facility is located in Zone 2 (Inland, Cycle 1); thus, RTCs may only be obtained from Zones 1 or 2.

PDWP's initial 1994 allocation is 766,098 lbs of RTCs and 1,314 non-tradable credits. The current PTE for the facility (existing four turbines, boiler B-3, and two emergency engines) is 446,400 lb/yr (from Table 24). The PTE for the boiler B-3 is 209,600 lb/yr (from Table 24) which will be replaced with a combined cycle turbine with a PTE of 56,652 lbs/yr (Table 11) for the first year of operation and 56,609 lbs per year (Table 13) for the subsequent years. Therefore, since this is an existing facility that will not exceed the 1994 allocation, it will only be required to hold RTCs for the first year of operation. The permit will be conditioned accordingly.

PDWP will be required to purchase the required NOx RTCs from the open market or use credits from their existing power plant facility located in the South Coast Air Basin. Therefore, compliance with Regulation XX, Rule 2005, is expected.

RULE 2005(g) – ADDITIONAL REQUIREMENTS

As with Rule 1303(b)(5) for the Non-RECLAIM pollutants, PDWP has addressed the alternative analysis, statewide compliance, protection of visibility, and CEQA compliance requirements of this rule for NOx. These requirements are essentially the same as those found in Rule 1303(b)(5), subparts A through D for non-RECLAIM pollutants, and are summarized below.

RULE 2005(g)(1) – STATEWIDE COMPLIANCE

The applicant certifies compliance with all applicable emission limitations and standards under the Clean Air Act.

RULE 2005(g)(2) – ALTERNATIVE ANALYSIS

The applicant is required to conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for the facility and to demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with this project. PDWP has performed a comparative evaluation of alternative sites as part of the CEQA process and has determined that the project proposal is the best option as opposed to developing other sites.

RULE 2005(g)(3) – COMPLIANCE THROUGH CEQA

The City of Pasadena, as the Lead Agency, prepared a draft Environmental Impact Report (EIR), SCH # 2011091056, which commenced public review on November 2, 2012 and concluded review on January 31, 2013. Compliance is expected with the approval of the EIR.

RULE 2005(g)(4) – PROTECTION OF VISIBILITY
Modeling analysis for plume visibility in accordance with Appendix B of Rule 2005 is required if the net increase in emissions from the new or modified source exceeds 40 tons per year of NOx and if it is within the distance specified in Table C-1, of the rule, from a specified Federal Class I area. The minimum distance between the facility and the nearest Class I area (San Gabriel Wilderness Area) is about 25 km, which is less than the maximum distance requirement of 29 km; however, the net annual emissions increase of the project is 28.2 tons, which is less than the rule threshold of 40 tons per year, thus no visibility analysis is required under Rule 2005.

RULE 2005(h) – PUBLIC NOTICE
PDWP will comply with the requirements for Public Notice found in Rule 212. Therefore compliance with Rule 2005(h) is demonstrated.

RULE 2005(i) – RULE 1401 COMPLIANCE.
PDWP will comply with Rule 1401 as demonstrated in HRA and subsequently reviewed and found to be satisfactory by AQMD modeling staff. Compliance is expected.

RULE 2005(j) – COMPLIANCE WITH STATE AND FEDRAL NSR.
PDWP will comply with the provisions of this rule by having demonstrated compliance with AQMD NSR Regulations XIII and Rule 2005-NSR for RECLAIM.

RULE 2012 – RECLAIM, MONITORING, REPORTING, & RECORDKEEPING REQUIREMENTS
The turbine will be classified as major NOx source under RECLAIM. As such, it is required to measure and record NOx concentrations and calculate mass NOx emissions with a Continuous Emissions Monitoring System (CEMS). The CEMS will include in-stack NOx and O2 analyzers, a fuel meter, and a data recording and handling system. NOx emissions are reported to AQMD on a daily basis. The CEMS system will be required to be installed within 90 days of start up. Compliance is expected.

INTERIM PERIOD EMISSION FACTORS
RECLAIM requires a NOx emission factor to be used for reporting emissions during the interim reporting period. The interim period is defined as a period, of no greater than 12 months from initial operation, when the CEMS has not been certified. During this period, the emissions cannot be accurately, monitored, or verified. The emissions during this period are assumed to be at uncontrolled levels. The interim reporting period can be broken down into the two parts which includes the commissioning period in which an uncontrolled emission rate is assumed and remaining period.

Since PDWP is included in NOx RECLAIM, an interim period emission factor will be determined. In the event CEMS data is not available, NOx emissions during the interim period will be calculated using monthly fuel usage and the emission factors shown below. There will be two interim period emission factors for NOx.

The first factor will be for use during the commissioning period when the turbine is assumed to be operating at uncontrolled levels (as shown in Table 7) and the second factor will be for use after commissioning is complete. The emission factors for NOx as well as the other criteria pollutants are shown in Table 38.

Table 38 Emission Factors for Interim Period

Pollutant	NOx	CO	VOC	PM10	SOx
Commissioning Emission Factors[a] (lb/MMscf)	42.83	-	-	-	-
Remaining Period Emission[b] Factors (lb/MMscf)	18.79	14.25	3.48	7.30	1.43

(a) Emission factors taken from Table 7.
(b) The aggregate emission factors are calculated as follows: *pollutant* lbs/month *{from Table 14}*/(0.554 MMscf/hr x 744 hrs/month)

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

An EIR was prepared for this project (SCH# 2011091056) by the City of Pasadena, the Lead Agency. The public review period commenced on November 2, 2012 and concluded review on January 31, 2013.

40CFR PART 60 SUBPART KKKK - NSPS FOR STATIONARY GAS TURBINES

The turbine is subject to Subpart KKKK because the heat input is greater than 10.7 gigajoules per hour (10.14 MMBtu per hour) at peak load, based on the higher heating value of the fuel fired. The standards applicable for a turbine firing natural gas with a heat input at peak load >50 MMBtu/hr and ≤850 MMBtu/hr are as follows:

NOx: 25 ppm at 15% O2 or 1.2 lb/MW-hr
SO2: 0.90 lbs/MW-hr discharge, or 0.060 lbs/MMBtu potential SO2 in the fuel

The proposed NOx limit will be 2.0 ppmv and should comply with concentration limit of this Rule.

SO2 = 0.77 lb/hr / 547.5 MMBtu/hr = 0.0014 lb/MMBtu

The SO2 emissions of 0.0014 lb/MMBtu are below the emissions limits of this Rule

MONITORING

The regulation requires that the fuel consumption and water to fuel ratio be monitored and recorded on a continuous basis, or alternatively, that a NOx and O2 CEMS be installed. For the SO2 requirement, either a fuel meter to measure input, or a watt-meter to measure output is required, depending on which limit is selected. Also, daily monitoring of the sulfur content of the fuel is required if the fuel limit is selected. However, if the operator can provide supplier data showing the sulfur content of the fuel is less than 20 grains/100scf (for natural gas), then daily fuel monitoring is not required.

The turbine will be required to install CEMS to comply with RECLAIM requirements for NOx Major Sources. Therefore, NOx monitoring requirements are satisfied. The turbine will fire natural gas provided by the Southern California Gas Company which contains less than 1 grains-sulfur/100scf. Daily monitoring will not be required for fuel sulfur content.

TESTING

An initial performance test is required for both NOx and SO2. For units with a NOx CEMS, a minimum of 9 RATA reference method runs is required at an operating load of +/- 25 percent of 100 percent load. For SO2, either a fuel sample methodology or a stack measurement can be used, depending on the chosen limit. Annual performance tests are also required for NOx and SO2.

Compliance with the requirements of this rule is expected.

<u>40CFR PART 63 SUBPART YYYY - NESHAPS FOR STATIONARY GAS TURBINES</u>
This regulation applies to gas turbines located at major sources of hazardous air pollutant (HAP) emissions. Per this subpart, a major source is defined as a facility with emissions of 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of a combination of HAPs. This subpart establishes national emission limitations and operating limitations for HAPs from stationary combustion turbines. Performance tests are required to demonstrate compliance as well as continuous monitoring of certain parameters. Turbines equipped with oxidation catalysts must monitor the inlet temperature. If operating limitations are chosen for compliance, then the operating limitations must be continuously monitored.

The individual HAP with the highest emission rate is formaldehyde, which is 2.80 tpy for the facility. The total HAP emissions for the facility are 5.19 tpy. Therefore, since the emissions are less than 10 tpy, for a single pollutant, and 25 tpy, for all the HAP pollutants, this subpart is not applicable.

<u>40 CFR PART 64 – COMPLIANCE ASSURANCE MONITORING</u>
The CAM regulation applies to each pollutant specific emissions unit (PSEU) at major stationary sources required to obtain a Title V permit, 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.

CAM applicability is based on specific criteria; the PSEU must:

- be subject to an emission limitation or standard, and
- use a control device to achieve compliance, and
- have **potential pre-control** emissions that exceed or are equivalent to the major source threshold.

NOx, CO, and VOC meet the criteria above for CAM applicability. Therefore, CAM requirements apply to these pollutants.

NOx

- <u>Emission Limit</u> – NOx is subject to a 2.0 ppm 1 hour BACT limit.
- <u>Control Equipment</u> – NOx is controlled with the SCR
- <u>Requirement</u> - As a NOx Major Source under Reclaim, the turbine is required to have CEMS under Rule 2012. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(vi).

CO

- <u>Emission Limit</u> – CO is subject to a 2.0 ppm 1 hour BACT limit.
- <u>Control Equipment</u> – CO is controlled with the oxidation catalyst.
- <u>Requirement</u> – The turbine will be required to use a CO CEMS under Rule 218. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(vi).

VOC

- <u>Emission Limit</u> – VOC is subject to a 2.0 ppm 1 hour BACT limit.
- <u>Control Equipment</u> – VOC is controlled with the oxidation catalyst.

- Requirement – The oxidation catalyst is effective at operating temperatures above 633°F. The facility will be required to maintain a temperature gauge on a continuous basis and record temperature on an hourly basis. The exhaust temperature will be at least 633°F (except during start-up and shutdowns).

Therefore, continuous monitoring and periodic source testing will ensure compliance with this subpart.

40 CFR PART 72 – ACID RAIN PROVISIONS
The PDWP facility is subject to the requirements of the federal Acid Rain program. The program is similar in concept to RECLAIM in that facilities are required to cover SO2 emissions with SO2 allowances; analogous to NOx RTCs. SO_2 allowances are however, not required in any year when the unit emits less than 1,000 lbs of SO_2. Facilities with insufficient allowances are required to purchase SO_2 credits on the open market. Appropriate conditions are in Appendix B of the Title V permit. PDWP is expected to comply with this regulation.

REGULATION XXX – TITLE V
The existing PDWP facility has a Title V permit. Per Rule 3000(b)(28), the addition of a new unit will result in a Significant Permit Revision and a public notice in accordance with Rule 3006(a) will be required before any permit action. The notice will be sent out along with the Rule 212(g) notice discussed under the Rule 212 section. EPA is afforded the opportunity to review and comment on the project within a 45-day review period.

RECOMMENDATION(S)
It is recommended that a Facility Permit to Construct be issued following the 30 day school notice and public comment period, and the 45 day EPA review period. The permit will be subject to the following conditions.

PERMIT CONDITIONS

FACILITY PERMIT CONDITIONS

F52.1 The facility is subject to the applicable requirements of the following rules or regulations:

The facility shall submit a detailed retirement plan for the permanent shutdown of Boiler B-3 (Device 15), describing in detail the steps and schedule that will be taken to render Boiler B-3 inoperable.

The retirement plan must be submitted to AQMD within 60 days of permit issuance. AQMD shall notify PDWP whether the plan is approvable. If AQMD notifies PDWP that the plan is not approvable, PDWP shall submit a revised plan addressing AQMD's concerns within 30 days.

PDWP shall not commence any construction of equipment for the repower project before the retirement plan for permanent shut down of Boiler B-3 is approved in writing by the AQMD.

PDWP shall provide AQMD with a notarized statement that Boiler B-3 is permanently shut down and that any re-start or operation of the unit shall require a new Permit to Construct and be subject to all requirements of nonattainment new source review and the prevention of significant deterioration program.

The notarized statement shall be submitted within 30 days following the permanent shutdown of Boiler B-3.

PDWP shall notify AQMD 30 days prior to the implementation of the approved retirement plan for permanent shut down of Boiler B-3.

PDWP shall cease operation of Boiler B-3 (Device 15) within 90 calendar days of the first fire of turbine GT-5(A).
[RULE 1304(a)(2)]

DEVICE CONDITIONS

A63.3 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
CO	LESS THAN OR EQUAL TO 5,873 LBS IN ANY ONE MONTH
PM10	LESS THAN OR EQUAL TO 3,010 LBS IN ANY ONE MONTH
VOC	LESS THAN OR EQUAL TO 1,436 LBS IN ANY ONE MONTH
SOx	LESS THAN OR EQUAL TO 588 LBS IN ANY ONE MONTH

The above limits apply after the equipment is commissioned.

The operator shall calculate the monthly emission limit(s) by using calendar monthly fuel use data and the following emission factors: VOC: 3.48 lbs/mmscf, PM10: 7.30 lbs/mmscf, SOx: 1.43 lbs/mmscf.

The operator shall calculate the emission limit(s) 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: normal operation: 14.25 lbs/mmscf.
[Rule 1303(b)(2) – Offset]

A99.8 The 42.83 LBS/MMCF NOx emission limit(s) shall only apply during the interim reporting period during initial turbine commissioning to report RECLAIM emissions.
[Rule 2012]

A99.9 The 18.79 LBS/MMCF NOx emission limit(s) shall only apply during the interim reporting period after initial turbine commissioning to report RECLAIM emissions.
[Rule 2012]

A99.10 The 2.0 PPM NOx emission limit(s) shall not apply during turbine commissioning, start-up, shutdown, Water Injection and Intercooler Tuning (WIIT), and Ammonia Injection Grid Tuning

(AIGT) periods. Start-up time shall not exceed 120 minutes for each start-up. Shutdown periods shall not exceed 60 minutes for each shutdown. The turbine shall be limited to a maximum of 5 start-ups per day, 155 start-ups per month, and 750 start-ups per year.

For the purposes of this condition, the beginning of start-up occurs at initial fire in the combustor of the combustion turbine through the full operation of the steam turbine generator. If during start-up, the process is aborted the process will count as one start-up.

For the purposes of this condition, shutdown is defined as the period of time from initiation of the shutdown sequence to cessation of firing.

For the purposes of this condition, WIIT shall be defined as the tuning of the gas turbine water injection and intercooler system. WIIT shall not exceed 12 hours. The operator shall limit the duration of WIIT to no more than 12 hours in any one month and 24 hours in any one year.

For the purposes of this condition, AIGT shall be defined as optimizing and re-balancing of the NH3 grid or catalyst modules, and the retuning of the turbine control systems. AIGT shall not exceed 10 hours. The operator shall limit the duration of AIGT to no more than 10 hours in any one year.

The commissioning period shall not exceed 204 hours.
[Rule 2005]

A99.11 The 2.0 PPM CO emission limit(s) shall not apply during turbine commissioning, start-up, shutdown, Water Injection and Intercooler Tuning (WIIT), and Ammonia Injection Grid Tuning (AIGT) periods. Start-up time shall not exceed 120 minutes for each start-up. Shutdown periods shall not exceed 60 minutes for each shutdown. The turbine shall be limited to a maximum of 5 start-ups per day, 155 start-ups per month, and 750 start-ups per year.

For the purposes of this condition, the beginning of start-up occurs at initial fire in the combustor of the combustion turbine through the full operation of the steam turbine generator. If during start-up, the process is aborted the process will count as one start-up.

For the purposes of this condition, shutdown is defined as the period of time from initiation of the shutdown sequence to cessation of firing.

For the purposes of this condition, WIIT shall be defined as the tuning of the gas turbine water injection and intercooler system. WIIT shall not exceed 12 hours. The operator shall limit the duration of WIIT to no more than 12 hours in any one month and 24 hours in any one year.

For the purposes of this condition, AIGT shall be defined as optimizing and re-balancing of the NH3 grid or catalyst modules, and the retuning of the turbine control systems. AIGT shall not exceed 10 hours. The operator shall limit the duration of AIGT to no more than 10 hours in any one year.

The commissioning period shall not exceed 204 hours.
[Rule 1703(a)(2) – PSD BACT]

A195.8 The 2.0 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 2005, Rule 1703 - BACT]

A195.9 The 2.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1703(a)(2) – PSD BACT]

A195.10 The 2.0 PPMV VOC emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1303(a) – BACT]

A195.11 The 5.0 ppmv NH3 emission limit(s) is averaged over 60 minutes at 15% O2, dry basis.

The operator shall calculate and continuously record the NH3 slip concentration using the following: NH3 (ppmv) = [a–b*c/1EE+06]*1EE+06/b, where: a = NH3 injection rate (lbs/hr)/17(lb/lb-mol), b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol), c = change in measured NOx across the SCR (ppmvd at 15% O2).

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.

The NOx analyzer shall be installed and operated within 90 days of initial start-up.

The operator shall use the above described method 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 without corroborative data using an approved reference method for the determination of ammonia.
[Rule 1303(a)(1) – BACT]

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

A433.1 The operator shall comply at all times with the 2.0 ppm 1-hour BACT limit for NOx, except as defined in condition A99.10 and for the following scenarios:

Operating Scenario	Maximum Limit	Operational Limit
Start-up	28.68 lb	The mass emission limit shall be determined for start-up using CEMS minute by minute emission data. It shall be calculated to 120 minutes

		from the commencement of initial fire in the combustor
Shutdown	11.78 lb	The mass emission limit shall be determined for shutdown using CEMS minute by minute emission data. It shall be calculated to 60 minutes counted back from the cessation of firing

Records of minute by minute start-up and shutdown data shall be maintained and made available to the Executive Officer upon request.
[Rule 2005]

A433.2 The operator shall comply at all times with the 2.0 ppm 1-hour BACT limit for CO, except as defined in condition A99.11 and for the following scenarios:

Operating Scenario	Maximum Limit	Operational Limit
Start-up	23.61 lb	The mass emission limit shall be determined for start-up using CEMS minute by minute emission data. It shall be calculated to 120 minutes from the commencement of initial fire in the combustor
Shutdown	9.90 lb	The mass emission limit shall be determined for shutdown using CEMS minute by minute emission data. It shall be calculated to 60 minutes counted back from the cessation of firing

Records of minute by minute start-up and shutdown data shall be maintained and made available to the Executive Officer upon request.
[Rule 1703(b)(1) - PSD BACT]

D12.9 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust 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 600°F and 900°F.
[Rule 2005]

D12.10 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of 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 12 months.

The differential pressure shall less than 6.5 inches of water column.
[Rule 2005]

D12.13 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 12 months.

The ammonia injection rate shall be between 84 and 107 lbs/hr.
[Rule 2005]

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

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
SOX emissions	AQMD Laboratory Method 307-91	Not applicable	Fuel Sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	District Method 201A	Approved Averaging Time	Outlet of the SCR serving this equipment
PM2.5 emissions	Approved District Method	Approved Averaging Time	Outlet of the SCR serving this equipment
NH3 emissions	District method 207.1 and 5.3 or EPA method	1 hour	Outlet of the SCR serving this

17		equipment

The test shall be conducted after AQMD approval of the source test protocol, but no later than 180 days after initial start-up. 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 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 AQMD approved 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 AQMD 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 natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined by CARB and AQMD, may be the following:

a) Triplicate stack gas samples are extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute,

b) Pressurization of the Summa canisters is done with zero gas analyzed/certified to containing less than 0.05 ppmv total hydrocarbons as carbon, and

c) Analysis of Summa canisters is per unmodified EPA Method TO-12 (with preconcentration) or the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmvC or less and reported to two significant figures, and

d) The temperature of the Summa canisters when extracting samples for analysis is not to be below 70 degrees Fahrenheit.

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than unmodified AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval, except for the determination of compliance with the BACT level of 2.0 ppmv VOC calculated as carbon set by CARB for natural gas fired turbines. The test results shall be reported with two significant digits.

The test shall be conducted when this equipment is operating at loads of 100, 75 and 50 percent of maximum load for NOx, CO, VOC, and ammonia tests. The PM10 and PM2.5 tests shall be conducted when this equipment is operating at 100 percent of maximum load.
[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 2005, Rule 1703(a)(2) – PSD BACT]

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

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted and the results submitted to the District within 45 days after the test date. The AQMD shall be notified of the date and time of the test at least 7 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 CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, 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 BACT concentration limit.

If the turbine is not in operation during one quarter, then no testing is required during that quarter. [Rule 1303(a)(1) – BACT]

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

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
SOX emissions	AQMD Laboratory Method 307-91	Not applicable	Fuel Sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	District Method 201A	Approved Averaging Time	Outlet of the SCR serving this equipment
PM2.5 emissions	District Approved Method	Approved Averaging Time	Outlet of the SCR serving this equipment

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

The test shall be conducted and the results submitted to the District within 60 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 natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined by CARB and AQMD, may be the following:

a) Triplicate stack gas samples are extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute,

b) Pressurization of the Summa canisters is done with zero gas analyzed/certified to containing less than 0.05 ppmv total hydrocarbons as carbon, and

c) Analysis of Summa canisters is per unmodified EPA Method TO-12 (with preconcentration) or the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmvC or less and reported to two significant figures, and

d) The temperature of the Summa canisters when extracting samples for analysis is not to be below 70 degrees Fahrenheit.

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than unmodified AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval, except for the determination of compliance with the BACT level of 2.0 ppmv VOC calculated as carbon set by CARB for natural gas fired turbines. The test results shall be reported with two significant digits.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emission limit.
[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 1703(a)(2) –PSD BACT]

D82.4 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 will 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% - %O2 d)][(Qg * HHV)/106], where

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

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

Fd = 8710 dscf/MMBTU natural gas

$\%O_2$ d = Hourly ave. % 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(a)(2) – PSD BACT, Rule 218]

D82.5 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 provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3).
[Rule 2005, Rule 2012, Rule 1703(a)(2) – PSD BACT]

E179.6 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 hour.

Condition no. D12.9
Condition no. D12.13
[Rule 2005]

E179.4 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. D12.10
[Rule 2005]

E193.2 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 final Environmental Impact Report (EIR), State Clearing House #2011091056.

[CEQA]

E193.3 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

The operator shall record the total net power generated in a calendar month in megawatt-hours.

The operator shall calculate and record greenhouse gas emissions of each calendar month using the following formula:

GHG = 59.187 * FF

Where, GHG is the greenhouse gas emissions in tons of CO2E and FF is the monthly fuel usage in millions standard cubic feet.

The GHG emissions from this equipment shall not exceed 280,502 tons per year. The average GHG emissions shall not exceed 1050 pounds per net megawatt-hours. The operator shall calculate and record the GHG emissions in tons per year and pounds per net megawatt-hours on a 12 month rolling average with a new monthly period starting at the beginning of each month.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition. The records shall be made available to AQMD upon request.

[Rule 1714]

H23.5 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart
NOx	40CFR60, SUBPART	KKKK
SOX	40CFR60, SUBPART	KKKK

[40CFR 60 SUBPART KKKK]

I297.1 This equipment shall not be operated unless the facility holds 56,652 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.

[Rule 2005]

K40.3 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 (lb/hr), and lb/MM cubic feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF and lbs/MMBtu.

All exhaust flow rate 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, fuel flow rate (CFH), heating content of the fuel, the flue gas temperature, and the generator power output (MW) under which the test was conducted.
[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 1703(a)(2) - PSD BACT, Rule 2005]

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]

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT *ENGINEERING & COMPLIANCE* APPLICATION PROCESSING AND CALCULATIONS	PAGES 59	PAGE NO. 1
	APPL. NO. 538671, 538672, & 538673	DATE 4/19/2013
	PROCESSED BY M SAULIS	CHECKED BY

ENGINEERING EVALUATION

COMPANY NAME AND ADDRESS

City of Pasadena, Department of Water and Power
85 E State St.
Pasadena, CA 91105

CONTACT(S): Dan B. Angeles, Principal Engineer, (626) 744-6240

EQUIPMENT LOCATION

AQMD ID 800 168
72 E Glenarm St.
Pasadena, CA 91105-3418

EQUIPMENT DESCRIPTION

Section H of the facility permit: Permit to Construct

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
Process 2: INTERNAL COMBUSTION					
System 1: TURBINES					
GAS TURBINE, GT-5A, NATURAL GAS, ROLLS ROYCE, MODEL TRENT 60 WLE ISI, COMBINED CYCLE, WITH WATER INJECTION, 551.6 MMBTU/HR @ 64°F WITH A/N 538672	D70	C74	NOX: MAJOR SOURCE	**CO:** 2000 PPMV (5) [RULE 407]; CO: 2 PPMV NATURAL GAS (4) [RULE 1303 – BACT], [RULE 1703] **NOX:** 2.0 PPMV NATURAL GAS (4) [RULE 2005], [RULE 1703]; NOX: 114.73 LBS/MMSCF NATURAL GAS (1) [RULE 2012]; NOX: 19.35 LBS/MMSCF NATURAL GAS (1) [RULE 2012]; NOX: 25 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK]	A63.4, A99.12, A99.13, A99.10, A99.11, A195.8, A195.9, A195.10, A195.11, A327.1, A433.3, A433.4, D29.6, D29.7, D29.8, D82.4, D82.5, E193.2, E193.4, H23.5, I297.2, K40.3, K67.6
GENERATOR, SERVING GT-5A, 59.2 GROSS MW @ 64°F	B71				
STEAM TURBINE, ST-5A, TBD, MODEL TBD	B72				
GENERATOR, SERVING ST-5A, 11.4 GROSS MW @ 64°F	B73				

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
				PM: 11 LBS/HR (5B) [RULE 475]; PM: 0.01 GRAINS/SCF (5) [RULE 475]; PM: 0.1 GRAINS/SCF (5A) [RULE 409] **SO2**: (9) [40 CFR 72 – ACID RAIN; SO2: 0.060 LB/MMBTU NATURAL GAS (8) [40 CFR 60 SUBPART KKKK] **VOC:** 2 PPMV NATURAL GAS (4) [RULE 1303 – BACT]	
CO OXIDATION CATALYST, NO. 5A, EMERACHEM, MODEL TBD, FIXED BED PLATINUM, VOLUME 179.5 CU FT; WITH A/N: 538673	C74	D70 C75			
SELECTIVE CATALYTIC REDUCTION, NO. 5A, HALDOR TOPSOE, MODEL TBD, CATALYST VOLUME 1129 CU FT; WITH A/N: 538673 AMMONIA INJECTION GRID, AQUEOUS AMMONIA	C75 B76	C74 S77		**NH3:** 5 PPMV (4) [RULE 1303 – BACT]	A195.11, D12.9, D12.12, D12.11, E179.3, E179.5, E193.2
STACK, SERVING GT-5A, HEIGHT: 125 FT; DIAMETER: 10.17 FT A/N 538672	S77	C75			

SUMMARY

City of Pasadena, Department of Water and Power (PDWP) operates the Glenarm power plant which has a Title V permit and is in the NOx RECLAIM program. PDWP submitted applications for Permits to Construct a combined cycle power generating unit, to be identified as GT-5A, along with associated air pollution control equipment that is a significant revision to the Title V permit. The project involves the repowering the power plant by replacing an existing utility boiler (B-3) that is exempt from offsets per Rule 1304(a)(2) – Electric Utility Boiler Replacement.

The construction schedule is expected to be 23 months from when the project permitting and CEQA has been approved. The first 5 months will include demolition, asbestos abatement, site clearing, grading and excavation. The remaining 18 months will include construction. The decommissioning process for the boiler will be within 90 days from the first fire of the gas turbine commissioning process which will likely be sometime in late 2014 or early 2015.

The combined cycle equipment will either include one General Electric (GE) LM6000 SPRINT PG combustion turbine generator or alternatively one Rolls Royce Trent 60 WLE unit. PDWP will make a determination at a later date as to which option it will pursue. ***This evaluation is for the RR Option***. The applications that were submitted are summarized in Table 1.

Table 1 Application Summary

Option	A/N	Equipment	Submittal Date	Deemed Complete	BCAT/ CCAT	Schedule	Base Fee[a]	XPP Fee	Total Filing Fees
General Electric (GE)	538115	GE LM6000 SPRINT PG Gas Turbine, 56.1 MW	6/7/12	7/2/12	033709	G	$15,811.76	$7,905.88	$23,717.64
	538120	SCR/CO Catalyst	6/7/12	7/2/12	81	C	$3,359.43	$1,679.72	$5,039.15
	538118	TV/RECLAIM Amendment	6/7/12	7/2/12	555009	-	$1,747.19	-	$1,747.19
Rolls Royce (RR)	538672	Rolls Royce Trent 60 WLE Gas Turbine, 59.2 MW	6/7/12	7/2/12	033709	G	$15,811.76	$7,905.88	$23,717.64
	538673	SCR/CO Catalyst	6/7/12	7/2/12	81	C	$3,359.43	$1,679.72	$5,039.15
	538671	TV/RECLAIM Amendment	6/7/12	7/2/12	033709	-	$1,747.19	-	$1,747.19
								Total	**$61,007.96**

There will also be an additional fee for the hours of work completed for the air quality analysis. In addition, the project triggers a school notice per Rule 212(c)(1), a public notice per Rule 212(g), and a significant modification per Rule 3006. Therefore, additional fees will be billed to the facility in accordance with Rule 301.

BACKGROUND

The City of Pasadena constructed the Glenarm power plant in 1907 and later expanded to the adjacent Broadway location, which currently consists of three steam generating units; two decommissioned boilers (B1 and B2) and one active unit (B-3). The facility currently has four natural gas fired combustion turbine generators (GT-1, GT-2, GT-3 and GT-4) which are located at the Glenarm site. The total capacity of the facility (Glenarm and Broadway) is 227 MW. The boiler (B-3) has a gross capacity of 71 MW and a net capacity of 65 MW. PDWP are proposing either a GE or RR turbine that will have a gross rating less than 71 MW, which will allow them to acquire the Rule 1304 offset exemption. The new unit, to be identified as GT-5A, and a new cooling tower will be located south of the Glenarm Building. The concept plan is shown in Figure 1.

The new turbine will be configured one-on-one with a Once-Through-Steam-Generator (OTSG) prior to the post-combustion emission control equipment, which will include an oxidation catalyst, for CO and VOC reduction, and selective catalytic reduction system, for NOx reduction. In addition, the turbine will have water injection to reduce NOx levels in the exhaust prior to the control equipment. Following the installation and commissioning of the new equipment, unit B-3 will be de-commissioned and removed from service. Simultaneous operation of the new turbine and boiler is allowed up to 90 days per Rule 1313(d). The 90 day clock commences from when the gas turbine is first fired. PDWP will be required to submit a detailed retirement plan for the boiler.

The project triggers a 30 day public notice per Rule 212(c)(2). Since the new unit will be located within 1,000 ft. from an existing K-12 school, it triggers a 30 day school notice. The noticing period for Rule 212 and for the significant revision per Rule 3006 will run concurrently along with the 45 day EPA review period.

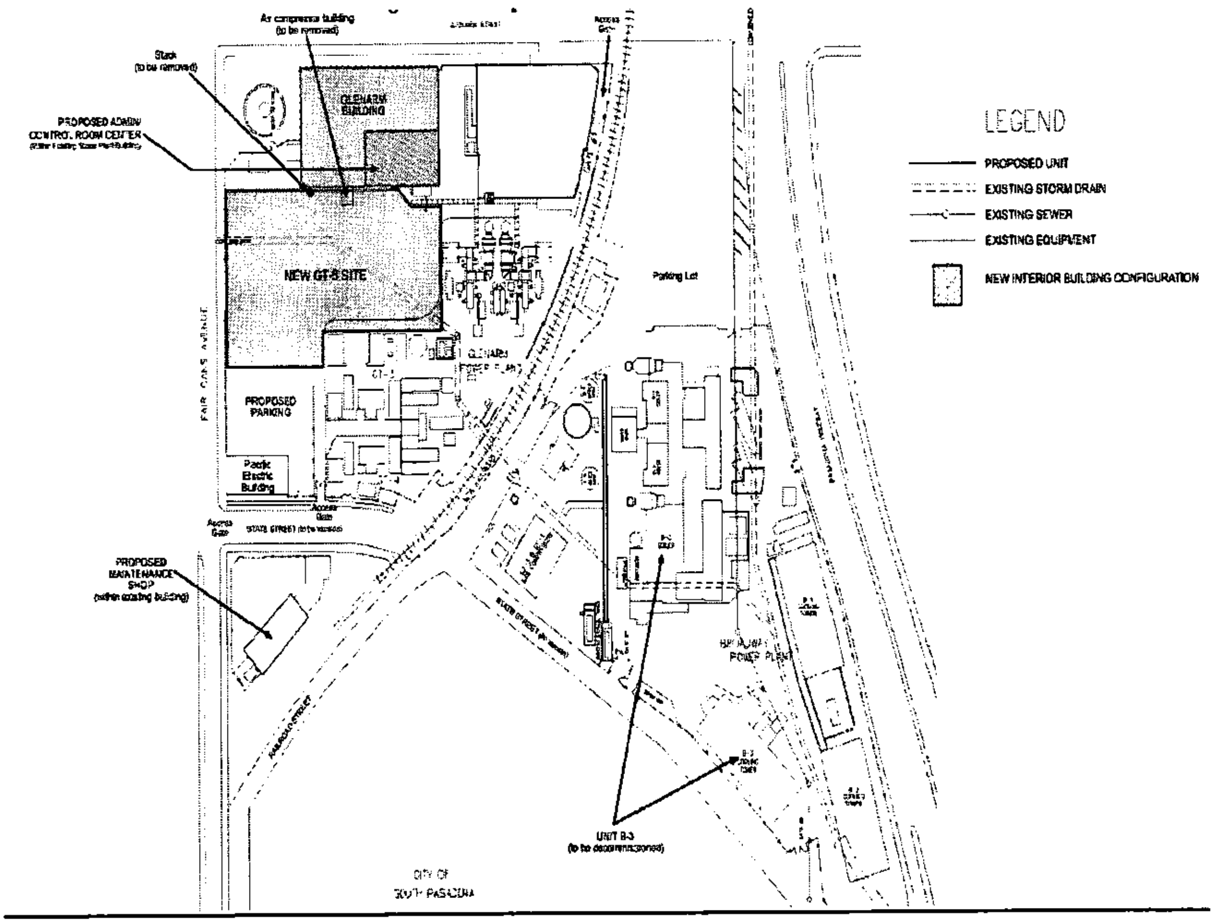

Figure 1 Proposed Location of the New GT-5A Site.

COMPLIANCE REVIEW

A review of the District Compliance database reveals that the facility received two Notices to Comply (NC) and three Notices of Violation (NOV) within the last two year period. The Notices are summarized below:

- NC D20376 was issued on 6/29/11 to the facility to provide emission records, start-up and shutdown records, CEMS calibration dates and monthly emissions. The NC was closed on 7/6/11.
- NC D20377 was issued on 7/14/11 to report records and to submit Title V for 500-ACC on time and calculate total monthly emissions. The NC was closed on 8/11/11.
- NOV P37217 was issued on 6/22/11 for unit GT-4 exceeding the 6.0 ppmv CO emission concentration as listed on the permit. The NOV was closed on 5/29/12.
- NOV P51970 was issued on 3/15/11 for device D36 exceeding the permitted shutdown period. The NOV was closed on 5/29/12.
- NOV P55663 was issued on 8/7/12 to the facility for failing to report total quarterly emissions for process units D11 and D12.

As a RECLAIM and Title V facility, inspections are conducted at this site on an annual basis.

PROCESS DESCRIPTION

GAS TURBINE GENERATOR (GTG) A/N 538672

The Rolls Royce option that the city is proposing is the Rolls Royce (RR) Trent 60 WLE+ISIS, which will be set-up in a combined cycle configuration with a Once-Through-Steam-Generator (OTSG) and a steam turbine. The RR Trent 60 is an aeroderivative turbine, which is derived from the Trent 700 and 800 aircraft engines. The Trent family of engines are based on the core design of the RB211, which is a three-shaft design that is more complex, but is shorter and more rigid which allows less degradation over time in comparison to a twin-spool system. The turbine uses an annular combustor modified to operate on gas or liquid. However, the PDWP turbine will be fired on natural gas only.

The proposed Trent 60 is the Wet Low Emissions (WLE) system that uses water injection to reduce emissions and boost performance. Whereas the Dry Low Emissions (DLE) system uses radial staged combustors to meet emission levels, but does not have the additional boost in capacity as the WLE. The WLE system will also be equipped with Inlet Spray Intercooling System (ISIS) to reduce the ambient inlet temperature and reduce the energy required for compression, resulting in higher power and efficiency. The advantage of this system is more pronounced at hotter days since the higher ambient temperature has a negative impact on heat rate. The water used will be demineralized through reverse osmosis and an ion exchange system treated on site and stored in demineralized tanks.

The RR combined cycle power plant is a factory packaged modular design that has the advantage of rapid field installation with maximum flexibility with fast start time, part power efficiency, and cyclic capabilities. The specifications of the turbine are summarized in Table 2.

Table 2 Rolls Royce Trent 60 WLE+ISIS Gas Turbine Specifications[a]

Parameter	Value
Manufacturer	Rolls Royce
Fuel Type	California Public Utilities Commission Quality Natural Gas
Maximum Fuel Consumption	0.545 MMscf/hr @64°F (full load with ISI+Fogging)
Maximum Exhaust Flow	1,293,900 lb/hr @64°F
Heat Input (LHV)	497.1 MMBtu/hr @64°F
Maximum Output (Gross)	59.2 MW @64°F
Gross Heat Rate (LHV)	8,395 Btu/kWh @64°F
Gross Heat Rate (HHV)	9,314 Btu/kWh @64°F
Ammonia Injection Rate	23 lb/hr NH3 (100%) @64°F
SO_2 to SO_3 Conversion Rate (%)	54
Steam Turbine Output (Gross)	11.4 MW @64°F
Plant Output (Gross)	70.6 MW @64°F
Plant Output (Net)	67.9 MW @64°F
Net Plant Heat Rate (LHV)	7,321 Btu/kWh @64°F
Net Plant Heat Rate (HHV)	8,124 Btu/kWh @64°F
Net Plant Efficiency	46.6% (LHV), 42.0% (HHV) @64°F with Inlet Fogger on
GTG Exhaust Temperature	804°F
Stack Outlet Temperature	406°F

[a] 64°F ambient temperature and 61% relative humidity represents the average conditions for Pasadena, California.

The turbine will be configured with a Once-Through-Steam-Generator (OTSG), which is a continuous-tube heat exchanger in which preheating, evaporation, and superheating of the feedwater takes place in series. Water is forced through tubes by a feedwater pump, entering at the cold end (top). It changes phase along the circuit and exits as steam at the hot end (bottom). Exhaust gas flows in a direction opposite to that of water and steam. The feedwater control valve is the single point of control for the OTSG. The feedwater flow is regulated using a feedforward and feedback algorithm programmed into the plant's distributed control system. These units require the use of demineralized water to prevent the build-up of solids deposition in the tube bundles. The tube materials are constructed of premium high nickel steel tubing which allows the OTSG to start-up, shutdown, and respond to load changes rapidly without exceeding material stress limits. The material also enables the OTSG to run dry, unaffected by the hot GTG exhaust.

CO OXIDATION CATALYST & SCR – A/N 538120

A carbon monoxide (CO) oxidation catalyst is located downstream of the gas turbine where it is used to control CO, VOC and HAP emissions. The catalyst is located within a structural catalyst frame integral to the housing, with room for additional layers of catalyst. Table 3 summarizes the specifications for the oxidation catalyst.

Table 3 CO Oxidation Catalyst Specifications

Parameter	Value
Make	EmeraChem
Model	TBD
Catalyst Type	Fixed Bed Platinum
Number of Layers or Modules	3
Size of Each Layer or Module (HxWxD)	20.48" x 19.25" x 2.25"
Total Catalyst Volume	179.5 ft^3
Total Weight	8,079 lbs
Space Velocity	64,751 – 106,238 hr^{-1}
Catalyst Life	36 months/25,000 hrs
Operating Temperature	Minimum Design: 556°F; Maximum Operating: 1,150°F
Operating Schedule	8,760 hrs/yr
Maximum Outlet CO	2 ppmvd @ 15% O2
Maximum Outlet VOC	2 ppmvd @ 15% O2
VOC Control Efficiencies	65.5% Design; 74.7% Maximum
CO Control Efficiencies	97.3% Design; 98.0% Maximum

NOx emissions are controlled with a SCR catalyst which will be located within a structural catalyst frame downstream of the CO oxidation catalyst. Aqueous ammonia will be provided by an existing permitted ammonia tank located on site. The ammonia is vaporized at the vaporization skid and diluted with air dilution fans and injected into the exhaust gas stream via a grid of nozzles located upstream of the SCR of the catalyst and downstream of the CO Oxidation catalyst. Table 4 summarizes the specifications for the SCR.

Table 4 SCR Catalyst Specifications

Parameter	Value
Make	Haldor Topsoe
Model	TBD
Type	Corrugated DNX-629
Number of Layers or Modules	1 layer, 14 modules per layer
Size of Each Layer or Module (LxWxH)	7.75 ft. x 45 ft. x 4.45 ft.
Catalyst Volume	32 m^3 per module
Catalyst Weight	31,000 lbs
Reducing Agent	Aqueous Ammonia, 19wt%
Space Velocity	10,526 – 17,270 hr^{-1}
Area Velocity	71.5 – 130.9 ft/hr
Catalyst Life	36 months/26,000 hours
Operating Temperature	Minimum Inlet: 600°F; Maximum: 900°F
Ammonia Injection Temperature	450°F
Ammonia Injection Rate	107 lb/hr, 19wt%
Pressure Drop across Catalyst	10 in. w.c.
Maximum Outlet NH3 Slip	5 ppmvd @ 15% O2
Operating Schedule	8,760 hrs
Maximum Outlet NOx	2 ppmvd @ 15% O2
NOx Control Efficiency	92%

WET COOLING TOWER – RULE 219(d)(3) EXEMPT

The excess heat from the combined cycle generating unit will be handled with a new wet cooling tower, which will be rated at 10,000 gallons per minute (gpm), with potable water as make-up, and will consist of two cells. The cooling tower will re-circulate the cooling water in a closed system, with limited amounts of make-up water to offset the blowdown and drift. The drift factor for the cooling tower will be 0.0005% of the circulation or 0.05 gpm. The specifications for the cooling tower and the data used to determine the PM10 emissions and toxic emissions for the maximum individual cancer risk (MICR) as well as the calculations are shown below:

Parameter	Value
Manufacturer	TBD
Circulation Rate	10,000 gpm
Make-up Rate of Cooling Water	173.75 gpm
Drift Eliminator Efficiency	0.0005 %
Cooling Tower Cycles of Concentration	6
Cooling Tower Length	56.67 ft
Cooling Tower Width	24.67 ft
Height to Fan Deck	16.93 ft
Height to Fan Exit	26.93 ft
Cooling Tower Air Exit Velocity	1,911 ft/min
Cooling Tower Hot Water Temperature	82°F @ Ambient Temperature of 64°F
Number of Cells	2
Cooling Tower Fan Shroud Diameter	16 ft
Maximum total dissolved solids (TDS)	660 mg/l or ppm

Cooling Tower PM10 Emissions

PM10 (lbs/day) = circulation rate (gpm) x drift%/100 x density (lb/gal) x TDS (ppm)/1E06 x no. cycles x 1440 min/day

= 10,000 x 0.0005/100 x 8.34 x 1440 x 660/1E06 x 6

= **2.38**

Cooling Tower Toxic Air Contaminant (TAC) Emissions

Pollutant	CAS no.	Conc. in Water[a] (ppb)	Drift[b] (gpm)	Make-up Water (gpm)	Emissions[c] (lb/hr)	Emissions[d] (lb/yr)
Arsenic	7440382	15	0.05	-	3.75E-07	3.29E-03
Fluoride	1101	6000	0.05	-	1.50E-04	1.32E+00
Chromium VI	18540299	0.78	0.05	-	1.95E-08	1.71E-04
Chlorine	7782505	0.03	-	173.75	2.61E-06	2.29E-02

(a) PDWP water quality report.
(b) Drift (gpm) = 10,000 gpm x 0.0005/100
(c) Inorganic compounds (Arsenic, Fluoride, and Chromium VI) calculated on drift only (lb/hr) = Drift (gpm) x 8.34 lb/gal x concentration (ppb)/1E09 x 60 min/hr; Organic compound (Chlorine) assumed to be removed in make-up water (lb/hr) = Make-up water (gpm) x 8.34 lb/gal x concentration (ppb)/1E09 x 60 min/hr
(d) Emissions (lb/yr) = Emissions (lb/hr) x 8760 hrs/yr

The cooling tower TAC emissions were used for the Health Risk Assessment (HRA) to determine the MICR and Rule 219 applicability of the cooling tower. The SCAQMD Rule 1401 Risk Assessment Calculator Excel program from the District website was used to conduct a Tier 2 analysis. The inputs to the program were the estimated TACs (table above), distance to the nearest receptors (65 meters at fence line for worker and 150 meters for resident), stack height (26.93 ft for fan exit), operating schedule (8760 hours per year), and the nearest meteorological station (Pasadena Station).

The MICR for the resident and worker were determined to be 1.27E-07 and 5.82E-08, respectively. Because MICR is less than Rule 1401 significance threshold of 1 in one million, the cooling tower is exempt per Rule 219(d)(3).

The process flow diagram below shows the RR GTG, OTSG, air pollution control equipment and auxiliary equipment for this proposal.

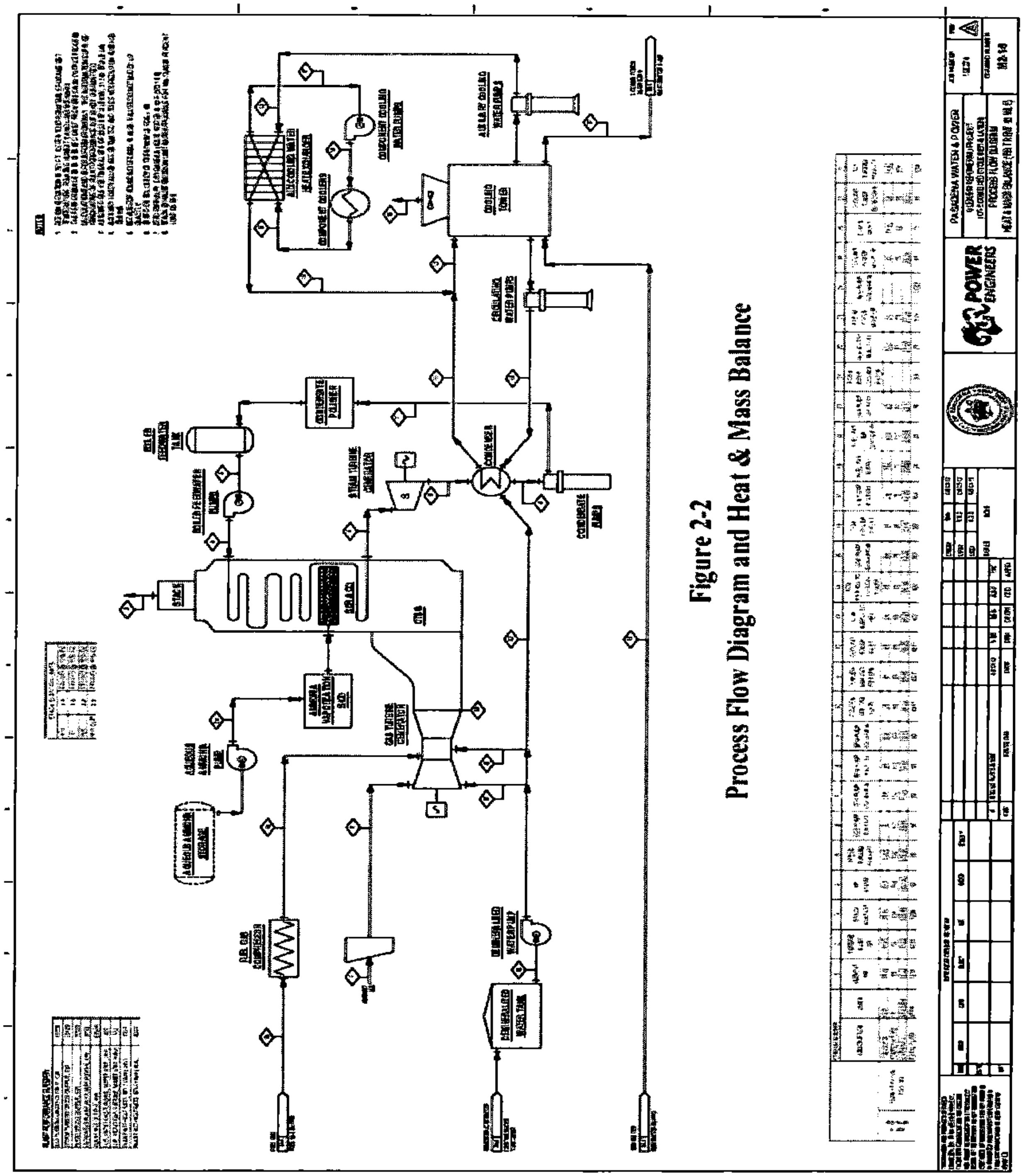

Figure 2 Process Flow Diagram for the Rolls Royce Turbine and Associated Equipment Referenced at 64°F and 61% RH (as provided in the Applicant's Permit Package).

EMISSION CALCULATIONS

The operation of the new turbine will result in emissions of criteria pollutants, toxic air contaminants (TACs), and greenhouse gases (GHGs). Emission of criteria pollutants will be described and calculated in this section and the TACs and GHGs will be described and calculated in the applicable sections to follow.

The turbine's modes of operation are described below.

START-UP

This is the period of time that begins with the introduction of fuel into the combustion turbine that result in a rise in temperature to the normal operating temperature where exhaust enters the air pollution control equipment and exits the stack. It commences with ignition of the combustion turbine through the full operation of the steam turbine generator. The CO, VOC and NOx concentrations during this mode of operation are high due to the phased effectiveness of the oxidation catalyst and SCR that gradually come online as the operating temperatures are being reached.

The turbine can reach full load in approximately 8 minutes from turbine ignition. Water injection commences after 5 minutes and ammonia injection is initiated after 11 minutes from ignition. Prior to water injection, NOx emissions reach a concentration as high as 145 ppm. Following water injection, NOx emissions drop to 25 ppm; however, the CO and VOC emissions rise with the introduction of water. From 11 minutes onward, as the catalysts warm up to operating temperature, the NOx emissions are being controlled from 25 to 2 ppm.

The facility is proposing a 120 minute start-up time for the combined cycle power plant. The NOx emissions during the first hour of operation are expected to be 23.21 lbs and 8.48 lbs for the second hour. The start-up emissions are summarized in Table 5.

The facility requested a 2 hour start-up period for a total of 5 per day, 155 per month and 750 per year. The evaluation is based on their requested amounts. The start-up mass emission rates will be placed on the permit to ensure the facility complies with the emission rates proposed for the equipment.

SHUTDOWN

Shutdown is the period of time from initiation of the shutdown sequence to cessation of firing. During the shutdown operation, all the emission controls may not be operating at full control efficiency; thus emissions will be higher than normal operation. The shutdown emissions are summarized in Table 5.

Table 5 Start-up and Shutdown Emissions

Event	Time Period (min)	NOx (lb)	CO (lb)	VOC (lb)	PM10 (lb)	SOx (lb)
Start-up (full load)	10	5.19	6.86	0.61	0.49	0.04
Start-up (first hour)	60	23.21	28.10	3.97	4.78	0.76
Start-up (second hour)	60 to 120	8.48	5.16	2.96	5.00	0.83
Start-up (total)	**120**	a **31.69**	b **33.26**	c **6.93**	d **9.78**	e **1.59**
Shutdown	**60**	f **11.92**	g **9.99**	h **1.64**	i **5.00**	j **0.83**

The facility is proposing a 60 minute shutdown period duration and 5 per day, 155 per month, and 750 per year. The shutdown mass emission rates will be placed on the permit to ensure the facility complies with the emission rates proposed for the equipment.

NORMAL OPERATION

Normal operation is achieved when the gas turbine and associated air pollution control equipment are operating at design levels. Although mass emission rates will vary depending on ambient conditions, they will remain below guaranteed levels of 2.0 ppmvd-NOx, 2.0 ppmvd-CO and 2.0 ppmvd-VOC at 15% O2 with the aid of the CO catalyst and SCR. RR provided performance data for ambient conditions at 17°F, 64°F, and 97°F for the Trent 60 WLE shown in the table below.

Ambient Temperature (°F)	Relative Humidity (%)	Foggerr Status	Turbine Load (%)	Gross Power (kW)	Gross Heat Rate (LHV) (Btu/kWh)	Heat Input (LHV) (MMBtu/hr)
17	71	Off	100	64,000	8,254	528.3
64	61	On	100	59,208	8,395	497.1
97	42	On	100	54,471	8,510	463.6

The temperatures represent the range of conditions in Pasadena; 17°F is the minimum temperature reported and 97°F represents the maximum monthly average temperature. The annual average for Pasadena is 64°F. The maximum firing rate at 17°F is used for determining the worst case emissions. The emissions during normal operation are shown in Table 6. *Note that the SOx emissions are higher during normal operation than during start-up and shutdown.*

Table 6 Normal Operation Emissions (lb/hr) and Emission Factors (lb/MMscf)

	Parameter	Unit	Value	Reference
Gas Turbine Data: 100% Load, 17°F, 71%RH				
	Parameter	**Unit**	**Value**	**Reference**
a	Power at Terminals, Gross	kW	64,000	Vendor Data
b	Heat Rate, LHV	Btu/kW-hr	8,254	Vendor Data
c	Fuel Input, LHV	MMBtu/hr	528.3	= a x b/1E06
d	Fuel Input, HHV	MMBtu/hr	586.2	= c x 1012/912
Stack Exhaust Parameters				
	Parameter	**Unit**	**Value**	**Reference**
e	Stack Diameter	ft	10.17	Vendor Data
f	Volumetric Flow Rate, wet	acfm	536,640	Vendor Data
g	Exhaust Temperature	°F	417	Vendor Data
h	Water Content	%	9.69	Vendor Data
i	Oxygen Content, dry	%	14.91	Vendor Data
j	Exhaust Rate, dry, 15% O2	MMscf/hr	17.5	= f x 60/1E06 x [(460+60)/(460+ g)] x [1- (h/100)] x [(20.9- i)/(20.9-15)]
Emission Limits				
	Parameter	**Unit**	**Value**	**Reference**
k	NOx	ppmvd, dry, 15% O2	2.0	Vendor Guarantee
l	CO	ppmvd, dry, 15% O2	2.0	Vendor Guarantee
m	VOC	ppmvd, dry, 15% O2	2.0	Vendor Guarantee
n	PM10	lb/hr	5.0	Vendor Guarantee
o	SOx	gr/100 scf	0.5	Vendor Data
p	NH3	ppmvd, dry, 15% O2	5.0	Vendor Guarantee
Emission Rates				
	Parameter	**Unit**	**Value**	**Reference**
q	NOx	lb/hr	**4.25**	= k x j x 46/379
r	CO	lb/hr	**2.59**	= l x j x 28/379
s	VOC	lb/hr	**1.48**	= m x j x 16/379
t	PM10	lb/hr	**5.00**	Vendor Guarantee
u	SOx	lb/hr	**0.83**	= [o x 1E06 x 64/32] / [100 x 7000 x 1012] x d
v	NH3	lb/hr	**3.92**	= p x j x 17/379
Emission Factors				
	Parameter	**Unit**	**Value**	**Reference**
w	NOx	lb/MMscf	**7.34**	= q / d x 1012
x	CO	lb/MMscf	**4.47**	= r / d x 1012
y	VOC	lb/MMscf	**2.56**	= s / d x 1012
z	PM10	lb/MMscf	**8.63**	= t / d x 1012
aa	SOx	lb/MMscf	**1.43**	= u / d x 1012

COMMISSIONING

Commissioning is the process of fine-tuning the equipment to ensure the proper performance of the turbine and associated control equipment following initial installation. Emissions are expected to be greater during commissioning than during normal operation as air pollution control equipment may only be partially operational or not operational at all. PDWP is proposing to commission the equipment in 12 phases over 12 days summarized in Table 7 below.

Table 7 Equipment Commissioning Emission Rates and Emission Factors

Event	Day – Phase	Load (%)	Runtime (hrs)	SCR (Y/N)	Rate LHV (MMBtu/hr)	Fuel Used HHV (MMBtu)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs)
First Fire/Core Idle Mode	1 - P1	0	16	N	89	1582.4	381	934	74	10.40	2.24
Initial Tuning + Run/Synch Idle	2 – P2	0	16	N	89	1582.4	381	934	74	10.40	2.24
Integrated Tuning/Fog+ISI start-up	3 – P3	25	16	N	194	3441.0	1582	243	37	22.70	4.87
Steam Blow Cleaning	4 – P4	25	12	N	194	2579.9	1187	182	28	17.00	3.65
OTSG Commissioning	5 – P5	100	24	N	497	13238.1	1231	1997	156	85.80	18.74
Steam Turbine Commissioning	6 – P6	25	24	N	194	5161.0	2374	365	55	34.10	7.31
SCR/CO System Commissioning	7 – P7	25	16	Y	194	3441.0	253	39	15	28.20	4.87
Emissions Tuning	8 – P8	25	16	Y	194	3441.0	253	39	15	28.20	4.87
RATA Test	9 – P9	100	16	Y	497	8825.0	66	106	21	75.27	12.50
Performance Test	10 – P10	100	16	Y	497	8825.0	66	106	21	75.27	12.50
24-hr Reliability Test	11 – P11	100	24	Y	497	13238.1	98	160	31	112.90	18.74
24-hr Reliability Test Continued	12 – P12	100	8	Y	497	4413.1	33	53	10	37.60	6.25
TOTAL			**204**			**69768.0**	**7905**	**5158**	**537**	**537.84**	**98.78**
Emission Factors[(a)] (lb/MMscf)							**114.73**	**74.86**	**7.79**	**7.81**	**1.43**

(a) Emission Factor (lb/MMscf) = Commissioning Pollutant (lbs) / (Fuel Used HHV (MMBtu) / 1012 (Btu/scf))

MAINTENANCE

The equipment must undergo periodic maintenance to ensure it operates as intended. In particular, the water injection and intercooler system as well as the ammonia injection grid require regular tuning. Each maintenance operation is discussed in further detail below.

Water Injection and Intercooler Tuning (WIIT)

Tuning of the water injection and intercooler system will involve setting the turbine at a 25 MW load and varying the water injection rate between 15% below and 15% above normal injection rate. The procedure will involve the incremental increase of load in steps of 5 MW and the variation of water injection at each step until the turbine reaches full load. Operation at each step will take about an hour and the total time for the tuning procedure will be 12 hours. The turbine will be required to undergo this procedure **twice per year**. During this tuning process, ammonia injection will be operational as well as the steam turbine. The emissions are shown in Table 8. *Note that on a pound per hour basis, the mass emission rates for SOx is less than the emission rates during normal operation in Table 6.*

Table 8 Water Injection and Intercooler Tuning (WIIT) Emissions

Event	Load (MW)	Runtime (mins)	Fuel LHV (MMBtu)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs)
Bring SCR online	0							
Stabilize temperature	30	15	74	3.7	1.3	0.36	1.3	0.12
Increase water injection rate from normal rate to 15%	30	40	199.2	9.8	8.7	1.91	3.3	0.31
Decrease water injection rate from normal rate to 15%	30	40	195.4	9.8	1.4	0.94	3.3	0.31
Increase and stabilize CT load at 35 MW	35	15	82.5	4.1	1.4	0.38	1.3	0.13
Increase water injection rate from normal rate to 15%	35	40	222	10.9	9.3	2.05	3.3	0.35
Decrease water injection rate from normal rate to 15%	35	40	217.8	10.9	1.5	1.01	3.3	0.34
Increase and stabilize CT load at 40 MW	40	15	90.9	4.5	1.5	0.41	1.3	0.14
Increase water injection rate from normal rate to 15%	40	40	244.8	12	9.9	2.19	3.3	0.38
Decrease water injection rate from normal rate to 15%	40	40	240.1	12	1.6	1.07	3.3	0.38
Increase and stabilize load to 45 MW	45	15	99.5	4.9	1.6	0.43	1.3	0.16
Increase water injection rate from normal rate to 15%	45	40	267.9	13.2	10.5	2.33	3.3	0.42
Decrease water injection rate from normal rate to 15%	45	40	262.7	13.2	1.7	1.14	3.3	0.41
Increase and stabilize load to 50 MW	50	15	108.7	5.4	1.6	0.46	1.3	0.17
Increase water injection rate from normal rate to 15%	50	40	292.6	14.4	10.7	2.47	3.3	0.46
Decrease water injection rate from normal rate to 15%	50	40	287	14.4	1.7	1.21	3.3	0.45
Increase and stabilize load to 55 MW	55	15	117.9	5.8	1.7	0.49	1.3	0.18
Increase water injection rate from normal rate to 15%	55	40	317.3	15.6	10.9	2.62	3.3	0.5
Decrease water injection rate from normal rate to 15%	55	40	311.2	15.6	1.8	1.29	3.3	0.49
Allow ISI to initiate and stabilize	56	15	120.4	6	1.7	0.5	1.3	0.19
Block Load and adjust NOx and ISI	56	40	321	15.9	4.6	1.33	3.3	0.5
Increase and stabilize load to 59 MW	59	15	124.3	6.2	2.1	0.56	1.3	0.19
Increase water injection/ISI rate from normal rate to 15%	59	40	334.5	16.4	13.7	3.04	3.3	0.52
Decrease water injection/ISI rate from normal rate to 15%	59	40	328.2	16.4	2.2	1.49	3.3	0.51
TOTAL (12 hrs)		**720**	**4860**	**240.9**	**103**	**29.7**	**59.90**	**7.6**
TOTAL (24 hrs)		**1440**	**9720**	**481.8**	**206**	**59.4**	**119.8**	**15.2**

Ammonia Injection Grid Tuning (AIGT)

The ammonia injection tuning process will involve the operation of the turbine at 50 MW for up to 10 hours. This procedure is only required once per year. During this tuning process, ammonia injection will be operational as well as the steam turbine. The emissions are shown in Table 9. *Note that on a pound per hour basis, the mass emission rates for SOx is less than the emission rates during normal operation in Table 6.*

Table 9 Ammonia Injection Grid Tuning (AIGT) Emissions

Event	Load (MW)	Runtime (mins)	Fuel LHV (MMBtu)	NOx (lbs)	CO (lbs)	VOC (lbs)	PM10 (lbs)	SOx (lbs)	NH3 (lbs)
Ramp-up, start Water Injection and SCR, stabilize to 29.6 MW	29.6								
Tune the AIG with NH3 injection in service to adjust NOx outlet distribution	Increase to 59	600		246.2	83.2	22.56	50.0	7.80	39.2
TOTAL (10 hrs)		600	4970.9	**246.20**	**83.2**	**22.56**	**50.00**	**7.80**	**39.2**

PROJECT EMISSIONS

The emissions for the project are shown for both commissioning and non-commissioning years and are determined based on a maximum operating capacity of **8760** hours per year. As mentioned in the Start-up and Shutdown section, the facility is proposing 750 per year, 155 per month, and 5 per day with two hour duration for start-ups and one hour duration for shutdowns. For estimating the number of start-ups and shutdowns during the commissioning year, it was assumed that there will be 60 startups and 60 shutdowns during the 12 days of commissioning operation (5 start-ups and 5 shutdowns per day). Thus there will be only 690 startups and 690 shutdowns during the commissioning year.

The annual, monthly, and daily hours for each mode of operation are shown in Table 10 for the commissioning and non-commissioning years. The commissioning period will be limited to 204 hours of runtime operation; however, the schedule presented in Table 7 shows the phases of commissioning to occur over a 12 day period, with the turbine operating between 8 to 16 hours and up to 24 hours in a day. Thus the total hours will be 288 but the actual runtime will only be 204 hours.

Table 10 Schedule of Hours for Each Mode of Operation

Commissioning Year							
	Annual	**Hours**	**Reference**		**Monthly**	**Hours**	**Reference**
a	Total	8760	Applicant	h	Total	744	31 days x 24 hrs
b	Commissioning	288	12 days x 24 hrs	i	Commissioning	288	12 days x 24 hrs
c	Start-ups	1380	[750 – 60 (commissioning)] x 2 hrs	j	Start-ups	190	(31 days – 12 days) x 5 starts x 2 hrs
d	Shutdowns	690	[750 – 60 (commissioning)] x 1 hr	k	Shutdowns	95	(31 days – 12 days) x 5 starts x 1 hr
e	WIIT	24	2 events x 12 hrs	l	Normal Operations	171	h – (i + j + k)
f	AIGT	10	1 event x 10 hrs				
g	Normal Operations	6368	a – (b + c + d + e + f)				
Non-Commissioning Year							
	Annual	**Hours**	**Reference**		**Monthly**	**Hours**	**Reference**
m	Total	8760	Applicant	s	Total	744	31 days x 24 hrs
n	Start-ups	1500	750 x 2 hrs	t	Start-ups	310	155 x 2 hrs
o	Shutdowns	750	750 x 1 hr	u	Shutdowns	155	155 x 1 h
p	WIIT	24	2 events x 12 hrs	v	WIIT	12	1 event x 12 hrs
q	AIGT	10	1 event x 10 hrs	w	AIGT	10	1 event x 10 hrs
r	Normal Operations	6476	m– (n + o + p + q)	x	Normal Operations	257	s – (t + u + v + w)
Daily Operating Schedule							
y	Total	24	Applicant				
z	Start-ups	10	5 events x 2 hrs				
aa	Shutdowns	5	5 events x 1 hr				
bb	Normal Operations	9	y – (z + aa)				

The turbine will be conditioned not to exceed 5 start-ups per day and 155 start-ups per month (31 days/month x 5 starts/day); therefore, the number hours of start-ups, and shutdowns, are less than a non-commissioning month. In addition, it is assumed that the worst-case non-commissioning month will include maintenance operations (WIIT and AIGT).

The annual commissioning year emissions in Table 11 are calculated using the hours of operation for the annual commissioning year from Table 10 (b to g) along with the start-up and shutdown rates (lb/hr) in Table 5 (a to j), normal operation rates (lb/hr) in Table 6 (q to u), commissioning emissions from Table 7, and the maintenance operations from Tables 8 and 10.

Table 11 Commissioning Year Emissions (lbs/year)

Pollutant	Normal Operations[(a)]	Start-up[(b)]	Shutdown[(c)]	WIIT[(d)]	AIGT[(e)]	Commission [(f)]	Total[(g)]	Tons per year[(h)]
NOx	27,051	21,866	8,225	482	246	7,905	65,775	33
SOx	5,270	1,097	573	15	8	99	7,061	4
PM10	31,840	6,748	3,450	120	50	538	42,746	21
CO	16,466	22,949	6,893	206	83	5,158	51,756	26
VOC	9,409	4,782	1,132	59	23	537	15,941	8

(a) Normal Operation Emissions (lb/hr) *{q to u from Table 6}* x Normal Operations (hrs/yr) *{ g from Table 10}*
(b) Start-up (lb) *{a to e from Table 5}* x 690 start-ups/yr
(c) Shutdown (lb) *{f to j from Table 6}* x 690 shutdowns/yr
(d) WIIT Emissions (lb) *{Total (24 hrs) from Table 8}*
(e) AIGT Emissions (lb) *{Table 10}*
(f) Commission Emissions (lb) *{Table 7}*
(g) (a) + (b) + (c) + (d) + (e) + (f)
(h) (g) / 2000

The commissioning month emissions in Table 12 is based on the month that commissioning is occurring, with the remainder of time for normal operation and the maximum number of start-ups and shutdown possible for the remainder of the month.

Table 12 Commissioning Month Emissions (lbs/month)

Pollutant	Normal Operations[(a)]	Start-up[(b)]	Shutdown[(c)]	Commission [(d)]	Total[(e)]	30-DA[(f)]
NOx	726	3,011	1,132	7,905	12,774	426
SOx	142	151	79	99	470	16
PM10	855	929	475	538	2,797	93
CO	442	3,160	949	5,158	9,709	324
VOC	253	658	156	537	1,604	53

(a) Normal Operation Emissions (lb/hr) *{q to u from Table 6}* x Normal Operations (hrs/mo) *{ l from Table 10}*
(b) Start-up (lb) *{a to e from Table 5}* x 95 start-ups/mo
(c) Shutdown (lb) *{f to j from Table 6}* x 95 shutdowns/mo
(d) Commission Emissions (lb) *{Table 7}*
(e) (a) + (b) + (c) + (d) *{Table 12}*
(f) (e) / 30 *{Table 12}*

There are more hours available for normal operation and for start-ups and shutdowns for the non-commissioning year shown in Table 13 since the 12 days of commissioning is available for regular operations. The hourly emissions for SOX and PM10 are higher or as high as the other modes of operation, thus only the normal operation emissions are shown.

Table 13 Non-Commissioning Year Emissions (lbs/year)

Pollutant	Normal Operations[a]	Start-up[b]	Shutdown[c]	WIIT[d]	AIGT[e]	Total[f]	Tons per year[g]
NOx	27,510	23,768	8,940	482	246	60,946	30
SOx	7,249	0	0	0	0	7,249	4
PM10	43,800	0	0	0	0	43,800	22
CO	16,745	24,945	7,493	206	83	49,472	25
VOC	9,569	5,198	1,230	59	23	16,078	8

(a) Normal Operation Emissions (lb/hr) *{q to u from Table 6}* x Normal Operations (hrs/yr) *{ r from Table 10}*; SOx and PM10 Are based on the maximum hourly emissions at 8760 hours/yr
(b) Start-up (lb) *{a to e from Table 5}* x 750 start-ups/yr
(c) Shutdown (lb) *{f to j from Table 6}* x 750 shutdowns/yr
(d) WIIT Emissions (lb) *{Total (24 hrs) from Table 8}*
(e) AIGT Emissions (lb) *{Table 10}*
(f) (a) + (b) + (c) + (d) + (e) *{Table 13}*
(g) (f) / 2000 *{Table 13}*

The monthly emissions for the non-commissioning year, in Table 14, depict the worst-case scenario, which include the 155 start-ups and shutdowns, as well as all the maintenance operations.

Table 14 Non-Commissioning Month Emissions (lbs/month)

Pollutant	Normal Operations[a]	Start-up[b]	Shutdown[c]	WIIT[d]	AIGT[e]	Total[f]	30-DA[g]
NOx	1,092	4,912	1,848	241	246	8,338	278
SOx[h]	616	0	0	0	0	616	21
PM10[i]	3,720	0	0	0	0	3,720	124
CO	665	5,155	1,548	103	83	7,554	252
VOC	380	1,074	254	30	23	1,760	59

(a) Normal Operation Emissions (lb/hr) *{q to u from Table 6}* x Normal Operations (hrs/mo) *{x from Table 10}*
(b) Start-up (lb) *{a to e from Table 5}* x 155 start-ups/mo
(c) Shutdown (lb) *{f to j from Table 6}* x 155 shutdowns/mo
(d) WIIT Emissions (lb) *{Total (12 hrs) from Table 8}*
(e) AIGT Emissions (lb) *{Table 10}*
(f) (a) + (b) + (c) + (d) + (e) *{Table 14}*
(g) (f) / 30 *{Table 14}*
(h) The SOx emission rate is higher during normal operation than the other modes of operation.
(i) The PM10 emissions will be the highest when the equipment operates during normal operation for the entire month (PM10 rate lb/hr x 31 days x 24 hrs)

The daily emissions shown in Table 15 will be the general day to day operations for the equipment, taking into account the maximum allowable start-ups and shutdowns for the day.

Table 15 Daily Operating Emissions (Non-tuning day) (lbs/day)

Pollutant	Normal Operations[a]	Start-up[b]	Shutdown[c]	Total[d]
NOx	38	158	60	256
SOx[e]	20			20
PM10[f]	120			120
CO	23	166	50	240
VOC	13	35	8	56

(a) Normal Operation Emissions (lb/hr) *{q to u from Table 6}* x Normal Operations (hrs/day) *{bb from Table 10}*
(b) Start-up (lb) *{a to e from Table 5}* x 5 start-ups/mo
(c) Shutdown (lb) *{f to j from Table 6}* x 5 shutdowns/mo
(d) (a) + (b) + (c) *{Table 15}*
(e) *Maximum daily SOx and PM10 emissions will occur with only Normal Operations*

The worst-case maximum 30-day emissions for the project are shown in Table 16 taken from Tables 12 and 14.

Table 16 Maximum 30-DA Emissions

Pollutant	30-DA	Reference
NOx[a]	**426**	Commissioning month Table 12
SOx	**21**	Non-commissioning month Table 14
PM10	**124**	Non-commissioning month Table 14
CO	**324**	Commissioning month Table 12
VOC	**59**	Commissioning month Table 14

(a) The facility is in the RECLAIM program, so the NOx is shown for informational purposes.

RULES EVALUATION

RULE 212-STANDARDS FOR APPROVING PERMITS AND ISSUING PUBLIC NOTICES

Rule 212 requires that a person shall not build, erect, install, alter, or replace any equipment, the use of which may cause the issuance of air contaminants or the use of which may eliminate, reduce, or control the issuance of air contaminants without first obtaining written authorization for such construction from the Executive Officer. Rule 212(c) states that a project requires written notification if there is an emission increase for ANY criteria pollutant in excess of the daily maximums specified in Rule 212(g), if the equipment is located within 1,000 feet of the outer boundary of a school, or if the MICR is equal to or greater than one in a million ($1x10^6$) during a lifetime (70 years) for facilities with more than one permitted unit, source under Regulation XX, or equipment under Regulation XXX, unless the applicant demonstrates to the satisfaction of the Executive Officer that the total facility-wide maximum individual cancer risk is below ten in a million ($10x10^6$) using the risk assessment procedures and toxic air contaminants specified under Rule 1402; or, ten in a million ($10x10^6$) during a lifetime (70 years) for facilities with a single permitted unit, source under Regulation XX, or equipment under Regulation XXX.

FACILITY / EQUIPMENT AND SCHOOL LOCATIONS

The closest kindergarten to grade 12 school is located within 1,000 feet as stated by the applicant and as determined by Greatschools (http://www.greatschools.org). Table 17 summarizes the name, location and proximity of nearby schools. A public notice will be required per section (c)(1).

Table 17 K-12 Schools Near Facility

Name of School	Address	Distance in miles
Blair High School	1201 South Marengo Ave., Pasadena, CA	0.2 (<1000 feet)
Pacific Clinics	66 Hurlbut St., Pasadena, CA	0.3
Aria Montessori School	693 S. Euclid Ave., Pasadena, CA	0.4
Sequoyah School	535 S. Pasadena Ave., CA	0.7
McKinley School	325 S. Oak Knoll Ave., Pasadena, CA	1.1
San Rafael Elementary School	1090 Nithsdale Rd., Pasadena, CA	1.6
Roosevelt School	315 North Pasadena, St., Pasadena, CA	1.7

DAILY EMISSIONS

As shown in table 18, the daily emissions from this project exceed the daily thresholds of Rule 212(g) for NOx, PM10, CO, and VOC; therefore, the project triggers a public notice for section (c)(2).

Table 18 Daily Emissions

Pollutant	Project	R212(g) Daily Threshold	Public Notice triggered?
NOx	426	40	**Yes**
SOx	21	60	No
PM10	124	30	**Yes**
CO	324	220	**Yes**
VOC	59	30	**Yes**

MAXIMUM INDIVIDUAL CANCER RISK (MICR)

The total facility wide MICR is less than $1x10^6$, as shown in the discussion under the Regulation XIV section; therefore, a public notice is not required for section (c)(3).

RULE 218 – CONTINUOUS EMISSION MONITORING

The turbine will be required to have CEMS to monitor both CO and NOx to verify compliance with hourly concentrations and monthly emission limits. The CO CEMS will need to comply with the requirements of Rule 218. As a result, a CEMS application for AQMD source testing staff review and approval is required prior to the installation of the CEMS for the turbine. The NOx CEMS must meet the requirements of Regulation XX and will be discussed under the RECLAIM rules section.

RULE 219 – EQUIPMENT NOT REQUIRING A WRITTEN PERMIT PURSUANT TO REGULATION II

PDWP will be installing a wet cooling tower with the project which is exempt from AQMD permit per section (d)(3). Therefore, an application for this equipment is not required.

RULE 401 - VISIBLE EMISSIONS

This rule limits visible emissions to an opacity of less than 20 percent (Ringlemann No.1), as published by the United States Bureau of Mines. It is unlikely, with the use of the SCR /CO catalyst configuration on a natural gas turbine that there will be visible emissions. However, in the unlikely event that visible emissions do occur, anything greater than 20 percent opacity is not expected to last for greater than 3 minutes. During normal operation, no visible emissions are expected. Therefore, based on the above and on experience with other natural gas fired turbines, compliance with this rule is expected.

RULE 402 - NUISANCE

This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. The new turbine is not expected to create a public nuisance based on experience with identical natural gas fired turbines. Therefore, compliance with Rule 402 is expected.

RULE 403 - FUGITIVE DUST

The purpose of this rule is to reduce the amount of particulate matter entrained in the ambient air as a result of man-made fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. This rule prohibits emissions of fugitive dust beyond the property line of the emission source. The installation and operation of the natural gas fired turbine is expected to comply with this rule.

RULE 407 – LIQUID AND GASEOUS AIR CONTAMINANTS

This rule limits CO emissions to 2,000 ppmvd and SO_2 emissions to 500 ppmvd, averaged over 15 minutes. For CO, the natural gas fired turbine will meet the BACT limit of 2.0 ppmvd @ 15% O_2, 1-hr average, and the turbine will be conditioned as such and will be required to verify compliance through CEMS data. For SO_2, equipment which complies with Rule 431.1 is exempt from the SO_2 limit in Rule 407. The applicant will be required to comply with Rule 431.1 and thus the SO_2 limit in Rule 407 will not apply.

RULE 409 – COMBUSTION CONTAMINANTS

This rule restricts the discharge of contaminants from the combustion of fuel to 0.1 grain per cubic foot of gas, calculated to 12% CO_2, averaged over 15 minutes. The equipment is expected to meet this limit based on the calculations shown in table 19.

Table 19 Particulate Matter Concentration in Exhaust Gas

	Parameter	Unit	Value	Reference
a	Volumetric Flow Rate, wet	acfm	487,271	Vendor Data
b	Exhaust Temperature	°F	406	Vendor Data
d	CO2 Content	%	3.16	Vendor Data
e	PM Emission Rate	lb/hr	5.00	Vendor Guarantee
f	Exhaust Rate	scf/hr	17,555,260	a x [(460+60)/(460+b)] x 60
g	Grain Loading	**0.008**	gr/dscf	e x 7000 x 12/ (d x f)

As shown in table 19, the grain loading is less than the 0.1 gr/dscf required by Rule 409. Compliance will be verified through source testing.

RULE 431.1-SULFUR CONTENT OF GASEOUS FUELS

The turbines will use pipeline quality natural gas which will comply with the 16 ppm sulfur limit, calculated as H2S, specified in this rule. Natural gas will be supplied by the Southern California Gas Company. The facility proposed an H2S content of 0.5 gr/100scf, which is equivalent to a concentration of about 8 ppm. It is also much less than the 1 gr/100scf limit typical of pipeline quality natural gas. Compliance is expected. The applicant will comply with the reporting and record keeping requirements as outlined in subdivision (e) of this Rule.

RULE 475-ELECTRIC POWER GENERATING EQUIPMENT

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. Requirements are that the equipment meet a limit for combustion contaminants of 11 lbs/hr or 0.01 gr/scf. Compliance is achieved if either the mass limit or the concentration limit is met. Emissions from the turbine will be 5.0 lb/hr and 0.006 gr/scf [(5 lb/hr x 7000 gr/lb)/(8710 dscf/MMBtu x (20.9/(20.9-3)) x 551.6) MMBtu/hr] during natural gas firing at maximum load. Therefore, compliance is expected and will be verified through source testing.

RULE 1134 – EMISSIONS OF OXIDES OF NITROGEN FROM GAS TURBINES

This rule applies to gas turbines, 0.3 MW and larger, installed on or before August 4, 1989. Therefore, as a new installation, the proposed turbine is not subject to this Rule.

RULE 1135 – EMISSIONS OF OXIDES OF NITROGEN FROM ELECTRIC POWER GENERATING SYSTEMS

This rule applies to the electric power generating systems of several of the major utility companies in the basin. The plants which are included in the RECLAIM program are no longer subject to the requirements of this rule. Therefore, the NOx requirements of this rule are not applicable to the proposed turbine.

REGULATION XIII – NEW SOURCE REVIEW (NSR)

The following section describes the NSR analysis for this project and it will be evaluated for compliance with the rules in the table below.

RULE 1303(a) & RULE 2005(b)(1)(A) – BACT FOR GAS TURBINES

These rules state that the Executive Officer shall deny the Permit to Construct for any new source which results in an emission increase of any non-attainment air contaminant, any ozone depleting compound, or ammonia unless the applicant can demonstrate that BACT is employed for the new source. The addition of the new equipment at this existing facility will result in an increase in emissions; therefore, BACT requirements are applicable.

Emission limits for combined cycle turbines can be found in the EPA RACT/BACT/LAER Clearinghouse (RLBC) database, CARB database, AQMD BACT Guidelines database, and from the most recent power plant projects in California. The most stringent determination found was in the AQMD database for Vernon City Light and Power dated January 30, 2004 for a similar size Alstom combined cycle turbine (A/N 394164)[1]. The limits are shown in Table 20.

[1] The EPA RLBC had a listing for a power plant in Massachusetts, IDC Bellingham, with a NOx limit of 1.5 ppm permitted in 2000; however, the project was cancelled and the proposed limit was never demonstrated as achievable. For CO, the Kleen power plant in Connecticut has limit of 0.9 ppm based on 1-hr average. The facility has only begun operation and source test data is currently unavailable. The Avenal Energy Project has a CO limit of 1.5 ppm. Construction of the Avenal Energy Project has not yet commenced.

Table 20 BACT Requirements for Combined Cycle Gas Turbines

Pollutant	BACT	PDWP Proposal	Complies?
NOx	2.0 ppmvd, @ 15% O_2, 1-hour average	2.0 ppmvd, @ 15% O_2, 1-hour average	Yes
CO	2.0 ppmvd, @ 15% O_2, 1-hour average	2.0 ppmvd, @ 15% O_2, 1-hour average	Yes
VOC	2.0 ppmvd, @ 15% O_2, 1-hour average	2.0 ppmvd, @ 15% O_2, 1-hour average	Yes
PM_{10}/SOx	PUC quality natural gas w/ S content ≤ 1 grain/100 scf	PUC quality natural gas w/ H2S content ≤ 0. 5 grain/100 scf	Yes
NH_3	5.0 ppmvd @ 15% O_2, 1-hour average	5.0 ppmvd @ 15% O_2, 1-hour average	Yes

A NOx CEMS will be used to verify compliance with the NOx concentration limit and a CO CEMS will be used to verify compliance with the CO limit. The proposed levels in the table above will meet current BACT requirements for all criteria pollutants including NH_3. It should be noted that the EPA re-designated the South Coast air basin on June 11, 2007 as attainment for CO. However, the District continues to require CO BACT for combustion sources since the control equipment for CO is the same as for VOC. The two pollutants generally change in the same direction; therefore, since no continuous monitoring is available for VOC, compliance can be tracked through CO with a CO limit and continuous monitoring of CO.

NOx control technologies include water injection and XONON™, water injection and EMx™ (formerly known as SCONOx), and water injection and SCR with ammonia injection. However at this time, only water injection with SCR and ammonia injection has been demonstrated to achieve 2 ppm on a 1-hr average. Oxidation catalyst will be used to control CO and VOC and natural gas as the primary fuel will be used for PM10 and SOx. BACT is satisfied for the turbine during base load operation. The turbine will be required to perform source testing to verify compliance with the BACT limits.

In order to meet the BACT concentration limits for NOx and CO, as well as VOC, shown in table 21, the CO oxidation catalyst and SCR are required to be in full operation. However, during the start-up phase the turbine is going from a cold/ambient temperature to operating temperatures; therefore, the control system is not effective when the temperatures are less than the minimum temperatures specified in tables 3 & 4.

Water injection commences before the SCR comes online during start-up and ends several minutes after ammonia injection is shut-off. Water injection allows NOx emissions to be reduced when the SCR catalyst has minimum effectiveness. The start-up and shutdown mass emission rates proposed for this project take into account water injection and phased SCR and CO oxidation catalyst control.

Two recently approved power plant projects in California, Hanford and Henrietta combined cycle power plants, are proposing to use the LM6000 GTG and the OTSG. The systems are similar to the system proposed by PDWP. The data presented for these power plants reveals that start-up will be completed in 70 minutes that will result in 13.8 lbs of NOx. However, these new plants have not been constructed yet, thus there is no operational data available. In addition, PDWP is proposing a Rolls Royce Trent 60 configured with the OTSG and no source test data is available. The equipment vendor provided emission estimates for the first 60 minutes as well as the total 120 minutes of start-up; 23.21 lbs of NOx for the first hour and 4.4 lbs for the second hour. PDWP is conservatively proposing twice the normal operation rate for NOx, CO and

VOC (at ambient temperature of 17°F) for the second hour of the start-up. The PM10 and SOx emissions were assumed to be equivalent to normal operations.

Proposed shutdown emission data for the Hanford and Henrietta plants reveals that the duration to be 30 minutes and NOx emissions at 9.8 lbs, which at present have not been achieved in practice. The equipment vendor provided emission estimates during the shutdown mode of operation which is expected to be completed in 60 minutes resulting in 11.92 lbs of NOx. The mass emission rates for both start-up and shutdown modes of operation are shown in Table 5. NOx and CO mass emission rate limits will be placed on the permit for start-up and shutdown.

RULE 1303(b)(1) – MODELING

Rule 1303(b)(1) requires air dispersion modeling for CO and PM10. The facility is located within a non-attainment area for PM10 and in an attainment area for CO. Compliance is demonstrated for PM10 through project modeling that will not cause exceedances of the significant change threshold concentrations specified in Table A-2, Appendix A of Rule 1303. For CO, the project concentrations plus the background concentrations should not create a violation of the ambient air quality standard. Thus for CO, the significance threshold would be the CO ambient air quality standard.

PDWP provided modeling evaluations using the AERMOD dispersion model, version 12060 and five years of meteorological data from 2005 through to 2009 from the District's Azusa Station and air data from Miramar NAS Station. Analyses were performed for the turbine's different modes of operation described under the Emission Calculations Section of this evaluation. The CO 1-hr and 8-hr, and the PM10 24-hr modeling analyses for normal operating modes were conducted using stack velocity and temperature that resulted in the lowest source release parameters along with the ambient conditions that resulted in the highest emission rates. Although PDWP conducted modeling at various operating scenarios, the worst case project impacts are shown in Table 21.

Table 21 Rule 1303(b)(1) Modeling Results

Pollutant	Averaging Time	Max Impact (ug/m3)	Background Concentration (ug/m3)	Total Impact (ug/m3)	Most Stringent Air Quality Standard (ug/m3)	Allowable Significant Change (ug/m3)
CO	1-hour	74.6	4,580.8	4,655	23,000	-
	8-hour	20.4	2,404.9	2,425	10,000	-
PM10	24-hour	0.64	-	-	-	2.5
	Ann Geo Mean	0.13	-	-	-	1.0

The maximum emission rate for CO is during Day 1 of commissioning. The maximum concentration for 24-hour PM10 is during Water Injection (WI) and Ammonia Injection Grid (AIG) tuning. The annual geometric mean is based on 8760 hours of operation with 750 start-ups and 750 shutdowns, along with 24 hours of WI tuning and 10 hours of AIG tuning with the remaining time at normal operation.

AQMD modeling staff reviewed the analyses for both air quality modeling and health risk assessment (HRA) – to be discussed under the Rule 1401 – New Source Review for Toxics section of this evaluation. Modeling staff provided their comments in a memorandum from Mr. Philip Fine to Mr. Brian Yeh dated January 4, 2013. A copy of this memorandum is contained in the project file. Staff's review of the modeling and HRA analyses concluded that the applicant used appropriate EPA AERMOD model along with the appropriate model options in the analysis. The memorandum states that the modeling as performed by the applicant conforms to the District's dispersion modeling requirements. No significant deficiencies in methodology were noted. Therefore compliance with modeling requirements is expected.

RULE 1303(b)(2) – OFFSETS
Emission offsets are required for all projects where there is an increase in emissions unless there is an exemption identified in Rule 1304.

Rule 1304(a)(2) - Modeling and Offset Exemptions: Electric Boiler Steam Boiler Replacement
Combined cycle gas turbines, intercooled, chemically recuperated gas turbines, other advanced gas turbines, or other equipment, to the extent that allow compliance with Rule 1135 or Regulation XX rules that replace electric utility steam boilers are exempt from emission offsets provided that the new equipment has a maximum electrical power rating that does not allow basinwide electricity generation capacity on a per-utility basis to increase. If there is an increase in basin wide capacity, only the increased capacity must be offset.

The project involves the replacement of an existing electric steam utility boiler, rated at 71 MW gross, with a new natural gas fired combined cycle generating system rated at 70.6 MW gross (gas turbine – 59.2 MW and steam turbine – 11.4 MW), with a OTSG and associated air pollution control equipment. The OTSG allows the system to start-up in 10 minutes, without having to wait for the steam turbine, which will eventually come online to provide the required MW. There will be no increase in capacity, thus the repowering project is exempt from having to provide external emission offsets.

RULE 1303(b)(4) – FACILITY COMPLIANCE
PDWP submitted a Form 500-A2 stating that the facility is in compliance with all applicable Rules and Regulations of the AQMD.

RULE 1303(b)(5) – MAJOR POLLUTING FACILITIES

RULE 1303(b)(5)(A) – ALTERNATIVE ANALYSIS
The applicant is required to conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for the facility and to demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with this project. The analysis was conducted as a part of the CEQA process under the Environmental Impact Report prepared by the City of Pasadena. It was determined that the proposed project is the most beneficial option.

RULE 1303(b)(5)(B) – STATEWIDE COMPLIANCE
The applicant certifies compliance with all applicable emission limitations and standards under the Clean Air Act.

RULE 1303(b)(5)(C) – PROTECTION OF VISIBILITY
Modeling analysis for plume visibility in accordance with Appendix B of Rule 1303 is required if the net increase in emissions from the new or modified source exceeds 15 tons per year of PM10 or 40 tons per year of NOx (NOx is covered under Rule 2005(g)(4)) and if it is within the distance specified in Table C-1, of the rule, from a specified Federal Class I area. The nearest Class I area (San Gabriel Wilderness Area) is 25 km away, which is less than the maximum distance requirement of 29 km and the net increase in PM10 emissions is 20.2 tons per year as shown in Table 22. Therefore, the project triggers a visibility screening analysis.

Table 22 Net Increase in PM10 and NOx Emissions in tons per year (tpy)

Parameter	PM10	NOx	Reference
Project PTE (tpy)	22	30	Table 13 of this Evaluation
Boiler B-3 (2010 and 2011 avg.) (tpy)	1.8	4.7	Applicant's Data
Net Increase (tpy)	**20.2**	**25.3**	

PDWP performed the visibility screening analysis to assess potential visibility impacts on the San Gabriel Wilderness Area following the procedures in US EPA's Workbook for Plume Visual Impacts Screening and Analysis (Revised). The facility used 5 years (2005 to 2009) of meteorological data from Asuza, CA along with the maximum hourly emissions for NOx and PM10. The maximum hourly NOx emission was estimated to occur during the AIG tuning operation. The maximum hourly PM10 emission was estimated to occur during WIIT. Hourly NOx and PM10 emissions during the above operations were used for the visibility analysis. The results of the visibility analysis are shown in Table 23.

Table 23 VISCREEN Modeling Results

Background	Meteorological Condition	Plume Perceptibility (ΔE)			Plume Contrast (C_p)		
		VISCREEN		Screening Criteria	VISCREEN		Screening Criteria
		Theta 10	Theta 140		Theta 10	Theta 140	
Sky	Level 1: F Stability, 1 m/sec	2.26	1.12	2.00	0.021	-0.022	0.05
	Level 2: E Stability, 1 m/sec	0.62	0.31	2.00	0.006	-0.006	0.05
Terrain	Level 1: F Stability, 1 m/sec	3.94	0.96	2.00	0.037	0.012	0.05
	Level 2: E Stability, 1 m/sec	1.11	0.26	2.00	0.010	0.003	0.05

As shown in Table 23, the initial Level 1 analysis exceeded the threshold for Plume Perceptibility; however, the Level 2 screening analysis was less than the threshold criteria of 2.00 for color contrast and 0.05 for plume contrast.

AQMD modeling staff reviewed the analysis and provided their comments in a memorandum from Mr. Philip Fine to Mr. Brian Yeh dated January 4, 2013. A copy of this memorandum is contained in the project file. Staff's review concluded that the applicant used appropriate model options in the analysis.

The memorandum states that the modeling as performed by the applicant conforms to the District's modeling requirements. Therefore compliance is expected.

RULE 1303(b)(5)(D) – COMPLIANCE THROUGH CEQA

An Environmental Impact Report (EIR) was prepared by the City of Pasadena, Lead Agency for CEQA. Compliance is expected. The final EIR is scheduled to be certified by the Pasadena City Council in mid-April. Compliance through CEQA will be fulfilled with a final document.

RULE 1325 – FEDERAL PM2.5 NEW SOURCE REVIEW PROGRAM

This rule applies to any new major polluting facility, major modifications to a major polluting facility, and any modification to an existing facility that would constitute a major polluting facility in and of itself; located in areas federally designated pursuant to Title 40 of the Code of Federal Regulations (40 CFR) 81.305 as non-attainment for PM2.5.

With respect to major modifications, this rule applies on a pollutant-specific basis to those pollutants for which (1) the source is major, (2) the modification results in a significant increase, and (3) the modification results in a significant net emissions increase.

Paragraph (d)(5) defines Major Polluting Facility, on a pollutant specific basis, as any emissions source located in areas federally designated pursuant to 40 CFR 81.305 as non-attainment for the South Coast Air Basin (SOCAB) which has actual emissions of, or the potential to emit, 100 tons or more per year of PM2.5, or its precursors. A facility is considered to be a major polluting facility only for the specific pollutant(s) with a potential to emit of 100 tons or more per year. Table 24 shows the facility emissions for NOx, PM2.5 (assumed to be equivalent to PM10), and SOx. The facility is a Major Polluting Facility for NOx.

Table 24 Existing Facility NOx, PM2.5 and SOx Emissions in tons per year (tpy)

Equipment	Pollutant	Calculation[a]	tpy
Turbine GT1	NOx	(9.3 lb/hr x 149000 MWh)/(30.58 MW x 2000)	22.7
	PM2.5	(298 MMBtu/hr x 149000 MWh x 7.37 lb/MMscf)/(1012 x 30.58 MW x 2000)	5.3
	SOx	298 MMBtu/hr x 149000 MWh/30.58 x 0.00141 lb/MMBtu/2000	1.0
Turbine GT2	NOx	(9.3 lb/hr x 149000 MWh)/(30.58 MW x 2000)	22.7
	PM2.5	(298 MMBtu/hr x 149000 MWh x 7.37 lb/MMscf)/(1012 x 30.58 MW x 2000)	5.3
	SOx	298 MMBtu/hr x 149000 MWh/30.58 x 0.00141 lb/MMBtu/2000	1.0
Turbine GT3	NOx	(8.15 lb/hr x 8760)/(2000)	35.7
	PM2.5	(448 MMbtu/hr x 8760 x 7.37 lb/MMscf)/(1012 x 2000)	14.3
	SOx	448 MMBtu/hr x 8760 x 0.00141 lb/MMBtu/2000	2.8
Turbine GT4	NOx	(8.15 lb/hr x 8760)/(2000)	35.7
	PM2.5	(448 MMbtu/hr x 8760 x 7.37 lb/MMscf)/(1012 x 2000)	14.3
	SOx	448 MMBtu/hr x 8760 x 0.00141 lb/MMBtu/2000	2.8
Boiler B-3	NOx	(30 ppm x 8710 x 46 x (20.9/(20.9-3))/(379 x 1E06 x 2000) x 646 MMBtu/hr x 8760	104.8
	PM2.5	(646 MMBtu/hr x 8760 x 7.6 lb/MMscf)/(1012 x 2000)	21.2
	SOx	646 MMBtu/hr x 8760 x 0.00141 lb/MMBtu/2000	4.0
Engine D11	NOx	(5.39 gal/hr x 200 hrs x 469 lb/1000 gal)/(2000)	0.3
	PM2.5	(5.39 gal/hr x 200 hrs x 33.5 lb/1000 gal)/(2000)	0.02
	SOx	96 bhp x 0.0049 g/bhp-hr/453.6 g/lb x 200 hrs	0.0
Engine D12	NOx	(26.6 gal/hr x 200 hrs x 469 lb/1000 gal)/(2000)	1.3
	PM2.5	(26.6 gal/hr x 200 hrs x 33.5 lb/1000 gal)/(2000)	0.09
	SOx	519 bhp x 0.0049 g/bhp-hr/453.6 g/lb x 200 hrs	0.0
TOTAL	**NOx**	**GT1 + GT2 + GT3 + GT4 + B-3 + D11 + D12**	**223.2**
	PM2.5	**GT1 + GT2 + GT3 + GT4 + B-3 + D11 + D12**	**60.5**
	SOx	**GT1 + GT2 + GT3 + GT4 + B-3 + D11 + D12**	**11.6**

[a] Information from applicant's data and Facility Permit

Paragraph (d)(4)(A) identifies Major Modification as any physical change in or change in the method of operation of a major polluting facility that would result in: a significant emissions increase of a regulated NSR pollutant; and a significant net emissions increase of that pollutant from the major polluting facility. Significant as defined in (d)(13), in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

Nitrogen oxides: 40 tons per year, Sulfur dioxide: 40 tons per year, and PM2.5: 10 tons per year. The project emission increases are shown in Table 25.

Table 25 Rule 1325 Applicability

Pollutant	Baseline PTE	Reference	Major Polluting Facility?	Net Increase	Reference	Triggers Rule 1325?
NOx	223.2	Table 24 of this evaluation	Yes	30	Table 13 of this evaluation	No
PM2.5[a]	60.5	Table 24 of this evaluation	No	22	Table 13 of this evaluation	No
SOx	11.6	Table 24 of this evaluation	No	4	Table 13 of this evaluation	No

Table 25 summarizes the facility's NOx, PM2.5, and SOx emissions and the project net increase in emissions. The facility is a Major Polluting Facility for NOx, but the net increase is below the 40 tpy threshold. The facility is not a Major Polluting Facility for PM2.5 or SOx; therefore, this project does not trigger the requirements of Rule 1325.

RULE 1401 – NEW SOURCE REVIEW OF TOXIC AIR CONTAMINANTS

This rule is applicable to applications deemed complete on or after June 1, 1990 and it imposes specific limits for maximum individual cancer risk (MICR), cancer burden, and non-cancer acute and chronic hazard indices from new permit units, relocations, or modifications to existing permit units which emit toxic air contaminants (TAC) listed in Table I of Rule 1401. The rule establishes allowable risks for permit units requiring new permit pursuant to Rules 201 or 203. The proposed gas turbine and associated control equipment is a new construction with an increase in TAC emissions shown in Table 26, thus Rule 1401 applies to this project.

Table 26 Turbine Toxic Air Contaminant (TAC) Emissions

TAC[a]	CAS No.	EF (lb/MMscf)	EF (lb/MMBtu)	Maximum Hourly (lb/hr)[b]	Maximum Annual (lb/yr)[c]
Ammonia	7664417	NA	NA	3.92E+00	3.43E+04
1,3-Butadiene	106990	4.35E-04	4.30E-07	2.52E-04	2.08E+00
Acetaldehyde	75070	4.05E-04	4.00E-07	2.34E-04	1.93E+00
Acrolein	107028	3.66E-03	3.62E-06	2.12E-03	1.75E+01
Benzene	71432	3.30E-03	3.26E-06	1.91E-03	1.58E+01
Ethylbenzene	100414	3.24E-02	3.20E-05	1.88E-02	1.55E+02
Formaldehyde	50000	3.64E-01	3.60E-04	2.11E-01	1.74E+03
Propylene Oxide	75569	2.93E-02	2.90E-05	1.70E-02	1.40E+02
Toluene	108883	1.32E-01	1.30E-04	7.62E-02	6.28E+02
Xylenes	1330207	6.48E-02	6.40E-05	3.75E-02	3.09E+02
Benzo(a)anthracene	56556	2.26E-05	2.23E-08	1.31E-05	1.08E-01
Benzo(a)pyrene	50328	1.39E-05	1.37E-08	8.03E-06	6.62E-02
Benzo(b)fluoranthene	205992	1.13E-05	1.12E-08	6.57E-06	5.41E-02
Benzo(k)fluoranthene	207089	1.10E-05	1.09E-08	6.39E-06	5.27E-02
Chrysene	218019	2.52E-05	2.49E-08	1.46E-05	1.20E-01
Diebenz(a,h)anthracene	53703	2.35E-05	2.32E-08	1.36E-05	1.12E-01
Indeno(1,2,3-cd)pyrene	193395	2.35E-05	2.32E-08	1.36E-05	1.12E-01
Naphthalene	91203	1.66E-03	1.64E-06	9.61E-04	7.92E+00

(a) TAC emission factors from AP-42, 3.1 Stationary Gas Turbines and CARB's California Air Toxics Emission Factors (CATEF) database.

(b), (c) Emissions were determined at an ambient temperature of 17°F and 100% Load at 586.2 MMBtu/hr.

The facility provided a health risk assessment (HRA) that was prepared using the guidelines under the District's Risk Assessment Procedures for Rules 1401 and 212 Version 7, July 2005, and the procedures outlined in the Supplemental Guidelines for Preparing Risk Assessments for the Air Toxics "Hot Spots" Information and Assessment Act (AB2588), June 2011, which supplement the Air Toxics Hotspots Program Guidance Manual for Preparation of Health Risk Assessments (OEHHA, 2003) and the CARB Recommended Interim Risk Management Policy for Inhalation-based Residential Cancer Risk (CARB, 2003). The HRA was prepared using CARB Hotspots Analysis Reporting Program (HARP) model which includes EPA's AERMOD model as well as the risk assessment calculation model based on the Air Toxics Hot Spots Risk Assessment Guidelines. The TACS from Table 26 were used in the assessment.

The modeling results are shown in Table 27, which show MICR less than 1 in a million, chronic and acute hazard indices less than 1.0 for the gas turbine. District staff reviewed the methodology and procedures of the modeling runs submitted by PDWP and it was determined that the results shown in table 27 were appropriately estimated. Please refer to internal memorandum in the project file from Mr. Philip Fine to Mr. Brian Yeh dated January 4, 2013. Therefore, compliance with Rule 1401 is expected.

Table 27 Turbine Toxic Air Contaminant (TAC) Emissions

Parameter	Workplace Receptor	Residential Receptor	Rule 1401 Limits	Complies
Maximum Individual Cancer Risk (MICR)	1.09E-08	5.23E-08	T-BACT: ≤ 1.00E-06 No T-BACT: 1.00E-05	**Yes**
Chronic Hazard Index	1.31E-03	1.21E-03	≤ 1.0	**Yes**
Acute Hazard Index	1.81E-03	2.61E-03	≤ 1.0	**Yes**

RULE 1401.1 – REQUIREMENTS FOR NEW AND RELOCATED FACILITIES NEAR SCHOOLS

The purpose of this rule is to provide additional health protection to children at schools or schools under construction from new or relocated facilities emitting toxic air contaminants. This rule applies to new and relocated, but not to existing facilities. Applications for Permit to Construct/Operate from such new or relocated facilities shall be evaluated under this rule using the list of toxic air contaminants in the version of Rule 1401 that is in effect at the time the application is deemed complete. The PDWP facility is an existing facility that is not new or relocated; therefore, the requirements of this rule are not applicable.

REGULATION XVII – PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

Rule 1703 – PSD Analysis

The AQMD and EPA entered into 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. Sine 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 40 CFR Part 52 Subpart 21, or apply to AQMD in accordance with the current requirements of Regulation XVII.

The PDWP has requested to determine PSD applicability under AQMD Regulation XVII opting for the emissions methodology outlined in Rule 1706(c)(1)(A) – the actual to potential test. PSD analysis applies to new major stationary sources and major modifications to existing stationary sources located in attainment areas. A major source is a listed facility that emits at least 100 tons per year of a listed PSD pollutant or any other facility that emits at least 250 tons per year of a listed PSD pollutant. The PDWP facility is located in an attainment area for CO, SO2, and NO2 and it is an existing major source under PSD definitions. A significant increase in emissions is defined as in increase in 40 tons per year of either NOx or Sox, or 100 tons per year of CO emissions over the emissions before the modifications a the stationary source per Rule 1706(c)(1)(B)(i).

The actual emissions from PDWP prior to the modification will be determined with data from the two-year period preceding the date of the permit application. The application was received in 2012, so the two year preceding period will be 2010 to 2011. The actual boiler emissions compared to the project PTE and the PSD applicability are shown in Table 28.

Table 28 Determination of Project PSD Applicability

Pollutant	Actual Boiler B-3 Emissions (tpy)[a]	GT-5A PTE (tpy)[b]	Emission Change (tpy)[c]	Triggers PSD Analysis?
NO2	4.7	33	28.3	N
SO2	0.1	4	3.9	N
CO	20.0	26	6	N

[a] Actual boiler emissions from January 2010 through December 2011.
[b] Taken from Tables 12 and 13 of this evaluation.
[c] (b) – (c)

As shown in Table 28, the increase in emissions is less than 40 tons per year for NO2 and SO2 and the increase in CO emissions is also less than 100 tons per year. Therefore, PSD analysis is not triggered for this re-powering project.

Rule 1714 – PSD for Greenhouse Gases

This rule sets forth preconstruction review requirements for greenhouse gases (GHG). The provisions of this rule apply only to GHGs as defined by EPA to mean the air pollutant as an aggregate group of six GHGs: carbon dioxide (CO2), nitrous oxide (N2O), methane (CH4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). All other attainment air contaminants, as defined in Rule 1702 subdivision (a), shall be regulated for the purpose of Prevention of Significant Deterioration (PSD) requirements pursuant to Regulation XVII, excluding Rule 1714. The provisions of this rule shall apply to any source and the owner or operator of any source subject to any GHG requirements under 40 Code of Federal Regulations Part 52.21 as incorporated into this rule. The rule specifies what portions of 40 CFR, Part 52.21 do not apply to GHG emissions, which are identified in Rule 1714(c)(1) as exclusions.

The GHG pollutants of CO2, N2O and CH4 are products of combustion. The use of HFCs, PFCs, and SF6 are associated with equipment that are used for the operation of the facility, such as: HFCs used as heat transfer medium in air condition control equipment, PFCs used as an agent in fire suppression equipment, and SF6 as gas used to insulate transformers as well as in circuit breakers. The facility is expected to follow appropriate procedures to minimize any release of GHGs during installation, operation, and maintenance activities. The purchase of equipment that meet applicable standards and the practice of proper maintenance will ensure compliance for the non-combustion GHG products.

A PSD permit is required, prior to actual construction, of a new major stationary source or major modification to an existing major source as defined in 40 CFR 52.21(b)(1) and (b)(2), respectively. The rule incorporates the EPA rule by reference, so determination of PSD applicability for GHG is done using the EPA's document PSD and Title V Permitting Guidance for Greenhouse Gases, March 2010. The GHG emissions calculated in Table 31, using the heat input data and emission factors from Tables 29 and 30, respectively, were used for the project GHG PSD applicability determination in Table 32.

Table 29 Maximum Fuel and Heat Input for Potential to Emit

Equipment		Parameter	Unit	Value	Reference
Boiler B-3	a	Rating	MMBtu/hr	646	Applicant's data and Facility Permit
	b	Hours	hrs/yr	8,760	Maximum allowable
	c	Annual Heat Input	MMBtu/yr	5,658,960	a x b
	d	Annual Fuel Use	MMscf/yr	5,592	c / 1012
GT-1/GT-2[(a)]	e	Rating	MMBtu/hr	298	Applicant's data and Facility Permit
	f	Annual Limit	MW-hr	149,000	Applicant's data and Facility Permit
	g	Output	MW	30.58	Applicant's data and Facility Permit
	h	Annual Heat Input	MMBtu/yr	1,451,995	e x f / g
	i	Annual Fuel Use	MMscf/yr	1,435	h / 1012
GT-3/GT-4[(b)]	j	Rating	MMBtu/hr	448	Applicant's data and Facility Permit
	k	Hours	hrs/yr	8,760	Maximum allowable
	l	Annual Heat Input	MMBtu/yr	3,924,480	j x k
	m	Annual Fuel Use	MMscf/yr	3,878	l /1012
ICE D11	n	Fuel Rate	gal/hr	5.39	Applicant's data
	o	Hours	hrs/yr	200	Applicant's data and Facility Permit
	p	Annual Fuel Use	gal/yr	1,078	n x o
	q	Annual Heat Input	MMBtu/yr	149	p x 0.138 MMBtu/gal
ICE D12	r	Fuel Rate	gal/hr	26.6	Applicant's data
	s	Hours	hrs/yr	200	Applicant's data and Facility Permit
	t	Annual Fuel Use	gal/yr	5,320	r x s
	u	Annual Heat Input	MMBtu/yr	734	t x 0.138 MMBtu/gal
GT-5A (new)	v	Rating	MMBtu/hr	551.6	HHV at 64°F
	w	Hours	hrs/yr	8,760	Maximum allowable
	x	Annual Heat Input	MMBtu/yr	4,832,016	v x w
	y	Annual Fuel Use	MMscf/yr	4,775	x / 1012

(a) Turbines GT-1 and GT-2 are identical units with the same permit conditions, thus the maximum potential fuel use is identical.

(b) Turbines GT-3 and GT-4 are identical units with the same permit conditions, thus the maximum potential fuel use is identical.

Table 30 GHG Emission Factors for Mass and Carbon Dioxide Equivalent (CO2E)

Fuel		GHG	kg/MMBtu[(a)]	ton/MMBtu (Mass)[(b)]	GWP[(c)]	ton/MMBtu (CO2E)[(d)]
Natural Gas	a	CO2	53.02	5.84E-02	1	5.84E-02
	b	CH4	0.001	1.102E-06	21	2.31E-05
	c	N2O	0.0001	1.102E-07	310	3.42E-05
Diesel	d	CO2	73.96	8.15E-02	1	8.15E-02
	e	CH4	0.003	3.306E-06	21	6.94E-05
	f	N2O	0.0006	6.612E-07	310	2.05E-04

(a) Emission Factors from EPA's Emission Factors for Greenhouse Inventories, November 2011

(b) kg/MMBtu x 1.102E-03 ton/kg

(c) Global Warming Potential (GWP) taken from EPA's Emission Factors for Greenhouse Inventories, November 2011

(d) ton/MMBtu (Mass) x GWP

Table 31 GHG Emission Rates for Mass and CO2E

Equipment	Mass (tpy)				CO2E (tpy)			
	CO2[a]	CH4[b]	N2O[c]	Total	CO2[d]	CH4[e]	N2O[f]	Total
Boiler B-3	330,642	6	1	330,649	330,642	131	193	330,966
GT-1	84,837	2	0	84,839	84,837	34	50	84,920
GT-2	84,837	2	0	84,839	84,837	34	50	84,920
GT-3	229,300	4	0	229,304	229,300	91	134	229,525
GT-4	229,300	4	0	229,304	229,300	91	134	229,525
ICE D11	12	0	0	12	12	0	0	12
ICE D12	60	0	0	60	60	0	0	60
			Existing Total	**959,008**			**Existing Total**	**959,928**
GT-5A (new)	282,325	5	1	282,331	282,325	112	165	282,602
			Project Total	**282,331**			**Project Total**	**282,602**

[a] Annual Heat Input MMBtu/hr *{from Table 29}* x CO2 ton/MMBtu (Mass) *{from Table 30}*
[b] Annual Heat Input MMBtu/hr *{from Table 29}* x CH4 ton/MMBtu (Mass) *{from Table 30}*
[c] Annual Heat Input MMBtu/hr *{from Table 29}* x N2O ton/MMBtu (Mass) *{from Table 30}*
[d] Annual Heat Input MMBtu/hr *{from Table 29}* x CO2 ton/MMBtu (CO2E) *{from Table 30}*
[e] Annual Heat Input MMBtu/hr *{from Table 29}* x CH4 ton/MMBtu (CO2E) *{from Table 30}*
[f] Annual Heat Input MMBtu/hr *{from Table 29}* x N2O ton/MMBtu (CO2E) *{from Table 30}*

Table 32 GHG PSD Applicability Flowchart for Project[a]

Step	GHG PSD Applicability Step	Result	Response
1	Will the permit be issued on or after July 1, 2011	Yes	Go to Step 2
2	Is this modification subject to PSD permitting for a regulated NSR pollutant other than GHGs?	No	Go to Step 3
3	Determine PTE for existing stationary source, before modification, for each of the 6 GHG pollutants. Determine the mass sum and the CO2e sum (using GWP equivalent).	Mass Sum: 959,008 tpy *{Table 31}* CO2E Sum: 959,928 tpy *{Table 31}*	Go to Step 4
4	Are the PTE for GHG emissions equal or greater than both 100,000 tons per year CO2e and 100 tons per year on mass basis?	Yes	Go to Step 5
5	Determine past actual (baseline) in tons per year for units that are a part of the modification for each of the 6 GHG pollutants. (For new units, the past GHG emissions are zero)	The turbine, GT-5A, will be a new unit; therefore, the past actual emissions are zero.	Go to Step 7
6	NA	NA	NA
7	For units that are part of the modification, determine the future projected actual emissions (or PTE) in tons per year for each of the 6 GHG pollutants.	Mass Sum: 282,331 tpy *{Table 31}* CO2E Sum: 282,602 tpy *{Table 31}*	Go to Step 8
8	For each unit, determine the increase or decrease in mass emissions of each of the 6 GHG pollutants by subtracting past actual emissions from future actual emissions. Note: For new units that are not "replacement units", future actual emissions are equal to the PTE.	**Boiler B-3** ***Past Actual*** Average fuel use for 2011 and 2012 was 476.43 MMscf/yr; thus, annual capacity factor is 0.0852 calculated as 476.43/5,592 *{Item d from Table 29}* Mass Sum: 28,171 tpy calculated as 0.0852 x 330,649 tpy *{Table 31}* CO2E Sum: 28,198 tpy calculated as 0.0852 x 330,642 *{Table 31}* ***Future Actual*** Mass Sum: 0 CO2E Sum: 0	Go to Step 9

		GT-5A ***Past Actual*** Mass Sum: 0 CO2E Sum: 0 ***Future Actual*** Mass Sum: 282,331 tpy *{Table 31}* CO2E Sum: 282,602 tpy *{Table 31}*	
9	For each unit, sum any increase or decrease in GHG emissions on a mass basis.	***Decrease*** 28,171 tpy – 0 = 28,171 tpy ***Increase*** 282,331 tpy – 0 = 282,331 tpy	Go to Step 10
10	For all units that have mass emission increase, sum the GHG emissions on a mass basis.	***Increase*** 282,331 tpy – 28,171 tpy = 254,160 tpy	Go to Step 11
11	Is the sum of GHG emissions over zero tons per year?	Yes	Go to Step 12
12	For each unit, convert any increase or decrease in emissions of each of the 6 GHG pollutants to their CO2e using the global warming potential factors applied to the mass of each of the 6 GHG pollutants and sum them for each unit to arrive at one GHG CO2e number for each unit.	***Increase*** 282,602 tpy	Go to Step 13
13	Sum the GHG emissions on a CO2e basis for all units that have an emissions increase. (Emission decreases are not considered in this step).	***Increase*** 282,602 tpy	Go to Step 14
14	Is the CO2e sum of the increase equal or greater than 75,000 tons per year CO2e?	Yes	Go to Step 15
15	Contemporaneous netting is required. Identify all contemporaneous creditable increases and decreases in emissions for each of the 6 GHG pollutants on a mass basis. Note: Creditable decreases are only those that have not been relied upon in prior PSD review and will be practically enforceable by the time construction begins.	The existing boiler B-3 will b e decommissioned as a part of this project.	Go to Step 16
16	For each credible activity, determine the increase or decrease in emissions for each of the 6 GHG pollutants.	***Decrease*** 28,171 tpy	Go to Step 17
17	Sum the increases and decreases, including the increases and decreases from the proposed modifications, for each of the 6 pollutants on a mass basis.	***Increase*** 282,602 tpy ***Decrease*** 28,198 tpy	Go to Step 18
18	Calculate the net GHG emissions on a mass basis.	***Net Increase*** 282,602 tpy – 28,198 tpy = 254,404 tpy	Go to Step 19
19	Are the net GHG emissions on a mass basis over zero tons per year?	Yes	Go to Step 20
20	Convert any contemporaneous, creditable increase or decrease in emissions of each of the 6 GHG pollutants and sum them.	***Increase*** 282,602 tpy ***Decrease*** 28,198 tpy	Go to Step 21
21	Calculate the net GHG emissions on a CO2e basis	***Net*** 282,602 tpy – 28,198 tpy = 254,404 tpy	Go to Step 22
22	Are the net GHG emissions on a CO2e basis equal to or greater than 75,000 tons per year CO2e?	Yes	**GHG emissions subject to PSD Review**

(a) Flowchart from Appendix D. GHG Applicability Flowchart – Modified Sources (On or after July 1, 2011) of EPA's document PSD and Title V Permitting Guidance for Greenhouse Gases, March 2010.

Table 32 identifies that this project is subject to PSD analysis for GHG Emissions. Therefore, BACT is required for GHG. The applicable BACT is Federal BACT, which includes consideration of such factors as energy and cost. The District follows the federal guidelines on BACT for GHGs as outlined in the EPA's document PSD and Title V Permitting Guidance for Greenhouse Gases, March 2010. The EPA recommends that permitting authorities use the five-step "top-down" BACT analysis outlined in Table 33 to determine BACT for GHGs.

Table 33 EPA's 5-Step Top-Down BACT Analysis Methodology

Step		Description
1	Identify all available control technologies	All available control options for the emissions unit analyzed are identified. Identifying all potential available control options consists of those air pollution control technologies or control techniques with a practical potential for application to the emissions unit and the regulated pollutant being evaluated.
2	Eliminate technically infeasible options	The technical feasibility of the control options identified in Step 1 are evaluated and the control options that are determined to be technically infeasible are eliminated. Technically infeasible is defined where a control option, based on physical, chemical, and engineering principles, would preclude the successful use of the control option due to technical difficulties.
3	Rank remaining control technologies	All control options that were not eliminated in Step 2 are ranked based on effectiveness.
4	Evaluate most effective controls and document results	Additional evaluation is conducted on the technologies presented in Step 3 based on environmental, energy, and economic impacts are all considered for the final BACT evaluation.
5	Select the BACT	BACT is selected as the highest ranked control technology not eliminated in Step 4.

GHG Top-Down BACT Analysis

Step 1: Identify all available control technologies.

A review was conducted on the AQMD BACT/LAER Guidelines, the Bay Area Air Quality Management District (BAAQMD) BACT Guidelines, EPA's RACT/BACT/LAER Clearinghouse (RBLC), pending projects in the California Energy Commission (CEC) Database, as well as information provided by the EPA on BACT limits for combine cycle natural gas turbines. A summary of the GHG BACT Assessments are listed in Table 34.

Table 34 GHG BACT Assessments

	Source	Location	GHG BACT
1	Palmdale Hybrid Power Project (PHPP) (570 MW)	Palmdale, California	1. Thermal efficiency limit of 774 lbs-CO2E/MWh (365 day rolling average) 2. Heat rate limit of 7,319 Btu/kWh (12 month rolling average) 3. Annual facility CO2E limit of 1,913,000 tpy
2	Lower Colorado River Authority (LCRA) Thomas C. Ferguson Power Plant (420 MW)	Marble Falls, Texas	1. Thermal efficiency limit of 0.459 tons-CO2E/MWh (net) (365 day rolling average) 2. Heat rate limit of 7,720 Btu/kWh (365 day rolling average) 3. Annual facility CO2E limit of 1,821,241.5 tpy
3	Portland General Electric Company's Carty Power Plant (415 MW)	Boardman, Oregon	Thermal Efficiency due to natural gas fueled combined cycle power plant
4	Russell City Energy Center (600 MW)	Hayward, California	Thermal Efficiency due to natural gas fueled combined cycle power plant
5	Hyperion Energy Center (532 MW)	Elk Point, South Dakota	Use of Integrated Gasification Combined Cycle (IGCC)
6	Pioneer Valley (400 MW)	Westfield, Massachusetts	1. 825 lbs-CO2E MWh (Initial Test) 2. 895 lbs-CO2E/MWh (365 day rolling average) (thereafter)
7	Woodbridge Energy (CPV Valley) (663 MW)	Woodbridge, New Jersey	925 lb-CO2/MWh
8	Newark Energy Center (655 MW)	Newark, New Jersey	879 lb-CO2/MWh
9	CPV Valley (650 MW)	Wawayanda, New York	925 lb-CO2/MWh
10	Cricket Valley Energy (1,000 MW)	Dover, New York	1. Thermal Efficiency 57.4% 2. Heat Rate ≤ 7,605 Btu/kWh
11	CPV St. Charles (640 MW)	Charles County, Maryland	1. Thermal Efficiency of 57.4% 2. Heat rate limit of 7,605 Btu/kWh (LHV) 3. Annual facility CO2E limit of 2,244,881 tpy
12	Gateway Cogen (168 MW)	Prince George County, Virginia	1. Thermal Efficiency 1050 lb-CO2/MWh 2. Heat Rate 8,983 Btu/kWh (HHV gross)
13	Pacific Corp Lakeside Phase II (637 MW)	Vineyard, Utah	950 lb-CO2E/MWh (gross) (12 month rolling average)

A list of CO2 control technologies were developed and discussed for the BACT analysis.

1. Carbon Capture and Sequestration
2. Lower Emitting Technology
3. Thermal Efficiency

Each of the technologies is discussed in detail in the following subsections.

1. Carbon Capture and Sequestration (CCS)

The most comprehensive information available is on the Department of Energy (DOE) website, which contains information regarding the Carbon Sequestration Program. A number of steps are involved in the process of CCS. First the CO2 emissions must be captured and separated from the streams to be treated, and it must be transported to the site of sequestration, and finally there is the sequestration site that will store the CO2.

A. Capture of CO2 Emissions

The process begins with the capture of CO2 from the flue gas stream. The type of post-combustion capture systems include: amine based solvent systems, which are already in use for removing CO2 from process gas, solid sorbents can be used to remove CO2 from flue gas through chemical adsorption, physical adsorption, or a combination of both; possible configuration include fluidized beds or membrane based technology.

B. Transportation of CO2
Once the CO2 is separated from the flue gas stream it must be transported to the site of sequestration. Large volumes of CO2 from a power plant require the use of a pipeline. At present, there are no pipelines in operation or under construction in California.

C. Sequestration
Sequestration may be accomplished through geologic storage, ocean storage, or mineral carbonation. Geologic sequestration involves the identification of a suitable geological formation within close proximity to the site of the proposed project where the compressed CO2 is delivered under high pressure via pipeline and injected into the formation at depths greater than 800 meters. Below this depth the pressurized CO2 remains supercritical and behaves like a liquid and occupies pore spaces in the surrounding rock displacing saline water. Over time solid carbonate minerals form as a result of reactions between dissolved CO2 in water and the surrounding rock.

A number of geological formations in California have been identified that may be suitable for sequestration. The Department of Energy Carbon Sequestration Atlas for the United States and Canada shows the nearest potential sequestration basins to the project site are north in the Lower San Joaquin Valley and west in Ventura County. The sites may prove to be suitable candidates for CO2 sequestration; however, geological technical analyses have not been conducted to date to verify that possibility. The major obstacle to the viability of using these sites for sequestration is the mountain range between the Pasadena project site and the location in south San Joaquin and Ventura County. Potential sites within the oil production fields of the Long Beach area would require the construction of a CO2 pipeline through the urban Los Angeles area, which would prove to be difficult to construct in regards to cost and environmental approval.

Ocean storage would involve the injection of CO2 into the ocean at depths below 1,000 meters via pipeline or ship. It is expected that the CO2 would dissolve or form a horizontal lens, which would delay the dissolution of CO2 into the surrounding environment. The depth of the water and the CO2 lensing would form an obstacle to the vertical migration of the injected CO2.

Mineral carbonation is the reaction of the CO2 with metal oxides forming metal carbonates that are stable. The natural reaction between metal oxides, which are abundant in silicate minerals and in waste streams, is a slow process. However, reaction time may be increased through enhancing the purity of the metal oxides. The large-scale production of the metal oxides to meet the demand required through electrical generation would be costly and energy intensive.

2. Lower Emitting Technology
Power production technology that is commercially available and low or non-GHG emitting is solar power, wind, geothermal, hydroelectric, nuclear, and biomass fueled facilities. These technologies were examined and considered as a part of the Alternatives Analysis in the Environmental Impact report.

The CEC identified locations in the state that have a high potential for viable solar, wind, and geothermal energy production. They rated California's solar potential by county and although Los Angeles as a county has a relatively high photovoltaic potential, most of the high potential areas are concentrated in the northeastern corner of the county around Lancaster, which is approximately 40 miles away from Pasadena. Large scale solar energy generation is not viable for the city; however, PDWP's Integrated Resource Plan (IRP) has proposed to increase local solar production by 3 MW in 2010, 10 MW by 2015, 15 MW by 2020, and 19 MW by 2024.

The CEC also studied the States' high wind resource potential and areas with winds above 11 mph within Los Angeles County are located at remote regions in the northwestern portion. In addition, transmission of either solar or wind-generated energy to Pasadena is limited to transmission capacity as PDWP has only a single point of connection with SCE at the TM Goodrich substation at the eastern border of Pasadena, limiting electricity at 215 MW.

There are no known geothermal resources located within Los Angeles County. The nearest geothermal resource is Sespe Hot Springs in Ventura County, which is approximately 60 miles away.

The IRP has identified targets to achieve reductions in electricity usage through reducing energy sales by 12.5% below business as usual levels by 2016, reducing peak load by 10% below business as usual levels by 2012, further reducing peak load by an additional 5 MW through education and economic incentives to customers. A number of residential energy programs and incentives are already offered to residents to improve energy and water usage. PDWP has also initiated the Advanced Meter Pilot Program, which is an American Public Power Association grant funded project to replace 200 existing electric meters with more advanced meter technology that combines a digital meter platform with wireless technology. These meters are able to detect power outages and abnormal voltage on power lines and alert PDWP staff who are than able to activate or deactivate electric service remotely. The meters may play an integral role in improving system reliability.

The lower GHG emitting technologies would fundamentally redefine the project and alter the business purpose. The EPA does not require a BACT analysis to redefine the applicants' project (EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, 2010). As a result, no additional lower emitting alternative technologies are feasible to incorporate into the project without changing the business purpose of the project.

3. Thermal Efficiency

The thermal efficiency of CO2 formation through combustion is governed by the thermodynamics of the system and is defined as the dimensionless ratio of the useful work obtained from the process and the heat input to the process. The reduction of CO2 from fossil fuel combustion is achieved by the use of less fuel through a more thermally efficient process or the use of a lower GHG emitting fuel.

PDWP is proposing to combust natural gas, which is the lowest emitting fossil fuel available, in a one by one combined cycle configuration; gas turbine generator, once-through-steam-generator (OTSG), and a steam turbine. The use of the OTSG, as described in the process description section, allows the gas turbine to operate without water in the tubes as opposed to a traditional heat recovery steam generator (HRSG). The OTSG can operate from a dry state to steam operation without any changes to turbine load. This set-up allows a faster start-up without the restrictions of conventional HRSGs thus minimizing emissions.

PDWP had established a number of minimum operating requirements that the new unit was to meet when they put the proposal out to bid. The new unit was required to meet the following requirements:

- 10 minute start for the gas turbine
- Once Through Steam Generator (OTSG) – dry run capable
- Gross output not more than 71 MW
- Guaranteed BACT emission levels
- Noise guarantee in accordance with the City of Pasadena's noise ordinance

The City of Pasadena issued a Request for Proposal (RFP) for the design and supply of equipment for their repowering project. The RFP was publicly circulated and available on the City of Pasadena's website as well as on www.planetbids.com, which as described on their website is:

> *"...a leading provider of web based modular procurement solutions designed to automate the procurement process thus improving communication between buyers and suppliers cost effectively and efficiently. Our leading web based solutions include supplier management, bid management, insurance certificate management, emergency operations management and contract management"*

This allowed the RFP to be accessed by vendors all across the United States, as well in Canada and the Republic of Korea. The RFP required vendors to perform process design and encouraged them to package the most efficient system possible. PDWP had 31 potential bidders that attended the on-site pre-bid meeting. Eventually, the city received 5 bids, of which all 5 had either the GE LM6000 PG or the Rolls Royce Trent 60 gas turbines as a part of their proposal. Based on the proposals received for this repowering project, the two turbines represent the most efficient units available capable of meeting the city's requirements for the combined cycle repower project.
In comparison to the existing boiler B-3, which will be removed and replaced with the modern high efficiency combined cycle system, the result will be an improvement in PDWP's generation system efficiency, reliability and flexibility. The new combined cycle system will have lower GHG emissions per MWh than the existing boiler and will result in a net reduction of GHG emissions.

Step 2: Eliminate Technically Infeasible Options
Technology identified in the previous steps is only feasible if they are available and applicable to the scope of the project. Any technology that is not commercially available for the scale of the project is also considered infeasible.

1. Carbon Capture and Sequestration (CCS)
The technical feasibility of each step of the CCS process is discussed below.

A. Carbon Capture

a. Solvent-based process

An amine system, developed by Fluor Corp. called Econamine FG Plus (EFG+), has been demonstrated at the 320 MW Bellingham Power Plant in Massachusetts, which has been able to capture 365 short tons per day from the exhaust of natural gas. The CO2 that was captured was sold to the food industry. The CO2 capture plant operated from 1991 to 2005. It closed due to the price of natural gas.

Amines are able to capture CO2 from streams with low CO2 partial pressure, such as flue gas, through reactions that form water soluble compounds as demonstrated with EFG+ process.
These solvent based amine (pure or blended) systems require regeneration with steam that results in a loss of power production, when combined with compression, results in a parasitic load of 20 to 30%. The PDWP proposal has a current parasitic load of approximately 4%, a 20 to 30% parasitic load would greatly impact the amount of power that would be available to the residents of Pasadena since the current proposal is only for 71 MW.

Potassium carbonate may also be used to capture CO2. The process converts carbonate to bicarbonate in the presence of CO2, which is then converted back to carbonate through heating and the subsequent release of the absorbed CO2. Carbonate systems have an advantage over amine systems because much less energy is required for regeneration. The demonstration on large scale power plants has yet to be shown.

There are other processes such as aqueous ammonia, ionic liquids and hydrates, as well as physical solvents that rely on the partial pressure of CO2 in the waste stream, that are being investigated; however, these processes have not been demonstrated on a large scale power plant.

b. Membrane-based process
The process of separating CO2 from flue gas is dependent on the CO2 partial pressure to move the CO2 across the membrane. A vacuum or a sweep gas would be needed to aid the transfer of CO2 across the membrane requiring additional energy. Compressing the CO2 to the high operating pressures needed for pipeline transportation would require significant amounts of energy. Demonstration at the commercial large scale level has not been achieved. The use of membranes as carbon capture is infeasible.

c. Solid Sorbents
Solid sorbent systems present more design and operating difficulties than other systems because the handling of solids is more problematic. Large volumes of CO2 from a power plant would require large scale equipment. As with the other technologies discussed previously, the demonstration of the technology on a commercial power plant has not been achieved.

d. Oxy-combustion
A high pressure combustor is used to ignite natural gas and oxygen to form approximately 10% CO2 and 90% steam, by volume. CO2 may be removed from the stream with the previously mentioned technology. Clean Energy Systems, Inc. (CES) operates a 5 MW oxy-fuel combustor powering a steam turbine in the San Joaquin Valley under a research permit. However, CES has not built a large scale power plant using oxy-fuel combustion.

B. CO2 Transportation
The large volumes of CO2 generated from a commercial power plant would require a pipeline as the only practical option to handle the high volume. Large pipelines are already in existence for carrying CO2 to enhanced oil recovery (EOR) operations, where the CO2 is injected into the formation to lower oil viscosity and promote its movement into the production wells.

C. Sequestration
a. Geologic Sequestration
Injection of CO2 into geological formations has been shown to be effective, especially in the case of EOR operations in which CO2 flooding has shown to revitalize mature oil fields. However, there are still a number of technical issues that need to be resolved before this can be applied to a large commercial power plant.

- The existence of a suitable repository for the injection of the recovered CO2, which should have one or more injection zones that can accept and store large volumes of CO2.
- The repository must be able of sequestering the CO2 for the period of time determined to be the time required to be sequestered. The seismicity of Southern California works against long-term sequestration.

- The repository is located within close proximity to the power plant to allow efficient transportation of the CO2.
- Standards for measuring, monitoring, and verification of containment will be required to be established to allow confidence that long term storage will occur.

b. Ocean Storage
The concept of using the ocean as a CO2 sink and any resulting ecological impacts are still in the research phase. Possible acidification and the resultant negative biological impacts may prove that ocean storage would never be viable for CO2 sequestration. Further research is required to determine this option as being technically feasible.

c. Mineral Carbonation
The chemistry of the formation of metal carbonates is understood and technically feasible; however, sequestration has not been demonstrated for large scale power production activities.

Summary of CCS Feasibility
The post-combustion carbon capture technologies are still in development and are not considered to be commercially available for a large, full-size commercial power plant.

2. Lower Emitting Technology
The lower emitting technology that was presented earlier was determined to be infeasible for the site and would fundamentally alter the business purpose of the source. Thus the alternative technology was not considered as part of the BACT analysis.

3. Thermal Efficiency
The California State Senate Bill (SB) 1368 requires the California Public Utilities Commission (CPUC) to establish a GHG emission performance standard for all baseload utilities by February 1, 2007. The California Energy Commission (CEC) was required to establish a similar standard for local publicly owned utilities by June 30, 2007. The CEC established a GHG performance standard of 1,100 pounds of CO2E per net MWh for baseload publicly owned electrical utilities. The California Legislature in Assembly Bill (AB) 1613 (2007), as amended by AB 2791 (2008), established a CO2 Emission Performance Standard (EPS) for combined heat and power facilities of 1,100 lbs CO2E/MWh. In 2010, the CEC promulgated its regulation to implement AB 1613 in its Guidelines for Certification of Combined Heat and Power Systems pursuant to the Waste Heat and Carbon Emissions Reduction Act.

The EPA released a prepublication version of a proposed rule on March 27, 2012 to establish, a new source performance standard (NSPS) for GHG emissions from fossil fuel-fired electric generating units. The standard, to be published in the Federal Register as Subpart TTTT, will require new fossil fuel-fired power plants to meet an output based standard (based on gross power) of 1,000 lb CO2/MWh on an average annual basis applicable to combined cycle generating systems. At this moment the proposed rule has not been finalized by the EPA.

The combined cycle generating system is already a highly efficient unit that will replace an inefficient steam boiler, which will result in an increase in GHG emissions efficiency over the existing baseline. The project will lower the GHG emissions and the GHG emission performance metric. The thermal efficiency achieved and proposed is a technically feasible alternative for reducing GHG emissions from a fossil fuel fired power plant. This combustion process inherent to the combined cycle system is achieved in practice and eligible for consideration under step 3 of the BACT analysis.

Step 3: Rank Remaining Control Technologies

CCS has been determined to be technically infeasible for the project; however, the option will be carried forward for further discussion and consideration. The control options are ranked below from most effective to least effective.

1. Carbon Capture and Sequestration
2. Thermal Efficiency

The effectiveness of each option is discussed below.

1. Carbon Capture and Sequestration (CCS)

The capture efficiency of post-combustion systems that are being developed are expected to control at least 90% of CO2. This places CCS as the top ranked control technology.

2. Thermal Efficiency

Thermal efficiency will lower the GHG emissions, but not as much as CCS. As previously presented, the proposed system already incorporates an increased thermal efficiency in design with the inclusion of a OTSG and combined cycle configuration. The system parasitic load is already low, at about 2.7 MW, and any further increases to thermal efficiency are not achievable without changing the objectives of the power plant.

Step 4: Evaluate the Most Effective Controls and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology beginning with the most effective technology.

1. Carbon Capture and Sequestration (CCS)

It was outlined earlier that CCS, at present, is not technically feasible for the PDWP but has been carried forward in the BACT evaluation anyway to determine the energy, environmental, and economic impacts.

The aspect of economic impacts was discussed in the EPA's PSD BACT Guidance document.

> *EPA recognizes that at present CCS is an expensive technology, largely because of the costs associated with CO2 capture and compression, and these costs will generally make the price of electricity from power plants with CCS uncompetitive compared to electricity from plants with other GHG controls. Even if not eliminated from Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even if in some cases where underground storage of the captured CO2 near the power plant is feasible. However, there may be cases at present where the economics of CCS are more favorable (for example, where the captured CO2 could be readily sold for enhanced oil recovery), making CCS a more viable option under Step 4.*

It is recognized that CO2 capture from the power plant may represent up to 75% of the total cost of CCS, there is also costs associated with the geologic or terrestrial sequestration of the CO2 for long term storage, which are also site-specific. Costs of geotechnical studies for sufficient repositories, pipeline construction, pumping, drilling, well construction, and monitoring represent higher substantial costs that would add to the project. Since CCS has been determined to be unfeasible for this particular project, a quantitative cost analysis was not conducted. Data on capture and control efficiency from a commercial sized power plant already in operation, as well as technical data from drilling studies, pilot studies, and geotechnical studies are unavailable to make any accurate estimates. Therefore, CCS will be analyzed qualitatively for this project.

The Hyperion Energy Center, GHG BACT determination number 5 in Table 34, is an IGCC project that conducted an extensive analysis on CCS. The South Dakota Department of Environment and Natural Resources (SD-DENR) determined that the implementation of CCS would require an additional 400 MW of power generation capacity for gas drying and boosting. The additional power capacity would significantly increase the amount of conventional pollutants, increase energy demands, and emit 23% of the GHG emissions that the CCS was designed to capture. SD-DENR rejected CCS as BACT for these factors and for the high costs and concluded that Hyperion's proposed measures of good combustion practices and energy efficiency measures incorporated into the plant design as GHG BACT.

There are no CO2 pipelines in operation or under construction in the State of California. CCS for this project would require the construction of a new pipeline from Pasadena to any potential sequestration locations. This would involve the construction of a new pipeline through the city of Los Angeles or through the Los Angeles and Los Padres National Forests to reach potential sequestration locations.

The information presented on CCS demonstrates that it is not technically feasible for this project and is eliminated from further consideration.

2. Thermal Efficiency

Table 34 identifies thirteen (13) GHG BACT analyses for combined cycle turbine power plants from 168 to 1,000 MW capacities. The generation capacity for the PDWP project, at 71 MW, will be significantly lower than capacities of the facilities in Table 34. Large capacity combined cycle power plants are expected to have higher thermal efficiencies in comparison to smaller capacity systems due to economies of scale. The heat rates and the calculated CO2E emissions in lbs/MWh (net) are shown in tables 35 and 36.

Table 35 PDWP Power Plant Data

DATA			
Total Operating Hours	8760		
Degradation	1.0%		
Load	50%	75%	100%
Starts	750	750	750
Shutdown	750	750	750
Normal Hours	6510	6510	6510
Heat Input (MMBtu/hr) LHV	293.3	393.3	497.1
Heating Value of Natural Gas			
Natural Gas Heating Value, LHV	912		
Natural Gas Heating Value, HHV	1012		
NET Power Data			
CTG power (kW)	28336	42447	56973
STG power (kW)	7410	9878	10961
CCGS power (kW)	35746	52325	67800
CTG heat rate (Btu/kWh)	10351	9266	8725
CCGS heat rate (Btu/kWh)	8205	7516	7317

Table 36 PDWP CO2E Emissions with Degradation

NET Power			
START-UP (does not include Steam Turbine)			
Fuel per SU (MMBtu)	1016.14		
Fuel per no electricity (MMBtu)	12		
Fuel Use for Power Generation (MMBtu)	1004.14		
Load	50%	75%	100%
Fuel Use (MMBtu)	1004.14	1004.14	1004.14
GTG Heat Rate (Btu/kWh)	10351	9266	8725
Power per SU (kWh)	97009	108368	115088
Total Power during Start-ups (MWh)	72757	81276	86316
SHUTDOWN (includes Steam Turbine)			
Fuel per SD (MMBtu)	433.05		
Fuel per no electricity (MMBtu)	7.57		
Fuel Use for Power Generation (MMBtu)	425.48		
Load	50%	75%	100%
Fuel Use (MMBtu)	425.48	425.48	425.48
CCGS Heat Rate (Btu/kWh)	8205	7516	7332
Power per SD (kWh)	51856	56610	58031
Total Power during Shutdowns (MWh)	38892	42458	43523
BASE LOAD			
Load	50%	75%	100%
Power per Normal Operation, NO (kWh)	35746	52325	67800
Total Power Base Load (MWh)	232706	340636	441378
TOTAL POWER SU + SD + NO (MWh)	344,355	464,370	571,217
CO2E EMISSIONS			
Load	50%	75%	100%
Annual Heat Input (MMBtu) HHV (degraded)	3,358,063	4,087,668	4,844,998
CO2E Emission Factor (ton/MMBtu)	0.05849	0.05849	0.05849
Annual CO2E (lb/yr)	392,826,210	478,175,403	566,767,866
CO2E (lbs/MWh)	**1141**	**1030**	**992**

As previously discussed, the State standard is 1,100 lbs-CO2E/MWh, which shall be measured over a 12 month rolling average from the annual CO2E emissions from fuel use and the measured MWh. The values calculated for the loads in Table 36 are conservatively based on no steam turbine contribution for each start-up and unit degradation that will result in an increased in fuel use. However, the steam turbine will come online sooner and contribute power. Although the values in Table 36 are theoretical, PDWP has proposed a more stringent value of 1084 lb-CO2E/MWh determined over a 12 month rolling average.

Step 5: Select BACT

Based on the Top-Down BACT Analysis, thermal efficiency is the only technical and economical option that is feasible for this facility. The current design of the facility and the proposal of a stringent CO2E emission rate per useful energy generated meets the BACT requirement for GHG reductions. A BACT limit of 282,602 tons of CO2E per year (from Table 31 for GT-5A) will be added as a permit condition, which will be determined by monitoring fuel use and calculating it with an emission factor of 59.187 tons-CO2E/MMscf[2]. A permit condition of 1,084 lb-CO2E/MWh will also be placed on the permit to ensure compliance with PSD BACT.

RULE 1714 – PSD FOR GHG, CIRCUIT BREAKERS

There will be no new circuit breakers installed at the facility. The existing SF6 containing circuit breakers will continue to be maintained and will be used to protect the new generating unit. No change in the amount of SF6 that will be used or stored at the facility is proposed. Therefore, BACT is not triggered for SF6 containing equipment.

REGULATION XX – REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)

The PDWP facility is in the NOx RECLAIM program and is subject to the requirements of this regulation.

RULE 2005(b)(1)(A) – BACT

The NOx BACT limit for natural gas fired combined cycle turbines were discussed in the Regulation XIII NSR section. A concentration of 2.0 ppmv, corrected to 15% O2 dry, and averaged over 1 hour is BACT. Permit conditions and verification through CEMS and source testing will ensure compliance.

RULE 2005(c)(1)(B) – MODELING

This section of the rule requires a facility that is located in an attainment area for nitrogen dioxide (NO2) to demonstrate through modeling analysis that the proposed NOx emission sources will not cause a violation of the most stringent ambient air quality standards. PDWP conducted dispersion modeling using the AERMOD model for the maximum project impacts of NO2 emissions. The results of the analysis are shown in Table 37.

Table 37 Rule 2005(c)(1)(B) Modeling Results

Criteria	Operation with maximum impact	Impact (ug/m3)	Background (ug/m3)	Total Impact (ug/m3)	Most Stringent AQ Standard (ug/m3)
NOx, 1-hour (CAAQS)	Commissioning, Phase 4, Day 4	95.50	207.0	302.5	339
NOx, 1-hour (NAAQS)	WIIT	5.34	127.9	133.2	188
NOx, annual	Maximum operation with 750 start-ups, 750 shutdowns, 24 hours of WI and IT Tuning	0.13	44.2	44.3	57

[2] Calculated as [(53.02 kg-CO2/MMBtu)(1 CO2E/CO2) + (0.001 kg-CH4/MMBtu)(21 CO2E/CH4) + (0.0001 kg-N2O/MMBtu) (310 CO2E/N2O)] x 0.001102 ton/kg x 1012 MMBtu/MMscf

Modeling staff provided their comments in a memorandum from Mr. Philip Fine to Mr. Brian Yeh dated January 4, 2013. A copy of this memorandum is contained in the project file. Staff's review of the modeling analysis concluded that the applicant used appropriate EPA AERMOD model along with the appropriate model options in the analysis. The memorandum states that the modeling as performed by the applicant conforms to the District's dispersion modeling requirements and no significant deficiencies in methodology were noted. Therefore compliance with modeling requirements is expected.

RULE 2005(b)(2)(A) – 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, paragraph (b)(2)(B) states that the RTCs must comply with the zone requirements of Rule 2005(e). The repower project is expected to undergo commissioning in Year 2015. Since the facility is located in Zone 2 (Inland, Cycle 1); thus, RTCs may only be obtained from Zones 1 or 2.

PDWP's initial 1994 allocation is 766,098 lbs of RTCs and 1,314 non-tradable credits. The current PTE for the facility (existing four turbines, boiler B-3, and two emergency engines) is 446,400 lb/yr (from Table 24). The PTE for the boiler B-3 is 209,600 lb/yr (from Table 24) which will be replaced with a combined cycle turbine with a PTE of **65,775 lbs/yr** (Table 11) for the first year of operation and 60,946 lbs per year (Table 13) for the subsequent years. Therefore, since this is an existing facility that will not exceed the 1994 allocation, it will only be required to hold RTCs for the first year of operation. The permit will be conditioned accordingly.

PDWP will be required to purchase the required NOx RTCs from the open market or use credits from their existing power plant facility located in the South Coast Air Basin. Therefore, compliance with Regulation XX, Rule 2005, is expected.

RULE 2005(g) – ADDITIONAL REQUIREMENTS
As with Rule 1303(b)(5) for the Non-RECLAIM pollutants, PDWP has addressed the alternative analysis, statewide compliance, protection of visibility, and CEQA compliance requirements of this rule for NOx. These requirements are essentially the same as those found in Rule 1303(b)(5), subparts A through D for non-RECLAIM pollutants, and are summarized below.

RULE 2005(g)(1) – STATEWIDE COMPLIANCE
The applicant certifies compliance with all applicable emission limitations and standards under the Clean Air Act.

RULE 2005(g)(2) – ALTERNATIVE ANALYSIS
The applicant is required to conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for the facility and to demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with this project. PDWP has performed a comparative evaluation of alternative sites as part of the CEQA process and has determined that the project proposal is the best option as opposed to developing other sites.

RULE 2005(g)(3) – COMPLIANCE THROUGH CEQA
The City of Pasadena, as the Lead Agency, prepared a draft Environmental Impact Report (EIR), SCH # 2011091056, which commenced public review on November 2, 2012 and concluded review on January 31, 2013. Compliance is expected with the approval of the EIR.

RULE 2005(g)(4) – PROTECTION OF VISIBILITY
Modeling analysis for plume visibility in accordance with Appendix B of Rule 2005 is required if the net increase in emissions from the new or modified source exceeds 40 tons per year of NOx and if it is within the distance specified in Table C-1, of the rule, from a specified Federal Class I area. The minimum distance between the facility and the nearest Class I area (San Gabriel Wilderness Area) is about 25 km, which is less than the maximum distance requirement of 29 km; however, the net annual emissions increase of the project is 27.3 tons, which is less than the rule threshold of 40 tons per year, thus no visibility analysis is required under Rule 2005.

RULE 2005(h) – PUBLIC NOTICE
PDWP will comply with the requirements for Public Notice found in Rule 212. Therefore compliance with Rule 2005(h) is demonstrated.

RULE 2005(i) – RULE 1401 COMPLIANCE.
PDWP will comply with Rule 1401 as demonstrated in HRA and subsequently reviewed and found to be satisfactory by AQMD modeling staff. Compliance is expected.

RULE 2005(j) – COMPLIANCE WITH STATE AND FEDRAL NSR.
PDWP will comply with the provisions of this rule by having demonstrated compliance with AQMD NSR Regulations XIII and Rule 2005-NSR for RECLAIM.

RULE 2012 – RECLAIM, MONITORING, REPORTING, & RECORDKEEPING REQUIREMENTS
The turbine will be classified as major NOx source under RECLAIM. As such, it is required to measure and record NOx concentrations and calculate mass NOx emissions with a Continuous Emissions Monitoring System (CEMS). The CEMS will include in-stack NOx and O2 analyzers, a fuel meter, and a data recording and handling system. NOx emissions are reported to AQMD on a daily basis. The CEMS system will be required to be installed within 90 days of start up. Compliance is expected.

INTERIM PERIOD EMISSION FACTORS
RECLAIM requires a NOx emission factor to be used for reporting emissions during the interim reporting period. The interim period is defined as a period, of no greater than 12 months from initial operation, when the CEMS has not been certified. During this period, the emissions cannot be accurately, monitored, or verified. The emissions during this period are assumed to be at uncontrolled levels. The interim reporting period can be broken down into the two parts which includes the commissioning period in which an uncontrolled emission rate is assumed and remaining period.

Since PDWP is included in NOx RECLAIM, an interim period emission factor will be determined. In the event CEMS data is not available, NOx emissions during the interim period will be calculated using monthly fuel usage and the emission factors shown below. There will be two interim period emission factors for NOx.

The first factor will be for use during the commissioning period when the turbine is assumed to be operating at uncontrolled levels (as shown in Table 7) and the second factor will be for use after commissioning is complete. The emission factors for NOx as well as the other criteria pollutants are shown in Table 38.

Table 38 Emission Factors for Interim Period

Pollutant	NOx	CO	VOC	PM10	SOx
Commissioning Emission Factors[a] (lb/MMscf)	114.73	-	-	-	-
Remaining Period Emission[b] Factors (lb/MMscf)	19.35	17.53	4.08	8.63	1.43

[a] Emission factors taken from Table 7.
[b] The aggregate emission factors are calculated as follows: *pollutant* lbs/month *{from Table 14}*/(0.579 MMscf/hr x 744 hrs/month

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

An EIR was prepared for this project (SCH# 2011091056) by the City of Pasadena, the Lead Agency. The public review period commenced on November 2, 2012 and concluded review on January 31, 2013.

40CFR PART 60 SUBPART KKKK - NSPS FOR STATIONARY GAS TURBINES

The turbine is subject to Subpart KKKK because the heat input is greater than 10.7 gigajoules per hour (10.14 MMBtu per hour) at peak load, based on the higher heating value of the fuel fired. The standards applicable for a turbine firing natural gas with a heat input at peak load >50 MMBtu/hr and ≤850 MMBtu/hr are as follows:

NOx: 25 ppm at 15% O2 or 1.2 lb/MW-hr
SO2: 0.90 lbs/MW-hr discharge, or 0.060 lbs/MMBtu potential SO2 in the fuel

The proposed NOx limit will be 2.0 ppmv and should comply with concentration limit of this Rule.

SO2 = 0.78 lb/hr / 551.5 MMBtu/hr = 0.0014 lb/MMBtu

The SO2 emissions of 0.0014 lb/MMBtu are below the emissions limits of this Rule

MONITORING

The regulation requires that the fuel consumption and water to fuel ratio be monitored and recorded on a continuous basis, or alternatively, that a NOx and O2 CEMS be installed. For the SO2 requirement, either a fuel meter to measure input, or a watt-meter to measure output is required, depending on which limit is selected. Also, daily monitoring of the sulfur content of the fuel is required if the fuel limit is selected. However, if the operator can provide supplier data showing the sulfur content of the fuel is less than 20 grains/100scf (for natural gas), then daily fuel monitoring is not required.

The turbine will be required to install CEMS to comply with RECLAIM requirements for NOx Major Sources. Therefore, NOx monitoring requirements are satisfied. The turbine will fire natural gas provided by the Southern California Gas Company which contains less than 1 grains-sulfur/100scf. Daily monitoring will not be required for fuel sulfur content.

TESTING

An initial performance test is required for both NOx and SO2. For units with a NOx CEMS, a minimum of 9 RATA reference method runs is required at an operating load of +/- 25 percent of 100 percent load. For SO2, either a fuel sample methodology or a stack measurement can be used, depending on the chosen limit. Annual performance tests are also required for NOx and SO2.

Compliance with the requirements of this rule is expected.

<u>40CFR PART 63 SUBPART YYYY - NESHAPS FOR STATIONARY GAS TURBINES</u>

This regulation applies to gas turbines located at major sources of hazardous air pollutant (HAP) emissions. Per this subpart, a major source is defined as a facility with emissions of 10 tons per year (tpy) or more of a single HAP or 25 tpy or more of a combination of HAPs. This subpart establishes national emission limitations and operating limitations for HAPs from stationary combustion turbines. Performance tests are required to demonstrate compliance as well as continuous monitoring of certain parameters. Turbines equipped with oxidation catalysts must monitor the inlet temperature. If operating limitations are chosen for compliance, then the operating limitations must be continuously monitored.

The individual HAP with the highest emission rate is formaldehyde, which is 2.81 tpy for the facility. The total HAP emissions for the facility are 5.20 tpy. Therefore, since the emissions are less than 10 tpy, for a single pollutant, and 25 tpy, for all the HAP pollutants, this subpart is not applicable.

<u>40 CFR PART 64 – COMPLIANCE ASSURANCE MONITORING</u>

The CAM regulation applies to each pollutant specific emissions unit (PSEU) at major stationary sources required to obtain a Title V permit, 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.

CAM applicability is based on specific criteria; the PSEU must:

- be subject to an emission limitation or standard, and
- use a control device to achieve compliance, and
- have **potential pre-control** emissions that exceed or are equivalent to the major source threshold.

NOx, CO, and VOC meet the criteria above for CAM applicability. Therefore, CAM requirements apply to these pollutants.

NOx

- <u>Emission Limit</u> – NOx is subject to a 2.0 ppm 1 hour BACT limit.
- <u>Control Equipment</u> – NOx is controlled with the SCR
- <u>Requirement</u> - As a NOx Major Source under Reclaim, the turbine is required to have CEMS under Rule 2012. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(vi).

CO

- <u>Emission Limit</u> – CO is subject to a 2.0 ppm 1 hour BACT limit.
- <u>Control Equipment</u> – CO is controlled with the oxidation catalyst.
- <u>Requirement</u> – The turbine will be required to use a CO CEMS under Rule 218. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(vi).

VOC

- <u>Emission Limit</u> – VOC is subject to a 2.0 ppm 1 hour BACT limit.
- <u>Control Equipment</u> – VOC is controlled with the oxidation catalyst.

- Requirement – The oxidation catalyst is effective at operating temperatures above 556°F. The facility will be required to maintain a temperature gauge on a continuous basis and record temperature on an hourly basis. The exhaust temperature will be at least 556°F (except during start-up and shutdowns).

Therefore, continuous monitoring and periodic source testing will ensure compliance with this subpart.

40 CFR PART 72 – ACID RAIN PROVISIONS

The PDWP facility is subject to the requirements of the federal Acid Rain program. The program is similar in concept to RECLAIM in that facilities are required to cover SO2 emissions with SO2 allowances; analogous to NOx RTCs. SO_2 allowances are however, not required in any year when the unit emits less than 1,000 lbs of SO_2. Facilities with insufficient allowances are required to purchase SO_2 credits on the open market. Appropriate conditions are in Appendix B of the Title V permit. PDWP is expected to comply with this regulation.

REGULATION XXX – TITLE V

The existing PDWP facility has a Title V permit. Per Rule 3000(b)(28), the addition of a new unit will result in a Significant Permit Revision and a public notice in accordance with Rule 3006(a) will be required before any permit action. The notice will be sent out along with the Rule 212(g) notice discussed under the Rule 212 section. EPA is afforded the opportunity to review and comment on the project within a 45-day review period.

RECOMMENDATION(S)

It is recommended that a Facility Permit to Construct be issued following the 30 day school notice and public comment period, and the 45 day EPA review period. The permit will be subject to the following conditions.

PERMIT CONDITIONS

FACILITY PERMIT CONDITIONS

F52.1 The facility is subject to the applicable requirements of the following rules or regulations:

The facility shall submit a detailed retirement plan for the permanent shutdown of Boiler B-3 (Device 15), describing in detail the steps and schedule that will be taken to render Boiler B-3 inoperable.

The retirement plan must be submitted to AQMD within 60 days of permit issuance. AQMD shall notify PDWP whether the plan is approvable. If AQMD notifies PDWP that the plan is not approvable, PDWP shall submit a revised plan addressing AQMD's concerns within 30 days.

PDWP shall not commence any construction of equipment for the repower project before the retirement plan for permanent shut down of Boiler B-3 is approved in writing by the AQMD.

PDWP shall provide AQMD with a notarized statement that Boiler B-3 is permanently shut down and that any re-start or operation of the unit shall require a new Permit to Construct and be subject to all requirements of nonattainment new source review and the prevention of significant deterioration program.

The notarized statement shall be submitted within 30 days following the permanent shutdown of Boiler B-3.

PDWP shall notify AQMD 30 days prior to the implementation of the approved retirement plan for permanent shut down of Boiler B-3.

PDWP shall cease operation of Boiler B-3 (Device 15) within 90 calendar days of the first fire of turbine GT-5(A).
[RULE 1304(a)(2)]

DEVICE CONDITIONS

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

CONTAMINANT	EMISSIONS LIMIT
CO	LESS THAN OR EQUAL TO 7,554 LBS IN ANY ONE MONTH
PM10	LESS THAN OR EQUAL TO 3,720 LBS IN ANY ONE MONTH
VOC	LESS THAN OR EQUAL TO 1,760 LBS IN ANY ONE MONTH
SOx	LESS THAN OR EQUAL TO 616 LBS IN ANY ONE MONTH

The above limits apply after the equipment is commissioned.

The operator shall calculate the monthly emission limit(s) by using calendar monthly fuel use data and the following emission factors: VOC: 4.08 lbs/mmscf, PM10: 8.63 lbs/mmscf, SOx: 1.43 lbs/mmscf.

The operator shall calculate the emission limit(s) 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 factors: normal operation: 17.53 lbs/mmscf.
[Rule 1303(b)(2) – Offset]

A99.12 The 114.73 LBS/MMCF NOx emission limit(s) shall only apply during the interim reporting period during initial turbine commissioning to report RECLAIM emissions.
[Rule 2012]

A99.13 The 19.35 LBS/MMCF NOx emission limit(s) shall only apply during the interim reporting period after initial turbine commissioning to report RECLAIM emissions.
[Rule 2012]

A99.10 The 2.0 PPM NOx emission limit(s) shall not apply during turbine commissioning, start-up, shutdown, Water Injection and Intercooler Tuning (WIIT), and Ammonia Injection Grid Tuning (AIGT) periods. Start-up time shall not exceed 120 minutes for each start-up. Shutdown periods shall not exceed 60 minutes for each shutdown. The turbine shall be limited to a maximum of 5 start-ups per day, 155 start-ups per month, and 750 start-ups per year.

For the purposes of this condition, the beginning of start-up occurs at initial fire in the combustor of the combustion turbine through the full operation of the steam turbine generator. If during start-up, the process is aborted the process will count as one start-up.

For the purposes of this condition, shutdown is defined as the period of time from initiation of the shutdown sequence to cessation of firing.

For the purposes of this condition, WIIT shall be defined as the tuning of the gas turbine water injection and intercooler system. WIIT shall not exceed 12 hours. The operator shall limit the duration of WIIT to no more than 12 hours in any one month and 24 hours in any one year.

For the purposes of this condition, AIGT shall be defined as optimizing and re-balancing of the NH3 grid or catalyst modules, and the retuning of the turbine control systems. AIGT shall not exceed 10 hours. The operator shall limit the duration of AIGT to no more than 10 hours in any one year.

The commissioning period shall not exceed 204 hours.
[Rule 2005]

A99.11 The 2.0 PPM CO emission limit(s) shall not apply during turbine commissioning, start-up, shutdown, Water Injection and Intercooler Tuning (WIIT), and Ammonia Injection Grid Tuning (AIGT) periods. Start-up time shall not exceed 120 minutes for each start-up. Shutdown periods shall not exceed 60 minutes for each shutdown. The turbine shall be limited to a maximum of 5 start-ups per day, 155 start-ups per month, and 750 start-ups per year.

For the purposes of this condition, the beginning of start-up occurs at initial fire in the combustor of the combustion turbine through the full operation of the steam turbine generator. If during start-up, the process is aborted the process will count as one start-up.

For the purposes of this condition, shutdown is defined as the period of time from initiation of the shutdown sequence to cessation of firing.

For the purposes of this condition, WIIT shall be defined as the tuning of the gas turbine water injection and intercooler system. WIIT shall not exceed 12 hours. The operator shall limit the duration of WIIT to no more than 12 hours in any one month and 24 hours in any one year.

For the purposes of this condition, AIGT shall be defined as optimizing and re-balancing of the NH3 grid or catalyst modules, and the retuning of the turbine control systems. AIGT shall not exceed 10 hours. The operator shall limit the duration of AIGT to no more than 10 hours in any one year.

The commissioning period shall not exceed 204 hours.
[Rule 1703(a)(2) – PSD BACT]

A195.8 The 2.0 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 2005]

A195.9 The 2.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1703(a)(2) – PSD BACT]

A195.10 The 2.0 PPMV VOC emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1303(a) – BACT]

A195.11 The 5.0 ppmv NH3 emission limit(s) is averaged over 60 minutes at 15% O2, dry basis.

The operator shall calculate and continuously record the NH3 slip concentration using the following: NH3 (ppmv) = [a–b*c/1EE+06]*1EE+06/b, where: a = NH3 injection rate (lbs/hr)/17(lb/lb-mol), b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol), c = change in measured NOx across the SCR (ppmvd at 15% O2).

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.

The NOx analyzer shall be installed and operated within 90 days of initial start-up.

The operator shall use the above described method 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 without corroborative data using an approved reference method for the determination of ammonia.
[Rule 1303(a)(1) – BACT]

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

A433.3 The operator shall comply at all times with the 2.0 ppm 1-hour BACT limit for NOx, except as defined in condition A99.10 and for the following scenarios:

Operating Scenario	Maximum Limit	Operational Limit
Start-up	31.69 lb	The mass emission limit shall be determined for start-up using CEMS minute by minute emission data. It shall be calculated to 120 minutes from the commencement of initial fire in the combustor
Shutdown	11.92 lb	The mass emission limit shall be

		determined for shutdown using CEMS minute by minute emission data. It shall be calculated to 60 minutes counted back from the cessation of firing

Records of minute by minute start-up and shutdown data shall be maintained and made available to the Executive Officer upon request.
[Rule 2005]

A433.4 The operator shall comply at all times with the 2.0 ppm 1-hour BACT limit for CO, except as defined in condition A99.11 and for the following scenarios:

Operating Scenario	Maximum Limit	Operational Limit
Start-up	33.26 lb	The mass emission limit shall be determined for start-up using CEMS minute by minute emission data. It shall be calculated to 120 minutes from the commencement of initial fire in the combustor
Shutdown	9.99 lb	The mass emission limit shall be determined for shutdown using CEMS minute by minute emission data. It shall be calculated to 60 minutes counted back from the cessation of firing

Records of minute by minute start-up and shutdown data shall be maintained and made available to the Executive Officer upon request.
[Rule 1703(b)(1) - PSD BACT]

D12.9 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust 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 600°F and 900°F.
[Rule 2005]

D12.12 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of 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 12 months.

The differential pressure shall less than 10 inches of water column.
[Rule 2005]

D12.11 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 12 months.

The ammonia injection rate shall be between 68 and 131 lbs/hr.
[Rule 2005]

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

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
SOX emissions	AQMD Laboratory Method 307-91	Not applicable	Fuel Sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	District Method 201A	Approved Averaging Time	Outlet of the SCR serving this equipment
PM2.5 emissions	Approved District Method	Approved Averaging Time	Outlet of the SCR serving this equipment
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted after AQMD approval of the source test protocol, but no later than 180 days after initial start-up. 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 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 AQMD approved 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 AQMD 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 natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined by CARB and AQMD, may be the following:

a) Triplicate stack gas samples are extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute,

b) Pressurization of the Summa canisters is done with zero gas analyzed/certified to containing less than 0.05 ppmv total hydrocarbons as carbon, and

c) Analysis of Summa canisters is per unmodified EPA Method TO-12 (with preconcentration) or the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmvC or less and reported to two significant figures, and

d) The temperature of the Summa canisters when extracting samples for analysis is not to be below 70 degrees Fahrenheit.

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than unmodified AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval, except for the determination of compliance with the BACT level of 2.0 ppmv VOC calculated as carbon set by CARB for natural gas fired turbines. The test results shall be reported with two significant digits.

The test shall be conducted when this equipment is operating at loads of 100, 75 and 50 percent of maximum load for NOx, CO, VOC, and ammonia tests. The PM10 and PM2.5 tests shall be conducted when this equipment is operating at 100 percent of maximum load.
[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 2005, Rule 1703(a)(2) – PSD BACT]

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

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location

NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

The test shall be conducted and the results submitted to the District within 45 days after the test date. The AQMD shall be notified of the date and time of the test at least 7 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 CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, 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 BACT concentration limit.

If the turbine is not in operation during one quarter, then no testing is required during that quarter. [Rule 1303(a)(1) – BACT]

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

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
SOX emissions	AQMD Laboratory Method 307-91	Not applicable	Fuel Sample
VOC emissions	District Method 25.3	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	District Method 201A	Approved Averaging Time	Outlet of the SCR serving this equipment
PM2.5 emissions	District Approved Method	Approved Averaging Time	Outlet of the SCR serving this equipment

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

The test shall be conducted and the results submitted to the District within 60 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 natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT as determined by CARB and AQMD, may be the following:

a) Triplicate stack gas samples are extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute,

b) Pressurization of the Summa canisters is done with zero gas analyzed/certified to containing less than 0.05 ppmv total hydrocarbons as carbon, and

c) Analysis of Summa canisters is per unmodified EPA Method TO-12 (with preconcentration) or the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmvC or less and reported to two significant figures, and

d) The temperature of the Summa canisters when extracting samples for analysis is not to be below 70 degrees Fahrenheit.

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than unmodified AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval, except for the determination of compliance with the BACT level of 2.0 ppmv VOC calculated as carbon set by CARB for natural gas fired turbines. The test results shall be reported with two significant digits.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emission limit.
[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 1703(a)(2) –PSD BACT]

D82.4 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 will 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% - %O2 d)][(Qg * HHV)/106], where

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

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

Fd = 8710 dscf/MMBTU natural gas

$\%O_2$ d = Hourly ave. % 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(a)(2) – PSD BACT, Rule 218]

D82.5 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 provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3).
[Rule 2005, Rule 2012, Rule 1703(a)(2) – PSD BACT]

E179.3 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 hour.

Condition no. D12.9
Condition no. D12.11
[Rule 2005]

E179.5 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. D12.12
[Rule 2005]

E193.2 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 final Environmental Impact Report (EIR), State Clearing House #2011091056.
[CEQA]

E193.4 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

The operator shall record the total net power generated in a calendar month in megawatt-hours.

The operator shall calculate and record greenhouse gas emissions of each calendar month using the following formula:

GHG = 59.187 * FF

Where, GHG is the greenhouse gas emissions in tons of CO2E and FF is the monthly fuel usage in millions standard cubic feet.

The GHG emissions from this equipment shall not exceed 282,602 tons per year. The average GHG emissions shall not exceed 1084 pounds per net megawatt-hours. The operator shall calculate and record the GHG emissions in tons per year and pounds per net megawatt-hours on a 12 month rolling average with a new monthly period starting at the beginning of each month.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition. The records shall be made available to AQMD upon request.
[Rule 1714]

H23.5 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart
NOx	40CFR60, SUBPART	KKKK
SOX	40CFR60, SUBPART	KKKK

[40CFR 60 SUBPART KKKK]

I297.2 This equipment shall not be operated unless the facility holds 64,132 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. RTCs held to satisfy this condition may be transferred only after one year from the initial start of operation. If the hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other condition(s) stated in this permit.
[Rule 2005]

K40.3 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 (lb/hr), and lb/MM cubic feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF and lbs/MMBtu.

All exhaust flow rate 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, fuel flow rate (CFH), heating content of the fuel, the flue gas temperature, and the generator power output (MW) under which the test was conducted.
[Rule 1303(a)(1) – BACT, Rule 1303(b)(2) – Offset, Rule 1703(a)(2) - PSD BACT, Rule 2005]

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]

South Coast
Air Quality Management District
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(909) 396-2000 · www.aqmd.gov

NOTICE OF INTENT TO ISSUE PERMIT
PURSUANT TO SCAQMD RULES 212, 1714, AND 3006

This notice is to inform you that the South Coast Air Quality Management District (SCAQMD) has received and reviewed permit applications for the Pasadena City, Department or Water & Power (PDWP) for the proposed replacement of an existing, older and less efficient electric generating utility boiler with a new and more efficient combined cycle gas turbine and associated air pollution control equipment at the Glenarm Power Plant. SCAQMD has reviewed these applications and after a careful review and detailed evaluation of the project it has been determined that the project complies with all applicable federal, state, and local air quality rules and regulations. Therefore, SCAQMD intends to issue a Title V permit at the end of the 30-day public and 45-day U.S. Environmental Protection Agency review and comment period and after all pertinent comments have been considered and all other requirements have been complied with.

The SCAQMD is the air pollution control agency for the four county-region including Orange County and parts of Los Angeles, Riverside and San Bernardino counties. Anyone wishing to install or modify equipment that could control or be a source of air pollution within this region must first obtain a permit from the SCAQMD. Under certain circumstances, before a permit is granted, a public notice, such as this, is prepared by the SCAQMD. For this project, public notification is required in accordance with SCAQMD Rule 212 (c)(1), Rule212 (c)(2), and Rule 212(g) because the project is located within 1,000 feet from Blair High School located at 1201 South Marengo Avenue, Pasadena, CA 91106 and the emissions from the gas turbine exceed the public notice thresholds for this rule. Public notification is also required by SCAQMD Rule 3006(a) and Rule 1714(e) because there will be a significant revision to the facility's existing air quality Title V permit and the project is subject to a Prevention of Significant Deterioration (PSD) Permit due to its greenhouse gas emissions.

The SCAQMD has evaluated the permit applications listed below for the following facility and determined that it meets or will meet all applicable federal, state, and SCAQMD rules and regulations as described below:

FACILITY: Pasadena City, Department of Water & Power
72 E Glenarm St.
Pasadena, CA 91105
Facility ID#: 800168

CONTACT: Mr. Dan Angeles, P.E., Principal Engineer
Pasadena City, Department of Water & Power
85 E State Street
Pasadena, CA 91105

SCAQMD APPLICATION NUMBERS

Application Number	Equipment Description
538115	GE LM6000 PG SPRINT Combined Cycle Gas Turbine Generator
538120	Air Pollution Control Equipment, SCR and CO Oxidation Catalyst for GE Turbine
538118	Title V Significant Permit Revision Application for the GE LM6000 PG SPRINT
538672	Rolls Royce (RR) Trent 60 WLE Combined Cycle Gas Turbine Generator
538673	Air Pollution Control Equipment, SCR and CO Oxidation Catalyst for RR Turbine
538671	Title V Significant Permit Revision Application for the RR Trent 60 WLE

PROJECT DESCRIPTION

The proposed project is to replace the existing 71 MW electric utility boiler generator Unit B-3 that is less efficient, and has been in operation since 1955 with a new and more efficient combined cycle gas turbine generating system. **The new generating system will consist of either one natural gas fired General Electric (GE) LM600 PG SPRINT combined cycle turbine or one natural gas fired Rolls Royce (RR) Trent WLE combined cycle gas turbine. PDWP has not made a selection on the model of gas turbine that will be installed at the facility, so applications were submitted to reflect each option.** Once PDWP has a made a decision on which system they will be installing, the applications for the other system will be cancelled. The combined generating capacity of the new GE system will be 70.8 MW and the capacity of the new RR system will be 70.6 MW. Both systems will be equipped with state of the art Best Available Control Technology (BACT), which consists of catalysts (selective catalytic reduction and oxidation catalyst). Other auxiliary equipment includes a cooling tower, which is exempt from SCAQMD permitting in accordance with Rule 219.

PROJECTED EMISSIONS

During normal operation, the total potential maximum emissions of criteria pollutants from the operation of the new power generating system are not expected to exceed the emission levels in the tables below. The emission levels listed below are only from the new equipment and do not include any emission reductions associated with the removal of the existing boiler from service.

ROLLS ROYCE (RR) COMBINED CYCLE GAS TURBINE MAXIMUM EMISSIONS

Pollutant	Maximum Potential Emissions (tons)		
	Daily	Monthly	Annual
Nitrogen Oxides (NOx)	0.14	4.17	30
Carbon Monoxide (CO)	0.13	3.78	25
Volatile Organic Compounds (VOC)	0.03	0.88	8
Particulate Matter (diameter less than 10 microns, PM_{10}, and diameter less than 2.5 microns, $PM_{2.5}$)	0.06	1.86	22
Sulfur Oxides (SOx)	0.01	0.31	4
Ammonia (NH3)	0.05	1.46	17
Carbon Dioxide equivalent (CO2E)	774	23,550	282,602

GENERAL ELECTRIC (GE) COMBINED CYCLE GAS TURBINE MAXIMUM EMISSIONS

Pollutant	Maximum Potential Emissions (tons)		
	Daily	Monthly	Annual
Nitrogen Oxides (NOx)	0.13	3.87	28
Carbon Monoxide (CO)	0.10	2.94	20
Volatile Organic Compounds (VOC)	0.02	0.72	7
Particulate Matter (diameter less than 10 microns, PM_{10}, and diameter less than 2.5 microns, $PM_{2.5}$)	0.05	1.51	18
Sulfur Oxides (SOx)	0.01	0.29	3
Ammonia (NH3)	0.05	1.40	16
Carbon Dioxide equivalent (CO2E)	768	23,375	280,502

The proposed project will not result in an increase in the generating capacity since the total electrical generating capacity of the new power generating system is about the same as the electrical generating capacity it replaces. SCAQMD Rule 1304(a)(2) provides an offset exemption for electric utility boiler replacement projects such as this one. Therefore, the repower project does not have to provide emission offset for VOC, PM10, and SOx; however, the SCAQMD still provides the required emission offsets from SCAQMD's internal offset bank. Also, the South Coast Air Basin meets and is in attainment with the ambient air quality standards for CO, so no CO offsets are required. All of the NOx emissions from this facility have to be offset with emission credits that PDWP either holds or purchases in the form of Regional Clean Air Incentives Market (RECLAIM) trading credits (RTCs) available in the market. The NOx RTCs are required to be provided by PDWP prior to the repower project commencing operation in accordance with SCAQMD RECLAIM Rule 2005. In addition, the facility's total $PM_{2.5}$ emissions will be less than 100 tons per year.

As a result of the burning of natural gas in the gas turbine, emissions from the proposed project also contains some pollutants that are considered toxic under SCAQMD Rule 1401 – New Source Review of Toxic Air Contaminants. Therefore, a health risk assessment was performed for this project. The health risk assessment uses some health protective assumptions in estimating actual risk to an individual person. The evaluation shows that the Maximum Individual Cancer Risk (MICR) increase from the project is less than one-in-a-million without accounting for the emission reductions from replacing the old boiler. Also, acute and chronic hazard indices (HIA and HIC, respectively), which measure non-cancer health impacts, are less than the threshold of one. These levels of estimated risk are below the threshold limits of SCAQMD Rule 1401 (d) established for new or modified sources. The maximum health risk assessment results are shown in the tables below.

ROLLS ROYCE (RR) GAS TURBINE HEALTH RISK ASSESSMENT RESULTS

Equipment	MICR, Resident	MICR, Worker	Chronic Hazard Index	Acute Hazard Index
Gas Turbine	0.05 in a million	0.01 in a million	0.001	0.003
Rule 1401 Limit	1 without BACT for Toxics (T-BACT) 10 with T-BACT		1.0	

GENERAL ELECTRIC (GE) GAS TURBINE HEALTH RISK ASSESSMENT RESULTS

Equipment	MICR, Resident	MICR, Worker	Chronic Hazard Index	Acute Hazard Index
Gas Turbine	0.07 in a million	0.01 in a million	0.002	0.003
Rule 1401 Limit	1 without BACT for Toxics (T-BACT) 10 with T-BACT		1.0	

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) FOR CRITERIA POLLUTANTS

The South Coast Air Basin is in attainment with the national ambient air quality standards for Nitrogen Dioxide (NO_2), Sulfur Dioxide (SO_2), and Carbon Monoxide (CO); therefore, the NO_2, SO_2, and CO emissions from the project are subject to SCAQMD's PSD Regulation XVII.

The PDWP Glenarm Power Plant is a major stationary source for NO_2; however, the project increases of NO_2, SO_2, and CO emissions are below the PSD significance thresholds that would require a PSD analysis.

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) FOR GREENHOUSE GASES

The project is subject to preconstruction review for greenhouse gas (GHG) emissions. The Environmental Protection Agency (EPA) has approved SCAQMD Rule 1714 on GHG emissions into the State Implementation Plan and as such approved SCAQMD's implementation of the GHG PSD permitting. As the permitting authority, the GHG emissions from the project were evaluated and determined to be in compliance with the Best Available Control Technology for GHGs and all applicable federal, state, and local air quality requirements. The repower project has been found to comply with SCAQMD Rule 1714 on GHG Emissions.

Based on the result of our detailed analysis and evaluation, the SCAQMD has determined that each proposal complies with all applicable federal, state, and SCAQMD air quality rules and regulations and therefore, SCAQMD intends to issue the Permits to Construct for the equipment described above. However, prior to issuance of a final permit, SCAQMD is providing an opportunity for a 30-day public comment period and an EPA review period. SCAQMD will consider issuance of the final permit only after all pertinent public and EPA comments, if any, have been received and considered.

The facility is a Federal Title IV (Acid Rain) and Title V facility. **Pursuant to SCAQMD Title V Permits Rule 3006 – Public Participation, any person may request a proposed permit hearing on an application for an Initial Title V, a Permit Renewal or significant permit revision by filing with the Executive Officer a complete Hearing Board Request Form (Form 500-G) for a proposed hearing by May 19, 2013.** This form is available on the SCAQMD website at http://www.AQMD.gov/permit/Formspdf/TitleV/AQMDForm500-G.pdf, or alternatively, the form can be made available upon request by contacting Mr. Marcel Saulis at the email and telephone number listed above. On or before the date the request is filed, the person requesting a proposed permit hearing must also send by first class a copy of the request to the facility address and contact person listed above.

The proposed permits and other information are available for public review at the SCAQMD's headquarters in Diamond Bar, and at the Allendale Branch Library, 1130 South Marengo Ave., Pasadena, CA 90220. Additional information including the facility owner's compliance history submitted to the SCAQMD pursuant to Section 42336, or otherwise known to the SCAQMD, based on credible information, is available at the SCAQMD for public review. For more information or to review additional supporting documents, call the SCAQMD's Title V hotline at (909) 396-3013. Written comments should be submitted to Mr. Marcel Saulis (msaulis@aqmd.gov), Engineering and Compliance, South Coast Air Quality Management District, 21865 Copley Drive, Diamond Bar, CA 91765-4178, (909) 396-3093. **Comments must be received by June 4, 2013.** Questions regarding zoning decisions and the process by which the facility has been cited in this location should be directed to the local city or county planning department. Anyone experiencing air quality problems such as dust or odor can telephone in a complaint to the SCAQMD 24 hours a day by calling 1-800-CUT-SMOG (1-800-288-7664).