Permit to Construct

COMPANY NAME
TESORO REFINING AND MARKETING CO
P.O. BOX 817, WILMINGTON, CA 90748-0817

EQUIPMENT LOCATION
2101 E. PACIFIC COAST HIGHWAY
WILMINGTON, CA 90744
Facility ID#: 800436
Facility Type: NOx & SOx RECLAIM (Cycle 1), Title V

1. **EQUIPMENT DESCRIPTION:**

Equipment	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
Process 17: Electric Generation					
System 2: Cogeneration Unit C					S11.3, S31.3
TURBINE, C, STEAM INJECTION, COMBINED CYCLE, REFINERY FUEL GAS/NATURAL GAS, GENERAL ELECTRIC, MODEL NO. PG6581B, 534 MMBTU/HR WITH A/N 484368	D1619	C1625 C1626	NOX: MAJOR SOURCE **; SOX: MAJOR SOURCE **	**CO:** 2000 PPMV (5) [**RULE 407, 4-2-1982]** **CO:** 2 PPMV (4) [**RULE 1703(a)(2)-PSD BACT,10-7-1988**] **NOX (Refinery Gas) :** 2.5 PPMV(4) **[Rule 2005 BACT, 4-20-2001]** **NOX (Nat Gas):** 2.0 PPMV(4) **[Rule 2005 BACT, 4-20-2001]** **NOX:** 74 PPMV (8) [**40CFR 60 Subpart KKKK, 7-6-2006]; NOX (INTERIM): 8.5** lb/MMSCF (1) **[RULE 2012, 12-5-2003, RULE 2012, 1-7-2005]; NOX (COMMIS): 43.6 lb/MMSCF (1) [Rule 2012, 12-5-2003, RULE 2012, 1-7-2005]** **SOX:** 0.06 lb/MMBTU (8) [**40CFR 60 Subpart KKKK, 7-6-2006];** **SOX:** 0.90 lb/MW-hr (8) [**40CFR 60 Subpart KKKK, 7-6-2006];** **SOX** (INTERIM)**:** 34.0 lb/ MMSCF (1) **[RULE 2011, 12-5-2003, RULE 2011, 1-7-2005]** **SOX** (COMMIS)**:** 6.65lb/MMSCF (1) **[RULE 2011, 12-5-2003, RULE 2011, 1-7-**	A63.8, A99.6, A99.7, A99.8, A99.9, A99.10, A99.11,A99.12, A195.9, A195.10, A197.17, A195.18, A195.19, A327.2, B59.7, B61.8, B61.10, D29.9, D29.11, D82.3, D82.4, D90.20, D90.21, E73.4, H23.37, I296.2, K40.3, K67.14

GENERATOR, 42.62 MW INJECTOR, STEAM INJECTION	D1624 D1620			**2005]** **VOC:** 2.0 PPMV (4) [**RULE 1303 (a)(1)-BACT, 5-10-1996**; RULE 1303(a)(1)-BACT, 12-6-2002] **PM:** Rule 475(a)(4) exemption (5) [**RULE 475, 10-8-1976;** RULE 475, 8-7-1978]; **PM:** 0.01 GRAINS/SCF (5) [**RULE 476, 10-8-1976**] **PM:** 11 LBS/HR (5A) [**RULE 476, 10-8-1976**] **PM10:** 0.1 GRAINS/SCF (5) [**RULE 409, 8-7-1981];**	
BURNER, DUCT, REFINERY GAS/NATURAL GAS, 95 MMBTU/HR	D1621	C1625 C1626	NOX: MAJOR SOURCE **; SOX: MAJOR SOURCE **		A63.8, A99.6, A99.7, A99.8, A99.9, A99.10, A99.11,A99.12, A99.17,A195.9, A195.10, A195.17, A195.18, A195.19, A327.2, B59.7, B61.8, B61.10, D29.9, D29.11, D82.3, D82.4, D90.20, 90.21, E73.4, H23.37, I296.2, K40.3, K67.14
BOILER, WASTE HEAT RECOVERY STEAM GENERATOR, UNFIRED	D1622				
TURBINE, STEAM 18.4 MW	D1623				
CO OXIDATION CATALYST, SERVING TURBINE C, WITH 130 CUBIC FEET CATLYST VOLUME, BASF OR EQUIVALENT, HEIGHT: 55.75 FT; WIDTH 10.5 FT;	C1625	D1619 D1621			D12.16, D12.17, E193.6

DEPTH: 0.3 FT; WITH A/N 484369					
SELECTIVE CATALYTIC REDUCTION, SERVING TURBINE C, WITH 472.5 CUBIC FEET CATALYST VOLUME, CORMETECH OR EQUIVALENT, VANADIUM-TITANIUM-TUNSTEN, HEIGHT: 55.75 FT; WIDTH 10.5 FT; DEPTH: 2 FT; WITH A/N 484369 AMMONIA INJECTION	C1626	D1619 D1621 S1627		NH3: 5 PPMV (4) [**RULE 1303 (a)(1)-BACT, 5-10-1996**; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.11, D12.10, D12.11, D12.12, D29.10, E179.3, E179.4, E193.6
STACK, DIAMETER: 10.5 FT (ID); HEIGHT: 120 FT, WITH A/N 484369	S1627	C1626			
COMPRESSORS, C-127, C128, and C-129, FUEL GAS, 3 TOTAL (Existing)	D973				
KNOCKOUT POT, V-1000, FEED GAS COMPRESSION SUCTION A/N 484369	D1640				
KNOCKOUT POT, V-1008, FUEL GAS COMPRESSION DISCHARGE A/N 484369	D1641				
KNOCKOUT POT, V-1012, RECYCLE GAS COMPRESSION SUCTION A/N 484369	D1642				
KNOCKOUT POT, V-1461, FUEL GAS COMPRESSION SUCTION A/N 484369	D1643				
KNOCKOUT POT, V-2409, FUEL GAS A/N 484369	D1644				

* (1) Denotes RECLAIM emission factor (2) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit (4) Denotes BACT emission limit
(5)(5A)(5B) Denotes command and control emission limit (6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit (8)(8A)(8B) Denotes 40 CFR limit(e.g. NSPS, NESHAPS,etc.)
(9) See App B for Emission Limits (10) See Section J for NESHAP/MACT requirements

** Refer to Section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

2. BACKGROUND:

Tesoro Refining and Marketing Company (TSO) purchased this refinery from EQUILON on May 11, 2007. TESORO is proposing this project to reduce RECLAIM NO_X emissions and minimize future RECLAIM Trading Credits (RTC) purchase. Currently, TESORO NO_X RTC holdings for 2009 and 2011 are 533 and 498 tons, respectively. These levels are significantly below the refinery 2007 NO_X emissions of 821 tons. Of this amount, RECLAIM major NO_X sources emitted 777.5 tons. NO_X emissions from the existing two gas turbines totaled 252 tons, representing 32% of NO_X emissions from all RECLAIM major sources at the refinery. Currently, the refinery complies with NO_X allocation by purchasing RTCs from the RECLAIM market. This project will allow TESORO to reduce emissions at the facility rather than purchasing NO_X RTCs. A new gas turbine with lower heat input demands (636 MMBTU/HR with duct firing) will replace the existing two gas turbines (A and B) with total combined heat input rated at 784 MMBTU/HR (HHV) heat input and 30 MW electricity output. The existing gas turbines A&B were retrofitted with Selective Catalytic Reduction System (SCR) in 2004 to control NO_X emissions.

The proposed new gas turbine is a cogeneration system that is more energy efficient than the existing gas turbines as it will use waste heat from the gas turbine exhaust to generate steam and electricity of use within the refinery. The new combustion-turbine generator (CTG) is a GE Frame 6 combustion gas turbine rated at 534 MMBTU/HR (HHV) heat input, and connected to an electric generator to produce 42.62 MW (nominal) electricity output at 63 °F. The turbine will exhaust into a heat recovery steam generator (HRSG) equipped with 95 MMBTU/HR (HHV) of duct burner capacity to produce additional steam. Steam produced in the waste heat boiler in the HRSG will be used to run one back pressure-type steam turbine connected to an electric generator having a nominal electricity output of 18.4 MW. The new cogeneration system is equipped with a selective catalytic reduction system (SCR) to reduce NO_X emissions, and an oxidation catalyst to reduce CO and VOC emissions.

The new cogeneration unit will replace the existing cogeneration units, Turbines A and B. The two existing United Technologies gas turbines A and B have a combined power output of 60 MW. The AQMD issued permits to construct these turbines in March 1981 (Applications C-34993 and C-34994). At the same time, the State of California Energy Resources Conservation and Development Commission (Currently – the program is administered by the California Energy Commission (CEC)) also granted a small power plant exemption pursuant to Public Resources Code Section 25541. This regulation provides that the Commission may exempt a thermal power plant with a generating capacity not exceeding 100 MW from the normal siting process. In March 2003, AQMD issue a permit to construct for a voluntary installation of an SCR system on each of the Turbines A and B. The new cogeneration facility will have a combined power generation capacity of 61.12 MW (42.62 MW from gas turbine and 18.4 MW from steam turbine) which is a net increase of 1.12 MW from the existing rated capacity of the existing turbines. Since this replacement results in less than 50 MW increase in permitted capacity, it is excluded from the California Energy Commission's jurisdiction. CEC staff has determined that Tesoro can continue to rely on the existing small power plant exemption issued to Texaco in March 1981.

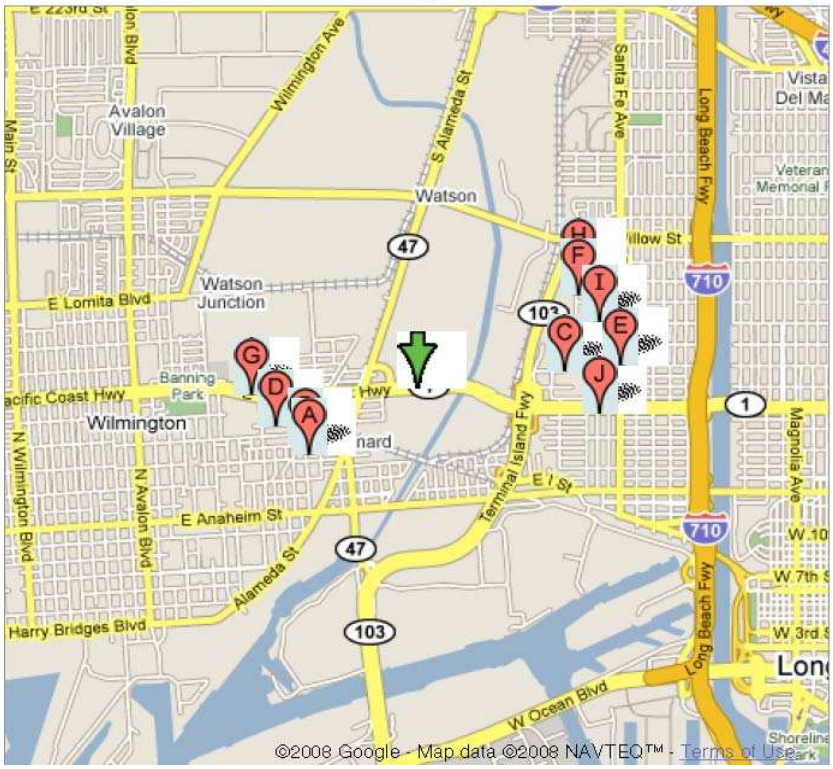
Table 1 – Applications for Permit to Construct Submitted to AQMD

Application Number	Equipment Description
484368	Gas Turbine C
484369	SCR/Oxidation Catalyst for Turbine C

Table 2 – Summary of Permit Processing Fees

A/N	Submittal Date	Deemed Complete	Equipment	Schedule	Processing Fee	XPP Fee	Total Fee
484368	6/27/08		Gas Turbine C	G	$13,884.29	$6,942.15	$20,826.44
484369	6/27/08		SCR/Oxidation Catalyst for Turbine C	C	$2,949.92	$1,474.96	$4,424.88
514662	9/10/10		TV/RECLAIM Administrative Application	Rule 301 (k)(5)	$1,723.07		$1,723.07
						Total Permit Processing Fee	**$26,974.39**

Nearby Schools: There is no school within 1000 feet of the refinery. The nearest school is 0.7 miles from the refinery. The closest 20 public and private schools and related education facilities are listed on this page and the following page.



A. Wilmington Park Elementary
1419 E Young St, Wilmington, CA
(310) 518-3207 -0.7 mi SW

B. Wilmington Park Erly Edu Center
1140 Mahar Ave, Wilmington, CA
(310) 830-8404 -0.7 mi SW

C. American Indian Changing
2120 W Williams St # 1, Long Beach, CA
(562) 388-8118 -0.8 mi E

D. Holy Family School
1122 E Robidoux St, Wilmington, CA
(310) 518-1440 -0.8 mi W

E. Cabrillo (Juan Rodriguez) High School
2001 Santa Fe Ave, Long Beach, CA
(562) 951-7797 -1.2 mi E

F. Hudson
2335 Webster Ave., Long Beach, CA
(562) 595-4120 -1.1 mi NE

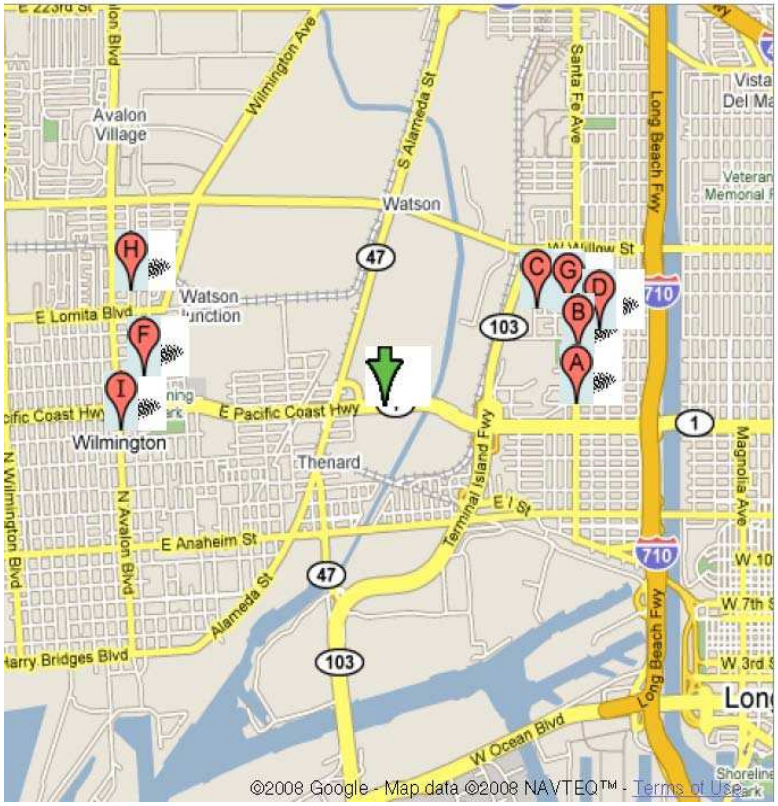
G. Harbor Trucking School
920 E Pacific Coast Hwy, Wilmington, CA
(310) 830-6201 -1 review -0.9 mi W

H. Long Beach Unified School District
2425 Webster Ave, Long Beach, CA
(562) 997-7550 -1.1 mi NE

I. Long Beach Child Development
2209 Seabright Ave, Long Beach, CA
(562) 595-5366 -1.1 mi E

J. Long Beach Japanese School Inc
1766 Seabright Ave, Long Beach, CA
(562) 435-0438 -1.0 mi E

Map of Schools Near Refinery (continue)



A. Long Beach Job Corps
1903 Santa Fe Ave, Long Beach, CA
(562) 983-1777 -1.2 mi E

B. West Child Development Center 2125 Santa Fe Ave, Long Beach, CA
(562) 436-5166 -1.2 mi E

C. Hudson Child Development Center
2335 Webster Ave, Long Beach, CA
(562) 424-1386 -1.1 mi NE

D. James A Garfield Elem School
2240 Baltic Ave, Long Beach, CA
(562) 424-8167 -1.4 mi E

E. Dynamic Educational
1903 Santa Fe Ave, Long Beach, CA
(562) 495-0124 -1.2 mi E

F. Phineas Banning Senior High School
1527 Lakme Ave, Wilmington, CA
(310) 830-5515 -1.5 mi W

G. St. Lucy School
2320 Cota Ave, Long Beach, CA
(562) 424-9062 -1.2 mi NE

H. Broad Avenue Elementary School
24815 Broad Ave, Wilmington, CA
(310) 835-6012 -1.7 mi NW

I. Aegis Medical Systems Inc
1322 N Avalon Blvd, Wilmington, CA
(310) 513-1300 -1.6 mi W

J. Garfield Head Start
2240 Baltic Ave, Long Beach, CA (562) 492-9259 -1.4 mi E

3. COMPLIANCE RECORD REVIEW

The facility's compliance history for the past 2 years indicates one NOV (P52842) is still pending (see Attachment 1). P52842 was issued to Tesoro on 4-27-10 for multiple violations of Rule 1189(c)(3)on the HGU #2 unit. An emergency hearing was conducted at the AQMD Hearing Board on 4-28-10 and the facility was denied a variance. Tesoro is expected to be placed under an abatement order by the District to have this compliance issue resolved. Note that the HGU-2 unit has been shutdown since 4-6-10 and is not expected to operate until a variance or order of abatement is granted. The details of this NOV are in Attachment 1.

4. PROCESS DESCRIPTION

Gas Turbine "C" With Heat Recovery Steam Generator (HRSG) (A/N 484368)

Tesoro is proposing to install a GE frame 6 gas turbine, a heat recovery steam generator (HRSG) with supplemental duct firing, and a steam turbine generator. The gas turbine is nominally rated at 42.62 MW with a steam turbine generator nominally rated at 18.4 MW. The gas turbine will be fired with refinery gas or combination of refinery and natural gas. The duct burner is rated at 95 MMBTU/hour HHV and will be fired with refinery gas or combination of refinery and natural gas.

The turbine will be used to generate electric power for the refinery and will be operated mainly under a base load operating scenario (continuous operation). Combustion air to the gas turbine will be supplied to the gas turbine through an inlet air filter, inlet air evaporative cooling system, and associated inlet air ductwork. Downstream of the air cooling section, the air will be compressed in a compressor prior to being fed to the combustor. The compressed air will be mixed with fuel in the combustor and the mixture will be ignited. The high-temperature, high-pressure gas produced in the combustion section will be expanded through the turbine blades, driving the turbine, the electric generator, and the turbine compressor. The exhaust gas from the turbine will pass through insulated ductwork to a horizontal HRSG. A duct burner will be placed in the HRSG to provide additional steam generation capacity during peak periods. The steam generated in the waste heat boiler at the HRSG will be used to drive a steam turbine generator nominally rated at 18.4 MW. Table 3 below lists technical specification for the CTG.

Table 3 – Combustion Gas Turbine/HRSG Specification

Manufacturer	General Electric (GE)
Model	PG6581B
Fuel Type	Refinery Fuel Gas/Natural Gas
Fuel Operating Temperature	149 °F – 176 °F
CTG Heat Input (HHV) @ Full Load	534 MMBTU/hr (36 °F ambient) 470 MMBTU/hr (103 °F ambient)
Duct Burner Heat Input (HHV)	95 MMBTU/hr
Exhaust Flow @ Full Load	237,060 SCFM w/o duct firing @ 36 °F ambient 241,620 SCFM w/ duct firing @ 36 °F ambient

	216,977 SCFM w/o duct firing @ 103 °F ambient 221,142 SCFM w/ duct firing @ 103 °F
CTG Exhaust Gas Temperature @ Full Load	1,014 °F (63 °F ambient)
HRSG Exhaust Temperature @ Full Load	382 °F w/o duct firing @ 36 °F ambient 346 °F w/ duct firing @ 36 °F ambient
CTG Gross Power Output	42.62 MW – 63 °F ambient
Steam Turbine Power Output	18.4 MW
CTG Gross Heat Rate (HHV)	11,572 MMBTU, HHV/kWh – 63 °F ambient
Control – Steam Injection	0.85 – 1.44 lb steam/lb fuel
CO emissions	40 PPMDV@ 15%O2
NOx emissions	42 PPMDV@ 15% O2

Note: Emissions calculation will be based on a worst-case operating scenario depending on the ambient temperature, the steam injection rates, and electrical load generated.

Turbine Operating Conditions

The three ambient operating conditions for which turbine performance is calculated are the extreme cold, annual average, and extreme hot ambient temperatures. These temperatures range from a low of 36 °F to a maximum of 103 °F. The maximum turbine scenario from an emissions standpoint occurs during the condition of maximum fuel consumption, which is duct firing during extreme cold ambient temperature. The turbine operating parameters associated with each of the three conditions are listed in Table 4 below.

Table 4 – Turbine Operating Conditions

Operating Condition	Low T		Annual T		High T	
Ambient Temperature, °F	36		63		103	
Inlet Humidity, %	74		65		25	
Ambient Pressure, PSIA	14.7		14.7		14.7	
Duct Firing	Off	On	Off	On	Off	On
Fuel Consumption, MMBTU/hr	534.0	629.0	508.4	603.4	469.6	564.6
Stack Gas Flow Rate, DSCFM	237,060	241,620	228,527	233,428	216,977	221,142
Exhaust Temperature, °F	382	346	379	342	375	338

Air Pollution Control (APC) Equipment for Gas Turbine (A/N484369)

The new CTG/HRSG will utilize two primary means for the reduction of NO_X emissions. The CTG will be equipped with steam injection to reduce the NO_X concentration prior to entry to the oxidation catalyst and SCR control systems. On the back end, an SCR catalyst with ammonia injection will be used down stream for further reduction of NO_X emissions.

Oxidation Catalyst The oxidation catalyst will be used to control the CO and VOC emissions from the gas turbine. The oxidation catalyst will be located in the HRSG upstream of the ammonia injection grid where the flue gas temperature will be approximately in the range of 800- 1250 °F during normal operation. The maximum pressure drop across the catalyst will be approximately 1.3 inch H_2O. The catalyst life is approximately 25,000 fired hours. Table 5 lists oxidation catalyst specifications.

Table 5 – Oxidation Catalyst Specification

Manufacturer	BASF or Equivalent
Catalyst Description	Stainless steel substrate, alumina washcoated, impregnated with platinum group metals
Catalyst Dimension	10 ft 6 inch wide by 55 ft 9 inch high
Catalyst Thickness	3.6 inch
Catalyst Volume	130 cubic feet
Space Velocity	132,000 hr^{-1}
Maximum Pressure Drop	1.5 inch H_2O
Maximum Outlet CO	2 ppmdv (1-hours average) at 15% O_2
Maximum Outlet VOC (as methane)	2 ppmdv (1-hours average) at 15% O_2
Minimum Operating Temperature	500 °F
Maximum Operating Temperature	1250 °F

Ammonia Injection Grid/SCR Catalyst The SCR catalyst will be used to control the NO_X emissions from the gas turbine. The catalyst will be located in the HRSG downstream of the oxidation catalyst and ammonia injection grid, where the flue gas temperature will be in the range of approximately 650 – 750 °F during normal operation. The maximum pressure drop across the SCR system will be approximately 2.8 inch H_2O. Catalyst life is 25,000 fired hours. Table 6 below lists CTG/HRSG SCR specifications.

Table 6 – SCR Specification

Manufacturer	Cormetech or Equivalent
Catalyst Description	Homogenous Honeycomb with Ti-V-W
Catalyst Dimension	10 ft 6 inch wide by 55 ft 9 inch high
Catalyst Thickness	2 feet
Catalyst Volume	472.5 cubic feet
Space Velocity	132,000 hr^{-1}
Maximum Pressure Drop	2.8 inch H_2O
Maximum Ammonia Injection Rate	243 lb/hr of 19% aqueous ammonia @63°F
Maximum Ammonia Slip	5 ppmv @ 15% O_2 (1-hour average)
Maximum Outlet NO_X	2.5 ppmv @ 15% O_2 (1-hour average)
Minimum Operating Temperature	510 °F
Maximum Operating Temperature	780 °F

5. EMISSIONS

Operation Scenarios

There are four possible modes of operation for the turbine emissions from the four operating modes are potentially different and hence are evaluated independently. Table 7 provides more detail on the four operating modes for the CTG/HRSG

Table 7 – Operating Modes for CTG/HRSG

Operating Mode	Description
Commissioning	The process of fine-tuning the CTG/HRSG. Facility follows a systematic approach to optimize performance of the CTG/HRSG, and associated control equipment. Emissions are expected to be greater during commissioning than during normal operation for some pollutants. This mode effects only the initial months and year of operation
Start Up	Up to a maximum of two hours per day could include a start up sequence for the CTG. Start-ups emissions are high because catalyst bed has not reached optimal temperature to begin the chemical reactions needed to reduce NOx and CO emissions. Depending on the duration, start-ups are subdivided in to cold, warm and hot. A cold start-up comes after the plant has been shutdown for at least 48 hours. The start-up considers hot if the shutdown came within 8 hours of previous. All start-ups that fall between 8 and 48 hours are considered warm.
Shutdown	Up to a maximum of one hour per day could include in a shutdown sequence for the CTG. Shutdown occurs at the initiation of the turbine shutdown sequence and ends with the cessation of fuel flow and firing. Typically the shutdown process will emit lesser amount of pollutants than during the startup process, but may emit slightly greater NO_X than during normal operation ammonia injection into SCR ceases during part of this operation.
Normal Operation	Normal operation occurs after the CTG and the control equipment work optimally at their designated levels. Emissions may vary due to ambient conditions.

Gas Turbine "C"/HRSG Emissions

Several factors, most importantly, the mode of operation and the ambient meteorological conditions affect emissions from gas turbines. The three basic operating modes from an emissions standpoint are start up, shutdown, and base load (normal) operation. Base load operation will assume to be at 100% load. Cold start up will take approximately 2 hours to achieve full control of NO_X, CO and VOC emissions. Warm and hot start up will take approximately 1.5 and 1 hour, respectively.

Emission Rates – Normal Operation at Full Load

For the purpose of making conservative emission estimates, it will be assumed that both turbine and duct burner are always operating at 100% load at the lowest ambient temperature of 36 °F.

Data:

Maximum Gas Turbine Heat Input = 534 MMBTU/hr HHV @ 36 °F
Maximum Gas Turbine Heat Input = 470 MMBTU/hr HHV @ 103 °F
Maximum Duct Burner Heat Input = 88 MMBTU/hr HHV
Fuel Sulfur Content = 40 PPMV over 1 hour period (Total Sulfur as H_2S) Refinery Fuel Gas Heat Content = 1200 BTU/SCF (Heat content for refinery gas ranges from 1200 – 1500 BTU/SCF. For worst case emissions calculation 1200 BTU/SCF is used)

Emission Factors:

The following formula and assumptions are used to calculate the energy-based emission factors:

$$EF\ (lb/MMBTU) = PPMVD \times MW \times (1/SMV)\ \frac{(20.9\%\ O_2 - 0\%\ O_2)}{(20.9\%\ O_2 - 15\%\ O_2)} \times F_D \times 10^{-6}$$

Where,

EF = emission factor
PPMVD = pollutant concentration at concentration corrected to 15 % O_2
SMV = molar volume at 68 °F = 385.3 DSCF/lb-mol
MW = molecular weight of pollutant
F_D = Oxygen Based Dry fuel Factor specific for TESORO LAR refinery gas tested in accordance with RECLAIM Rule 2012 Protocol = 8552 DSCF combustion products/MMBTU

Standard Condition:

Pressure = 29.92 inches Hg (14.7 psia)- Temperature = 68 °F

Emission Rate:

Uncontrolled Emission Rate = Uncontrolled EF (lb/MMBTU) x Heat Input HHV (MMBTU/hr)
Controlled Emission Rate = Controlled EF (lb/MMBTU) X Heat Input HHV (MMBTU/hr)

Assumption:

1. NO_X concentration from CTG prior to steam injection = 85.2 PPMV [a]

NO_X concentration from CTG after steam injection = 42 PPMV @ 15% O_2[a]
NO_X emission from duct burner prior to SCR = .05 lb/MMBTU [a]
NO_X concentration after SCR = 2.5 PPMV @ 15% O_2 (1-hr average) [a]
[a] Manufacturer's data
NO_X concentration after SCR = 2.0 PPMV @ 15% O_2 (24-hr average)

2. PM10 emission is based on manufacturer guarantee which is 0.01 lb/mmbtu [a] in attachment 2 of the evaluation.

However,

Assume < 8 % SO2 to SO3 Conversion and PM10 as ammonium sulfate:

$$\frac{40\ \text{lb-mole Total S as H2S}}{10^6\ \text{lb- mole FG}} \times \frac{\text{lb-mole SO2}}{\text{lb-mole H2S}} \times \frac{64\ \text{lb SO2}}{\text{lb-mole SO2}} \times \frac{\text{lb-mole FG}}{385.3\ \text{SCF FG}} \times \frac{\text{scf FG}}{1200\ \text{BTU}} \times \frac{629\ \text{MMBTU}}{\text{HR}} \times \frac{0.08\ \text{lbSO3}}{\text{lb SO2}} = \frac{0.278\ \text{lb SO3}}{\text{HR}}$$

$$\frac{0.278\ \text{lb SO3}}{\text{Hr}} \times \frac{\text{lb-mole SO3}}{80\ \text{lb SO3}} \times \frac{\text{lb-mole (NH4)2 SO4}}{\text{lb-mole SO3}} \times \frac{132\ \text{lb (NH4)2 SO4}}{\text{lb-mole (NH4)2 SO4}} = 0.46\ \text{lb/hr} \times 24\ \text{hr/day} = 11\ \text{lb/day}$$

0.46 lb/hr/629 mmbtu/hr = 7.3E-4lb/mmbtu+0.010 lb/mmbtu = .0107lb/mmbtu
[a] Manufacturer's data

3. SO_X emission is based on 40 PPMV total sulfur in refinery fuel gas expressed as H_2S averaged over a 1 hour period. One mole of H2S coverts to one mole SO2 (H2S MW = 34 lb/lb-mole, SO2 MW = 64 lb/lb-mole)

4. VOC concentration CTG prior to oxidation catalyst 1.4 PPMVW @ stack O_2 [a] (1.8 PPMVD @ 15% O_2)
   VOC emission from duct burner prior to oxidation catalyst = .01 lb/ MMBTU (manufacturer guarantee).
   VOC concentration after catalyst = 2.0 PPMV @ 15% O_2 (1-hr average) [a]
   Emissions factor for VOC emissions, due to gas combustion, proposed for use in condition A63.8, is calculated below. These are based on the limitation of 2 ppmv @ 15% O2. The limit will be verified through source testing. The calculations make use of the values of F_d-Factor dscf/MMBtu and heating value for refinery gas Btu/scf obtained from plant measurements.

   VOC (lbs/MMscf) For Refinery Gas $= \frac{2 \text{ ppm} \times 16 \text{ lb/lb-mole} \times 20.9\% \times \text{F-Factor} \times \text{HV}}{10^6 \text{ ppm} \times (20.9\%-15\%) \times 385.3 \text{ cf/lb-mole}}$

   $= 2.94\text{E-}7 \times F_d\text{-Factor} \times \text{HV}$ (units of lbs/MMscf)

5. CO concentration CTG prior to oxidation catalyst = 38 PPMVD @ 15% O_2 [a]
   CO emission from duct burner prior to oxidation catalyst = .05 lb/ MMBTU [b]
   CO concentration after catalyst = 2.0 PPMV @ 15% O_2 (1-hr average) [a]
6. Stack Gas Moisture (with duct firing) = 10%
7. Stack Gas Oxygen (with duct firing) = 12% wet, 13.3% dry
8. Normal Operation at full load with duct burner on – worst case 36 °F Ambient

[a] Manufacturer's data [b] AP-42, 7/98, Tables 1.4.1 and 1.4.2

Emissions from gas turbine and duct burner under normal operation are calculated as shown in Appendix B. The worst case emissions occurred during ambient temperature of 36 °F when fuel consumption is at the highest level. Emissions from gas turbine without duct burner firing and gas turbine with duct burner firing are summarized in Table 8

Table 8 – Mass Emission Rates for CTG/HRSG Base Load Operation

Pollutant	Operating Mode	Uncontrolled Emissions (lb/hr)	Controlled Emissions (lb/hr)
NO_X	CTG (36 °F)	81.12	4.83
	CTG + Duct Burner (36 °F)	85.87	5.62
SO_X	CTG (36 °F)	2.23	2.23
	CTG + Duct Burner (36 °F)	2.63	2.63
VOC	CTG (36 °F)	1.21	1.34
	CTG + Duct Burner (36 °F)	2.16	1.57
PM10	CTG (36 °F)	5.30	5.30
	CTG + Duct Burner (36 °F)	6.18	6.25
	With SO2 to $(NH3)_2$ SO4	6.18	6.60
NH_3	CTG (36 °F)	0	3.65
	CTG + Duct Burner (36 °F)	0	3.77
CO	CTG (36 °F)	44.67	2.35
	CTG + Duct Burner (36 °F)	49.42	2.74

CTG/HRSG Emission Rates – Start-Up Emissions:

Start-Up Emissions:

Start-up begins with the turbine's initial firing and continues until the unit meets the emission concentration limits. Depending on the duration, start-ups are subdivided in to cold, warm and hot. A cold start-up comes after the plant has been shutdown for at least 48 hours. The start-up considers hot if the shutdown came within 8 hours of previous. All start-ups that fall between 8 and 48 hours are considered warm. They differ in their technical approach; i.e., in hot start-up, preheating of the steam lines is not necessary. Start-ups procedure depends on steam generator type and unit start-up protocol. The duration for the cold, warm and hot start up for the proposed turbine will not exceed 2 hours, 1.5 hours, and 1 hour, respectively.

During start-up operations, the turbine is assumed to operate at elevated NOx and CO average concentration rates due to the phased-in effectiveness of the SCR reactor and CO oxidation catalysts.

Natural gas is used during startup as it is required by the manufacturer. However, the emissions calculation will assume the refinery gas is used for the purpose of making conservative estimate of gas turbine emissions (highest emission values). Under actual operation, the refinery will operate the turbine as a base load unit with minimum numbers of start-ups and shutdowns expected. However, unforeseen circumstance may occur causing the unit to trip requiring re-start or maintenance. The calculation below represents the worst case scenario: (1) cold start NOX emission rate is use for all start up cases, (2) assuming the turbine is operating at full load during the entire start up period for all other pollutants

Data:

Maximum number of start-ups per day = 3 (1 cold, 1 warm, 1 hot = 4.5 hours)
Maximum number of start-ups per month = 12 (2 cold, 4 warm and 6 hot = 16 hours)
Maximum number of start up per year = 48 (8 cold, 10 warm, 30 hot = 61 hours)
Start up duration: 2 hour cold, 1.5 hour warm, and 1 hour hot

Start-up emissions per event and per hour are calculated as shown in the following page and summarized in Table 9.

Table 9 – CTG/HRSG Start – Up Emissions Summary

	Cold Start-Up 2.0 hour/event		Warm Start-Up 1.5 hours/event		Hot Start-Up 1.0 hour/event		Max Daily lb	Max Monthly lb	Max Yearly lb
	Lb/hr	Lb/event	Lb/hr	Lb/event	Lb/hr	Lb/event			
NOX	92	184	92	138	92	92	414	1,472	5,612
SOX	2.63	5.26	2.63	3.95	2.63	2.63	12	42	160
VOC	12	24	12	18	12	12	54	192	732
PM10	6.60	13.20	6.60	9.90	6.60	6.60	30	106	403
CO	138.5	277	138.5	277	138.5	138.5	623	2,216	8,449

Calculations:

1. Maximum Hourly Cold Start-Up Emissions:

NO_X = (184 lb/event) * (event/2 hours) = 92 lb/hour

SO_X = Emissions are the same as normal operation (2.63 lb/hr).
VOC = (24 lb/event) = 12 lb/hr
PM10 = Emissions are the same as normal operation (6.6 lb/hr).
CO = (277 lb/event) * (event/2 hours) = 138.5 lb/hr

2. Maximum Hourly Warm Start-Up Emissions:
NO_X = (138 lb/event) * (event/1.5 hours) = 92 lb/hour
SO_X = Emissions are the same as normal operation (2.63 lb/hr).
VOC = (18 lb/event) * (event/1.5 hours) = 12 lb/hr
PM10 = Emissions are the same as normal operation (6.6 lb/hr).
CO = (277 lb/event) * (event/1.5 hours) = 138.5 lb/hr

3. Maximum Hourly Hot Start-Up Emissions:
NO_X = (92 lb/event) * (event/1 hour) = 92 lb/hour
SO_X = Emissions are the same as normal operation (2.63 lb/hr).
VOC = (12 lb/event) * (event/1 hour) = 12 lb/hour
PM10 = Emissions are the same as normal operation (6.6 lb/hr).
CO = (277 lb/event) x (event/ 1 hour) = 138.5 lb/hr

CTG/HRSG Shutdown Emissions

Shutdown of CTG/HRSG is a relatively simple process and will take no more than a 30 minute period from the initiation of the shutdown sequence to the cessation of fuel flow and firing. Prior to commencing the gas turbine shutdown, the duct burner firing rate is reduced to zero. Subsequently the temperature of the CO catalyst drops. During shutdown period, the ammonia injection system is shutdown and the SCR temperature drops below 500 ^{o} F.
Consequently, the CO catalyst and the SCR catalyst are no longer operational and in 30 minutes, the heat input is reduced from maximum to zero. During this period, total heat input per hours is assumed to be half of the normal load. Shutdown emissions are calculated as shown and summarized in Table 10 below.
Data:
Maximum number of shutdown per day = 3 (1.5 hours)
Maximum number of shutdown per month = 12 (6 hours)
Maximum number of shutdowns per year = 48 (24 hours)

Table 10 – CTG/HRSG Shutdown Emissions

	Shutdown 0.5 hour/event		Max Daily (3events/day)	Max Monthly (12events/month)	Max Yearly (48events/year)
	Lb/hr	Lb/event	lb	lb	lb
NOX	46	23	69	276	1104

SOX	1.32	0.66	2	8	32
VOC	6	3	9	36	144
PM10	3.30	1.65	5	20	80
CO	70	35	105	420	1,680

1. Maximum Hourly Shutdown Emissions:
NO_X = (23 lb/event) * (event/0.5 hour) = 46 lb/hour
SO_X = (0.66 lb/event) * (event/0.5 hour) =1.32 lb/hour
VOC = (3 lb/event) * (event/0.5 hour) = 6 lb/hour
PM10 = (1.65 lb/event) * (event/0.5 hr) = 3.3 lb/hour
CO = (35 lb/event) * (event/0.5 hour) = 70 lb/hour

2. Maximum Daily Shutdown Emissions:
NO_X = (23 lb/event) * (3 event/day) = 69 lb/day
SO_X = (0.66 lb/event) * (3 event/day) = 2.0 lb/day.
VOC = (3 lb/event) * (3 event/day) = 9 lb/day
PM10 = (1.65 lb/event) * (3 event/day) = 5 lb/day
CO = (35 lb/event) * (3 event/day) = 105 lb/day

3. Maximum Monthly Shutdown Emissions:
NO_X = (23 lb/event) * (12 events/month) = 276 lb/month
SO_X = (0.66 lb/event) * (12 event/month) = 8 lb/month
VOC = (3 lb/event) * (12 events/month) = 36 lb/month
PM10 = (1.65 lb/event) * (12 event/month) = 20 lb/month
CO = (35 lb/event) * (12 events/year) = 420 lb/month

4. Maximum Yearly Shutdown Emissions:
NO_X = (23 lb/event) * (48 events/year) = 1104 lb/year
SO_X = (0.66 lb/event) * (48 event/year) = 32 lb/year
VOC = (3 lb/event) * (48 events/year) = 144 lb/year
PM10 = (1.65 lb/event) * (48 event/year) = 65 lb/year
CO = (35 lb/event) * (48 events/year) = 1680 lb/year

<u>Emission Rates – CTG/HRSG Initial Commissioning Period</u>
Initial commissioning period expects to last no more than 514 hours for a period of no more than 90 days. During the initial part of the commissioning period, there will be relatively frequent start-ups and shutdowns with gas turbine operating at low load with no NO_X control. The emissions per unit of heat input will decrease significantly after the low load commissioning work is completed.

Estimated maximum emissions during the commissioning period is estimated as shown in Appendix C (Table C1) and summarized in Table 11 below.

Table 11 – CTG/HRSG Initial Commissioning Period Emissions

Pollutant	Total Emissions lbs
NO_X	6,818
SO_X	781
VOC	1,195
PM10	2,002
CO	9,596

Table 12- Emissions from Fugitive Components Associated with Cogeneration System

The majority of fugitive components being installed are in refinery gas service.

Sources	No. of Sources	Emission Factor (lb/yr)	Emissions (lb/yr)	Emissions (lb/month)
Valves				
Sealed bellows	70	0	0	0
AQMD Approved I&M gas/vapor *	78	23	1794	149.5
Others –Light Liquid	0	0	0	0
Heavy Liquid	68	0	0	0
Pumps				
Double or Tandem Mechanical Seal – LL	0	104	0	0
HL	10	80	800	66.67
(6 dedicated pumps for cogeneration, and 12 lube oil pumps outside the battery limit of the cogen, however, for the purpose of calculation, 4 are apportion to the cogen C each permit unit) see the attached e-mail by Pang Mueller for the lube oil pumps				
Flanges (Fittings) -	432	1.5	648	54
Compressor (Existing Permitted Sources)	3	514	N/A	N/A
Total Fugitive Emissions VOC increase	N/A	N/A	3242	270.16
Total Daily Fugitive Emissions VOC increase			9.00lb/day	

*The exemption list of all non-leakless valves is in Attachment 4

RULE COMPLIANCE EVALUATION

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

The California Environmental Quality Act (CEQA), Public Resources Code Section 21000 et seq., requires that the environmental impacts of proposed "projects" be evaluated and that feasible methods to reduce, avoid or eliminate significant adverse impacts of these projects be identified and implemented. Tesoro Reliability Improvement and Regulatory Compliance project qualifies as a significant project so preparation of a CEQA document was required. The draft Environmental Impact Report (DEIR) for the project was issued on January 21, 2009. The public review period for this document ended on March 6, 2009, 2008. The final Environmental Impact Report (FEIR) was certified on April 10, 2009.

The Cogen C related permit(s) will be issued with condition (S11.3) that specifies that Tesoro shall comply with all applicable mitigation measures stipulated in the "Statement of Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan" document which is part of the AQMD Certified Final Environmental Impact Report.

Rule 212 – Standards for Approving Permits

This project is subject to Rule 212 public notice requirements because the daily maximum CO, NOX, SOX, PM10, and VOC emissions from the CTG/HRSG and CO, NOX, PM10 and VOC emissions from the turbine will exceed the emission thresholds specified in subdivision (g) of this rule.

In accordance with subdivision (d) of this rule, the applicant will be required to distribute the public notice to each address within ¼ mile radius of the project.

Subdivision (g) requires that the public notification and comment process include all applicable provisions of 40 CFR Part 51, Section 51.161(b) and 40 CFR Part 124, Section 124.10. The minimum requirements specified in the above documents are included in paragraphs (g)(1), (g)(2), and (g)(3).

In accordance with paragraph (g)(1) of this rule, the District will make the following information available for public inspection (i.e. public library) during the 30 days comment period: public notice, project information submitted by the applicant, and the District permit to construct evaluation.

In accordance with paragraph (g)(2) of this rule, the public notice will be published in a newspaper that serves the area that will be impacted by the project.

In accordance with paragraph (g)(3) of this rule, the public notice will be mailed to the following persons: the applicant, the Region IX EPA Administrator, the California Air Resources Board, the chief executives of the city and county where the project will be located, the regional land use planning agency, and the state and federal land managers whose lands may be affected by the emissions from the proposed project.

Rule 218 – Continuous Emission Monitoring

The CO CEMS will comply with the requirements of Rule 218.

Rule 401 – Visible Emissions

This rule limits visible emissions from exceeding 20% opacity for an aggregate period of greater than 3 minutes in any one hour. The gas turbine and duct burner will be fired with gaseous fuel only. Base on current operation of combustion devices burning refinery gas at LAR, no visible emissions is expected. Therefore, compliance with this rule is expected.

Rule 402 – Nuisance

This rule requires that a person not discharge from any source air contaminants or 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 equipment will utilize the best available control technologies to reduce emissions. Therefore, the equipment is not expected to create public nuisance problems.

Rule 403 – Fugitive Dust

This rule requires the use of best available control measures to minimize fugitive dust formation from "active operations" including but not limited to, earth moving, construction, and vehicular movement. The rule prohibits active operations from causing visible emissions that extend beyond the facility's fence line. The applicant will use best available control measures during construction of the proposed permit units.

Rule 404 – Particulate Matter Concentration

This rule does not apply to emissions resulting from combustion of liquid or gaseous fuels in steam generators or gas turbines. Therefore the turbine is exempt from this rule. Steam generators have the same definition in Rule 1146 and 1146.1. Pursuant to these rules, steam generator means any combustion equipment fired with liquid and/or gaseous and/or solid fuel and used to produce steam or heat water and that is not use exclusively to produce electricity for sale. steam generator does not include any waste heat recovery boiler that is used to recovered sensible heat from the exhaust of a combustion turbine or any unfired waste heat recovery boiler that is used to recover sensible heat from any combustion equipment.

Rule 407 – Liquid and Gaseous Air Contaminants

This rule limits CO emissions to 2000 PPM. SO2 limit is subsumed by the RECLAIM program pursuant to Rule 2001 and is not applicable. CO emissions from the gas turbine/HRSG will be below 2000 PPM. Full compliance with this rule is expected.

Rule 409 – Combustion Contaminants

This rule limits particulate emissions (from combustion process) to 0.1 grain per standard cubic foot (at 12% CO2). Based on the estimated PM-10 emissions from the turbine/HRSG, compliance is expected as shown in the calculation below.

Turbine/HRSG:

Max grain loading (w/duct firing) = (6.60lb/hr)(7000grains/lb)/[241,620 dscfm)(60Min / hr)]
= .0032 grains/dscf

Max grain loading (no duct firing) = (5.3lb/hr)(7000grains/lb)/[237,060 dscfm)(60 Min / hr)]
= .0029 grains/dscf

Rule 431.1 – Sulfur Content of Gaseous Fuels

This rule is not applicable for this facility because it is subject to the SOX RECLAIM program under Regulation XX. The sulfur content requirement is subsumed under the RECLAIM program pursuant to Rule 2001.

Rule 474 – Fuel Burning Equipment – Oxides of Nitrogen

This rule is superseded by NOX RECLAIM.

Rule 475 – Electric Power Generating Equipment

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. The rule prohibits equipment emissions from exceeding both of the following two limits (means it may exceed any one of the limit, but not both at the same time): 11 lb/hr or 0.01 grain/scf. However, section (a)(4) of this rule states that the limits specified in section (a)(3) shall not apply to equipment at any location that discharges 50% or less of mass amount of oxides of nitrogen from equipment which it replaces, provided that the emissions of combustion air contaminants does not exceed .05 grains/DSCF

The proposed Turbine "C"/HRSG NOX emissions will be less than 50% of NOX emissions from the replaced Cogeneration Unit A and B. The maximum NOx emissions from the new turbine is estimated to be no greater than 60,503 lb/year, while July 1, 2006- June 30, 2007 NOx emissions from existing Turbine A and B were 242,964 lbs and 161,367 lbs, respectively.

Rule 476 – Steam Generating Equipment

NOX requirements in this rule are subsumed by Regulation XX-RECLAIM. However, the requirements for combustion air contaminants are still applicable. This rule applies to steam generating equipment with heat input of greater than 50 MMBTU/hr that are installed after May 7, 1976. The rule prohibits discharge of combustion air contaminants (PM) to the atmosphere at the rate greater than both of the following limits: 0.01 grain/DSCF and 11 lb/hr. The turbine may exceed one of the limits, but not both. The proposed gas turbine PM emissions will not exceed 11 lb/hr.

Regulation IX – NSPS for Steam Generators – 40CFR Part 60 Subpart Da

Subpart Da does not apply to the proposed HRSG/duct burner because the HRSG has unfired waste heat boilers and the duct burner heat input will be less than 250 MMBTU/hr at peak load.

Regulation IX – NSPS for Steam Generators 40 CFR60 Subpart Db: Standards of performance for industrial commercial institutional steam generating units

The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 million Btu/hour).

The HRSG and duct burners on the new cogeneration unit will not be subject to the requirements of this regulation because they will be subject to 40CFR60 Subpart KKKK. According to §60.4305(b) in Subpart KKKK, heat recovery steam generators and duct burners regulated under Subpart KKKK are exempted from the requirements of subparts Da, Db, and Dc.

Regulation IX – NSPS for Gas Turbines – 40CFR Part 60 Subpart GG

Subpart GG applies to gas turbine because the heat input is greater than 10.14 MMBTU HHV/hr (10.7 gigajoules per hour). However, the proposed turbine is subject to subpart KKKK, and therefore, is exempt from Subpart GG.

Regulation IX – 40CFR60 SUBPART GGGa

Standards Of Performance For Equipment Leaks Of Vocs In Petroleum Refineries For Which Construction, Reconstruction, Or Modification Commenced After November 7, 2006

This NSPS is applicable to affected facilities in refineries that begin construction after November 7, 2006. The following are affected facilities under this subpart:

- Compressors
- The group of all the equipment within a process unit.

The proposed Cogen C is not a process unit as defined in this regulation. The Cogen C permit unit does not contain any compressors. For these reasons, the equipment in the Cogen C permit unit is not subject to the requirements of this regulation.

Regulation IX – NSPS Standard for Petroleum Refineries – 40 CFR Part 60 Subpart J

Subpart J applies to existing equipment. The final Subpart Ja published on May 8, 2008, applies to equipment which construction, modification or reconstruction commenced on or after May 14, 2007 is subject to Subpart Ja. Since Subpart J applies only to existing equipment, it is not applicable to the new turbine being proposed for this project.

Regulation IX – NSPS Standard for Petroleum Refineries – 40 CFR Part 60 Subpart Ja

This regulation limits SOX emissions from fuel gas combustion devices (and also set NOX emission limits for heaters > 40 MMBTU/hr) Sulfur content standards for Subpart Ja applies to the proposed turbine. Tesoro select to comply with the H_2S limit in fuel gas for all combustion equipment. The H_2S limits in Subpart J are 162 PPM H_2S 3 hours rolling average and 60 ppm H_2S 365 successive days rolling average. The proposed turbine is expected to use fuel gas in compliance with this requirement. Condition 90.20 specifies that Tesoro install a continuous monitoring system the H2S concentration in the fuel gas. By continuously monitoring the H2S concentration, compliance is expected.

Regulation IX – NSPS Standard for Stationary Combustion Turbines – 40 CFR Part 60 Subpart KKKK

This regulation applies to stationary combustion turbine with a heat input at peak load equal to or greater than 10 MMBTU HHV/hr (heat input associated with HRSG or duct burners are not subject to this regulation), and commences construction, modification or reconstruction after February 18, 2005. Gas turbine subject to this subpart is exempt from the requirements of subpart GG of Part 60. The HRSG and duct burners subject to this subpart are exempted from subparts Da, Db, and Dc of Part 60.

Turbine located on the continent must comply with either one of the following two SO2 limits:

(a) SO2 $\leq$ 0.9 lb/MWH gross output; or

(b) SO2 $\leq$ 0.06 lb/MMBTU heat input

New gas turbine burning fuel other than natural gas and with heat input greater than 50 MMBTU/hr but less than or equal to 850 MMBTU/hr, must not exceed one of the following two NOX limits:

(a) NOX = 74 PPM @ 15% O2, or

(b) NOX = 3.6 lb/MWh

SO2 emissions under normal operation when the turbine is fired at full load is .004 lb/MMBTU or 0.035 lb/MWh which is significantly lower than the 0.06 lb/MMBTU or 0.9 lb/MWh limits. NOX emissions from this turbine under normal operation will not exceed 2.5 PPM or .09 MWh which is significantly lower than the 74 PPM or 3.6 lb/MWH limits.

Regulation X: National Emission Standards for Hazardous Air Pollutants (NESHAPS)

Subpart DDDDD-National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heater

This maximum achievable control technology (MACT) standard was originally promulgated by EPA on September 13, 2004 and was vacated and remanded by the US court of Appeals for the District of Columbia Circuit on June 19, 2007. A new rule was proposed on June 4, 2010. The public comment period for the proposed rule ended on August 3, 2010.

§63.7485 *Am I subject to this subpart?*

A facility is subject to this subpart if it operates an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP as defined in §63.2.

§63.7575 defines

Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat boiler are not considered waste heat boilers, but are considered boilers. Waste heat boilers are also referred to as heat recovery steam generators.

Based on these definitions, the duct burners and associated heat recovery steam generator for the proposed cogeneration unit would be subject to the proposed regulation as boilers.

§63.7490 *What is the affected source of this subpart?* The boiler is considered a new source since it is not existing or reconstructed.

Emission limits for new boilers are specified in Tables 1 and 2 of the proposed regulation. The tables do not contain any emission limits for new boilers in the natural gas/refinery gas category. As specified in Table 3 of the proposed regulation, boilers in the natural gas /refinery gas subcategory that have heat input capacity greater than 10 MMBtu/hr would be subject to annual tune-up.

Since the cogen unit burners/HRSG are not subject to any emission limits, they are also not subject to any of the operating limits, performance testing, or other compliance requirements specified in tables 4 through 8 of the proposed regulation.

§63.7595(b) ***When do I have to comply with this subpart?*** Due to a lack of emission limits, it is not expected that the regulation, as proposed, will have a significant impact on the design of the proposed cogen unit or associated air pollution control systems. Based on past compliance with similar regulations, it is expected that Tesoro would comply with this regulation as proposed. No additional action is required at this time.

<u>40CFR63 SUBPART YYYY: National Emission Standards For Hazardous Air Pollutants For Stationary Combustion Turbines</u>

This NESHAP establishes emission limitations and operating limitations for HAP emissions from stationary combustion turbines located at major sources of HAP emissions. However, as specified in §63.6095, gas-fired stationary combustion turbines must comply only with the Initial Notification requirements set forth in §63.6145.

The emission and operating limits for gas turbines have been stayed until EPA takes final action on a proposal to delist lean premix gas-fired stationary combustion turbines and diffusion flame gas-fired stationary combustion turbines as source categories subject to NESHAP (MACT) standards. The proposed Cogen C turbine is a lean- premix type turbine.

No additional analysis is required.

<u>REGULATION XI: SOURCE SPECIFIC STANDARDS</u>

<u>Rule 1109: Emission Of Oxides Of Nitrogen From Boilers And Process Eaters In Petroleum Refineries</u>

Tesoro is subject to the requirements of Regulation XX (RECLAIM), which supersedes the requirements of Rule 1109 per Rule 2001(j). Therefore, the Duct Burners/HRSGs are not subject to the requirements of Rule 1109.

<u>Rule 1123 – Refinery Process Turnarounds</u>

This rule specifies requirements for displacement of organic materials during turnaround and also requires a turnaround plan to be submitted. This facility operates in compliance with this rule and continued compliance with Rule 1123 is expected.

RULE 1134: Emission Of Oxides Of Nitrogen From Stationary Gas Turbines
This rule is applicable to all existing stationary gas turbines, 0.3 megawatt (MW) and larger, as of August 4, 1989. It is not applicable to new gas turbines such as the proposed Cogen C turbine.

RULE 1135: Emission Of Oxides Of Nitrogen From Electric Power Generating Systems
The proposed cogeneration system is not subject to this regulation since it is not "electric power generating system" as defined at 1135(b)(10). Also, the requirements of this rule have been subsumed by RECLAIM per 2001(j).

Rule 1146: Emission Of Oxides Of Nitrogen From Industrial, Institutional, And Commercial Boilers, Steam Generators, And Process Heaters
This regulation contains NOx and CO emission limits for certain boilers, steam generators, and process heaters. According to 1146(b), this rule applies to boilers, steam generators, and process heaters of equal to or greater than 5 million Btu per hour rated heat input capacity used in all industrial, institutional, and commercial operations with the exception of:
(1) boilers used by electric utilities to generate electricity; and
(2) boilers and process heaters with a rated heat input capacity greater than 40 million Btu per hour that are used in petroleum refineries; and
(3) sulfur plant reaction boilers.

The cogen duct burners/HRSG are not subject to this regulation since they are used in a refinery and have a rated heat input capacity greater than 40 MMBtu/hr. Also, the NOx related requirements of this rule have been subsumed by RECLAIM per 2001(j) for RECLAIM facilities.

Rule 1173 – Fugitive Emissions of Volatile Organic Compounds
This rule specifies monitoring and reporting requirements for fugitive components and associated emissions. It also specifies atmospheric PRV monitoring requirements. This facility operates in compliance with this rule and continued compliance is expected. New fugitive components will comply with BACT requirements.

Regulation XIII, Rule 2005, and Rule 1703 – New Source Review

LAR is a RECLAIM facility. NOX and SOX are subject to RECLAIM new source review under Rule 2005, while VOC, PM10 and NH3 are subject to Regulation XIII -New Source Review. NO_2, SO_2 and CO are attainment air pollutants and any increases above significant threshold are subject to PSD analysis under Regulation XVII. LAR is a PSD facility and the significant emission increase is 40 tons per year or more of NO_2 or SO_2; or 100 tons per year or more of CO.

Rule 1303 (a) and 2005 (c) (1)(A) – BACT/LEAR

These rules state that the Executive Officer shall deny a 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 proposed Cogen C is a new source with an increase in emissions of CO, NOx, PM10, SOx, VOC and NH3. It is subject to BACT for CO, PM10, VOC, and NH3 under Rule 1303. Additionally, the source is subject to BACT for NOx and SOx under Rule 2005 and for CO, NOx and SOx under Regulation XVII. The GE model MODEL NO. PG6581B turbine proposed for construction by Tesoro will be operated on a combined cycle with HRSG and steam turbine. For major sources, BACT is determined at the time the Permit to Construct is issued, and is the Lowest Achievable Emission Rate (LAER) which has been achieved in practice. Based on recently issued permits for combined cycle facilities including Chevron Products Co (A/N 470782), Magnolia Power (A/N 386305) and Vernon City Power (A/N 394164), AQMD has determined that BACT for combined cycle CGTs is as follows:

BACT (LAER) Requirements for Combined Cycle Gas Turbines(Natural Gas)

NOX 2005(c)(1)(A)	SOX Rule2005(c)(1)(A)	VOC Rule1303(a)	PM10 Rule1303(a)	NH3 Rule1303(a)	CO Rule 1703 (a)(2)
2 PPMV @15% O2 1-hr average	Natural Gas Fuel with Fuel Sulfur Content of no more than 1 grain/100 scf (about 16 ppm) regulated by the Public Utility Commission(PUC)	2.0 PPMV @15% O2 1-hr average	Natural Gas Fuel with Fuel Sulfur Content of no more than 1 grain/100 scf (about 16 ppm) regulated by the Public Utility Commission(PUC)	5 ppmv @15% O2 1-hr average	2 PPMV @ 15% O2 1-hr average

Criteria pollutants from Tesoro gas turbine will be controlled to very low levels for this type of equipment. The District has worked with the applicant and considers theses standards to be BACT/LAER for refinery gas/ natural gas turbines. These standards are stated below

Proposed BACT (LAER) Levels for Tesoro Cogen C(Refinery/Natural Gas)

NOX Rule2005(c)(1)(A)	SOX Rule 2005(c)(1)(A)	VOC Rule1303(a)	PM10 Rule 1303(a)	NH3 Rule1303(a)	CO Rule1703(a)(2)
2.5 PPMV[(1)] @15% O2 1-hr average 2.0 PPMV[(1)] @15% O2 3-hr average 2.0 PPMV[(2)] @15% O2 1-hr average	Use of Refinery Fuel gas with the following limitations for total reduced sulfur concentration, calculated as H2S: 40 ppm(1 hour average) and,Use of Natural gas regulated by the Public Utility Commission(PUC) or combination	2.0 PPMV @15% O2 1-hr average	Use of Refinery Fuel gas with the following limitations for total reduced sulfur oncentration, calculated as H2S: 40 ppm (1 hour average) and,Use of Natural gas regulated by the Public Utility Commission(PUC) or combination	5 ppmv @3% O2 1-hr average	2 PPMV @ 15% O2 1-hr average

(1) This NOx limit is applicable for Refinery gas fired cogeneration, Refinery gas is defined as a mixture of refinery fuel gas, produced within the refinery, and natural gas obtained from a utility regulated by the Public Utilities Commission (PUC), for which the natural gas component of the mixture does not exceed 50% of the total, by Higher Heating Value (HHV) content.
(2) This NOx limit is applicable for Natural gas fired cogeneration, Natural gas is defined as a mixture of refinery fuel gas, produced within the refinery, and natural gas obtained from a utility regulated by the Public Utilities Commission (PUC), for which the natural gas component of the mixture exceeds 50% of the total, by Higher Heating Value (HHV) content.

Tesoro performed an analysis for an alternative NOX control technology in addition of Selective catalytic Reduction (SCR) which is Emerachem EMx technology(See Tesoro evaluation in attachment 3 for EmeraChem EMx &ESx Evaluation for Turbines). In the evaluation, the conclusion was that the SCONOX/SCOSOx process is not commercially demonstrated on larger scale.

All of the EMX and SCONOx installation are for natural gas and dual fuel(pipeline NG and low –sulfur diesel fuel oil) gas turbines. The dual fuel gas turbines are significantly smaller than the Tesoro gas turbine and EMX may not have achieved demonstration for similar:"class of service".
The EMx and ESx technologies have no demonstrated experience on equipment fired with refinery gas. The refinery fuel gas could potentially poison the EMx catalyst and cause reduced performance. The impact of this reduced performance could mean more frequent required downtime for catalyst washing and/or replacement.

Fugitive Components: BACT for VOC service fugitive components is summarized below. The majority of fugitive components being installed are in natural gas service. These components are not considered to be in VOC service since natural gas contains less than 10% VOC.

- *Valves*: Bellow-sealed valves are required with the following exemptions.

  1. Heavy liquid service (i.e., streams with a vapor pressure <0.1 psia @ 100 ^{o}F (kerosene) based on the most volatile class present > 20% by volume)
  2. Control valve
  3. Instrument tubing application
  4. Applications requiring torsional valve stem motion
  5. Applications where valve failure could pose safety hazard (e.g., drain valves with valve stem in horizontal position)
  6. Retrofit/special applications with space limitation (special applications such as skid mounted standard packaged systems)
  7. Valves not commercially available

  Valves installed where Bellow-sealed valves are not available will be subject to a leak rate of less than 500 ppmv by EPA Method 21 and an approved I&M program.

  Permit condition S31.2 specifies the requirement to install bellow-sealed (leakless) valves except for the exempt applications listed above. This condition also specifies that Tesoro must submit a list of all non-leakless valves to the District prior to the startup of the cogeneration unit. The preliminary list of all nonleakless valves is in attachment 4.

- *Relief Valves*: BACT for emergency pressure relief valves (PRVs) is connection to a closed vent system. No new PRVs are being installed in this proposed permit unit.

- *Process Drain*: BACT for new process drains is installation of p-traps or seal pots and inclusion in an approved I&M program. According to Tesoro, new process drains will be equipped with p-traps for VOC control.

- *Pumps*: BACT for pumps in light liquid service is double or tandem seals vented to a closed system and inclusion in an approved I&M program. BACT for pumps in heavy liquid service is single mechanical seals and inclusion in an approved I&M program. Tesoro is installing two heavy liquid pumps. Each will be equipped with the required single mechanical seals.

- *Flanges*: BACT for new flanges is compliance with ANSI/API standards and inclusion in an approved I&M program. New flanges will comply with these requirements.

- *Compressors*: BACT for rotary compressors is an enclosed seal system connected to closed vent system and for centrifugal type is a seal system with a higher pressure barrier fluid. The only compressor being installed in this permit unit is a natural gas booster compressor, which is not subject to BACT.

Rules 1303(b)(1) and 2005(c)(1)(B) – NO2 and PM10 Impacts Modeling

These rules require the applicant to substantiate with modeling that each permit unit will not cause a violation, or make significantly worse an existing violation of any state or national ambient air quality standards at any receptor location in the District. For this project, air dispersion modeling is required for cogeneration unit to determine the impacts from the proposed gas turbine/HRSG.

The applicant submitted dispersion modeling and health risk analysis with the application for the cogeneration unit. U.S. EPA ISCST3 (Version 02035) air dispersion model was used to determine ground level concentration for PM10 and NO2. The ISCST3 model is run using the Long Beach meteorological data available from the District.
The emissions from the gas turbine/HRSG will vary depending on the operating condition and the ambient temperature. The various operating conditions for this project are as follows: cold start-up, warm start-up, and hot start-up, base load (100%) with duct firing, and base load without duct firing. The ambient temperatures used in the analysis were 36 F and 63 F.

The maximum ground level concentrations predicted by the model are provided in Table 13. The numbers shown in this table reflect the increase in ambient concentration on a permit unit basis. The increases in ambient concentrations for the CTG/HRSG are less than the significant change thresholds shown in Table A-2 of Rule 1303. The applicant performed the air quality analysis per the District's modeling requirements, and the predicted air quality impacts from the proposed project meet the standards specified in Rule 1303 and Rule 2005. Applicant's modeling analysis has been reviewed by the District's modeling staff in the Rules and Planning Office. Based on this review, compliance with the rule requirements is expected.

Table 13-NSR Impact Modeling Result for CTG/HRSG

Pollutant	Averaging Period	Ambient Background Conc(ug/m3)	Calculated Conc. (ug/m3)	Total Conc. (ug/m3)	Most Stringent Air Quality Standard (ug/m3)	Significant Change in Air Quality Conc(ug/m3)	Below Threshold ? Yes/No
PM10	24-hr	78.0	**0.522**	-	50	**2.5**	Yes
	Annual Arthmetic Mean AAM	31.1	**0.120**	-	30 *(20)*	**1**	Yes
NO2	1-hr	264.3	33.909	**298.2**	**500** *(339)*	20	Yes
	Annual	45.5	0.111	**45.6**	**100** *(57)*	1	Yes

Note(1): Non-attainment air contaminant PM-10 is compared to the Significant Change in Air Quality Concentration thresholds. The attainment air contaminants NO2 is combined with the maximum ambient concentrations and compared to the Most Stringent Air Quality Standard.

Note(2): Although the current Board adopted version of Rule 1303 and 2005 specifies the most stringent ambient air quality standard as shown in Table13. The more stringent state ambient air quality standard is also shown in italic and underlined.

Rule 1303(b)(2) and Rule 2005(c)(2) – Offsets

The proposed cogeneration system will emit NOX, SOX, VOC, and PM10 subject to these rules. NOX and SOX are RECLAIM pollutants and are subject to the requirements of Rule 2005(c)(2). VOC and PM10 are non-RECLAIM pollutants and are subject to Rule 1303 (b)(2). Increases in emissions include start ups and shutdowns and are calculated based on maximum rated equipment capacity and maximum operating hours (24 hours/day, 365 days per year) as show below

PM10 and VOC Emissions

Daily PM10 and VOC emissions increases calculated pursuant to Rule 1306 (b) are shown in Appendix E and are summarized below:

Pollutant	CTG/HRSG (lb/day)
PM10	163.68
VOC	55.59

Since the two existing gas turbines will removed from service after the new turbine start operation, increases in emissions from the proposed permit unit is eligible for exemption offset requirement pursuant to Rule 1304 (c) – Concurrent Facility Modification. The two existing gas turbine were issued a permit to construct in March 1981 and was subject to the New Source Review Evaluation under Regulation XIII. Emission decreases for concurrent facility modification is calculated using Rule 1306 (d)(2). The permitted PM10 and VOC emissions for the existing gas turbine as recorded in the District NSR data based is as follows:

Pollutant	Turbine A (lb/day)	Turbine B (lb/day)	Total (lb/day)
PM10	176	176	352
VOC	75	75	150

Therefore, there is a net decrease in emissions from concurrent facility modifications as calculated below:

Net Decrease in PM10 = 163.68 lb/day (new project) –352 lb/day (removed from service)
= -188.32lb/day

Net Increase in VOC = 55.59 lb/day (new project) – 150 lb/day (removed from service)
= -94.41 lb/day

Constructions of the proposed cogeneration unit qualify for offset exemptions under concurrent facility modification because:

(a) Gas turbines A and B will be removed from service after the date of submittal of this application.

(b) Gas turbines A and B will be removed from service before start operation of the new cogeneration unit (except for the 90 days simultaneous operation as allow under Rule 1313 (d))

(c) Removing gas turbines A and B from service is not required by AQMP Control Measure, or a Proposed AQMD Rule, adopted federal, state, District rule, regulation or statue, and are not part of category or class of equipment included in a demonstration program required by District rule or regulation.

To ensure compliance with emission offset requirements, the permit will include a condition limiting monthly PM10 and VOC emissions. The permit includes emissions factors that are to be used to calculate the monthly PM10 and VOC emissions from the gas turbine/HRSG.

<u>Emission Factors to Calculate Monthly PM10 and VOC Emissions</u>

The emission factors for PM10 and VOC are based on maximum hourly emissions (with and without duct firing) divided by the maximum hourly heat input (which is based on maximum equipment rating).

For compliance with RECLAIM offset under Rule 2005 (c)(2), applicant is required to demonstrate that they hold sufficient RTCs to offset the total NO_X and SO_X emission increase for each pollutant during the first year of operation using a 1-to-1 offset ratio. The total first year (commissioning year) emissions will be as follows:

	NOX (lb/year)	SOX (lb/year)	Start Operation
Turbine C	59,253	22,468	January 1, 2012

For compliance with RECLAIM offset under Rule 2005 (f)(1), applicant is required to hold sufficient RTCs in the amount shown below at the beginning of each subsequent compliance year. The total subsequent year emissions will be as follows:

	NOX (lb/year)	SOX (lb/year)	Start Operation

Turbine C	52,453	23,039	January 1, 2012

Rule 1303 (b)(4)– Facility Compliance
This facility complies with or is on schedule of compliance with applicable rules and regulations of the District.

Rule 1303 (b)(5)(A) and 2005 (g)(2) – Alternative Analysis
Applicant must conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source and demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with that project.

As specified at 1303(b)(5)(D)(iii), the requirements for an alternative analysis under this subparagraph may be met through compliance with the California Environmental Quality Act if the proposed project has been analyzed by an environmental impact report pursuant to Public Resources Code Section 21002.1 and Title 14 California Code of Regulations Section 15080 et seq. As discussed earlier, the final EIR for the Project, which was performed as required by CEQA, was certified on 4-10-2009 by the District. The requirements of 1303(b)(5)(A) are satisfied.

Rule 1303 (b)(5)(B) and 2005 (g)(1) – Statewide Compliance
The applicant must demonstrate prior to the issuance of a Permit to Construct, that all major stationary sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in the State of California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act.

A letter from Mr. David Reed, the Tesoro Los Angeles Refinery Manager, indicating that all major sources owned or operated by Tesoro Refining and Marketing Company in California are in compliance or are on a schedule for compliance with all applicable standards emission limitations and standards under the clean Air Act. The certification letter dated July 22, 2010, is provided in Attachment 5.

Rule 1303 (b)(5)(C) and 2005 (g)(4)(A) – Protection of Visibility
Modeling of plume visibility, as described under 1303(b)(5)(C) is not required because the project does not result in an emissions increase of 15 tons PM_{10}/year or 40 tons NO_x/year. Further, the site location is not within the prescribed distances (28 to 32 km) of a Federal Class I Area.

Rule 1401 – Toxic Air Contaminants
This rule establishes the allowable risks for new or modified permit units that will emit toxic air contaminants (TAC). Rule 1401 significant levels are as follows:

Maximum Individual Cancer Risk = 1 in 1 million

Cancer Burden = 0.5
Maximum Chronic Hazard Index =1
Maximum Acute Hazard Index = 1

The applicant's health risk assessment (HRA) was reviewed by AQMD modeling staff and the analysis was deemed acceptable. The HRA was prepared in accordance with the District's guidelines and compliance with this rule is expected.

The California Air Resources Board (CARB) Hotspots Analysis Reporting Program (HARP) combines with the US EPA Industrial Source Complex dispersion model with a risk calculation model based on the Air Toxics Hot Spots Program Risk Assessment Guidelines (OEHHA) were used in the analysis. The table below shows source parameters use for model inputs.

Source	UTME	UTMN	Release Height	Temperature (F)	Diameter (ft)	Velocity (ft/min)
Turbine/HRSG	385677	3739433	120	346	10.5	5,106

The summary of the modeling results is included in the table below.

Source	MICR	Acute Hazard Index	Chronic Hazard Index
Gas Turbine/HRSG	0.11×10^{-06}	.0078	.0035

Regulation XVII – Prevention of Significant Deterioration

On July 25, 2007 AQMD and EPA have signed a new PSD delegation agreement for issuance of PSD permits except when the project proponent seeks to used a Plant-wide Applicability Limit (PAL) and additional calculation methodologies promulgated in 40 CFR 52.21 as discussed in the following paragraph:

On December 31, 2002, EPA finalized revisions to the regulations at 40 CFR 52.21, which became effective on March 3, 2003. On June 24, 2005, the District of Columbia Court of Appeals vacated two provisions of the revised PSD regulations but upheld new provisions for additional calculation methodologies for determining if a proposed project will result in a major modification and for the application of a Plant-wide Applicability Limit (PAL). The provisions upheld by the court are not specifically addressed by South Coast AQMD Regulation XVII. Therefore, the delegation agreement does not delegate authority to the District to modify PSD permits when the applicant seeks to use the additional calculation methodologies promulgated in 40 CFR 52.21 but not set forth in District Regulation XVII and it does not delegate authority to issue new or modified PSD permits based on PALS.

The table below shows the net potential to emit PTE emissions at LAR during non-commissioning years due to the addition of the proposed cogeneration unit and the removal of Cogeneration Unit A and B to be as follows:

Activity	NOX(ton/year)	SOX (ton/year)	CO (ton/year)

New CTG/HRSG	28.29	11.52	16.95
Removal of Existing Turbines A and B	-141.91	-64.2	-83.9
Net Emissions	-113.62	-52.69	-66.95
PSD Significant Threshold	40	40	100
PSD Analysis	NO	NO	NO

Although PSD analysis is not required for this project because the increase in emissions is below the significant threshold. Rule 1703 (a)(2) specifies BACT.

Regulation XX –RECLAIM

Rule 2005: New Source Review For Reclaim (Amended 5/06/05)
Sources that are subject to RECLAIM must comply with the New Source Review requirements of Rule 2005 instead of Regulation XIII.

2005 (c): Requirements for Existing Facilities
According to this section, a permit to construct (RECLAIM Facility Permit Amendment) cannot be approved for installation of a new source or modification of an existing source that results in an emission increase of NOx or SOx at an existing RECLAIM unless the following requirements are met:

1.) Best Available Control Technology is applied to the source [2005(c)(1)(A)]

2.) The operation of the source will not result in a significant increase in the air quality concentration for NO2 as specified in Appendix A [2005(c)(1)(B)], and

3.) The applicant demonstrates that the facility holds sufficient RECLAIM Trading Credits to offset the annual emission increase for the first year of operation at a 1-to-1 ratio [2005(c)(2)].

According to 2005(d), "An increase in emissions occurs if a source's maximum hourly potential to emit immediately prior to the proposed modification is less than the source's post-modification maximum hourly potential to emit. The amount of emission increase will be determined by comparing pre-modification and post-modification emissions on an annual basis by using: (1) an operating schedule of 24 hours per day, 365 days per year; or (2) a permit condition limiting mass emissions."

Since the proposed Cogen C is a new source, there is an increase in both NOx and SOx emissions. As seen in the Calculation Section, the NOx and SOx emissions are estimated to be 52,453 lb/year and 23,039 lb/year, respectively.

BACT [2005(c)(1)(A)]: The Executive Officer shall not approve an application for a Facility Permit Amendment to authorize the installation of a new source or modification of an existing source which results in an emission increase as defined in subdivision (d), unless the

applicant demonstrates that Best Available Control Technology (BACT) will be applied to the source.

As discussed is the evaluation of Rule 1303, The BACT determination for the proposed Cogen C is also contained in the Rule 1303 evaluation.

Modeling [2005(c)(1)(B)]: The Executive Officer shall not approve an application for a Facility Permit Amendment to authorize the installation of a new source or modification of an existing source which results in an emission increase as defined in subdivision (d), unless the applicant demonstrates that the operation of the source will not result in a significant increase in the air quality concentration for NO2 as specified in Appendix A. The applicant shall use the modeling procedures specified in Appendix A.

According to Appendix A, an applicant must either (1) provide an analysis approved by the Executive Officer or designee, or (2) show by using the Screening Analysis in Appendix A, that a significant change (increase) in air quality concentration will not occur at any receptor location for which the state or national ambient air quality standard for NO2 is exceeded.

As discussed in the Rule 1303 evaluation, Tesoro performed modeling that showed that the proposed Cogen C will not result in a significant increase in the air quality concentration for NO2

Reclaim Trading Credits [2005(c)(2)]: The applicant is required to demonstrate that they hold sufficient RTCs to offset the annual emission increase for the first year of operation using a 1-to-1 offset ratio.

TESORO NO_X RTC holdings for 2009 and 2011 are 533 and 498 tons, respectively. These levels are significantly below the refinery 2007 NO_X emissions of 821 tons. Of this amount, RECLAIM major NO_X sources emitted 777.5 tons. NO_X emissions from the existing two gas turbines totaled 95.28 tons for year 2009, representing 18% of NO_X emissions from all RECLAIM major sources at the refinery. Currently, the refinery complies with NO_X allocation by purchasing RTCs from the RECLAIM market. This project will allow TESORO to reduce emissions at the facility rather than purchasing NO_X RTCs.

TESORO SO_X RTC holdings for 2009 and 2011 are 246 and 188 tons, respectively. These levels are significantly below the refinery 2007 SO_X emissions of 363 tons. Of this amount, RECLAIM major SO_X sources emitted 316 tons. SO_X emissions from the existing two gas turbines totaled 45 tons, representing 15% of SO_X emissions from all RECLAIM major sources at the refinery. Currently, the refinery complies with SO_X allocation by purchasing RTCs from the RECLAIM market. This project will allow TESORO to reduce emissions at the facility rather than purchasing SO_X RTCs.

Additional Federal Requirements for Major Stationary Sources [2005(g)]: The Executive Officer shall not approve the application for a Facility Permit or an Amendment to a Facility Permit for a new, relocated or modified major stationary source, as defined in the Clean Air Act, 42 U.S.C. Section 7511a(e), unless the applicant complies with the requirements contained under this clause.

A major stationary source is defined as any facility which emits, or has the potential to emit 10 tons per year or more of NOx or 100 tons per year or more of SOx. The Tesoro Refinery is a major stationary source since it has the potential to emit more than 10 ton/yr of NOx and 100 ton/yr of SOx. Compliance with the requirements under 2005(g) is required.

(1) *Statewide Compliance:* The applicant must certify that all other major stationary sources in the state which are controlled by the applicant are in compliance or on a schedule for compliance with all applicable federal emission limitations or standards (42 U.S.C. Section 7503(a)(3))

A letter from Mr. David Reed, the Tesoro Los Angeles Refinery Manager, indicating that all major sources owned or operated by Tesoro Refining and Marketing Company in California are in compliance or are on a schedule for compliance with all applicable standards emission limitations and standards under the clean Air Act. The certification letter dated July 22, 2010, is provided in Attachment 5.

(2) *Alternative Analysis* – Applicant must conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source and demonstrate that the benefits of the proposed project significantly outweigh the environmental and social costs associated imposed as a result of its location, construction, or modification (42 U.S.C. Section 7503(a)(5));

It is specified at 2005(g)(3)(C), that "if the proposed project has been analyzed by an environmental impact report pursuant to Public Resources Code Section 21002.1 and Title 14 California Code of Regulations, Section 15080 et seq., paragraph (g)(2) shall be deemed satisfied." As discussed previously, the final EIR for Tesoro Reliability Improvement and Regulatory Compliance Project was certified on April 10, 2009. The requirements of 2005(g)(2) are satisfied.

(4)(A): *Protection of Visibility* – the applicant shall conduct a modeling analysis for plume visibility in accordance with the procedures specified in Appendix B if the net emission increase from the new or modified source exceeds 40 tons/year of NOX; and the location of the source, relative to the closest boundary of a specified Federal Class I area, is within the distance specified in Table 4-1 of this rule.

As discussed in the Calculation Section, there is no increase of NOx emissions for the proposed cogeneration unit. Therefore, visibility analysis is not required.

Public Notice [2005(h)]: - The applicant shall provide public notice, if required, pursuant to Rule 212 - Standards for Approving Permits.

As discussed in the Rule 212 evaluation, a public notice will be issued for the proposed permits.

Rule 1401 [2005(i)]: All new or modified sources shall comply with the requirements of Rule 1401 - New Source Review of Carcinogenic Air Contaminants, if applicable.

This modified source complies with the requirements of Rule 1401 (See R1401 analysis).

Rule 2011: Requirements for Monitoring Reporting and Recordkeeping for Oxides of Sulfur (SOX) Emissions

This rule establishes the monitoring, reporting and recordkeeping requirements (MRR) for SOX emissions under the RECLAIM program. The turbine/HRSG is classified as a Major SOX sources and stack emissions are measured by a Continuous Emission Monitoring System (CEMS) which is certified.

Rule 2012: Requirements for Monitoring Reporting and Recordkeeping for Oxides of Nitrogen (NOX) Emissions

This rule establishes the monitoring, reporting and recordkeeping requirements (MRR) for NOX emissions under the RECLAIM program. The turbine/HRSG is classified as Major NOX sources and stack emissions are measured by a Continuous Emission Monitoring System (CEMS) which is certified.

In addition, emission factors for SO_X and NO_X are specified for the initial commissioning period, and for the interim period prior to CEMS certification. Detailed emission factor calculations are included in Appendix G.

Emission Factors to Calculate NO_X and SO_X emissions during the Commissioning Period and Interim Period prior to CEMS Certification

Rule 2002 requires the District to specify a RECLAIM NOX and SOX emission factors for the turbine/HRSG. Interim NOX and SOX emission factors for the turbine/HRSG with BACT are specified in Table 1 and 2 of Rule 2002 as 8.5 lb/MMSCF and 34 lb/MMSCF, respectively. However, average hourly NOX emissions during commissioning period is higher due to the intermittent testing of control devices; therefore an emission factor of 43.6 lb/MMSCF is used for turbine/HRSG(as calculated in Appendix G).

Reg XXX Title V Permits

Rule 3001(a): Applicability (Amended November 14, 1997)

Tesoro Refinery is currently subject to Title V. The permit issued for the new cogeneration unit will be issued as a revision of the Title V permit. Permit revisions are categorized into the following four types: administrative, minor, de minimus significant and significant.
As defined in Rule 3000, a significant permit revision means any facility permit revision that is not eligible for administrative permit revision, minor permit revision, or de minimis significant permit revision procedures. Such revisions include any of the following:

1. relaxation of any monitoring, recordkeeping, or reporting requirement, term, or condition in the Title V permit;
2. the addition of equipment or modification to existing equipment or processes that result in an emission increase of non-RECLAIM pollutants or hazardous air pollutants (HAP) in excess of any of the emission threshold levels ;
3. any modification at a RECLAIM facility that results in an emission increase of RECLAIM pollutants over the facility's starting Allocation plus the nontradeable Allocations;
4. requests for a permit shield when such requests are made outside applications for initial permit or permit renewal issuance;
5. any revision that requires or changes a case-by-case evaluation of: reasonably available control technology (RACT) pursuant to Title I of the federal Clean Air Act; or maximum achievable control technology (MACT) pursuant to 40 CFR Part 63, Subpart B;
6. any revision that results in a violation of regulatory requirements;
7. any revision that establishes or changes a permit condition that the facility assumes to avoid an applicable requirement;
8. installation of new equipment subject to a New Source Performance Standard (NSPS) pursuant to 40 CFR Part 60, or a National Emission Standard for Hazardous Air Pollutants (NESHAP) pursuant to 40 CFR Part 61 or 40 CFR Part 63; or,
9. modification or reconstruction of existing equipment, resulting in an emission increase subject to new or additional NSPS requirements pursuant to 40 CFR Part 60, or to new or additional NESHAP requirements pursuant to 40 CFR Part 61 or 40 CFR Part 63.

Since the proposed installation of a new cogeneration (Cogen C) that will be subject to new NSPS requirements pursuant to 40 CFR Part 60, and new NESHAP requirements pursuant to 40 CFR Part 61 or 40 CFR Part 63, this revision will be considered a significant revision to the existing Title V permit. For Significant revisions, AQMD needs to notify the public and the EPA prior to permit issuance. Therefore, the permit is subject to a 30 day public Notice and a 45 day EPA review and comment period.

Since Tesoro is expected to be placed under order of Abatement for the NOV(P52842) that was issued for HGU-2 unit and this unit has been shutdown since 4-6-2010 and is not expected to operate till a variance or order of abatement is granted, the District considers this facility to be in compliance with all the permit requirements, and recommends the issuance of the subject permit to construct.

<u>40CFR Part 64 Compliance Assurance Monitoring</u>
This regulation applies to stationary sources that utilize control equipment to comply with a criteria pollutant emission limit. The purpose is to ensure that the stationary source complies with the emission limit(s) by monitoring the operation and maintenance of the control equipment.

As specified in §64.2(a), the requirements of this regulation apply to a stationary source at a major source that is required to obtain a part 70 or 71 permit and satisfies all of the following criteria:

(1) The source is subject to an emission limit or standard for an air pollutant (or a surrogate thereof) except for an emission limit that is exempt under §64.2(b)(1);
(2) The source uses a control device to achieve compliance with the emission limit or standard; and
(3) The potential pre-control emissions of the pollutant are greater than or equal to the major source threshold for the pollutant.

Control device is defined in §64.1 as equipment, other than inherent process equipment, that is used to destroy or remove air pollutant(s) prior to discharge to the atmosphere. For purposes of this regulation, a control device does not include passive control measures that act to prevent pollutants from forming, such as the use of seals, lids, or roofs to prevent the release of pollutants, use of low-polluting fuel or feedstocks, or the use of combustion or other process design features or characteristics.

The CAM Rule contains the following exemptions, which are specified in §64.2(b)(1):

(i) Emission limits or standards for NSPSs or NESHAPs that were proposed after 11-15-90;
(ii) Stratospheric ozone protection requirements under Title VI of the CAA;
(iii) Acid rain requirements under 40CFR72;
(iv) Emission limitations or standards that apply solely under an emissions trading program;
(v) An emission cap that meets the requirements in §70.4(b)(12);
(vi) Emission limits for which a part 70 (Title V) permit specifies a continuous compliance determination method.

Continuous compliance determination method, which is referenced in the exemption specified in §64.2(b)(1)(vi), is defined in §64.1 as a method, specified by the applicable standard or an applicable permit condition, which: (1) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and (2) Provides data either in units of the standard or correlated directly with the compliance limit.

The proposed new cogeneration unit is potentially subject to this regulation for NOx, CO, and VOC since the pre-control emissions of these pollutants exceed the South Coast Air

Basin major source threshold of 10 ton/yr, 50 ton/yr and 10 ton/yr, respectively, and the unit will utilize an SCR for control of NOx and a CO catalyst for control of CO and VOC. The unit is not equipped with control devices for PM10 and SOx so CAM is not applicable for these pollutants.

For the proposed Cogen C, the NOx and CO CEMS specified in permit conditions D82.3 and D82.4, respectively, meet the definition for a continuous compliance determination method. Therefore, the new cogeneration unit C is exempt from CAM for NOx and CO per the exemption specified in §64.2(b)(1)(vi).

The CO CEMS is also believed to provide an adequate determination of continuous compliance with the VOC emission limits. In development of the MACT Standard for FCCUs (40CFR60 Subpart UUU), EPA determined that CO emissions are a good surrogate for organic HAPS for FCCUs since efficient combustion in the regenerator that would yield low CO emissions would also be expected to yield low organic HAP emissions. For the subject cogeneration unit, CO and VOC concentrations are a function of combustion efficiency and control efficiency of the CO catalyst. CO emissions are the best available indicator of combustion efficiency and the efficiency of the CO catalyst. The CO CEMs will be supplemented with a VOC source test every three years.

For the reasons discussed above, a CAM Plan is not required for the proposed Cogen C.

<u>40CFR Part 72 – Acid Rain Provision</u>

The proposed 61 MW cogeneration unit is not subject to any requirements under Title IV and does not have to apply for an exemption under §72.7 because (1) this equipment is not a "utility unit" as defined in §72.2 (no electricity from the unit is sold). Since the unit is not a utility unit, it is not an "affected unit" under §72.6(a); (2) this equipment is not listed in Table 1 of Section 73.10(a) or Table 2 or 3 of Section 73.10.

CONCLUSION

The proposed permit is expected to comply with all applicable rules and requirements. Issuance of permits to construct is recommended subject to the following conditions

PERMITS CONDITIONS

SYSTEM CONDITIONS

S11.3 The operator shall comply with all applicable mitigation measures stipulated in the "Statement of Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan" document which is part of the AQMD Certified Final Environmental Impact Report dated 4-10-2009 for this facility.

This condition shall only apply to equipment listed in Section H of this facility permit.

[CA PRC CEQA, 11-23-1970]

[Systems subject to this condition : Process 8, System 1, Process 17, System 4]

S31.3 The following BACT requirements shall apply to VOC service fugitive components associated with the devices that are covered by application number(s), 484368 &484369

All new valves and major components in VOC service as defined by Rule 1173, except those specifically exempted by Rule 1173 and those in heavy liquid service as defined in Rule 1173, shall be distinctly identified from other components through their tag numbers (e.g., numbers ending in the letter "N"), and shall be noted in the records.

All open-ended valves shall be equipped with cap, blind flange, plug, or a second valve.

All pressure relief valves shall be connected to closed vent system or equipped with rupture disc.

All process drains shall be equipped with water seal, or a closed vent system and control device.

All sampling connections shall be closed-purge, closed-loop, or closed-vent system.

All components are subject to District Rule 1173.

All new components in VOC service as defined in Rule 1173, except valves and flanges, shall be inspected quarterly using EPA reference Method 21. All new valves

and flanges in VOC service except those specifically exempted by Rule 1173 shall be inspected monthly using EPA Method 21.

All new components in VOC service, a leak greater than 500 ppm but less than 1,000 ppm measured as methane above background as measured using EPA Method 21, shall be repaired within 14 days of detection.

All new valves in VOC service shall be of leakless type, except those specifically exempted by Rule 1173 or approved by the District in the following applications: heavy liquid service, control valves, instrument piping/tubing, applications requiring torsional valve stem motion, applications where failures could pose safety hazards (e.g. drain valves with valve stems in horizontal position), retrofits with space limitations, and valves not commercially available.

If 98.0 percent or greater of the new valve and the new flange population inspected is found to leak gaseous or liquid volatile organic compounds at a rate less than 500 ppm for two consecutive months, then the operator may revert to a quarterly inspection program with the approval of the executive officer. This condition does not apply to leakless valves.

The operator shall keep records of the monthly inspection (and quarterly where applicable), subsequent repair, and reinspection, in a manner approved by the District.

The operator shall provide to the District, no later than 90 days after initial startup, a recalculation of the fugitive emissions based on actual components installed and removed from service. The operator shall also submit a complete, as built, piping and instrumentation diagram(s) and copies of requisition data sheets for all non-leakless type valves with a listing of tag numbers and reasons why leakless valves were not used.

For the purpose of this condition, leakless valve shall be defined as any valve equipped with sealed bellow or equivalent as approved in writing by the District prior to installation.

Components shall be defined as any valve, fitting, pump, compressor, pressure relief device, diaphragm, hatch, sight-glass, and meter, which are not exempt by Rule 1173.

[RULE 1303(a)(1)-BACT, 5-10-1996]

[Systems subject to this condition : Process 17, System 4]

Gas Turbine/HRSG and Related APC Equipment

A. Emission Limits

A63.8 The operator shall limit emissions from this equipment as follows

CONTAMINANT	EMISSIONS LIMIT
VOC	Less than or equal to 1,978 LBS IN ANY ONE MONTH
PM10	Less than or equal to 4,910 LBS IN ANY ONE MONTH

For the purposes of this condition, the limit(s) shall be based on the total combined emissions from equipment D1619 (Gas turbine) and D1621 (Duct Burner). The operator shall calculate VOC emissions by using monthly fuel use data and emissions factors, in units of lbs VOC/MMscf: 2.94E-7 x F_d-Factor x HV for the fuel gas; where the F_d-Factor is the ratio of the volume of products of combustion to the fuel heat content, in units of dscf/MMBtu, and HV is fuel heating value, in units of Btu/scf. Monthly averages of F_d-Factor and HV for the gas shall be used in this calculation.

The operator shall calculate the monthly emissions for PM10 using the equation below and the following emission PM10 = .0105 lb/MMBTU.
Monthly Emissions, lb/month = X * (EF). Where X = monthly heat input, MMBTU/month; and EF = emission factor indicated above.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002**]**

[Devices subject to this condition: D1619, D1620]

(1)See page 19 of this evaluation for the emission factors

A99.6 The 2.0 PPM and 2.5 PPM NOX emission limit(s) shall not apply during turbine commissioning, startup, and shutdown periods. The commissioning period shall not exceed 514 operating hours. The turbine shall limited to a maximum of 48 startups per year. The time for cold startup shall not exceed 2 hours for each startup. The time for warm startup shall not exceed 1.5 hours. The time for hot startup shall not exceed 1 hour. The time for shutdown shall not exceed 1/2 hour. The turbine shall be limited to 8 cold startups per year, 10 warm startups per year, 30 hot startups per year and 48 shutdowns per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer or his designee.

For the purposes of this condition, start-up and shutdown shall be defined as the period when the exhaust temperature of this equipment is below 500 degree F.

[RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 2005,4-20-2001; RULE 2005, 5-6-2005]

[Devices subject to this condition : D1619, D1621]

A99.7 The 2.0 PPM CO emission limit(s) shall not apply during turbine commissioning, startup, and shutdown periods. The commissioning period shall not exceed 514 operating hours. The turbine shall limited to a maximum of 48 startups per year. The time for cold startup shall not exceed 2 hours for each startup. The time for warm startup shall not exceed 1.5 hours. The time for hot startup shall not exceed 1 hour. The time for shutdown shall not exceed 1/2 hour. The turbine shall be limited to 8 cold startups per year, 10 warm startups per year, 30 hot startups per year and 48 shutdowns per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer or his designee.

For the purposes of this condition, start-up and shutdown shall be defined as the period when the exhaust temperature of this equipment is below 500 degree F.

[RULE 1703(a)(2) - PSD-BACT, 10-7-1988]
[Devices subject to this condition : D1619, D1621]

A99.8 The 2.0 PPM VOC emission limit(s) shall not apply during turbine commissioning, startup, and shutdown periods. The commissioning period shall not exceed 514 operating hours. The turbine shall limited to a maximum of 48 startups per year. The time for cold startup shall not exceed 2 hours for each startup. The time for warm startup shall not exceed 1.5 hours. The time for hot startup shall not exceed 1 hour. The time for shutdown shall not exceed 1/2 hour. The turbine shall be limited to 8 cold startups per year, 10 warm startups per year, 30 hot startups per year and 48 shutdowns per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer or his designee.

For the purposes of this condition, start-up and shutdown shall be defined as as the period when the exhaust temperature of this equipment is below 500 degree F.

[RULE 1303(a)(1)-BACT, 5-10-1996]
[Devices subject to this condition : D1619, D1621]

A99.9 The 43.6 LBS/MMSCF NOX emission limit(s) shall only apply during the interim reporting period during initial turbine commissioning to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.

[RULE 2012, 5-6-2005]
[Devices subject to this condition : D1619, D1621]

A99.10 The 8.5 LBS/MMSCF NOX emission limit(s) shall only apply during the interim reporting period after initial turbine commissioning when the turbine is operating with or without duct firing to report RECLAIM emissions.
The interim reporting shall not exceed 12 months from entry into RECLAIM.

[RULE 2012, 5-6-2005]

[Devices subject to this condition : D1619, D1621]

A99.11 The 6.65 LBS/MMSCF SOX emission limit(s) shall only apply during the interim reporting period during initial turbine commissioning to report RECLAIM emssions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.

[RULE 2011, 5-6-2005]

[Devices subject to this condition : D1619, D1621, D1629, D1634]

A99.12 The 34 LBS/MMSCF SOX emission limit(s) shall only apply during the interim reporting period after initial turbine commissioning when the turbine is operating with or without duct firing to report RECLAIM emissions.

The interim reporting shall not exceed 12 months from entry into RECLAIM.

[RULE 2011, 5-6-2005]

[Devices subject to this condition : D1619, D1621, D1629, D1634]

A195.9 The 2.5 PPMV NOX emission limit(s) is averaged over 1 hour at 15 percent O2 dry.

For the purpose of this condition, this limit shall apply only when the cogeneration unit is burning Refinery gas. Refinery gas is defined as a mixture of refinery fuel gas, produced within the refinery, and natural gas obtained from a utility regulated by the Public Utilities Commission (PUC), for which the natural gas component of the mixture does not exceed 50% of the total, by Higher Heating Value (HHV) content.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 2005, 5-6-2005]

[Devices subject to this condition : D1619, D1621]

A195.10 The 2.0 PPMV CO emission limit(s) is averaged over 1 hour at 15 percent O2 dry.

[RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition : D1619, D1621]

A195.11The 5 PPMV NH3 emission limit(s) is averaged over 1 hour at 15 percent O2 dry.

The operator shall calculate and continuously record the NH3 slip concentration using the following:NH3(ppmv)=[a-b*c/1E6]*1E6/b, where a=NH3 injection rate(lb/hr)/17 (lb/lbmole), b= dry exhaust gas flow rate (scf/hr)/385.3 scf/lbmole, and c= change in measured NOx across the SCR(ppmvd at 15 percent O2). The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppm accurate to within plus or minus 5 percent calibrated at least once every 12 months.

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

The operator shall use the method described above or another alternative method approved by the Executive Officer.

The ammonia slip calculation procedures described above shall not be used for compliance determination for emission information determination without corroborative data using an approved reference test method for the determination of ammonia.

[RULE 1303(a)(1)-BACT, 5-10-1996]

[Devices subject to this condition : C1626]

A195.17 The 2.0 PPMV VOC emission limit(s) is averaged over 1 hour at 15 percent O2 dry.

[RULE 1303(a)(1)-BACT, 5-10-1996]

[Devices subject to this condition : D1619, D1621]

A195.18 The 2.0 PPMV NOX emission limit(s) is averaged over 3 hour at 15 percent O2 dry. For the purpose of this condition, this limit shall apply only when the cogeneration unit is burning Refinery gas. Refinery gas is defined as a mixture of refinery fuel gas, produced within the refinery, and natural gas obtained from a utility regulated by the Public Utilities Commission (PUC), for which the natural gas component of the mixture does not exceed 50% of the total, by Higher Heating Value (HHV) content.

[RULE 2005, 5-6-2005]

[Devices subject to this condition : D1619, D1621]

A195.19 The 2.0 PPMV NOX emission limit(s) is averaged over 1 hour at 15 percent O2 dry. For the purpose of this condition, this limit shall apply only when the cogeneration unit is burning Natural gas. Natural gas is defined as a mixture of refinery fuel gas, produced within the refinery, and natural gas obtained from a utility regulated by the Public Utilities Commission (PUC), for which the natural gas component of the mixture exceeds 50% of the total, by Higher Heating Value (HHV) content.

[RULE 2005, 5-6-2005]

[Devices subject to this condition : D1619, D1621]

A327.2 For the purpose of determining compliance with District Rule 476, combustion contaminant emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.

[RULE 476, 10-8-1976]

[Devices subject to this condition : D1619, D1621, D1629, D1634]

B. Material/Fuel Type Limits

B59.7 The operator shall only use the following material(s) in this device :

Refinery fuel gas meeting sulfur limit specified by condition B61.8, natural gas, or mixture of refinery fuel gas and natural gas

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition : D1619, D1621 D1629, D1634]

B61.8 The operator shall not use fuel gas containing the following specified compounds:

Compound		ppm by volume
total sulfur compounds calculated as H2S	greater than	40

The total reduced sulfur concentration limit shall apply to refinery fuel gas and be based on one-hour averaging period and measured before blending with natural gas

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : D1619, D1621, D1629, D1634]

B61.10 The operator shall not use fuel gas containing the following specified compounds:

Compound		ppm by volume
H2S	greater than	162
H2S	greater than	60

The 162 ppm limit shall be based on a rolling 3-hour averaging period
The 60 ppm limit shall be based on a rolling 365 successive calendar day rolling average

[40CFR 60 Subpart Ja, 6-24-2008]

[Devices subject to this condition : D1619, D1621 D1629, D1634]

D. Monitoring/Testing Requirements

D12.10 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the the total hourly throughput recorded of injected ammonia.

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.

[RULE 1303(a)(1)-BACT, 5-10-1996]

[Devices subject to this condition : C1626, C1631, C1636]

D12.11 The operator shall install and maintain a(n) temperature reading device to accurately indicate the temperature of 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 12 months.

[RULE 1303(a)(1)-BACT, 5-10-1996]

[Devices subject to this condition : C1626, C1631, C1636]

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 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.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 2012, 5-6-2005**]

[Devices subject to this condition : C1631, C1636]

D12.16 The operator shall install and maintain a(n) differential pressure gauge to accurately indicate the differential pressure across the CO catalyst bed.

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.

For the purpose of this condition, continuously record shall be defined as

recording at least once every week and shall be calculated based upon the average of the continuous monitoring for that week

[RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition : C1625]

D12.17 The operator shall install and maintain a(n) temperature reading device to accurately indicate the temperature at the inlet of the CO catalyst bed. CO catalyst bed.

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.

For the purpose of this condition, continuously record shall be defined as recording at least once every hour and shall be based upon the average of the continuous monitoring for that hour

[RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition : C1625]

D29.9 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test	Averaging Time	Test Location
NOx emissions	Approved District Method	District-approved averaging time	Stack Outlet
SOx emissions	Approved District Method	District-approved averaging time	Stack Outlet
CO emissions	Approved District Method	District-approved averaging time	Stack Outlet
ROG emissions	Approved District Method	District-approved averaging time	Stack Outlet
PM10 emissions	Approved District Method	District-approved averaging time	Stack Outlet
NH3 emissions	Approved District Method	District-approved averaging time	Stack Outlet

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 test shall record the fuel flow rate(CFH), the flue gas flowrate, and the turbine and steam turbine generating output in MW.

The test shall be conducted in accordance with AQMD approved source test protocol. The protocol shall be submitted to the AQMD no later than 45 days before the proposed test date and shall be approved by the AQMD before test commences. The test protocol shall include the proposed operating conditions of the turbine during the test, 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.

The test shall be conducted with and without duct firing when this equipment is operating at maximum , average, and minimum load.

VOC compliance shall be demonstrated as follows a) Stack gas samples are extracted into summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters are done with zero gas analyzer/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA Method TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70°F

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than 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 VOC BACT level of 2.0 ppmv calculated as carbon for gas fired turbine

Because the VOC BACT level was set using derived from various source test results, this alternative VOC compliance method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time.

The test results shall be reported with two significant digits

For the purpose of this condition, alternative test methods may be allowed for each of the above pollutants upon concurrence AQMD and EPA

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002; **RULE1303(b)(2)-Offset, 5-10-1996;** RULE 1303(b)(2)-Offset, 12-6-2002; RULE 1703(a)(2) PSD-BACT, 10-7-1988; **RULE 2005, 4-20-2001; RULE 2005, 5-6-2005**]

[Devices subject to this condition : D1619, D1621]

D29.10 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
NH3 emissions	Approved District Method	District-approved averaging time	Stack Outlet

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 or not yet certified, the test shall be conducted to determine the NOx emissions using District Method 100.1 measured over 60 minutes averaging time period.

The test shall be conducted no later than 180 days after initial start up

The test results shall be 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 7 days prior to the test

The test shall be conducted to demonstrate compliance with Rule 1303 concentration limit. If the equipment is not operated in any given quarter, the operator may elect to defer the required testing to a quarter in which the equipment is operated.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002]
[Devices subject to this condition : C1626, C1631, C1636]

D29.11 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test	Averaging Time	Test Location
VOC emissions	Approved District Method	District-approved averaging time	Stack Outlet
PM10 emissions	Approved District Method	District-approved averaging time	Stack Outlet

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

The test shall be conducted and the results submitted to the AQMD within 60 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 with and without duct firing when this equipment is operating at least at 80 percent of maximum load.

The test shall be conducted to demonstrate compliance with the monthly emission limit.

[**RULE 1303(a)(1)-BACT, 5-10-1996;** RULE 1303(a)(1)-BACT, 12-6-2002;
RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition : D1619, D1621]

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

CO concentration in ppmv at the outlet of the SCR serving the equipment

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 Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval. Within two weeks of the turbine start-up, the operator shall provide written notification to the AQMD of the exact date of start-up

The CEMS shall be installed and operated to measure the CO concentration over a 15 minute averaging time period. The CO mass emission shall be calculated monthly based on monthly fuel gas usage multiply by monthly average CO concentration

[RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

Devices subject to this condition : D1619, D1621]

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

NOx concentration in ppmv

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

The CEMS shall be installed and operating no later than 90 days after initial start up of the turbine and shall comply with the requirements of Rule 2012. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3). Within two weeks of turbine start-up date, the operator shall provide written notification to the District of the exact date of start-up

The CEMS shall be installed and operating (for BACT purposes only) no later than 90 days after initial start up of the turbine.

[**Rule 2005, 5-6-2005**; **RULE 2012, 5-6-2005**]
Devices subject to this condition : D1619, D1621]

D90.20 The operator shall continuously monitor the H2S concentration in the fuel gases before being burned in this device according to the following specifications:

The operator shall use Gas Chromatograph meeting the requirements of 40CFR60 Subpart Ja to monitor the parameter.

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

The operator may monitor the H2S concentration at a single location for fuel combustion devices, if monitoring at this location accurately represents the concentration of H2S in the fuel gas being burned in this device.

[40CFR 60 Subpart Ja, 6-24-2008]

[Devices subject to this condition : D1619, D1621, D1629, D1634]

D90.21 The operator shall continuously monitor the total sulfur compounds calculated as H2S concentration in the fuel gases before being burned in this device and before blending with natural gas according to the following specifications:

The CEMS shall be approved by the District before the initial start-up
The operator shall also install and maintain a device to continuously record the parameter being monitored.

The operator may monitor the total sulfur compounds calculated as H2S concentration at a single location for fuel combustion devices, if monitoring at this location accurately represents the concentration of total sulfur compounds calculated as H2S in the fuel gas being burned in this device.

[RULE 2005, 5-6-2005]

[Devices subject to this condition : D1619, D1621, D1629, D1634]

E. Equipment Operation/Construction Requirements

E73.4 Notwithstanding the requirements of Section E conditions, the operator may, at his discretion, choose not to use ammonia injection if any of the following requirement(s) are met:

The inlet exhaust temperature to the SCR reactor is below 500 degrees F

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 2005, 5-6-2005]**

[Devices subject to this condition : D1619, D1621]

E179.3 For the purpose of the following condition number(s), continuously record shall be defined as once every hour and shall be calculated upon average of the continuous monitoring for that hour.

Condition Number D 12-10

Condition Number D 12-11

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 2012, 12-5-2003; RULE 2012, 1-7-2005]

[Devices subject to this condition : C1626, C1631, C1636]

E179.4 For the purpose of the following condition number(s), continuously record shall be defined as once every month and shall be calculated upon average of the continuous monitoring for that month.

Condition Number D 12-12

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 2012, 12-5-2003; RULE 2012, 1-7-2005]

[Devices subject to this condition : C1626, C1631, C1636]

E193.6 The operator shall construct, operate, and maintain this equipment according to the following specifications:

To establish equivalency of a catalyst, the operator shall submit the following information for the catalyst to the district permitting engineer: manufacturer, description (type), configuration, dimensions(per block), number of blocks, total volume, space velocity, life, vendor performance guarantee, performance curve(versus temperature), minimum operating temperature, estimated SO2 to SO3conversion, estimated NO to NO2 conversion, and concentration of Rule 1401 TACs

The operator shall not install and use an "equivalent" catalyst until approval is received in writing from the District

[**RULE 1303(a)(1)-BACT, 5-10-1996**]

[Devices subject to this condition : C1625, C1626]

H. Applicable Rules

H23.37 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, 7-6-2006]

[Devices subject to this condition : D1619, D1621]

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

To comply with this condition, the operator shall prior to the first compliance year hold a minimum 60,503 lbs/yr of NOx RTCs and 22,468 lbs/yr of SOx RTCs. This condition shall apply to the first year of operation, commencing with the initial operation of the gas turbine

To comply with this condition, the operator shall, prior to the begining of all years subsequent to the first compliance year, hold a minimum 56,574 lbs/yr of NOx RTCs and 23,039 lbs/yr of SOx RTCs for operation of the gas turbine. In accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the first year

For the purpose of this condition, unused RTCs is the difference between (1) the amount of NOx RTCs required to be held at the begining of a compliance year as specified in this condition and the amount of NOx emissions during each applicable compliance year and (2) the amount of SOx RTCs required to held at the begining of a compliance year as specified in this condition and amount of SOx emissions during each applicable compliance year

[RULE 2005, 5-6-2005]

[Devices subject to this condition : D1619, D1621]

K40.2 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 60 days after the source test was conducted.

Emission data shall be expressed in terms of concentration (ppmv), corrected to 15 percent oxygen, dry basis.

Emission data shall be expressed in terms of mass rate (lbs/hr). In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

Emission data shall be expressed in terms of lbs/MM cubic feet.

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

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1303(b)(2)-Offset, 5-10-1996**; RULE 1303(b)(2)-Offset, 12-6-2002]

K67.14 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

Fuel use during the commissioning period

fuel use after the commissioning period and prior to CEMS certification

fuel use after CEMS certification

[RULE 2012, 5-6-2005]

[Devices subject to this condition : D1619, D1629, D1634]

Appendix A – CTG/HRSG Stack Parameters

Table A-1 CTG/HRSG Stack Parameters

Load (%)	**Ambient Temp** (°F)	**Duct Burner** (On/Off)	**Stack Gas Temp** (°K)	**Stack Gas Velocity** (m/s)	**Stack Gas Flow Rate At Stack Temp** (m^3/s)	**Stack Gas Flow Rate** (SCFM)
100	**36**	**On**	**448 (346 °F)**	**25.93 (85.1 ft/s)**	**207 (7,310 ft^3/s)**	**241,620**
100	36	Off	468 (382 °F)	26.92 (88.3 ft/s)	214.9 (7,589 ft^3/s)	237,060
75	36	Off	465 (377 °F)	21.38 (70.1 ft/s)	170.65 (6,026 ft^3/s)	189,680
100	103	On	443 (338 °F)	23.43 (76.9 ft/s)	187 (6,602 ft^3/s)	221,142
100	103	Off	464 (375 °F)	24.4 (80.1 ft/s)	194.6 (6,872 ft^3/s)	216,977
75	103	Off	460 (368 °F)	18.98 (62.3 ft/s)	150.4 (5,311 ft^3/s)	169,521

Note:

1. Duct Burner only comes on at full load
2. Stack Parameter: Diameter: 3.19 m (10.5 ft), Area: 7.99 m^2 (86.0 ft^2) and Height: 36.58 m (120.0 ft)

Appendix B – CTG/HRSG Emission Calculations – Normal Operation (Full Load)
(Information in this appendix is summarized in Table 8 of this report)

Emission Factors:

The following formula and assumptions are used to calculate the energy-based emission factors:

$$EF\ (lb/MMBTU) = PPMVD \times MW \times (1/SMV)\ \frac{(20.9\%\ O_2 - 0\%\ O_2)}{(20.9\%\ O_2 - 15\%\ O_2)} \times F_D \times 10^{-6}$$

Where,

EF = emission factor

PPMVD = pollutant concentration at concentration corrected to 15 % O_2

SMV = molar volume at 68 °F = 385.3 DSCF/lb-mol

MW = molecular weight of pollutant

F_D = Oxygen Based Dry fuel Factor specific for TESORO LAR refinery gas tested in accordance with RECLAIM Rule 2012 Protocol = 8552 DSCF combustion products/MMBTU

Standard Condition:

Pressure = 29.92 inches Hg (14.7 psia), Temperature = 68 °F

Emission Rate:

Uncontrolled Emission Rate = Uncontrolled EF (lb/MMBTU)xHeat Input HHV (MMBTU/hr)

Controlled Emission Rate = Controlled EF (lb/MMBTU) X Heat Input HHV (MMBTU/hr)

Assumption:

1. NO_X concentration from CTG prior to steam injection = 85.2 PPMV [a]
   NO_X concentration from CTG after steam injection = 42 PPMV @ 15% O_2[a]
   NO_X emission from duct burner prior to SCR = .05 lb/MMBTU [a]
   NO_X concentration after SCR = 2.5 PPMV @ 15% O_2 (1-hr average) [a]
   NO_X concentration after SCR = 2.0 PPMV @ 15% O_2 (3-hr average) [a]
2. PM10 emission is based on manufacturer guarantee
3. SO_X emission is based on 40 PPMV total sulfur in refinery fuel gas expressed as H_2S averaged over a 1 hour period. One mole of H2S coverts to one mole SO2 (H2S MW = 34 lb/lb-mole, SO2 MW = 64 lb/lb-mole)
4. VOC concentration CTG prior to oxidation catalyst 1.4 PPMVW @ stack O_2 [a] (1.8 PPMVD @ 15% O_2)
   VOC emission from duct burner prior to oxidation catalyst = .01 lb/ MMBTU (manufacturer guarantee).
   VOC concentration after catalyst = 2.0 PPMV @ 15% O_2 (1-hr average) [a]
5. CO concentration CTG prior to oxidation catalyst = 38 PPMVD @ 15% O_2 [a]
   CO emission from duct burner prior to oxidation catalyst = .05 lb/ MMBTU [b]
   CO concentration after catalyst = 2.0 PPMV @ 15% O_2 (1-hr average) [a]
6. Stack Gas Moisture (with duct firing) = 10%
7. Stack Gas Oxygen (with duct firing) = 12% wet, 13.3% dry
8. Normal Operation at full load with duct burner on – worst case 36 °F Ambient

[a] Manufacturer's data [b] AP-42, 7/98, Tables 1.4.1 and 1.4.2

Table B-1: NOx Emissions (Normal Operations)

Operating Condition (100% Capacity)	Heat Input (HHV) (MMBTU/hr)	Duct Burner Heat Input (HHV) (MMBTU/hr)	CTG Uncontrolled Emission Rate (lb/hr)	Duct Burner Uncontrolled Emission Rate (lb/hr)	CTG+DB Uncontrolled Emission Rate (lb/hr)	Pollutant Conc. Controlled (PPMVD)	Emission Factor Controlled (lb/MMBTU)	Emission Rate Controlled (lb/hour)
CTG(103F)	470	N/A	71.40	N/A	N/A	2.5	.009	4.25
CTG (36 F)	534	N/A	81.12	N/A	N/A	2.5	.009	4.83
CTG + DB (103 F)	565	95	N/A	4.75	76.14	2.5	.009	5.05
CTG + DB (36 F)	629	95	N/A	4.75	85.87	2.5	.009	5.62

Table B-2: CO Emissions (Normal Operations)

Operating Condition (100% Capacity)	Heat Input (HHV) (MMBTU/hr)	Duct Burner Heat Input (HHV) (MMBTU/hr)	CTG Uncontrolled Emission Rate (lb/hr)	Duct Burner Uncontrolled Emission Rate (lb/hr)	CTG+DB Uncontrolled Emission Rate (lb/hr)	Pollutant Conc. Controlled (PPMVD)	Emission Factor Controlled (lb/MMBTU)	Emission Rate Controlled (lb/hour)
CTG(103F)	470	N/A	39.32	N/A	N/A	2.0	.0044	2.07
CTG (36 F)	534	N/A	44.67	N/A	N/A	2.0	.0044	2.35
CTG + DB (103 F)	565	95	N/A	4.75	44.07	2.0	.0044	2.46
CTG + DB (36 F)	629	95	N/A	4.75	49.42	2.0	.0044	2.77

Table B-3: VOC (expressed as CH_4) Emissions (Normal Operations)

Operating Condition (100% Capacity)	Heat Input (HHV) (MMBTU/hr)	Duct Burner Heat Input (HHV) (MMBTU/hr)	CTG Uncontrolled Emission Rate (lb/hr)	Duct Burner Uncontrolled Emission Rate (lb/hr)	CTG+DB Uncontrolled Emission Rate (lb/hr)	Pollutant Conc. Controlled (PPMVD)	Emission Factor Controlled (lb/MMBTU)	Emission Rate Controlled (lb/hour)
CTG(103F)	470	N/A	1.06	N/A	N/A	2.0	.0025	1.18
CTG (36 F)	534	N/A	1.21	N/A	N/A	2.0	.0025	1.34
CTG + DB (103 F)	565	95	N/A	0.95	2.01	2.0	.0025	1.40
CTG + DB (36 F)	629	95	N/A	0.95	2.16	2.0	.0025	1.57

Table B-4: PM10 Emissions (Normal Operations)

Operating Condition	Heat Input (MMBTU/hr)	Fuel Flow Rate CTG (DSCF/hr)	Emission Factor (lb/MMSCF)	Emission Rate CTG Uncontrolled (lb/hr)	Fuel Flow Rate DB (DSCF/hr)	Emission Rate DB Uncontrolled (lb/hr)	Emission Rate CTG+DB Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
CTG(103F)	470	391,667	13.2	4.66	N/A	N/A	N/A	4.66
CTG (36 F)	534	445,000	13.2	5.30	N/A	N/A	N/A	5.30
CTG + DB (103 F)	565	470,833	N/A	N/A	79,167	0.95	5.54	5.61
CTG + DB (36 F)	629	524,167	N/A	N/A	79,167	0.95	6.18	(CTG + DB) 6.25
SO2 to SO4 Conversion	Assume < 8 % SO2 to SO3 Conversion and PM10 as ammonium sulfate: $\frac{40 \text{ lb-mole Total S as H2S}}{10^6 \text{ lb-mole FG}} \times \frac{\text{lb-mole SO2}}{\text{lb-mole H2S}} \times \frac{64 \text{ lb SO2}}{\text{lb-mole SO2}} \times \frac{\text{lb-mole FG}}{385.3 \text{ SCF FG}} \times \frac{\text{scf FG}}{1200 \text{ BTU}} \times \frac{629 \text{ MMBTU}}{\text{HR}} \times \frac{0.08 \text{ lb SO3}}{\text{lb SO2}} = \frac{0.28 \text{ lb SO3}}{\text{hr}}$ $= \frac{0.28 \text{ lb SO3}}{\text{Hr}} \times \frac{\text{lb-mole SO3}}{80 \text{ lb SO3}} \times \frac{\text{lb-mole (NH4)2 SO4}}{\text{lb-mole SO3}} \times \frac{132 \text{ lb (NH4)2 SO4}}{\text{lb-mole (NH4)2 SO4}} = 0.46 \text{ lb/hr} \times 24 \text{ hr/day} = 11.04 \text{ lb/day}$							0.46+6.25=6.71 6.71/629mmbtu/hr =0.0106 lb/mmbtu

Table B-5: SOx Emissions (Normal Operations)

Operating Condition	Heat Input (MMBTU/hr)	Fuel Flow Rate CTG (DSCF/hr)	Emission Factor (Grains Sulfur as H2S/100 DSCF Fuel)	Emission Rate CTG Uncontrolled SO2 (lb/hr)	Fuel Flow Rate DB (DSCF/hr)	Emission Rate DB Uncontrolled (lb/hr)	Emission Rate CTG+DB Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
CTG(103F)	470	391,667	1.00	1.96	N/A	N/A	N/A	1.96
CTG (36 F)	534	445,000	1.00	2.23	N/A	N/A	N/A	2.23
CTG + DB (103 F)	565	470,833	1.00	N/A	79,167	0.40	2.36	2.36
CTG + DB (36 F)	629	524,167	1.00	N/A	79,167	0.40	2.63	2.63

Table B-6: NH3 Emissions (Normal Operation)

Operating Condition At Full Load	Heat Input HHV (MMBTU/hr)	Stack Gas Flowrate (SCF/hr)	Stack Gas Moisture (%)	Stack Gas Oxygen (wet) (%)	Stack Gas Flow Rate (DSCF/hr)	Stack Gas Oxygen (dry) (%)	NH3 Concentration @15%O2 (PPMVD)	Emission Rate (lb/hr)
CTG (36 F)	470	14,223,600	8.5	12.3	13,014,594	13.4	5	3.65
CTG(103 F)	534	13,018,620	9	13.8	11,912,037	15.2	5	2.54
CTG+DB (36 F)	565	14,497,200	10	12	13,264,938	13.3	5	3.77
CTG+DB (103 F)	629	13,268,520	10	12	12,140,696	13.3	5	3.45

Appendix C – Commissioning Period Emissions

Table C1 – CTG Commissioning Period Emissions

Commissioning Task	Total Fuel Consumption MMSCF	Total Hours	CO (lb/task)	NOx (lb/task)	PM10 (lb/task)	VOC (lb/task)	SOx (lb/task)	CO EF (lb/MMSCF)	NOx EF (lb/MMSCF)	PM10 EF (lb/MMSCF)	VOC EF (lb/MMSCF)	SOx EF (lb/MMSCF)
First Fired/ Overspeed trip	0.82	2	740	261	11	19	4	900	318	12.8	23	5.0
FSNL/Spinning Reserve Sync	2.46	8	2,218	784	32	57	12	900	318	12.8	23	5.0
Combustion Tuning Sync	8.22	24	1,643	1,314	105	189	41	200	160	12.8	23	5.0
Duct Burner Testing	14.44	40	2,888	2,310	185	332	72	200	160	12.8	23	5.0
Catalyst Loading	0	60										5.0
Slip Test/Steam Blow	19.25	50	250	385	246	116	96	13	20	12.8	6	5.0
Steam Blow	9.65	40	154	193	124	58	48	16	20	12.8	6	5.0
CEMS Drift Test/ RATA	91.9	250	643	1,378	1176	368	460	7	15	12.8	4	5.0
Full Load Rejection Testing	9.63	40	1,059	193	123	58	48	110	20	12.8	6	5.0
Totals	156.37	514	9,596	6,818	2,002	1,195	781					

The turbine commissioning period will be approximately 90 days with the total commission hours not to exceed 514.

Appendix D –AEIS Emissions Calculation

Data:
CTG/HRSG operation with duct firing = 8675 hours/year
CTG/HRSG Cold Starts = 16 hours/year (8 events)
CTG/HRSG Warm Starts = 15 hours/year (10 events)
CTG/HRSG Hot Starts = 30 hours/year (30 events)
CTG/HRSG Shutdown = 24 hours/year (48 events)

Table D-1: CTG/HRSG Uncontrolled Emission Calculations (Hourly Emissions from Table 8,9,10, 11, 12 and 14 of This Report)

Operating Condition	Hours per Year	CO (lb/hr)	NO_X (lb/hr)	PM10 (lb/hr)	VOC (lb/hr)	SO_X (lb/hr)	CO (lb/year)	NO_X (lb/year)	PM10 (lb/year)	VOC (lb/year)	SO_X (lb/year)
Cold Starts	16	138.5	92	6.60	12	2.63	2,216	1,472	106	192	42
Warm Starts	15	138.5	92	6.60	12	2.63	2,076	1,380	99	180	39
Hot Starts	30	138.5	92	6.60	12	2.63	4,155	2,760	198	360	79
Shutdown	24	70	46	3.30	6	1.32	1,680	1,104	79	144	32
Normal Operation (36 F, DB ON)	8,675	49.42	85.87	6.60	2.16	2.63	428,718	744,922	57,255	18,738	22,815
Total CTG/HRSG	8,760						435,810	748,602	57,737	19,007	23,007
							lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Uncontrolled Emissions (lb/hr)							49.75	85.46	6.60	2.16	2.63

Table D-2: CTG/HRSG Controlled Emission Calculations

Operating Condition	Hours per Year	CO (lb/hr)	NO_X (lb/hr)	PM10 (lb/hr)	VOC (lb/hr)	SO_X (lb/hr)	CO (lb/year)	NO_X (lb/year)	PM10 (lb/year)	VOC (lb/year)	SO_X (lb/year)
Cold Starts	16	138.5	92	6.60	12	2.63	2,216	1,472	106	192	42
Warm Starts	15	138.5	92	6.60	12	2.63	2,078	1,380	99	180	39
Hot Starts	30	138.5	92	6.60	12	2.63	4,155	2,760	198	360	79
Shutdown	24	70	46	3.3	6	1.32	1,680	1,104	79	144	32
Normal Operation (36 F, DB ON)	8,675	2.74	5.62	6.60	1.57	2.63	23,770	39,003*	57,255	13,620	22,815
Total	8,760						33,898	44,615	57,737	14,496	23,007
							lb/hr	lb/hr	lb/hr	lb/hr	lb/hr
Controlled Emissions (lb/hr)							3.87	5.10	6.60	1.65	2.63

- Based on 2.00 ppm NOx @15% -3-hour average

Appendix E – Emission Offset Calculations (Non-RECLAIM Pollutants)

CTG/HRSG Data:

CTG/HRSG operation with duct firing = 744 hours/month (assume 31 days/month and duct firing for all normal operation for calculating the most conservative emissions offset requirement.) **Daily offset calculated from 31 days calendar monthly divided by 30 days (per Rule 1306 (b)**

CTG/HRSG Cold Starts = 4 hours/month
CTG/HRSG Warm Starts = 6 hours/month
CTG/HRSG Hot Starts = 6 hours/month
CTG/HRSG Shutdown = 6 hours/month
Maximum number of start-ups per day = 3 (1 cold, 1 warm, 1 hot = 4.5 hours)
Maximum number of start-ups per month = 12 (2 cold, 4 warm and 6 hot = 16 hours)
Maximum number of start up per year = 48 (8 cold, 10 warm, 30 hot = 61 hours)
Start up duration: 2 hour cold, 1.5 hour warm, and 1 hour hot
Shutdown duration: ½ hour
Assume 31 days/month, 365 days/yr. Daily offset calculated from 31 days calendar monthly divided by 30 days (per Rule 1306 (b))

Table E-1: CTG/HRSG Emission Offsets Calculation
(Data from Tables 10, 11, 12 and 14 of this report)

Operating Condition	Hours per Month	PM10 (lb/hr)	VOC (lb/hr)	PM10 (lb/month)	VOC (lb/month)
Cold Starts	4	6.60	12.00	26.40	48.00
Warm Starts	6	6.60	12.00	39.60	72.00
Hot Starts	6	6.60	12.00	39.60	72.00
Shutdown	6	6.60*	12.00*	39.60	72.00
Normal Operation (36 F) with Duct Burner	722	6.60	1.57	4765.20	1133.54
Total CTG/HRSG	744			4910.40	1,397.54
Fugitive Components	744				270.16
Total Permit Unit	744			4910.40	1,667.7
				lb/day	lb/day
30-Day Avg Emissions (lb/day)				163.68	55.59

**The actual PM10 and VOC emissions during shutdown in Table 12 is 3.3 lb/hr and 6 lb/hr respectively, to be conservation, the calculation uses 6.6 lb/hr for PM10 and 12 lb/hr for VOC in this offset calculation*

Appendix F – NOX RTC Calculations

Table F-1: RECLAIM Pollutants Emissions from CTG/HRSG – First Year

Operating Condition	Hours per Year	NO_X (lb/hr)	SO_X (lb/hr)	NO_X (lb/year)	SO_X (lb/year)
Commissioning	514	-	-	6,818	781
Cold Starts	16	92	2.63	1,472	42
Warm Starts	15	92	2.63	1,380	40
Hot Starts	30	92	2.63	2,760	79
Shutdown	24	92	2.63	2,208	63
Normal Operation (36 F) with Duct Burner	8,161	5.62	2.63	44,615	21,463
Total	8,760			59,253	22,468

Note: Although NOX and SOX emissions during shutdowns are 46 and 1.32 lb/hr respectively, for the purpose of determining NOX and SOX required to be held at the beginning of each year, the most conservative NOX and SOX estimates (lb/hr) are used in this table by assuming maximum firing rate with duct firing and with no control during start-up, shutdown. Maximum firing rate with duct firing and control is assumed during normal operation.

Table F-1B: RECLAIM Pollutants Emissions from CTG/HRSG – Subsequent Years

Operating Condition	Hours per Year	NO_X (lb/hr)	SO_X (lb/hr)	NO_X (lb/year)	SO_X (lb/year)
Cold Starts	16	92	2.63	1,472	42
Warm Starts	15	92	2.63	1,380	40
Hot Starts	30	92	2.63	2,760	79
Shutdown	24	92	2.63	2,208	63
Normal Operation (36 F) with Duct Burner	8,675	5.62	2.63	44,615	22,815
Total	8,760			52,435	23,039

Note: Although NOX and SOX emissions during shutdowns are 46 and 1.32 lb/hr respectively, for the purpose of determining NOX and SOX required to be held at the beginning of each year, the most conservative NOX and SOX estimates (lb/hr) are used in this table by assuming maximum firing rate with duct firing and with no control during start-up, shutdown. Maximum firing rate with duct firing and control is assumed during normal operation.

Total Turbine C, – First Year	NOx (lb/year)	SOx (lb/year)
	59,253	22,468
Total Turbine C, – Each subsequent Year	NOx (lb/year)	SOx (lb/year)
	52,435	23,039

Appendix G– Interim Period RECLAIM Emission Factor Calculations for CTG & Duct Burner

Data:
Maximum CTG Heat Input = 534 MMBTU/HR HHV
Maximum CTG Fuel Usage = (534 MMBTU/HR) * (1 SCF/1200 BTU) = 0.445 MMSCF/HR
Maximum CTG + Duct Burner Heat Input = 622 MMBTU/HR HHV
Maximum CTG + Duct Burner Fuel Usage = (622 MMBTU/HR) * (1 SCF/1200 BTU) = 0.518 MMSCF/HR

Table G-1: Emission Factors (Base Load , Start Up and Shutdown)

Pollutant	Turbine Reported Value (RV) for RECLAIM Start Year Allocation (lb/MMSCF)
SOX	34
NOX	8.5

From Table D-2 (page65)
NOx = 92 lb/hr(16 hrs/year) + 92 lb/hr(15 hrs/year)+ 92 lb/hr(30 hrs/year)+ 46lb/hr(24 hrs/year)+ 39003 lbs/yr
NOx = 44,615 lbs/year
Fuel consumption (MMSCF/hr)
= (724 MMBTU/hr)(8670hrs/year)
=(6342240 MMBTU/year)(SCF/1200 BTU)
=5285.2 MMSCF/year
EF (LB/MMSCF)= 44,615 LBS/YEAR/5285.2 MMSCF/YEAR
EF (LB/MMSCF)=8.45 ***LB/MMSCF***

Table G-2: Emission Factors (Commissioning Period)

Pollutant	Emissions (lbs)	Fuel Flow Rate (MMSCF)	EF (lb/MMSCF)
Turbine - NOX Commissioning	6,818	156.37	43.6
Turbine - SOX Commissioning	1,040	156.37	6.65