SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT ***OFFICE OF ENGINEERING AND COMPLIANCE*** APPLICATION PROCESSING AND CALCULATIONS	PAGES 69	PAGE 1
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	PROCESSED BY: Bob Sanford	CHECKED BY

PERMIT TO CONSTRUCT
Application Nos. 526607 - 526609

COMPANY NAME: Chevron Products Company

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El Segundo, CA 90245

EQUIPMENT LOCATION: 324 W. El Segundo Blvd.
El Segundo, CA 90245

BACKGROUND/SUMMARY

Chevron is currently constructing the Cogeneration Train D under permit to construct (PC) application number (A/N) 470782. Construction is expected to be completed in November 2012. The cogeneration unit will include a combustion gas turbine (CGT), heat recovery steam generator (HRSG), and back-pressure steam turbine generator. The total gross power output of the turbines is 46.2 MW at ISO conditions. The CGT will burn natural gas and the duct burners in the HRSG will burn natural gas and/or refinery fuel gas.

Following issuance of Permit to Construct 470782, Chevron identified that the fuel system for the CGT and HRSG needs to be equipped with pressure relief valves (PRVs) for safety reasons. The vent lines for these PRVs will be connected to the Refinery Blowdown Gas Recovery System (commonly called LSFO Vapor Recovery System (VRS)) and LSFO Flare. Chevron submitted the subject applications to permit the PRVs and connection of the PRVs to the LSFO VRS and Flare.

EQUIPMENT DESCRIPTION:

New permits to construct including the subject PRV connections will be issued for the Cogeneration Train D, LSFO VRS and LSFO Flare in Section H of the RECLAIM/Title V Facility Permit. The proposed permit pages for each of these permits are contained in this section. In these proposed permit pages, new text is indicated by underline and deleted text is indicated by strikeout.

Section H: Permit to Construct and Temporary Permit to Operate

Equipment	ID No.	Connect To	RECLAIM Source	Emissions and Requirements	Conditions
PROCESS 17: ELECTRIC GENERATION					
SYSTEM 7: COGENERATION TRAIN D					S7.4, S15.7, S31.20
GAS TURBINE, No. 4, NATURAL GAS, GENERAL ELECTRIC MODEL NO. PG6581 (FRAME 6B), 508.7 MMBTU/HR (HHV) DRY LOW NOX COMBUSTOR GENERATOR, ELECTRIC, GE MODEL PG-3700, 43.75 MW **A/N: ~~470782~~ 526607**	D4354	C4360 C4361	NOx: MAJOR SOURCE; SOX: MAJOR SOURCE	**CO:** 2,000 PPMV (5) [RULE 407]; **CO:** 2 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996] [RULE 1703(a)(2) – PSD - BACT]; **NOx**: 2 PPMV (4) [RULE 2005; 4-20-2001]; **NOx**: 25 PPMV (8) [40CFR 60 SUBPART KKKK, 7-06-2006]; **PM**: 0.1 GR/SCF (5) [RULE 409]; **PM**: 0.01 GR/SCF (5A) [RULE 475]; **PM**: 11 LBS/HR (5B) [RULE 475]; **SO2**: 0.06 LBS/MMBTU (8A) [40CFR 60 SUBPART KKKK, 7-06-2006]; VOC: 2 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996]	A63.30, A63.31, A63.32, A99.11, A99.12, A99.13, A99.14, A99.15, A195.19, A195.20, A195.21, A327.1, C1.147, D29.12, D82.13, D82.14, E73.2, H23.27, H23.48, I296.1, K40.5, K67.74
BURNER, DUCT BURNER NO. 4, NATURAL GAS, REFINERY GAS, COEN, LOW NOX TYPE, 132 MMBTU/HR (HHV) **A/N: ~~470782~~ 526607**	D4355	C4360 C4361	NOx: MAJOR SOURCE; SOX: MAJOR SOURCE	**CO**: 2,000 PPMV (5) [RULE 407]; **NOx**: 25 PPMV (8) [40CFR 60 SUBPART KKKK, 7-06-2006]; **PM**: 0.1 GR/SCF (5) [RULE 409]; **PM**: 0.01 GR/SCF (5A) [RULE 476]; **PM**: 11 LBS/HR (5B) [RULE 476], **SO2**: 0.06 LBS/MMBTU (8) [40CFR 60 SUBPART KKKK, 7-06-2006];	A99.14, A99.15, A327.2, B61.12, B61.13, C1.148, D29.12, D90.40, D90.41, H23.48, H23.49, I296.1, K67.74
COMPRESSOR, FUEL BOOSTER, K-3120, NATURAL GAS, **A/N: ~~470782~~ 526607**	D4356				
TURBINE, STEAM, TPG-3750 GENERATOR, ELECTRIC, PG-3750, 4.0 MW **A/N: ~~470782~~ 526607**	D4357				
BOILER, HEAT RECOVERY STEAM GENERATOR, E-3700, UNFIRED TUBE TYPE **A/N: ~~470782~~ 526607**	D4358				
FUGITIVE EMISSIONS, MISCELLANEOUS **A/N: ~~470782~~ 526607**	D4359				H23.3

Description	ID No.	Connect To	RECLAIM Source Type	Emissions and Requirements	Conditions
Process 20: Air Pollution Control					
System 7: LSFO Emergency Relief System (Flare)					S7.4, S13.2, S18.7
FLARE, ELEVATED WITH STEAM INJECTION, F-2500, HEIGHT: 175 FT; DIAMETER: 3 FT 6 IN **A/N: ~~508902~~ 526609**	C1757				B61.11, D12.14, D323.2, H23.44, H23.46, I1.1
DRUM, V-1198, CRUDE UNIT RELIEF, WITH STEAM COIL, LENGTH: 20 FT; DIAMETER: 11 FT 6 IN **A/N: ~~508902~~ 526609**	D1759				
DRUM, V-1290, NAPHTHA HYDROTREATER RELIEF, WITH STEAM COIL, LENGTH: 16 FT; DIAMETER: 5 FT **A/N: ~~508902~~ 526609**	D1760				
DRUM, V-1591, VRDS RELIEF, WITH STEAM COIL, LENGTH: 32 FT; DIAMETER: 10 FT 6 IN **A/N: ~~508902~~ 526609**	D1761				
DRUM, V-1691, VGO RELIEF, WITH STEAM COIL, LENGTH: 30 FT; DIAMETER: 10 FT 6 IN **A/N: ~~508902~~ 526609**	D1762				
DRUM, V-1890, HYDROGEN PLT, H2S RECOVERY, H2 BOOSTER COMPR & PENTANE PLUS PLT RELIEF, WITH STEAM COIL, LENGTH: 21 FT; DIAMETER: 6 FT 6 IN **A/N: ~~508902~~ 526609**	D1763				
KNOCK OUT POT, V-956, THERMAL DISTILLATION RECOVERY SYSTEM, LENGTH: 7 FT; DIAMETER: 2 FT **A/N: ~~508902~~ 526609**	D1764				
VESSEL, SEPARATOR, DEGASSER, V-1175, HEIGHT: 19 FT; DIAMETER: 7 FT 1 IN **A/N: ~~508902~~ 526609**	D1767				
KNOCK OUT POT, NHT NO. 3, V-1098, LENGTH: 20 FT; DIAMETER: 10 FT **A/N: ~~508902~~ 526609**	D2220				E336.1
FUGITIVE EMISSIONS, MISCELLANEOUS **A/N: ~~508902~~ 526609**	D3678			HAP: (10) [40CFR 63 Subpart CC, #5A, 5-25-2001]	H23.3

Description	ID No.	Connect To	RECLAIM Source Type	Emissions and Requirements	Conditions
VESSEL, SEPARATOR, V-2502, PROCESS GAS, HEIGHT: 4 FT 7 IN; DIAMETER: 1 FT 8 IN **A/N: ~~482505~~ <u>526609</u>**	D3028				
FILTER, K-2502, PROCESS GAS, HEIGHT: 1 FT 2. 25 IN; DIAMETER: 11. 5 IN **A/N: ~~482505~~ <u>526609</u>**	D3029				
KNOCK OUT POT, V-2500, LENGTH IS TANGENT TO TANGENT, WITH STEAM COIL, LENGTH: 25 FT; DIAMETER: 12 FT **A/N: ~~482505~~ <u>526609</u>**	D3840				

Description	ID No.	Connect To	RECLAIM Source Type	Emissions and Requirements	Conditions
Process 20: AIR POLLUTION CONTROL					
System 10: REFINERY BLOWDOWN GAS RECOVERY SYSTEM					S7.4, S13.2, S15.5, S15.9, S18.12
KNOCK OUT POT, V-2010, RESID STRIPPER, LENGTH: 10 FT; DIAMETER: 7 FT 1 IN **A/N: ~~508901~~ <u>526608</u>**	D1772				
COMPRESSOR, ELECTRIC DRIVEN, K-2006, TWO-STAGE, RECIPROCATING, 4 MMSCFD, DUAL PACKING RINGS WITH NITROGEN PURGE GAS VENTED TO A FUEL GAS SYSTEM **A/N: ~~508901~~ <u>526608</u>**	D4211				E73.8, H23.47
COMPRESSOR, ELECTRIC DRIVEN, K-2007, TWO-STAGE, RECIPROCATING, 4 MMSCFD, DUAL PACKING RINGS WITH NITROGEN PURGE GAS VENTED TO A FUEL GAS SYSTEM **A/N: ~~508901~~ <u>526608</u>**	D4212				E73.8, H23.47
COMPRESSOR, ELECTRIC DRIVEN, K-2008, TWO-STAGE, RECIPROCATING, 4 MMSCFD, DUAL PACKING RINGS WITH NITROGEN PURGE GAS VENTED TO A FUEL GAS SYSTEM **A/N: ~~508901~~ <u>526608</u>**	D4213				E73.8, H23.47
FUGITIVE EMISSIONS, MISCELLANEOUS **A/N: ~~508901~~ <u>526608</u>**	D3679			HAP: (10) [40CFR 63 Subpart CC, #5A,5-25-2001]	H23.19

System Conditions

S7.4 The following conditions shall apply to all refinery operation and related devices from this system:

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 09-May-2008 for this facility.

The operator shall maintain records in a manner approved by the District, to demonstrate compliance with the applicable measures stipulated in the "Statement of Findings, Statement of Overriding Considerations, and Mitigation Monitoring Plan" document.

[CA PRC CEQA, 11-23-1970]

[Systems subject to this condition: Process 3, System 1**;** Process 7, System 4**;** Process 12, System 28; Process 13, System 10, 11, 12, 13; **Process 17, System 7,** 8; Process 20, System 4, 7, 10, 31]

S13.2 All devices under this system are subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1123

[**RULE 1123, 12-7-1990**]

[Systems subject to this condition: Process 1, System 3, 5, 13, 17; Process 2, System 1, 5, 6; Process 3, System 1 , 5; Process 4, System 1, 3, 5, 7, 9, 11, 13; Process 5, System 1; Process 6, System 1, 3, 4; Process 7, System 2, 4, 7; Process 8, System 1, 2, 5, 7, 8, 10; Process 9, System 1 , 2; Process 10, System 1 , 4; Process 12, System 2, 4, 7, 9, 10, 11, 12 , 13, 16, 17, 18, 22, 26, 27, 28; **Process 20, System** 3, 4, **7, 10**, 11, 12, 14, 18, 19, 23; Process 21, System 13, 14, 16, 18]

S15.5 The vent gases from all affected devices of this process/system shall be vented as follows:

All emergency vent gases from the vapor recovery system shall be directed to the flare system.

This process/system shall not be operated unless the flare(s) is in full use and has a valid permit to receive vent gases from this system.

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

[Systems subject to this condition: Process 2, System 5; Process 8, System 9; **Process 20, System 10**, 28, 29, 30, 34, 37]

S15.7 The vent gases from all affected devices of this process/system shall be vented as follows:

All emergency vent gases shall be directed to a vapor recovery system and/or flare system except Devices IDs D15, D3195, D3199, D3200 (Process 1, System 3), D106 (Process 1, System 13), D3574, D3371, D3373, D591, D595, D597, D3372, D592, D598 & D602 (Process 6, System 4) that vent to the atmosphere.

This process/system shall not be operated unless the vapor recovery system and/or flare system is in full use and has a valid permit to receive vent gases from this system.

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

[Systems subject to this condition : Process 1, System 3, 5, 13, 17; Process 2, System 1; Process 3, System 1 , 5; Process 4, System 1, 3, 5, 7, 9, 11, 13; Process 5, System 1; Process 6, System 4; Process 7, System 4 , 7; Process 8, System 1, 2, 5, 7, 8, 10; Process 9, System 1, 2; Process 10, System 1; Process 12, System 2, 7, 9, 11, 13, 17, 22, 23, 25, 26, 27; **Process 17, System 7**; Process 20, System 18, 19; Process 21, System 18]

S15.9 The vent gases from all affected devices of this process/system shall be vented as follows:

All sour gases shall be directed to the sour gas treating unit(s).

This process/system shall not be operated unless the sour gas treating unit(s) is in full use and has a valid permit to receive vent gases from this system.

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

[Systems subject to this condition : Process 1, System 3 , 5 , 13; Process 2, System 1; Process 3, System 1; Process 4, System 1 , 3 , 7 , 9 , 11 , 13; Process 7, System 4; Process 8, System 1; Process 10, System 1; Process 12, System 7; **Process 20, System** 4, **10**, 28 , 29 , 30]

S18.7 All affected devices listed under this process/system shall be used only to receive, recover and/or dispose of vent gases routed from the system(s) or process(es) listed below, in addition to specific devices identified in the "connected to" column:

Crude Distillation (Process: 1, System: 3, 5 & 13)

Delayed Coking (Process: 2, System: 1 & 5)

FCCU (Process: 3, System: 1 & 5)

Hydrotreating (Process: 4, System: 1, 7, 9, 11 & 13)

Hydrogen Generation (Process: 6, System: 4)

Alkylation (Process: 8, System: 1, 2, 5, 7, 8, 9 & 10)

Oxygenates Production (Process: 9, System: 2)

LPG Production (Process: 10, System: 1 & 2)

Treating & Stripping (Process: 12, System: 2, 7, 9, 11, 13, 17, 22, 23, 25, 26, 27 & 28)

Sulfur Production (Process 13, System 10, 11)

Electric Generation (Process 17, System 7)

Air Pollution Control (**Process: 20, System: 10** & 34)

Miscellaneous (Process: 21, System: 13 & 18)

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

[Systems subject to this condition: **Process 20, System** 3, **7**, 23]

S18.12 All affected devices listed under this process/system shall be used only to receive, recover and/or dispose of vent gases routed from the system(s) or process(es) listed below, in addition to specific devices identified in the "connected to" column:

Crude Distillation (Process: 1, System: 3, 5 & 13)

Coking & Residual Conditioning (Process: 2, System: 1)

Hydrotreating (Process: 4, System: 1, 9, 11 & 13)

Hydrogen Generation (Process: 6, System: 4)

Alkylation (Process: 8, System: 2 & 5)

Coker Depropanizer (Process: 10, System: 1)

Treating and Stripping (Process: 12, System: 26, 27, 28)

Sulfur Production (Process 13, System 10, 11)

Electric Generation (Process 17, System 7)

Vapor Gathering System (Process: 20, System: 18)

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

[Systems subject to this condition: Process 2, System 5; **Process 20, System 10**]

S31.20 The following BACT requirements shall apply to VOC service fugitive components associated with the devices that are covered by application number(s) 466149, 466876, 467141, 467544, 470739, ~~and~~ 470782 and 526607:

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

All new valves in VOC service shall be 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 valve failure could pose safety hazard (e.g., drain valves with valve stems in horizontal position), retrofits/special applications with space limitations, and valves not commercially available.

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

All new components in VOC service as defined by 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. Components shall be defined as any valve, flange, fitting, pump, compressor, pressure relief device, diaphragm, hatch, sight-glass, and meter, which are not exempted by Rule 1173.

The following leaks shall be repaired within 7 calendar days -- all light liquid/gas/vapor components leaking at a rate of 500 to 10,000 ppm, heavy liquid components leaking at a rate of 100 to 500 ppm and greater than 3 drops/minute, unless otherwise extended as allowed under Rule 1173.

The following leaks shall be repaired within 2 calendar days -- any leak between 10,000 to 25,000 ppm, any atmospheric PRD leaking at a rate of 200 to 25,000 ppm, unless otherwise extended as allowed under Rule 1173.

The following leaks shall be repaired within 1 calendar day -- any leak greater than 25,000 ppm, heavy liquid leak greater than 500 ppm, or light liquid leak greater than 3 drops per minute.

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 ppmv for two consecutive months, then the operator may revert to a quarterly inspection program with the approval of the Executive Officer. This condition shall not apply to leakless valves.

The operator shall revert from quarterly to monthly inspection program if less than 98.0 percent of the new valves and the new flange population inspected are found to leak gaseous or liquid volatile organic compounds at a rate less than 500 ppmv. This condition shall not apply to leakless valves.

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

The operator shall provide to the District, prior to initial startup, a list of all non-leakless type valves that were installed. The list shall include the tag numbers for the valves and reasons why leakless valves were not used. The operator shall not startup the equipment prior to the Districts approval for the use of all non-leakless valves

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 or field inspection surveys for all non-leakless type valves with a listing of tag numbers and reasons why leakless valves were not used.

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

[Systems subject to this condition: Process 12, System 28; Process 13, System 11; Process 16, System 10; **Process 17, System 7**; Process 20, System 37]

Device Conditions

A63.30 The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
VOC	Less than or equal to 42.2 lbs in any one day

The operator shall calculate the emission limit(s) by using monthly fuel use data and the following emission factors: 2.73 lbs/MMscf for normal operation; 5.7 lb/start-up and 26.9 lb/shutdown.

[**RULE 1303(b)(2)-Offset, 5-10-1996**]

[Devices subject to this condition: **D4354**]

A63.31 The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
PM10	Less than or equal to 577 lbs in any one day

For the purpose of this condition, the limit shall be based on the combined total emissions from the Cogeneration A Train (D2198 and D2199 in Process 17, System 1), Cogeneration B Train (D2207 and D2208 in Process 17, System 2), Cogeneration D Train (D4354 and D4355 in Process 17, System 5) and the Auxiliary Boiler (D2216 in Process 18, System 1).

The operator shall initially calculate the daily PM10 emissions using the daily fuel use data for each combustion unit (D2198, D2199, D2207, D2208, D2216, D4354 and D4355), the high heating value of the fuel burned in each combustion unit, and the following emissions factors: Cogeneration Train A – 0.0098 lb/MMBtu (HHV), Cogeneration Train B – 0.0083 lb/MMBtu (HHV), Cogeneration Train D - 0.0071 lb/MMBtu (HHV); Auxiliary Boiler (D2216) – 0.0086 lb/MMBtu (HHV).

The PM10 emission factor for the Cogen Trains A and B and the Auxiliary Boiler shall be revised annually based on results of individual PM10 source tests performed as specified in permit condition D29.5. The PM10 emission factor shall be calculated as the average emission rate in lb/MMBtu/hr for all valid source test runs during the annual source test.

The PM10 emission factor for the Cogen Train D shall be revised initially and annually, thereafter, based on results of PM10 source tests performed as specified in permit condition D29.12. The PM10 emission factor shall be calculated as the average emission rate in lb/MMBtu for all valid source test runs during each individual source test.

[**RULE 1303(b)(2)-Offset, 5-10-1996**]

[Devices subject to this condition: **D4354**]

A63.32 The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
PM10	Less than or equal to 113 lbs in any one day

The operator shall calculate the daily PM10 emissions using the daily fuel use data for the turbine (D4354) and duct burner (D4355), the high heating value of the fuel burned in each combustion unit, and an emission factor of 0.0071 lb/MMBtu.

The PM10 emission factor for the Cogen Train D shall be revised initially and annually, thereafter, based on results of PM10 source tests performed as specified in permit condition D29.12. The PM10 emission factor shall be calculated as the average emission rate in lb/MMBtu for all valid source test runs during each individual source test.

[**RULE 1303(b)(2)-Offset, 5-10-1996**]

[Devices subject to this condition: **D4354**]

A99.11 The 2.0 PPM CO emission limit shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 166 hours. Start-up time shall not exceed 2 hours for each start-up. Shutdown periods shall not exceed 2 hours for each shutdown. The turbine shall be limited to a maximum of 12 start-ups per year with a maximum of 4 start-ups per month. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.

For the purpose of this condition, start-up and shutdown shall be defined as the time period during the startup and shutdown of the cogeneration unit when the temperature of the exhaust gas at the inlet to CO Catalyst is below 851 degree F.

[RULE 1303(a)(1)-BACT, 5-10-1996][RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition: **D4354**]

A99.12 The 2 PPM NOX emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 166 hours. Start-up time shall not exceed 2 hours for each start-up. Shutdown periods shall not exceed 2 hours for each shutdown. The turbine shall be limited to a maximum of 12 start-ups per year with a maximum of 4 start-ups per month. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.

For the purpose of this condition, start-up and shutdown shall be defined as the time period during the startup and shutdown of the cogeneration unit when the temperature of the exhaust gas at the inlet to SCR is below 597 degree F.

NOx emissions shall not exceed 32.1 lb/startup and 29.5 lb/shutdown.

[RULE 2005, 5-6-2005]

[Devices subject to this condition: **D4354**]

A99.13 The 2 PPM VOC emission limit(s) shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 166 hours. Start-up time shall not exceed 2 hours for each start-up. Shutdown periods shall not exceed 2 hours for each shutdown. The turbine shall be limited to a maximum of 12 start-ups per year with a maximum of 4 start-ups per month. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.

For the purpose of this condition, start-up and shutdown shall be defined as the time period during the startup and shutdown of the cogeneration unit when the temperature of the exhaust gas at the inlet to CO Catalyst is below 851 degree F.

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

[Devices subject to this condition: **D4354**]

A99.14 The 65.5 LB/MMSCF NOx emission factor(s) shall only apply during initial combustion gas turbine and duct burner commissioning to report RECLAIM emissions.

[**RULE 2012, 5-6-2005**]

[Devices subject to this condition: **D4354, D4355**]

A99.15 The 8.03 LB/MMSCF NOx emission factor(s) shall only apply during the interim reporting period after initial combustion gas turbine and duct burner commissioning to report RECLAIM emission. The interim reporting shall not exceed 12 months from entry into RECLAIM.

[**RULE 2012, 5-6-2005**]

[Devices subject to this condition: **D4354, D4355**]

A195.19 The 2 PPMV NOx emission limit(s) is averaged over 1 hour, 15 percent oxygen, dry basis.

[Rule 2005, 5-6-2005]

[Devices subject to this condition: **D4354**]

A195.20 The 2 PPMV CO emission limit(s) is averaged over 1 hour, 15 percent oxygen, dry basis.

[RULE 1703(a)(2) - PSD-BACT, 10-7-1988; RULE 1303(a)(1)-BACT, 5-10-1996]

[Devices subject to this condition: **D4354**]

A195.21 The 2 PPMV VOC emission limit(s) is averaged over 1 hour, 15 percent oxygen, dry basis.

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

[Devices subject to this condition: **D4354**]

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

[**RULE 475, 10-8-1976**; RULE 475, 8-7-1978]

[Devices subject to this condition: **D2198, D2207, D3053, D4354**]

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: **D4355**]

B61.11 The operator shall not use / combust vent gas containing the following specified compounds:

H2S greater than 160 ppm by volume

The H2S concentration limit shall be based on a rolling 3-hour averaging period.

The H2S concentration limit shall not apply to vent gas resulting from an emergency, shutdown, startup, process upset or relief valve leakage.

[**Rule 1118, 11-4-2005**]

[Devices subject to this condition: C1746, C1749, **C1757**, C1785, C3012, C4116]

B61.12 The operator shall not use fuel gas containing the following specified compounds:

Compound	ppm by volume
Total Reduced Sulfur (calculated as H2S) greater than	40
Total Reduced Sulfur (calculated as H2S) greater than	30

The 40 ppm limit shall be based on a rolling 1-hour averaging period

The 30 ppm limit shall be based on a rolling 24-hour averaging period

For all but 72 hours per year, the total reduced sulfur concentration of the refinery fuel gas shall be measured before blending with natural gas. The total reduced sulfur of the refinery fuel gas may be measured after blending with natural gas for a maximum of 72 hours per year.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition.

[Rule 2005, 5-6-2005]]

[Devices subject to this condition: **D4355**]

B61.13 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: **D4355**]

C1.147 The operator shall limit the firing rate to no more than 508.7 MM Btu per hour.

For the purpose of this condition, firing rate shall be defined as energy or heat input of natural gas to the equipment combustion chamber based on the higher heating value (HHV) of the natural gas used.

To comply with this condition, the operator shall install and maintain a(n) ~~continuous monitoring system that includes~~ a continuous fuel flow meter ~~and continuous or semi-continuous HHV analyzer~~ for the natural gas fed to the turbine. <u>The operator shall use the RECLAIM default HHV for natural gas.</u>

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

This limit shall be based on a rolling 1-hr averaging period.

[**RULE 1303(b)(2)-Offset, 5-10-1996, Rule 2005, 5-6-2005**]

[Devices subject to this condition: **D4354**]

[Note: For consistency with RECLAIM monitoring and reporting requirements, conditions C1.147 and C1.148 are being modified to allow the use of the RECLAIM default HHV for natural gas in lieu of a dedicated HHV analyzer.]

C1.148 The operator shall limit the firing rate to no more than 132 MM Btu per hour.

For the purpose of this condition, firing rate shall be defined as energy or heat input of natural gas and/or refinery fuel gas to the equipment based on the higher heating value (HHV) of the natural gas and/or refinery fuel gas used.

To comply with this condition, the operator shall install and maintain a(n) ~~continuous monitoring system that includes~~ a continuous fuel flow meter ~~and continuous or semi-continuous HHV analyzer~~ for both the natural gas and refinery gas streams fed to the duct burner(s). <u>The operator shall install a continuous or semi-continuous HHV analyzer for refinery gas and use the RECLAIM default HHV for natural gas.</u>

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

This limit shall be based on a rolling 1-hr averaging period.

[**RULE 1303(b)(2)-Offset, 5-10-1996, Rule 2005, 5-6-2005**]

[Devices subject to this condition: **D4355**]

D12.14 The operator shall install and maintain a(n) thermocouple or any other equivalent device to accurately indicate the presence of a flame at the pilot light.

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

[**RULE 1303(a)(1)-BACT, 5-10-1996; 40CFR 60 Subpart A, 4-9-1993; 40CFR 63 Subpart A, 3-16-1994**]

[Devices subject to this condition: C1746, C1749, **C1757**, C1785, C3012]

D29.12 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	District Method 100.1	1 hour	Stack Outlet
SOx emissions	District Method 100.1 or 6.1	1 hour	Stack Outlet
CO emissions	District Method 100.1 or 10.1	1 hour	Stack Outlet
ROG emissions	District Method 25.1 or 25.3	1 hour	Stack Outlet
PM emissions	~~District Method 5.2~~ <u>District Approved Method</u>	District-approved averaging time	Stack Outlet
PM10 emissions	~~EPA Method 201A~~ <u>District Approved Method</u>	District-approved averaging time	Stack Outlet
Acetaldehyde and Formaldehyde	CARB method 430	District-approved averaging time	Stack Outlet
Benzene, Toluene, Ethyl benzene, and Xylene	CARB Method 410A or 410B	District-approved averaging time	Stack Outlet

The test shall be conducted when turbine and its duct burner are each operating at 80 percent or greater of their maximum design capacity. All of the fuel combusted in the duct burner(s) during the source test shall be refinery fuel gas.

The test(s) shall be conducted within 90 days after achieving maximum production rate, but no later than 180 cumulative days of operation after initial start-up.

The test shall be conducted to determine the concentration and report the mass emission rate in pounds per hour for NOx, SOx, ROG, CO, Total PM, PM10 and the following compounds: Acetaldehyde, Benzene, Formaldehyde, Toluene, Ethyl Benzene, Xylene.

The District shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen concentration. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the electricity generation of the turbines in MW.

The test(s) shall be conducted at least annually after the initial source test for PM10, total PM, NOx, SOx, CO, and O2.

The test(s) shall be conducted at least every three years after the initial source test for ROG and O2.

The test shall be conducted for NOx, SOx and CO (for initial and subsequent testing) until their CEMS are Rule 218 or RECLAIM certified. Once certified, source test data may be substituted with CEMS data.

[**RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(b)(2)-Offset, 5-10-1996**; RULE 1401, 3-5-2005; **RULE 2005, 4-20-2001; RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997; RULE 407, 4-2-1982**]

[Devices subject to this condition: **D4354, D4355**]

D82.13 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: **D4354**]

D82.14 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

[RULE 1303(a)(1)-BACT, 5-10-1996][RULE 1703(a)(2) - PSD-BACT, 10-7-1988]

[Devices subject to this condition: **D4354**]

D90.40 The operator shall continuously monitor the total reduced 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: **D4355**]

D90.41 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: **D4355**]

D323.2 The operator shall conduct an inspection for visible emissions from all stacks and other emission points of this equipment whenever there is a public complaint of visible emissions, whenever visible emissions are observed, and on an semi-annual basis, at least, unless the equipment did not operate during the entire semi-annual period. The routine semi-annual inspection shall be conducted while the equipment is in operation and during daylight hours.

If any visible emissions (not including condensed water vapor) are detected that last more than three minutes in any one hour, the operator shall verify and certify within 24 hours that the equipment causing the emission and any associated air pollution control equipment are operating normally according to their design and standard procedures and under the same conditions under which compliance was achieved in the past, and either:

1). Take corrective action(s) that eliminates the visible emissions within 24 hours and report the visible emissions as a potential deviation in accordance with the reporting requirements in Section K of this permit; or

2). Have a CARB-certified smoke reader determine compliance with the opacity standard, using EPA Method 9 or the procedures in the CARB manual "Visible Emission Evaluation", within three business days and report any deviations to AQMD.

The operator shall keep the records in accordance with the recordkeeping requirements in Section K of this permit and the following records:
1). Stack or emission point identification;
2). Description of any corrective actions taken to abate visible emissions;
3). Date and time visible emission was abated; and
4). All visible emission observation records by operator or a certified smoke reader.

[**RULE 3004(a)(4)-Periodic Monitoring, 12-12-1997; RULE 401, 3-2-1984**]

[Devices subject to this condition: C1746, C1749, **C1757**, C1785, C3012]

E71.27 The operator shall not use this equipment when all of the blowers K-101, K-102, K-201 and K-202 are operating simultaneously together. This equipment shall only be used as a spare unit.

[**RULE 1303(b)(2)-Offset, 5-10-1996**]

[Devices subject to this condition: **D3835**]

E71.28 The operator shall not use this equipment when all of the blowers K-701 and K-751 are operating simultaneously together. This equipment shall only be used as a spare unit.

[**RULE 1303(b)(2)-Offset, 5-10-1996**]

[Devices subject to this condition: **D3836**]

E73.8 Notwithstanding the requirements of Section E conditions, the operator is not required to use all three Refinery Blowdown Gas Recovery System compressors concurrently if: The load on the Refinery Blowdown Gas Recovery System is not sufficient to require all compressors to be online.

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

[Devices subject to this condition: **D4211, D4212, D4213**]

E73.2 Notwithstanding the requirements of Section E conditions, the operator may, at his discretion, choose not to use or inject ammonia in the SCR if any of the following requirement(s) are met:

During startup and shutdown of the cogeneration trains.

For the purpose of this condition, start-up and shutdown shall be defined as the time period during the startup and shutdown of the cogeneration unit when the temperature of the exhaust gas at the inlet to SCR is below 597 degree F.

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

[Devices subject to this condition: **D2198, D2207, D3053, D4354**]

E336.1 The operator shall vent the vent gases from this equipment as follows:

All vent gases under normal operating conditions shall be directed to the coker blowdown system (Process 2, System 5) or/and refinery blowdown system (Process 20, System 10).

This equipment shall not be operated unless the above blowdown system(s) is in full use and has a valid permit to receive vent gases from this equipment.

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

[Devices subject to this condition: **D2220**]

H23.3 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1173

[RULE 1173, 5-13-1994; RULE 1173, 2-6-2009**]**

[Devices subject to this condition : D3576, D3588, D3610, D3631, D3635, D3640, D3642, D3644, D3645, D3646, D3654, D3655, D3656, D3657, D3659, D3660, D3663, D3671, D3672, D3673, **D3678**, D3681, D3687, D3688, D3691, D3694, D4086, D4087, D4088, **D4359]**

H23.19 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1173
VOC	40 CFR 60	Subpart GGG

[**RULE 1173, 5-13-1994**; RULE 1173, 2-6-2009; **40CFR 60 Subpart GGG, 6-7-1985**]

[Devices subject to this condition : D3577, D3579, D3580, D3581, D3583, D3587, D3613, D3622, D3634, D3636, D3637, D3638, D3639, D3675, D3676, **D3679**, D3686, D3803, D3921, D3969, D4085, D4107, D4208]

H23.27 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
CO	District Rule	218

[**RULE 218, 8-7-1981**; RULE 218, 5-14-1999]

[Devices subject to this condition: **D4354**]

H23.44 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
H2S	40 CFR 60	Subpart J

[**40CFR 60 Subpart J, 6-24-2008; CONSENT DECREE CIVIL NO. C 03-04650 CRB, 6-27-2005**]

[Devices subject to this condition: D453, D502, D504, C1746, **C1757**, C2158, C3012, C3493]

H23.46 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
SOx	40 CFR 60	1118

[**RULE 1118, 11-4-2005**]

[Devices subject to this condition: C1746, C1749, **C1757**, C1785, C3012, C4116]

H23.47 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1173
VOC	40 CFR 60	GGGa

[**RULE 1173, 5-13-1994;** RULE 1173, 2-6-2009; **40CFR 60 Subpart GGGa, 6-2-2008**]

[Devices subject to this condition: D3261, D4205, D4206, D4208, **D4211, D4212, D4213**]

H23.48 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
NOx	40CFR60, Subpart	KKKK
SO2	40CFR60, Subpart	KKKK

[40CFR 60 SubpartKKKK, 7-6-2006]

[Devices subject to this condition**: D4354, D4355]**

H23.49 This equipment is subject to the applicable requirements of the following rules or regulations:

Contaminant	Rule	Rule/Subpart
H2S	40CFR60, Subpart	Ja

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

[Devices subject to this condition**: D4355]**

I296.1 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 43,644 lbs/yr of NOx RTCs and 7,791 lbs/yr of SOx RTCs. This condition shall apply to the first year of operation, commencing with the initial operation of the turbine/duct burner.

To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the first compliance year, hold a minimum 41,290 lbs/yr of NOx RTCs and 8,435 lbs/yr of SOx RTCs for operation of the turbine/duct burner. 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 beginning 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 beginning 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: **D4354, D4355**]

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

Source test results shall be submitted to the District no later than 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), mass rate (lb/hr), and lb/MMSCF. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains/DSCF.

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

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

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

[**Rule 2005, 5-6-2005; Rule 1303(a)(1)-BACT, 5-10-1996; Rule 1303(b)(2)-Offset, 5-10-1996**]

[Devices subject to this condition: **D4354**, C4361]

K67.74 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 1303(a)(1)-BACT, 5-10-1996; Rule 1303(b)(2)-Offset, 5-10-1996; RULE 2012, 5-6-2005**]

[Devices subject to this condition: **D4354, D4355**]

FEE ANALYSIS

As shown in the following table, Chevron has paid all applicable fees for all of the subject applications.

Summary of Fee Analysis

A/N	Equipment Description	BCAT/ CCAT	Fee Schedule	Fee Type	Fiscal Year (1)	Fee
526607	Turbine Engine (<=50MW); NG & Process Gas	033081 (BCAT)	D	Alteration/Modification	11-12	$ 6,954.87 (2)
526608	VRS Serving Refinery Unit	59 (CCAT)	E	Alteration/Modification	11-12	$ 7,995.99 (2)
526609	Refinery Flare System	92 (CCAT)	F	Alteration/Modification	11-12	$15,929.48 (2)

A/N	Equipment Description	BCAT/ CCAT	Fee Schedule	Fee Type	Fiscal Year (1)	Fee
526610	RECLAIM/Title V Permit	555009 (BCAT)	na.	Facility Permit Amendment	11-12	$ 1,747.19
				Total		**$32,627.53**
				Fees Paid		**$32,627.53**
				Outstanding Balance		**$ 0.00**

(1) Based on the date that the application was submitted.
(2) Includes 50% additional fee for expedited permit processing.

PERMIT HISTORY

The permit histories for the Cogen Train D, Refinery Blowdown Gas Recovery System (LSFO VRS) and LSFO Flares are contained in the following tables.

Permit History for Cogeneration Train D (P17S7)

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
470782	10/27/10	na.	na.	Original Construction. Construction is expected to be complete by November 2012.
526607	na.	na.	na.	Modification of permit to construct for connection of emergency pressure relief valves PRVS on the fuel supply system to the LSFO VRS and Flare.

Permit History for LSFO Emergency Relief System (P20S7)

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
A75857	01/73	M00754	7/21/77	Original construction of this emergency relief system (ERS) consisting of a ground flare as a primary flare with an elevated flare to handle relief loads that were greater than the 50,000 lb/hr capacity of the ground flare. The ERS was constructed to handle process upsets in the following process units: Crude Unit No. 4, Naptha Hydrotreater No. 12, Steam Naptha Reformer, Isomax VRDS, Isomax VGO, H2S Recovery Plant No. 5, and the pentanes plus plant.
160485		D05666	2/8/89	Connection of the emergency PRDs in the Copex Plant, Caustic Treating Plant No. 3, and the vapor recovery compressors (K-1 through K-5) to the LSFO ERS.
212958		D33226	10/25/90	Connection of the Thermal Distillation Recovery System (TDRS) to the LSFO ERS through a K.O drum. Appears that this TRDS was either never constructed or has been taken out of service.
235938	1/01/91	na.	na.	Chevron modified the Alky Units Vapor Recovery System. Previously, relief gases were discharged to two gas holders (T-2010 and T-20202) that were upstream of some Houdry Compressors. If the compressors were unavailable or

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
				overloaded, the tanks were vented to the atmosphere. Under this modification, the gas holders were removed and the Alky VRS was tied into the LSFO and FCCU ERSs. Included installation of associated K.O pots and pumps.
301080	4/27/95	na.	na.	Connection of emergency PRDs in the Penex Isomerization Plant (P8S5) and Naptha Hydrotreater No. 3 (P4S13) as part of Chevron's RFG II project. Also removed the connection for the old Alkylation Plant (P4S2), which was removed from service. Include installation of a separator vessel and filter to minimize scaling in the spark arrestor.
336106	2/06/98	na.	na.	Removed the ground flare from operation.
406045	02/18/03	na.	na.	Administrative application. PC AN 336106, permitted the removal of the ground flare but it was not removed from the permit until the flare was removed from service. Since a PO had not been issued with the ground flare removed. Chevron requested the removal. Also included existing K.O pot V-2500 in the permit.
419472	11/04/03	na.	na.	Connection of emergency PRDs in the new No. 6 H2S Recovery Plant (P12S26).
434803	na.	na.	na.	Change of condition application related to the flame monitoring condition (D12.14). Consolidated with AN 454964 for evaluation.
454964	8/09/06	na.	na.	Heavy Crude Project: Connection of emergency PRDs in the new No. 6 H2S Plant Amine Regeneration Unit (P12S27).
482505	5/14/10	na.	na.	PRO Project: Connection of emergency PRDs in the new Sour Water Stripper (P12S28), SRU No. 73 (P13S10), and TGTU No. 73 (P13S11). Construction of these new units expected to be complete in Nov. 2012.
526609	na.	na.	na.	Connection of pressure relief valves on the fuel supply system of the Cogen Train D to the LSFO VRS and Flare.

Permit History for the Refinery Blowdown Gas Recovery (P20S10)

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
9152	4-8-54			Modification to connect additional vent streams. Note: No records found when original P/O was issued.
A5252, A16700, A5666, A8601, A12519, A51775	-- -- 4-14-59 -- -- --	-- -- -- 16426 -- --		Modifications to connect additional vent streams.

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
A68367	--	P-49866		Modification by replacement of 1st stage cylinder of K-202 compressor and the addition of a condensate drum & PRV connection to the FCCU flare.
A75078	--	P-54448		Modification by addition of service to No. 3 caustic treating plant and to a waste gas compressor station or additional vent streams.
C-12975	--	M03864	4-18-78	Minor modification to include listing of fuel gas K.O. drum and filter in the permit, and also the alteration of the numbering to the system.
C20468		M24849	5/12/82	Modification by the replacement of pump P-2010 and removal of compressor K-20.
421284	na.	F70108	8/04/04	Modification of Condition S18.12 to allow this vapor recovery system to receive vent gases from the new No. 6 H2S Recovery Plant (Process 12, System 26).
464817	7/10/07	na.	na.	Replacement of the three Houdry Compressors @ 2 MMSCFD with three new larger compressors at 4 MMSCFD each..
482504	5/14/10	na.	na.	PRO Project: Connection of PRDs in the new Sour Water Stripper (P12S28), SRU No. 73 (P13S10) and TGTU No. 73 (P13S11).). Construction of these new units expected to be complete in Nov. 2012.
526608	na.	na.	na.	Connection of pressure relief valves on the fuel supply system of the Cogen Train D to the LSFO VRS and Flare.

COMPLIANCE RECORD REVIEW

There are no ongoing violations for any of the equipment covered in this evaluation.

PROCESS DESCRIPTION:

COGENERATION TRAIN D

A combustion gas turbine (CGT) is an internal combustion engine that operates with rotary motion. In electrical power generation applications, such as the Cogen Train D, the high-pressure, high-temperature gas produced in the combustion chamber is expanded through the turbine blades to produce shaft power that is utilized to drive an electric generator and the combustion air compressor. Hot exhaust gas from the turbine flows through an insulated duct to an exhaust gas heat exchanger called a heat recovery steam generator (HRSG). The HRSG of the Cogen Train D will be equipped with duct burners to provide additional heat for steam production. Most of the steam will be utilized in a back-pressure steam turbine/generator to produce electrical power. Excess steam will be utilized in the refinery.

The Cogen Train D CGT will be a General Electric (GE) Model PG6581B, which is a Frame 6 gas driven turbine. The combustor will be a dry low-NOx (DLN) type in which air and natural gas are pre-mixed. Pre-mixing inhibits NOx formation by minimizing the flame temperature and the concentration of oxygen at the flame front. The CGT will be fired on natural gas and the duct burner on refinery fuel gas or natural gas. The refinery fuel gas will be supplied from the V-4540 fuel mix drum. The CGT and steam turbine generators are rated at 42.8 and 4.0 MW gross power (at 65°F), respectively. The technical specifications for the CGT and HRSG are shown in the following table.

Combustion Gas Turbine and HRSG Specifications

Parameter	Specifications
Manufacturer	Gas Turbine: General Electric
Model	Gas Turbine: Frame 6B (PG6581B)
Turbine NOx Combustion Control (type)	Dry Low NOx (DLN)
Natural Gas Heating Value (HHV)	22,939 Btu/lb 1,029 Btu/SCF 1,050 Btu/SCF (SCAQMD default) used for emission calculations
Natural Gas Heating Value (LHV)	20,672 Btu/lb 927 Btu/SCF
Gas Turbine Heat Input (HHV)	493 MMBtu/hr at ISO 486 MMBtu/hr at annual avg. temp. 508.7 MMBtu/hr at 40^{o} F.
Net Gas Turbine Heat Rate, LHV	10,633 BTU/kW-hr at ISO 10,674 BTU/kW-hr at annual avg. temp.
Net Gas Turbine Heat Rate, HHV	11,799 BTU/kW-hr at ISO 11,845 BTU/kW-hr at annual avg. temp.
Duct Burner Heat Input (HHV)	115.1 MMBtu/hr at ISO base loaded 115.4 MMBtu/hr at annual avg. temp. at base 132.0 MMBtu/hr (max)
Steam Turbine Power Generation	4.0 MW at 36°F 4.0 MW at ISO 4.0 MW at annual avg. temp.
Gas Turbine Power Generation	43.8 MW at 36°F 42.2 MW at ISO 41.4 MW at annual avg. temp.
Total Gross Power Generation[1]	47.8 MW at 36°F 46.2 MW at ISO 45.4 MW at annual avg. temp.
Total Net Power Generation	44.5 MW at ISO 43.8 MW at annual avg. temp.
Net Plant Heat Rate, (HHV)	13,660 BTU/kW-hr at ISO 13,741 at annual avg. temp.
Net Plant Heat Rate, (LHV)	12,331 BTU/kW-hr at ISO 12,404 BTU/kW-hr at annual avg. temp.
Net Plant Efficiency, (LHV)	27.7% electrical efficiency at ISO 27.5% electrical efficiency at annual avg. temp 87.2% cogen efficiency at ISO 87.6% cogen efficiency at annual avg. temp.

(1) Normal operation at 100% load with duct burners on

A CO catalyst and SCR catalyst will be integrated into the HRSG. The CO oxidization catalyst will be used to control CO and VOC emissions down to 2 ppmv (15% O2) each. The oxidation catalyst will also provide some control of BTEX, formaldehyde and acetaldehyde emissions. The SCR, which will be located downstream of the CO catalyst, will provide control of NOx emissions down to 2 ppmv (15% O2).

<u>LSFO EMERGENCY RELIEF SYSTEM (FLARE) AND REFINERY BLOWDOWN GAS RECOVERY SYSTEM (*commonly called LSFO VRS*)</u>

PRDs and maintenance vents from the following process units are currently connected into the LSFO VRS/Flare:

- No. 4 Crude Unit,
- Nos. 2 and Naphtha Hydrotreaters,
- Penex,
- Vacuum Gas Oil Desulfurizer,
- Nos. 5 and 6 H2S Plants,
- Steam Naphtha Reformer Hydrogen Plant, Sulfur Recovery unit No. 70, and
- C-810 Sour Water Concentrator.

New PRDs in the following permit units, which are currently under construction, will also be connected into the LSFO VRS/Flare.

- Sour Water Stripper
- Sulfur Recovery Unit No. 73
- Tail Gas Treatment Unit No. 73

Chevron proposes to connect the Cogen Train D PRVS, which are shown in the table below, to the LSFO VRS/Flare. As specified in the table, four of the PRVs are sized to prevent overpressure of the specified equipment in the case of a fire. The fifth is sized to prevent overpressure in the case of a block valve at the outlet of a coalescing oil separator (K-3124) on the natural gas supply.

Cogen Train D Pressure Relief Valves

PRV No.	Size (in.)	Set Pressure (psig)	Equipment Served	Service	Design Basis	Capacity (lb/hr)
PSV-5081	1 x 2	500	Filter coalescer on NG to CGT	Nat. Gas	Fire	2,000
PSV-5082	1 x 2	500	Filter coalescer on NG to CGT	Nat. Gas	Fire	2,000
PSV-5083	1 x 2	150	Filter Coalescer (V-3788) on gas to duct burners	Nat. Gas or Refinery Gas	Fire	1,500
PSV-5120	1 x 2	500	NG Booster Comp. Suction KO Drum (V-3120)	Nat. Gas	Fire	2,000
PSV-5121	2 x 3	500	Coalescing Oil Separator (K-3124)	Nat. Gas	Blocked Discharge	24,400

The outlet of each of the new PRVs will be connected to existing Flare Knockout Drum V-3670 (D3479), which is part of the permit for the Cogen Train A (Process 17, System 1). V-3670 connects to the LSFO relief system through Knockout Pot V-217 (D2219), which is part of the permit to operate for the Alky Unit Vapor Recovery System (P20S11).

The LSFO Emergency Flare system was originally installed in 1973 to handle emergency waste gas releases in the event of a general power failure or process upset in the No. 4 Crude Unit, No. 12 Naptha Hydrotreater, SNR Hydrogen Plant, Isomax VRDS, Isomax VGO, No. 5 H2S Recovery Plant, and the pentanes plus plant. The LSFO Flare and VRS are interconnected with the FCCU and Alky Flares and VRSs. The flares are interconnected so that one of the flares can be shut down for maintenance or repairs without shutting down all of the equipment connected to the flare. The valves to switch flow from one flare to another are manual.

The main flare relief header is a 36 inch header that connects into the LSFO Flare knockout pot (V-2500). A 42 inch line goes from the knockout pot to the base of the flare. The base of the flare contains a 64 inch water seal to maintain back pressure on the flare header. The LSFO VRS was recently upgraded by the replacement of three reciprocating compressors with a capacity of 2 MMSCFD each by three reciprocating compressors with a capacity of 4 MMSCFD each. These three electrically driven compressors (K-2006, K-2007, and K-2008) operate in parallel. The K-2005 compressor in the Coker Blowdown System (Process 2, System 5) functions as a backup compressor. The compressors, which pull suction on the flare relief system, discharge the compressed gas to the No. 5 H2S Plant. The goal of the recovery system is to keep the pressure of the flare header below 64 inches water column to prevent relief gases from flowing through the water seal into the flare. The compressors can be operated independently or concurrently at any given time on “as needed” basis depending on the volume of gases available for recovery.

The flare stack is a freestanding stack fitted with a Flaregas FS Type tip, which is equipped with 100 “flarejectors”. This cluster of “flarejectors” are designed to provide thorough mixing of steam, air, and gas. The 150 psi steam that is supplied to these “flarejectors” aspirates air and gas through the “flareejectors”. The upper section of the flare tip has a conical shape with a maximum diameter of 68 inches. The flare stack is equipped with a “flarex” (molecular) seal. The stack is continuously purged with nitrogen. The nitrogen in conjunction with the molecular seal prevents air from entering into the flare stack.

The capacity of a flare is limited by the hydraulics of the relief system and the flare tip velocity. As required by 40CFR60 Subpart A, the flare tip velocity should be maintained below 400 ft/sec. The current maximum loads to the flare are 788,800 lb/hr (@ MW = 17.8) during a total refinery power failure and 960,000 lb/hr (@ MW = 105) during a reflux failure at the No. 4 Crude Unit. The PRVs on the Cogen Train D fuel supply systems will only vent to the flare in the case of a fire so the maximum load to the flare is not impacted by the connection of the new emergency PRVs. The flare tip velocity at the maximum load is 244 ft/sec, which is well below the maximum flare tip velocity of 400 ft/sec.

Based on the estimated maximum velocity at the worst case load of 788,000 lb/hr and a tip exit diameter of 68 inches, the tip velocity was calculated to be 229 ft/sec, which is under the maximum allowable rate of 400 ft/sec.

$$Velocity = \left(\frac{(FlowRate\ lb/hr)(379 scf/lb - mole)(TemperatureatFlareR)}{(MW)(TipFlowAreaft2)(3600\sec/hr)(TemperatureS\tan dardR)} \right)$$

$$Velocity = \left(\frac{(788{,}000\ lb/hr)(379 scf/lb - mole)(659R)}{(17.8)(25.2 ft2)(3600\sec/hr)(532R)} \right) = 229 \text{ ft/sec}$$

The smokeless capacity of the flare varies depending on the properties of the flared stream. Based on the maximum continuous steam flow of 50,000 lbs/hr of steam, actual smokeless burning capacity varies from about 280,000 lb/hr (0.18 lb steam to 1 lb gas) to about 100,000 lb/hr (0.49 lb steam to 1 lb gas).

The flare is equipped with 4 pilots with a total combined natural gas flow of 800 scfh. Each of the headers in the relief header system is purged with natural gas. The total purge natural gas flow through the flare header system varies from 400 to 1380 scfh. There is no expected increase in the amount of purge natural gas through the flare header system since the new PRDs are being connected to existing headers such that the current purge gas flow will still be adequate to purge the entire header system. During normal operation of the system, the flare header purge gas will be captured by the LSFO VRS. The flare stack normally has a purge flow of 3600 – 5700 scfh of nitrogen. A flow of 500 – 800 scfh of natural gas is used when nitrogen is not available.

CALCULATIONS

This section contains criteria air pollutant (CO, NOx, PM_{10}, SO2, and VOC) emission estimates for each of the permit units. The Cogen Train D and LSFO Flare each have emissions from combustion as well as fugitive VOC emissions. The LSFO VRS has only fugitive VOC emissions.

<u>FUGITIVE VOC EMISSIONS</u>

Each of the subject permit units contain or will contain fugitive components (valves, flanges, connectors, pumps, compressors, PRVs and drains) that handle VOC containing liquids or gases. The VOC liquids or gases periodically leak from the components. VOC emissions for these fugitive components are estimated by multiplying the total number of each fugitive component type by an appropriate emission factor. In the engineering evaluation for PC A/N 470782, fugitive VOC emissions were estimated with emission factors that were developed for estimation of fugitive VOC emissions for the CARB Reformulated Fuels projects that were performed at the refineries in the South Coast Basin. Subsequent to the issuance of PC A/N 470782, the District switched to the use of emission factors based on the correlation equations from the following document: *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities* (CARB/CAPCOA - 1999).

The following table contains a summary of the estimated fugitive VOC emissions for each of the subject permit units using the CARB/CAPCOA emission factors. VOC emission estimates for the subject permit units using the previous emission factors are contained in the footnotes to the table. The detailed fugitive component counts and VOC emissions estimates are contained in Appendices D through G.

Estimated Pre- and Post-Modification VOC Emissions from Fugitive Components on a Permit Unit Basis

Permit Unit	Estimated VOC Emissions (lb/day)(1)(2)		Change in VOC Emissions	
	Pre-Mod	Post-Mod	(lb/day)(1)	(lb/year)
Cogeneration Train D (3)	0	7.07	+7.07	+2545
Cogeneration Train D (4)	6.73 (5)	7.07	+0.34	+121
LSFO Flare	27.0 (6)	27.0 (6)	0	0
LSFO VRS	39.2 (7)	39.2 (7)	0	0
Total				

(1) 30 day average VOC emissions calculated as annual VOC emissions divided by 360.
(2) Based on CARB/CAPOA emission factors.
(3) Total estimated VOC emission increase for construction of the Cogen Train D
(4) Estimated VOC emission increase for installation of subject PRVs and connection to LSFO VRS/Flare.
(5) VOC emissions were estimated to be 3.92 lb/day using previous emission factors.
(6) VOC emissions were estimated to be 24.5 lb/day using previous emission factors.
(7) VOC emissions were estimated to be 35.8 lb/day using previous emission factors.

The baseline VOC emission estimates in the District's NSR database will be updated to reflect the change due to the use of the CARB/CAPCOA emission factors.

<u>COMBUSTION EMISSIONS</u>

Cogeneration Train D

The Cogen Train D combustion emission estimates include emissions for the following non-emergency operating conditions: normal operation, commissioning, planned shutdowns (SD) and start-ups (SU). Emissions from emergency events are not included since they cannot be accurately anticipated or estimated.

The estimated CO, NOx and VOC emissions are greater for the commissioning period than for normal operation as air pollution control equipment may only be partially operational or not operational at all. The CO, NOx and VOC emissions will also be higher during start-ups due to the phased effectiveness of the SCR and CO catalysts that gradually come online as the operating temperatures are being reached. Emissions during shutdowns will be higher than normal operation but lower than start-up emissions. More detailed documentation of these combustion emission estimates for SU, SD and commissioning is contained in Appendices A through C. A more detailed discussion of these estimates was contained in the engineering evaluation for PC A/N 470782.

30-day average emission estimates must be made for normal operating months as well as commissioning months. As a conservative estimate, it is assumed that the commissioning of the cogen unit is completed in one month. The emissions for a normal operating month must include emission from shutdowns and start-ups. Chevron anticipates that the cogen be shutdown an average of 4 times per year for scheduled maintenance and inspection activities. The permit is conditioned with a limit of 4 SU/SDs per month and 12 SU/SDs per year. Calendar monthly emissions during normal operation of the cogen are based on 27-days of full operation at the maximum combustion rate of 640.7 MMBtu/hr (HHV) and four days with 8 hours of full load operation, one shutdown, 12 hours of downtime and one start-up. Annual emission estimates are also evaluated for both a commissioning and non-commissioning year. The commissioning year includes one 31-day commissioning month. The remainder of the year will include 322 days of continuous operation at full load and 12 days that each include 8 hours of full load operation, a shutdown, 12-hour downtime period and a start-up. The non-commissioning year is comprised of 353 days of continuous operation at full load and 12 days that each includes 8 hours of full load operation, a shutdown, 12-hour downtime period and a start-up.

The CO, NOx and VOC emissions during normal operation are based on the following formula and assumptions:

$$\text{EF (lb/MMBTU)} = \text{ppmvd} \times \text{MW} \times \left(\frac{1}{\text{MV}}\right)\left(\frac{20.9}{5.9}\right) \times \text{Fd}$$

where,

ppmvd = Pollutant concentration limit at stack outlet at 15% O_2,dry basis
MW = Molecular weight, lb/lb-mol
MV = Molar volume at 60ºF = 379.5 dscf/lb-mol
F_d = Dry oxygen f-factor for natural gas = 8,710 dscf/MMBTU

The SO2 emissions during normal operation are based on the following formula and assumptions:

$$\text{Emissions} = \left[508.7\ \text{MMBtu/hr} \times \left(\frac{1}{\text{HHV}}\right) \times 5\ \text{ppmvd} \times \text{MW} \times \left(\frac{1}{\text{MV}}\right)\right] + \left[132\ \text{MMBtu/hr} \times \left(\frac{1}{\text{HHV}}\right) \times 30\ \text{ppmvd} \times \text{MW} \times \left(\frac{1}{\text{MV}}\right)\right] = 1.05\ \text{lb/hr}$$

where,

HHV = High heating value of fuel (conservatively assume HHV for natural and refinery fuel gas is 1050 Btu/scf)
MW = Molecular weight of SO2 (64 lb/lb-mol)
MV = Molar volume at 60ºF = 379.5 dscf/lb-mol

The PM10 emission estimates are based on the default PM emission factor of 7.5 lb/MMcf for the category “NG combustion; external, other” from the Instruction Book for the District’s AER Program. This factor equates to 0.0071 lb/MMBtu based on an assumed high heating value (HHV) of 1050 Btu/scf. It is assumed that PM is equivalent to PM10 for a gaseous fuel fired combustion source. It is also assumed that PM10 emissions are the same during commissioning, startup and shutdown as during normal operation.

Maximum hourly emissions are shown in the following table.

Maximum Hourly Emissions

Type Operation	Emissions (lb/hr)				
	CO	PM10	VOC	NOx	SO2
Normal (1)	2.92	4.55	1.67	4.80	1.05
Commissioning (2)	68.2	4.55	5.28	38.4	0.52
Start-up (2)	33.6	3.44	4.27	25.8	0.39
Shutdown (2)	192.2	2.55	22.0	25.9	0.29

(1) Operation at full load of 640.7 MMBtu/hr (HHV). CO, NOx and VOC emission estimates based on 2 ppmvd (15% O2) stack limit. SO2 emission estimates based on 30 ppmv sulfur limit for refinery fuel gas and average natural gas sulfur content of 5 ppmv.
(2) Based on consultants/manufacturers estimates.

Commissioning, Shutdown and Start-up Emissions (Per Event)

Event	Emissions (lb)				
	CO	PM10	VOC	NOx	SO2
Commissioning (1)	4270	670	394	5862	74
One Cold Start-up (1)	44	4.5	5.7	32	0.5
One Shutdown (1)	231	3.5	27	29	0.4

(1) Based on manufacturers estimates.

Maximum Annual Emissions (1)

Type Operation	Emissions (lb/yr)				
	CO	PM10	VOC	NOx	SO2
Normal Year (2)	28319	39858	14701	42048	9198
Commissioning Year (3)	30416	37143	13852	44339	8491

(1) Based on 365-day year
(2) Emissions for the following scenario that yields the highest emissions: (1) 365 days of full load operation or (2) 353 days of continuous operation at full load with 12 days consisting of 8 hours of operation, a shutdown, 12 hours of downtime and a start-up.
(3) Emissions for the following scenario that yields the highest emissions: (1) 31 days of commissioning and 334 days of full load operation, or 31 days of commissioning and 322 days of full load operation with 12 days consisting of 8 hours of operation, a shutdown, 12 hours of downtime and a start-up.

Maximum Monthly Emissions (31-day Month)

Type Operation	Emissions (lb/month)				
	CO	PM10	VOC	NOx	SO2
Normal Month (1)	3086	3126	1266	3508	718
Commissioning Month (2)	4270	670	394	5862	74

(1) Emissions for the following scenario that yields the highest emissions: (1) 31 days of continuous operation at full load or (2) 27-days of continuous operation at full load with 4 days consisting of 8 hours of operation, a shutdown, 12 hours of downtime and a start-up.
(2) Assumes commissioning is completed in a 31-day month.

Daily (30-day Average) Emissions

Type Operation	Emissions (lb/day)				
	CO	PM10	VOC	NOx	SO2
Normal Month (1)	103	113	42.2	119	26
Commissioning Month (1)(2)	142	22	13.1	195	2.5

(1) 30-day average emissions = (maximum monthly emissions) / 30
(2) Assumes commissioning is completed in a 31-day month.

30-day average VOC emissions of 46.1 lb/day were estimated for PC A/N 470782 including the combustion emissions of 42.1 lb/day and fugitive VOC emissions of 3.9 lb/day using the previous fugitive VOC emission factors. The estimated 30-day average VOC emissions for the Cogen Train D excluding the emissions for the subject PRVS are 48.9 lb/day including the combustion emissions of 42.1 lb/day and fugitive VOC emissions of 6.7 lb/day. The NSR entry for the Cogen Train D will be update to account for this change in estimated 30-day VOC emissions that is caused by the change in fugitive VOC emissions factors.

As detailed above, the total fugitive VOC emissions for the Cogeneration D Train permit unit including the proposed PRVs are estimated to be 7.07 lb/day with the new emissions factors. The total 30-day average emissions, including the 42.2 lb/day of combustion emissions and 7.07 lb/day of fugitive VOC emissions, are estimated to be 49.3 lb/day.

LSFO Flare:

This section contains an estimate of criteria pollutant emissions from non-emergency operation of the LSFO Flare. These non-emergency emissions are from the combustion of pilot and flare purge gas streams. Criteria pollutant emissions from the combustion of gases generated from process upsets or equipment malfunctions are not included in the Regulation XIII emission estimates. The proposed fuel system PRVs will only vent to the flare during emergencies. They will not vent to the VRS/flare during Cogeneration Train D SUs, SDs or normal operation. The header purge gas is also not combusted in the flare during normal operation since it is captured in the vapor recovery system. Therefore, neither of these streams are utilized in estimation of normal flare emissions.

The estimated criteria pollutant emissions from the combustion of the pilot and flare purge gas streams in the LSFO Flare is shown in the table below. These emission estimates utilize District AER/Rule 1118 emission factors for natural gas combustion. As noted in the *Process Description* section, the flare pilots combust natural gas and the flare purge gas is normally nitrogen but natural gas is occasionally utilized. For the purpose of estimating maximum potential emissions, it is assumed that the flare purge gas is natural gas. The design pilot and flare purge gas flow rates are each 38 lb/hr (800 scfh). Therefore, the maximum natural gas flow rate to the flare during normal operation is 1600 scfh.

Note that the proposed connection of new PRDs does not cause any increase in the normal emissions from the flare since there is no increase in the amount of pilot gas, flare purge gas, or fugitive components. The PRDs are included in the fugitive component count for the Cogen Train D.

LSFO Flare: Estimate of Maximum Potential Emissions from Combustion of Pilot/Purge Gas

Pollutant	Total Pilot/Purge Gas (MMscf/day)	Emission Factor (lb/MMscf)	Emissions (lb/day)	Emissions (lb/yr)
NOx	0.038	130	4.94	1803
SOx	0.038	0.83	0.03	11
CO	0.038	35	1.33	485
PM10	0.038	7.5 (1)(2)	0.29	106
VOC	0.038	7 (1)	0.27	99

Total VOC emissions for the flare are 27.3 lb/day including the 27.0 lb/day from fugitive components and the 0.27 lb/day from combustion of pilot and purge gas.

RULE COMPLIANCE REVIEW:

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. The PRO project, which includes construction of the Cogen Train D, qualified as a significant project so preparation of a CEQA document was required. The draft Environmental Impact Report (DEIR) for the PRO project was issued on March 6, 2008. The public review period for this document ended on April 22, 2008. The final Environmental Impact Report (FEIR) was certified on May 9, 2008. An addendum to the FEIR was certified on May 13, 2010.

The permits for the Cogen Train D, LSFO VRS and LSFO Flare include condition S7.4 that specifies that Chevron 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.

According to Jeff Inabinet of the District's CEQA Group, the FEIR adequately addresses the Cogeneration Train D including the addition of the five PRVs. In the FEIR, maximum fugitive VOC emissions for the Cogen Train D are estimated at 7.3 lb/day, which is greater than the maximum fugitive VOC emissions of 7.07 lb/day estimated in the *Calculation Section* of this engineering evaluation. Therefore, no additional analysis is required.

REGULATION II: PERMITS

RULE 212: STANDARDS FOR APPROVING PERMITS

212(c)(1): Public notice is required for a project if any of the modified permit units are located within 1000 feet of a school. As seen in Appendix H, the distance to the nearest school from the Cogen D stack is 2601 feet. Public notice is not required under this clause.

212(c)(2): Public notice is required for any "new or modified facility", which has on-site emission increases exceeding any of the daily maximums specified in subdivision (g) of Rule 212. Public notice was required under this clause for the permit to construct for the Cogen Train D since the increase in maximum potential emissions for the PRO Project exceeded the CO, PM10, SO2 and VOC emission increase thresholds contained in 212(g).

Air Contaminant	R212(g) Daily Maximum Threshold (lb/day)	Estimated Emission Increase (lb/day) (1)	
		Cogeneration D Train	Entire Project (2)
CO	220	142	379
NOx	40	195	-235
PM10	30	113	117
SO2	60	26	202
VOC	30	46	203
Lead	3	0	0

1) Increase in 30-day average maximum potential to emit. Includes emissions from commissioning, startup and shutdown.
2) Estimated emission increase for entire PRO Project from the PRO Project FEIR.

A public notice will be issued for the proposed addition of PRVS to the fuel supply system for the Cogen Train D since the PRVs are considered to be an essential component of the Cogen Train being constructed.

212(c)(3): Public notice is required for any new or modified permit units that have an increase in toxic air contaminants that results in an increase of maximum individual cancer risk (MICR) of more than one in a million (1×10^{-6}) during a lifetime (70 years). As discussed in additional detail in the evaluation of Rule 1401, the addition of PRVS to the fuel supply system does not cause an emission increase that causes an increase in MICR of more than 1×10^{-6}. Public notice is not required under this clause.

212(g): 212(g) specifies that any new or modified sources subject to Regulation XIII which undergo construction or modifications resulting in an emissions increase exceeding any of the daily maximum emission thresholds (listed in the table above) will require notification. From Regulation XIII (Rule 1302), the definition of "Source" is any permitted individual unit, piece of equipment, article, machine, process, contrivance, or combination thereof, which may emit or control an air contaminant. This includes any permit unit at any non-RECLAIM facility and any device at a RECLAIM facility.

Public notice was required under this clause for the permit to construct for the Cogen Train D since the estimated CO, NOx, PM10 and VOC emissions for the unit exceed the Rule 212(g) thresholds. A public notice will be issued for the proposed addition of PRVS to the fuel supply system for the Cogen Train D since the PRVs are considered to be an essential component of the Cogen Train being constructed.

REGULATION IV - PROHIBITIONS

RULE 401: VISIBLE EMISSIONS

This rule specifies that a person shall not discharge emissions from a source for a period or periods aggregating more than three minutes in any one hour which are as dark or darker in shade as that designated No. 1 on the Ringelmann Chart or emissions of such opacity that it obscures an observers view to an equal or greater level. This is equivalent to opacity of 20%.

Cogen Train D: Visible emissions are not expected since the subject turbine will combust natural gas and the duct burner will combust natural gas and/or low sulfur refinery fuel gas. The cogen permit is conditioned with emission limits for all criteria air pollutants including CO and NH_3. Also, Chevron has a long record of operating the three existing cogen units within the limits of this rule. Compliance with this regulation is expected.

LSFO Flare: Gas releases to this flare are minimized since it is equipped with a vapor recovery system to capture all normal releases and a portion of the emergency releases from PRDs. The Chevron refinery has been relatively effective at minimizing flaring events. As discussed later in the evaluation of District Rule 1118, SOx emissions from Chevron’s flares during 2009 and 2010 were well below current and future Rule 1118 SOx performance targets. Under a recently completed project, the capacity of the LSFO VRS was increased by 6 mmscfd through replacement of the three existing vapor recovery compressors with larger compressors.

As discussed earlier, the potential for emergency releases from the new PRVs is low because they are designed to open only in the event of a catastrophic fire or blockage of the fuel line. Even though the potential for flaring is not expected to increase significantly, all refinery flares do have some potential for exceedance of 20 percent opacity for a period of greater than 3 minutes during an extreme emergency if the load to the flare exceeds the smokeless capacity of the flare. As discussed in the process description section of this evaluation, the LSFO Flare is equipped with steam injection to provide smokeless combustion up to the smokeless capacity of the flare. This smokeless capacity varies depending on the properties of the gas being combusted. For releases up to the smokeless capacity of the flare, smoking will occur only during a short transitory period while the steam injection system adjusts to the load being sent to the flare. An increase of the smokeless capacity of these flares is not warranted since additional steam would have to be produced around the clock to cover visible flaring events that are relatively rare. Production of additional steam would cause an increase in criteria and toxic pollutants for steam that could not be utilized during normal operational periods when no flaring occurred.

Emergency situations such as a loss of power are covered by the “Breakdown Provisions” of Regulation 430. If the emergency qualifies as a “Breakdown” and Chevron complies with the requirements of 430(b)(3)(A), the smoking during an emergency will not be a violation of this rule.

RULE 402: NUISANCE

This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property.

Cogen Train D: Nuisance is not expect since the subject turbine will combust natural gas and low sulfur refinery fuel gas and will be conditioned with emission limits for all CAPs including CO and NH_3. Also, Chevron has a long record of operating the three existing cogen units and the Auxiliary Boiler without causing nuisance. Compliance with this regulation is expected.

LSFO VRS and Flare: There is no record of nuisance complaints for the LSFO Flare over the last three year period. The flare is equipped with steam injection to minimize the nuisance potential of the flare. Connection of the new PRVs to the VRS/flare is not expected to cause a significant increase in the nuisance potential.

RULE 404: PARTICULATE MATTER - CONCENTRATION

This rule sets concentration limits for total PM (solid and condensable) emissions. The rule limit varies based on the quantity of exhaust gas (dry basis) discharged from a source.

Cogen Train D: As specified at 404(c), the provisions of this rule do not apply to emissions resulting from the combustion of liquid or gaseous fuels in steam generators or gas turbines. Therefore, the cogeneration units and auxiliary boiler are not subject to this regulation.

LSFO Flare: PM emissions from the normal operation of the LSFO flare is estimated using the District AER (and Rule 1118) emission factor (EF) of 7.5 lb/MMscf of natural gas combusted. An "F" factor of 8710 scf of flue gas per MMBtu per hour of natural gas combustion is believed to provide a reasonable estimate of the exhaust gas flow rate for the combustion of pilot and purge natural gas in the flare. The calculation of the PM concentration for the exhaust gas from normal operation of the flare is shown below.

$$PM = \left(\frac{7.5lbPM}{MMscfNG}\right)\left(\frac{scfNG}{1050BTU}\right)\left(\frac{MMBtu}{8710scffluegas}\right)\left(\frac{7000grain}{lb}\right) = 0.006 \text{ grain/dscf}$$

The estimation of the exhaust gas flow for the LSFO flare is shown below.

$$Iso\max FlareExhaustRate = \left(\frac{2180scfNG}{hour}\right)\left(\frac{1050Btu}{scgNG}\right)\left(\frac{8710scffluegas}{MMBtu}\right)\left(\frac{hour}{60\min}\right)$$

$$= 330 \text{ dscfm}$$

From Table 404(a) in Rule 404, the PM limit for exhaust gas flows below 883 dscfm is 0.196 gr/dscf. Even at high levels of excess O2, the flue gas flow rate should be below 883 dscfm. The estimated PM concentration of 0.006 gr/dscf is well below the Rule 404 limit of 0.196 gr/dscf. Compliance with this rule is expected.

RULE 405: SOLID PARTICULATE MATTER - WEIGHT

This rule sets solid PM mass emission limits for the processing of solid materials. It is not applicable to combustion sources such as the subject cogeneration unit and flare.

RULE 407: LIQUID AND GASEOUS AIR CONTAMINANTS

This rule contains the following emission limits:

- Carbon monoxide (CO) - 2,000 ppmv (dry; 15 minute average) [407(a)(1)]
- Sulfur Compounds - 500 ppmv (calculated as SO2; 15 minute average) [407(a)(2)(B)]

CO Limit

<u>*Cogen Train D*</u>: The Cogen D Train will be equipped with a CO catalyst and the permit will be conditioned with a CO emission limit of 2 ppmvd (15% O2, 1-hr avg.). According to the turbine manufacturer, maximum CO emissions during start-up and shutdown are expected to be 645 and 175 ppmvd (15% O2), respectively. Compliance with the 2000 ppmv CO limit is expected.

<u>*LSFO Flare*</u>: According to R407(b)(3), the provisions of this rule shall not apply to emissions from emergency venting due to equipment failure or process upset. During normal operation, all vent gases are captured by the VRS so only pilot and purge gas are being combusted in the flare. Compliance with the 2000 ppmv CO limit is expected during normal operation of these flares.

Sulfur Compound Limit:

<u>*Cogen Train D*</u>: The 500 ppmv sulfur compound limit is subsumed by RECLAIM [Rule 2001(j)] for the cogeneration unit, which will be classified as a major source under RECLAIM and will be equipped with an SO2 analyzer to comply with RECLAIM monitoring requirements.

<u>*LSFO Flare*</u>: As discussed in more detail in the analysis of RECLAIM requirements, flares are exempt from RECLAIM. Therefore, the flare is subject to the sulfur compound limit of Rule 407 during normal operation of the flare. As discussed above, the provisions of this rule do not apply to emissions from the emergency venting from equipment failure or process upset. Compliance with the 500 ppmv sulfur compound limit is expected during normal operation of these flares, which includes the combustion of pilot and purge natural gas flows to the flare. These flares are only expected to be challenged with a significant amount of high sulfur vent gases during equipment malfunctions or process upsets. Compliance with this rule is expected.

RULE 409: COMBUSTION CONTAMINANTS

This rule contains limit on combustion contaminants from the combustion of fuel of 0.23 gram per cubic meter (0.1 grain per cubic foot) of flue gas (15 minute avg. at 12% CO2).

<u>*Cogen Train D*</u>: PM/PM10 source tests were performed on the Cogen Train A, Cogen Train B and Cogen Train C during April 2008. As seen on the following table, the measured PM emissions for each of these units is substantially lower than the 0.1 gr/dscf limit of this regulation.

Source	Measured PM Emissions (gr/dscf)	Rule 409 PM Emission Limit (gr/dscf)	Rule 409 Compliant
Cogeneration A Train	0.0042	0.1	Yes
Cogeneration B Train	0.0035	0.1	Yes
Cogeneration C Train	0.0030	0.1	Yes

With the large margin of compliance for the existing cogeneration units, it is expected that the Cogeneration D Train will also comply with the PM emission limit of this rule.

LSFO Flare: As shown in the evaluation of Rule 404, the estimated PM emissions from the combustion of natural gas in the LSFO Flare is 0.006 gr/dscf, which is well below the limit of this rule. Compliance with the requirements of this rule is expected during normal operation of these combustion devices.

RULE 475: ELECTRIC POWER GENERATING EQUIPMENT

This rule applies to power generating equipment rated greater than 10 MW installed after May 7, 1976. Requirements specify that the equipment must comply with a PM mass emission limit of 11 lb/hr or a PM concentration limit of 0.01 grains/dscf. Compliance is demonstrated if either the mass emission limit or the concentration limit is met. As seen in the Rule 409 evaluation, PM emissions measured in the most recent source test of the existing cogeneration units are below 0.01 gr/dscf. Average PM emissions for the three cogeneration units during the source test were less than 7.5 lb/hr. It is expected that the Cogen Train D will also comply with the PM emission limits of this regulation.

REGULATION IX - NEW SOURCE PERFORMANCE STANDARDS (NSPS)

SUBPART A – GENERAL CONTROL DEVICE REQUIREMENTS (40CFR60.18)

40CFR60.18 of Subpart A contains general requirements for control devices used to comply with applicable subparts of parts 60 and 61. The control device requirements of NSPS Subpart A include:

60.18(c)(1): "Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours."

As stated in 60.11(c), the "opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard". Chevron is required to meet the requirement for operation of the flare with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours at all times except startup, shutdown, or malfunction as defined in Subpart A. Compliance with this requirement is expected since the flare only combusts pilot and purge natural gas during normal operation and is equipped with a water seal and VRS. .

60.18(c)(2): "Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f)." (f)(2) states that "the presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame." Chevron utilizes a thermocouple (with an infrared detector as a backup) to monitor the existence of a flame. Condition D12.14 for each of the flares requires that "operator shall install and maintain a(n) thermocouple or any other equivalent device to accurately indicate the presence of a flame at the pilot light. The operator shall also install and maintain a device to continuously record the parameter being measured." Chevron has the monitoring and recording systems in place to comply with the requirements of this section. Continued compliance is expected.

60.18(c)(4)(ii): Steam-assisted and non-assisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf). The net heating value of the gases that would be combusted in these flares is greater than 1000 btu/scf so an exit velocity of less than 400 ft/sec is required. As shown in the *Process Description* section of this evaluation, the exit velocity for the maximum estimated load to the flare is 229 ft/sec.

60.18(c)(6): Flares used to comply with this section shall be steam-assisted, air-assisted, or non-assisted. The LSFO Flare is steam assisted.

60.18(e): Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them. Compliance with this requirement is expected.

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 Cogen Train D 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.

40CFR60 SUBPART J- STANDARDS OF PERFORMANCE FOR PETROLEUM REFINERIES

This NSPS is applicable to the following affected facilities in petroleum refineries:
- Fluid Catalytic Cracking Unit Catalyst Regenerators
- Fuel Gas Combustion Devices
- All Claus Sulfur Recovery Plants (SRPs)(except Claus Plants of 20 long tons per day (LTD) or less

Fuel gas combustion device is defined as "any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid". Fuel gas is defined as any gas which is generated at a petroleum refinery and which is combusted. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery.

The LSFO Flare meets the NSPS Subpart J definition of a fuel gas combustion device so it would be subject to this NSPS if it was constructed, reconstructed, or modified after June 11, 1973 but before May 14, 2007. The flare was not constructed, reconstructed, or modified within the specified time period but it did become subject to this NSPS under Consent Decree No. C 03-04650 CRB (CD), which was filed in U.S. District Court in San Francisco on October 16, 2003 and approved by a US District Court Judge on June 28, 2005. This Consent Decree is the result of a settlement between Chevron and EPA over alleged violations of the certain Clean Air Act and CERCLA/EPCRA provisions including the New Source Performance Standards. Under the terms of this CD, all of the flares at the Chevron Refinery, with the exception of the SMR and SNR Hydrogen Plant ground flares, will become subject to NSPS Subpart J according to the schedule specified in the CD. Under the schedule in the CD, the LSFO Flare became subject on December 31, 2008. In the RECLAIM/Title V Permit, the flare (C1757) is tagged with condition H23.44, which denotes that the flare is subject to applicable requirements of this regulation.

This regulation has a limit of 160 ppm H2S for any fuel gas combusted in the flares. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this standard. A process upset gas is defined as “any gas generated by a petroleum refinery process unit as a result of start-up, shutdown, upset, or malfunction.

District Rule 1118 allows vent gas to be sent to a general service flare during emergencies, shutdowns, startups, turnarounds or essential operational needs. *Essential operation need* is defined as an activity determined by the Executive Officer to meet one of the following:

(A) Temporary fuel gas system imbalance due to: (i) Inability to accept gas compliant with Rule 431.1 by an electric generation unit at the facility that produces electricity to be used in a state grid system, or (ii) Inability to accept gas compliant with Rule 431.1 by a third party that has a contractual gas purchase agreement with the facility, or (iii) The sudden shutdown of a refinery fuel gas combustion device for reasons other than poor maintenance or operator error;

(B) Relief valve leakage due to malfunction;

(C) Venting of streams that cannot be recovered due to incompatibility with recovery system equipment or with refinery fuel gas systems, including supplemental natural gas or other gas compliant with Rule 431.1 that is used for the purpose of maintaining the higher heating value of the vent gas above 300 British Thermal Units per standard cubic foot. Such streams include inert gases, oxygen, gases with low or high molecular weights outside the design operating range of the recovery system equipment and gases with low or high higher heating values that could render refinery fuel gas systems and/or combustion devices unsafe;

(D) Venting of clean service streams to a clean service flare or a general service flare;

(E) Intermittent minor venting from: (i) Sight glasses; (ii) Compressor bottles; (iii) Sampling systems; or (iv) Pump or compressor vents; or

(F) An emergency situation in the process operation resulting from the vessel operating pressure rising above pressure relief devices’ set points, or maximum vessel operating temperature set point.

The VRS/flare system is designed such that any normal plant venting, relief valve leakage, intermittent minor venting or blowdowns are handled by the combination of the flare water seal and LSFO VRS. It is expected that only vent gases from emergencies (upset or malfunction) or qualifying refinery operational needs that exceed the capacity of the LSFO VRS will go to the LSFO Flare. As stated above, emergency gases are exempt from the 160 ppmv H2S limit of this regulation. All non-emergency vent gases sent to the flare due to *essential operational need* are expected to comply with the 160 ppmv H2S limit. Compliance with the requirements of this regulation is expected.

40CFR60 SUBPART Ja -- STANDARDS OF PERFORMANCE FOR PETROLEUM REFINERIES FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER MAY 14, 2007

This NSPS is applicable to the following affected facilities in petroleum refineries which were constructed, reconstructed, or modified after May 14, 2007:

- Fluid Catalytic Cracking Unit Catalyst Regenerators,
- Fluid Coking Units,
- Delayed Coking Units,
- Fuel Gas Combustion Devices (except flares), and
- Claus Sulfur Recovery Plants (SRPs)

Fuel gas combustion device is defined “as any equipment, such as process heaters, boilers, and flares, used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid”. Fuel gas is defined as any gas which is generated at a petroleum refinery and which is combusted. Fuel gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery.

Cogen Train D: The Cogen Train D gas turbine is not subject to this regulation because it will combust only commercial natural gas, which is produced outside of the refinery. The Cogen Train D duct burners will be subject to this regulation since they will combust natural gas and refinery fuel gas. The refinery fuel gas will be supplied to the duct burners from the V-4540 fuel mix drum, which also supplies fuel gas to the Cogen A and B Train duct burners.

According to §60.102a(g)(1), the owner or operator of an effected fuel gas combustion device shall comply with either stack gas SO2 concentration limits of 20 ppmvd (0% O2, 3-hr rolling avg.) and 8 ppmvd (0% O2, 365 successive calendar day rolling avg.) or fuel gas H_2S concentration limits of 162 ppmv (3-hr rolling avg.) and 60 ppmv (365 successive calendar day rolling avg.). The duct burner exhaust gas is diluted by the exhaust gas from the gas turbine so Chevron must comply with the fuel gas H2S limits. TRS concentrations for the fuel gas from the V-4540, as measured by a semi-continuous fuel sulfur GC, re routinely below 40 ppmv. The existing fuel sulfur GC will be utilized to verify compliance with the subject H2S limits. Compliance with the H2S limits of this regulation is expected.

This regulation also contains a stack gas NOx concentration limit of 40 ppmvd (0% O2, 24-hr rolling avg.) for process heaters with a rated capacity of greater than 40 MMBtu/hr. A process heater is defined as “an enclosed combustion device used to transfer heat indirectly to process stream materials (liquids, gases, or solids) or to a heat transfer material for use in a process unit instead of steam”. The duct burner is not subject to this NOx limit since it is not a process heater.

LSFO Flare: As specified at §60.102a(h), the "combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from paragraph (g) of this section". The referenced paragraph (g) contains the emission limits for fuel gas combustion devices. Connection of new PRVs to the subject flare is not considered a modification of the flare since there is no increase in SOx emissions from the flare during normal operation. During normal operation, all vent gases from the new PRVs will be captured by the VRS. Therefore, the flare is not subject to this NSPS.

40CFR60 SUBPART GG: STANDARDS OF PERFORMANCE FOR STATIONARY GAS TURBINES

This NSPS is applicable to all stationary gas turbines that commenced construction, reconstruction, or modification after Oct. 3, 1977 and has a heat input at peak load of 10.7 gigajoules (10 MMBtu) per hour, based on the fuels lower heating value.

The proposed Cogen D turbine and duct heater are subject to 40CFR60 Subpart KKKK. According to §60.4305(b) in Subpart KKKK, turbines regulated under Subpart KKKK are exempted from the requirements of subpart GG. Therefore, the Cogen D Turbine is not subject to the requirements of this regulation.

40CFR60 SUBPART GGG – STANDARDS OF PERFORMANCE FOR EQUIPMENT LEAKS OF VOCS IN PETROLEUM REFINERIES FOR WHICH CONSTRUCTION, RECONSTRUCTION, OR MODIFICATION COMMENCED AFTER JANUARY 4, 1983, AND ON OR BEFORE NOVEMBER 7, 2006

The following are affected facilities under this subpart:

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

The definition for process unit and equipment follows: "*Process unit* means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product." "*Equipment* means each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service." From Subpart VVa (as referenced from GGGa), the definition of "*in VOC service*" is that "the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight".

Cogen Train D: The equipment in the Cogen Train D is not subject to this regulation since it does not meet the definition of a process unit and it is being constructed after November 7, 2006.

LSFO VRS: The equipment in this permit unit is subject to this regulation. The "Fugitive Emissions, Miscellaneous" device (D3679) for this permit unit is tagged with condition H23.19, which specifies that the permit unit is subject to Rule 1173 and 40CFR60 Subpart GGG. NSPS Subpart GGG references the requirements of NSPS Subpart VV - Standards of Performance for Equipment leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry. In general, the equipment leak inspection and monitoring requirements of Rule 1173 are equally or more stringent than this regulation but pertinent requirements of this regulation have been incorporated into Chevron's Inspection and Monitoring (I&M) Program for fugitive emissions. Compliance with the requirements of this regulation are expected.

LSFO Flare: The equipment in the Cogen Train D is not subject to this regulation since it does not meet the definition of a process unit.

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.

Cogen Train D: The equipment in the Cogen Train D is not subject to this regulation since it does not meet the definition of a process unit. The only compressor in the Cogen D permit unit is not in VOC service cine it is a natural gas booster compressor (D4356).

LSFO VRS: The equipment in this permit unit is not subject to this regulation since it has not been modified after November 7, 2006. The three compressors in the VRS are subject to the requirements of this regulation since they were installed in 2007 as replacements for smaller compressors. Each of the compressors (D4211, D4212, D4213) are tagged with condition H23.47, which specifies that the permit unit is subject to Rule 1173 and 40CFR60 Subpart GGGa. It is specified in §60.482–3a(a) that each compressor shall be equipped with a seal system that includes a barrier fluid system and that prevents leakage of VOC to the atmosphere, except as provided in §60.482–1a(c) and paragraphs (h), (i), and (j) of this section. It is specified in paragraph (h) that a compressor is exempt from the requirements of paragraphs (a) and (b) of this section, if it is equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that complies with the requirements of §60.482–10a. As specified in the equipment description in the permit, each of the compressors in the LSFO VRS are equipped with dual packing rings with nitrogen gas purged to a fuel gas system. Therefore, the compressors are exempt from the seal requirements specified in §60.482–3a(a) and (b). Compliance with the requirements of these regulations is expected.

LSFO Flare: The equipment in the LSFO Flare permit unit is not subject to this regulation since it does not meet the definition of a process unit.

40CFR60 SUBPART KKKK: STANDARDS OF COMPLIANCE FOR STATIONARY COMBUSTION TURBINES

This subpart establishes NOx and SO_2 emission standards and compliance schedules for the control of emissions from stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value, that commenced construction, modification or reconstruction after February 18, 2005.

The heat input capacity of the proposed Cogen D turbine is 508 MMBtu/hr (HHV) so it will be subject to the requirements of this regulation._Note that the emission limits of this subpart apply to both the combustion turbine and the duct burner/HRSG (if applicable).

NOx Limit
According to §60.4320 and Table 1 to this NSPS, this turbine is subject to a NOx emission limit of 25 ppmv (@ 15% O2) since it has a heat input capacity between 50 and 850 MMBtu/hr and fires natural gas. This limit is well above the 2 ppmv NOx limit that will be imposed on the proposed cogeneration unit under Rule 2005 (BACT).

SOx Limit
The turbine is also subject to one of the following SO2 related limits:
(1) Exhaust gas with SO2 greater than 110 nanograms per Joule (ng/J) (0.90 pounds per megawatt-hour (lb/MWh)) gross output, or
(2) fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

The turbine will be permitted to burn natural gas only. Historically, the TRS concentration of natural gas supplied to the refinery is less than 5 ppmv, which is equivalent to 0.0008 lb SO2/MMBtu. The refinery fuel gas provided to the duct burner will be limited to a total reduced sulfur (TRS) concentration of 40 ppmv, which is equivalent to 0.006 lb SO2/MMBtu. Compliance with the 0.06 lb SO_2/MMBtu limit of this regulation is expected.

Monitoring
A NOx analyzer is required under this regulation. The cogen unit will be required to install CEMS to comply with RECLAIM requirements for NOx Major Sources. Therefore, NOx monitoring requirements are satisfied. Daily monitoring of the sulfur content of the fuel is required if the fuel limit is selected. However, if the operator can provide supplier data showing the sulfur content of the fuel is less than 20 grains/100scf (for natural gas), then daily fuel monitoring is not required. The turbine will fire natural gas provided by the Southern California Gas Company which contains less than 1 grains-sulfur/100scf. Therefore, daily monitoring of the natural gas sulfur content is not required. TRS content of the refinery fuel mix drum will be measured with a fuel sulfur GC to comply with RECLAIM. This fuel sulfur monitoring system will also satisfy the monitoring requirements of this NSPS.

<u>REGULATION X - NATIONAL EMISSION STANDARD FOR HAZARDOUS AIR POLLUTANTS (NESHAPS)</u>

40CFR63 SUBPART CC: NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FROM PETROLEUM REFINERIES
This Subpart applies to petroleum refining sources and related emission sources that are specified in section 63.640 (c)(5) through (c)(7) (e.g. miscellaneous process vents (except for FCCU, SRU, and CRU vents), storage vessels, wastewater stream, equipment leaks, gasoline loading racks, marine vessel loading, etc.) that are located in a major source and emit or have equipment contacting one or more of the hazardous air pollutants (HAPs) listed in Table 1 of this subpart.

Cogeneration Train D - The only sources in the cogeneration unit that must be evaluated as potentially affected sources under this NESHAP are fugitive components in the refinery fuel gas supply systems. The equipment leak standards as specified in 63.648 are applicable to fugitive components that are "in organic hazardous air pollutant service". In "organic hazardous air pollutant service" is defined as a piece of equipment that either contains or contacts a fluid (liquid or gas) that is at least 5% by weight of total organic HAPs as determined according to 63.180(d). The refinery fuel gas does not 5% or more by weight of total organic HAPs. Therefore, none of the fugitive components in this permit unit are subject to this regulation.

LSFO VRS and LSFO Flare – Both of these permit units have existing fugitive components that are subject to this regulation. The "fugitive emissions, miscellaneous" device, which represents the fugitive components in a permit unit, for each of these permit units is tagged with "HAP: 40CFR 63 Subpart CC, 5-25-2001" to denote that each permit unit contains some fugitive components that are subject to this regulation. As mentioned previously, no new fugitive components are being installed in these permit units.

This regulation refers to the fugitive component monitoring requirements of NSPS Subpart VV and NESHAP Subpart H with exceptions that are specifically noted in the regulation. In general, the equipment leak inspection and monitoring requirements of District Rule 1173 are equally or more stringent than this regulation but pertinent requirements of this regulation have been incorporated into Chevron's Inspection and Monitoring (I&M) Program for fugitive emissions. Continued compliance with the inspection, maintenance, and record keeping requirements of this rule is expected.

Applicability for Miscellaneous Process Vents: *Miscellaneous process vent* is defined as "a gas stream containing greater than 20 parts per million by volume organic HAP that is continuously or periodically discharged during normal operation of a petroleum refining process unit. Miscellaneous process vents include gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device prior to control or discharge to the atmosphere".

The definition of a *miscellaneous process vent* at 40CFR63.641 specifies a number of vent streams that are not considered to be *miscellaneous process vents*, which are subject to the requirements of this rule. Some of the streams that are included in this list of exempt streams are:

- Gaseous streams routed to a fuel gas system
- Relief valve discharges
- "Episodic or nonroutine releases such as those associated with startup, shutdown, malfunction, maintenance, depressuring, and catalyst transfer operations.
- Sulfur plant vents

The discharge streams from the subject PRVs are exempt streams that are not subject to the miscellaneous process vent requirements of this regulation.

40CFR63 SUBPART YYYY: NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR STATIONARY COMBUSTION TURBINES

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 D turbine is a lean- premix type turbine.

No additional analysis is required.

40CFR63 SUBPART DDDDD - NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR INDUSTRIAL, COMMERCIAL AND INSTITUTIONAL BOILERS AND PROCESS HEATERS

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 23, 2010. On May 18, 2011, EPA announced delay of the effective dates of the rule pending completion of their reconsideration of the rule. Further action on the rule is pending EPA internal review.

In the proposed regulation, *boiler* is defined as an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. *Waste heat boiler* is defined as a device that recovers normally unused energy and converts it to usable heat. Waste heat recovery 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.

Based on these definitions, the duct burners and associated heat recovery steam generator would be subject to the proposed regulation as boilers. The proposed regulation does not include a date that delineates between new and existing units so it is not currently possible to determine if the Cogen D duct burner/HRSG will be considered a new or existing unit. Existing units will be required to comply with the regulation within three years after the final rule is published in the federal register.

The proposed regulation defines eleven (11) subcategories of boilers and process heaters. The Auxiliary Boiler and cogeneration unit duct burners/HRSGs fit into the subcategory specified as *units designed to burn natural gas/refinery gas*. Emission limits for new and existing boilers and process heaters are specified in Tables 1 and 2 of the proposed regulation. The tables do not contain any emission limits for new or existing boilers or process heaters in the natural gas/refinery gas category. As specified in Table 3 of the proposed regulation, boilers and process heaters in the natural gas/refinery gas subcategory that have a heat input capacity greater than 10 MMBtu/hr would be subject to an annual tune-up. Additionally, all existing boilers would be subject to a one-time energy assessment performed by qualified personnel.

Since the duct burners/HRSG are not subject to any emission limits, they are also not subject to any operating limits, performance testing, or other compliance requirements specified in Tables 4 through 8 of the proposed regulation. Based on past compliance with similar regulations, it is expected that Chevron would comply with this regulation as proposed. No changes to the permit or additional action are required at this time.

REGULATION XI: SOURCE SPECIFIC STANDARDS

RULE 1109: EMISSION OF OXIDES OF NITROGEN FROM BOILERS AND PROCESS EATERS IN PETROLEUM REFINERIES

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

RULE 1118: EMISSIONS FROM REFINERY FLARES

Background

This rule was adopted on February 13, 1998 and subsequently amended on November 4, 2005. It applies to all gas flares used at petroleum refineries, sulfur recovery plants and hydrogen production plants. The LSFO Flare is subject to the requirements of this rule as an general service flare. The purpose of Rule 1118 as adopted in 1998 was to monitor and gather data on refinery flares for evaluation of the need of additional controls to minimize flaring events. The primary requirements of 1998 version were submission and approval of a monitoring plan [1118(c)(1)], monitoring of release events, and quarterly reporting of monitoring results. The remainder of this section contains an evaluation of the requirements of the current version of this rule.

Current Requirements

Flare Pilot [1118(c)(1)(A)] - Maintain a pilot flame present at all times a flare is operational. The LSFO Flare is equipped with a thermocouple to monitor the existence of the pilot light.

Annual Leak Survey [1118(c)(1)(C)] - Conduct an annual acoustical or temperature leak survey of all pressure relief devices (PRDs) connected directly to a flare and repair leaking pressure relief devices no later than the next turnaround. The survey shall be conducted no earlier than 90 days prior to the scheduled process unit turnaround. This requirement is not applicable since the PRDs for the subject LSFO VRS/Flare are not connected directly to the flare. The water seal prevents any PRD leakage from flowing to the flares.

Specific Cause Analysis [1118(c)(1)(D)] - Conduct a Specific Cause Analysis for any flare event, excluding planned shutdown, planned startup and turnarounds, with emissions exceeding either:

- o 100 pounds of VOC;
- o 500 pounds of sulfur dioxide;
- o 500,000 standard cubic feet of vent gas combusted

This analysis must be submitted to the District within 30 days of the event unless an extension is granted [1118(i)(3)]. Compliance with this analysis and reporting requirement is expected.

Relative Cause Analysis [1118(c)(1)(E)] - Conduct an analysis and determine the relative cause of any other flare events where more than 5,000 standard cubic feet of vent gas are combusted. When it is not feasible to determine relative cause, state the reason why it was not feasible to make the determination. According to Chevron, reports of these analyses are contained in their quarterly reports using a code system developed by the District. For example, flaring due to equipment failure is assigned a District Relative Cause Code of 3.

Evaluation of Options for Reduction in Flaring [1118(c)(3)] - Submit an evaluation of options to reduce flaring during planned shutdowns, startups and turnarounds, including, but not limited to slower vessel depressurization and storing vent gases. Chevron has specified that they will minimize flaring through slower vessel depressurization.

Flare Minimization [1118(c)(4)] - Operate all flares in such a manner that minimizes all flaring and that no vent gas is combusted except during emergencies, shutdowns, startups, turnarounds or essential operational needs. Chevron recently upgraded the LSFO VRS compressors to assist in compliance with this requirement. Connection of the new PRVs to the LSFO VRS is not expected to impact compliance with this requirement.

H2S Limit [1118(c)(5)] - Effective January 1, 2009, a refinery shall prevent the combustion in any flare of vent gas with a hydrogen sulfide concentration in excess of 160 ppm, averaged over three hours, excluding any vent gas resulting from an emergency, shutdown, startup, process upset or relief valve leakage. The LSFO flare is tagged with condition B61.11, which specifies this H2S limit. Compliance with this requirement is expected since the LSFO VRS has adequate capacity to collect and recover all vents gases during normal operation of the permit units that vent to the VRS/Flare.

Performance Targets [1118(d)] - A refinery shall minimize flare SO2 emissions and meet the following performance targets for SO2 emissions. Compliance with the performance targets are determined at the end of each calendar year based on the facility's annual flare sulfur dioxide emissions normalized over the crude oil processing capacity in calendar year 2004.

- Calendar Years 2006 and 2007: 1.5 tons per million barrels of crude processing capacity
- Calendar Years 2008 and 2009: 1.0 tons per million barrels of crude processing capacity
- Calendar Years 2010 and 2011: 0.7 tons per million barrels of crude processing capacity
- Beginning in calendar year 2012: 0.5 tons per million barrels of crude processing capacity

  If a refinery exceeds the performance targets for any calendar year, the owner or operator must:
  - Submit a Flare Minimization Plan, and
  - Pay the District mitigation fees. The rule includes a sliding fee schedule based on the relative amount of the exceedance. The rule includes a 60 day public review period for the Flare Minimization plan prior to approval of the plan.

Chevron has a total of 7 flares that are subject to this rule. As seen in the table below, Chevrons' SO2 emissions from flaring were below the targets for 2006 – 2010.

SO2 Emissions from Flaring

Year	SO2 Target (ton/yr)(1)	SO2 Emissions (ton/yr)
2006	142.7	25.3
2007	142.7	49.3
2008	95.2	43.7
2009	95.2	58.5
2010	66.6	22.8
2011	66.6	9.0 (2)
2012 & subsequent years	47.6	na.

(1) Based on crude capacity of 95.16 MMbbl/yr
(2) SO2 emissions for first 6 months of 2011

TRS concentrations in the refinery fuel gas burned in the duct burners are limited to 40 ppmv or less on a 1-hr average basis and 30 ppmv on a 24-hr basis per condition B61.12. Due to the low concentrations of sulfur compounds in the refinery fuel gas, the proposed connection of the subject refinery fuel gas system PRDs to the LSFO VRS and flare is not expected to impact Chevron's ability to achieve their SO2 performance targets.

Monitoring and Recording Requirements [1118(g)(3)] - The monitoring and recording requirements for emergency and general service flares are summarized in the following table:

Operating Parameter	Monitoring and Recording Requirement
Gas Flow	Measured and Recorded Continuously with Flow Meter(s) and/or On/Off Flow Indicator(s)
Gas Higher Heating Value	Continuously Measured and Recorded with a Higher Heating Value Analyzer
Total Sulfur Concentration	Semi-Continuously Measured and Recorded with a Total Sulfur Analyzer

Chevron has installed the required monitoring and recording system. The system is pending final certification by the District.

Color Video Monitors [1118(g)(7)] - Monitor all flares for visible emissions using color video monitors with date and time stamp, capable of recording a digital image of the flare and flame at a rate of no less than one frame per minute. According to Chevron, the required cameras and recorders have been installed and are recording images at a rate of once per minute.

Flare Monitoring and Recording Plan [1118(g)(7)] - By June 30, 2006, submit a revised Flare Monitoring and Recording Plan, which shall include all information specified at 1118(f)(3) [1118(f)(1)(A)]. They must comply with the existing plan until a revised plan is approved. A facility must start monitoring and recording in accordance with the Revised

Flare Monitoring and Recording Plan within 6 months after the plan is approved [1118(g)]. Chevron submitted this plan (AN 458606) on June 30, 2006. Chevron has also submitted two addendums to the plan. Chevrons plan submittal is currently being reviewed by the District.

Flare Inquiry Phone Service [1118(i)(1)] - Provide a 24 hour telephone service for access by the public for inquiries about flare events Chevron's 24 hour Community Hotline number is (310) 615-5342. This number is listed on the District's web site.

Notification of Unplanned Flare Events [1118(i)(2)] - Notify the Executive Officer by telephone within one hour of any unplanned flare event with emissions exceeding either 100 pounds of VOC or 500 pounds of sulfur dioxide, or exceeding 500,000 standard cubic feet of flared vent gas. Compliance with this notification requirement is expected.

Notification of Planned Flare Events [1118(i)(4)] - Notify the District at least 24 hours prior to the start of a planned flare event with emissions exceeding either 100 pounds of VOC or 500 pounds of sulfur dioxide, or 500,000 standard cubic feet of combusted vent gas. These notifications are made through the District's Flare Event Notification web page. A record of all notifications can be accessed through the web page.

Quarterly Report [1118(i)(5)] - Submit a quarterly report in an electronic format approved by the District within 30 days after the end of each quarter. Chevron has submitted all required quarterly reports. Continued compliance with this requirement 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 D turbine. Also, the requirements of this regulation have been subsumed by RECLAIM per 2001(j)

RULE 1135: EMISSION OF OXIDES OF NITROGEN FROM ELECTRIC POWER GENERATING SYSTEMS

The Cogen Train D will not be subject to this regulation since it will not be an "electric power generating systems" 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 Train D duct burners/HRSG will not be subject to this regulation since they will be located 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).

RULE 1173: CONTROL OF VOLATILE ORGANIC COMPOUND LEAKS FROM COMPONENTS OF PETROLEUM FACILITIES AND CHEMICAL PLANTS

This rule is intended to control volatile organic compound (VOC) leaks from fugitive components at refineries, chemical plants, oil and gas production fields, natural gas processing plants, and pipeline transfer stations. It contains identification requirements, leak standards, inspection requirements, maintenance and repair requirements, and recordkeeping and reporting requirements for fugitive components.

The only new components for the proposed Cogen D and existing components for the existing cogeneration trains that are subject to this regulation are those components that handle refinery fuel gas. Chevron has an existing fugitive emission component inspection and monitoring (I&M) program for compliance with the requirements of this rule. Where applicable, new components installed under this project will be integrated into this I&M program. Compliance with the requirements of this regulation is expected.

REGULATION XIII - NEW SOURCE REVIEW

As specified in Rule 1301, Regulation XIII, sets forth pre-construction review requirements for new, modified, or relocated facilities, to ensure that the operation of such facilities does not interfere with progress in attainment of the national ambient air quality standards (NAAQS), and that future economic growth within the South Coast Air Quality Management District (District) is not unnecessarily restricted. The specific air quality goal of this regulation is to achieve no net increases from new or modified permitted sources of nonattainment air contaminants or their precursors.

The South Coast Air Basin (SOCAB) is designated in attainment of the NAAQSs for CO, NOx and SOx. The following are currently considered nonattainment air contaminants that are subject to new source review (NSR): NOX, SOx, $PM_{2.5}$, PM_{10}, and VOC. NOx and VOC are included since they are precursors for ozone. NOx, SOx and VOC are included as $PM_{2.5}$ and PM_{10} precursors.

NSR requirements for these attainment pollutants are specified in the following rules:
- Rule 1303 – PM10 and VOC (all facilities); NOx and SOx (non-RECLAIM facilities)
- Rule 1325 – PM2.5
- Rule 2005 – NOx and SOx (RECLAIM facilities)

Since Chevron is a RECLAIM facility, it is subject to the NSR requirements for NOx and SOx specified in Rule 2005 of the RECLAIM regulation (Regulation XX). Sources that emit ammonia, CO, and Ozone Depleting Compounds (ODCs) are subject to only the BACT requirements of Rule 1303 for these pollutants.

RULE 1303: REQUIREMENTS

This rule requires the Executive Officer to deny a Permit to Construct for any new, modified or relocated source which results in an emission increase of CO, PM10, VOC, any ozone depleting compound, or ammonia, unless BACT is used. This rule also requires modeling and offset (among other requirements) if there is a net increase in PM10 or VOC emissions for any new or modified source. Since the installation of the subject PRVs are a change to the project that is currently under construction, the evaluation of Rule 1303 is based on the total VOC emissions for the project and not just the increase in VOC emissions due to the installation of the PRVs. The evaluation will not change for other pollutants since the installation of the PRVs does not impact the emission of any of these other pollutants.

1303(a)(1): Best Available Control Technology (BACT): Any new or modified source which results in an emission increase of any nonattainment air contaminant, any ozone depleting compound, or ammonia, must employ BACT for the new or relocated source or for the actual modification to an existing source. Per District policy, BACT is required for any increase in emissions that exceeds 1.0 lb per day on a maximum daily basis.

For the permit to construct issued under A/N 470782, the Cogen Train D was subject to BACT (LAER) for CO, PM10, VOC, and NH3 under Rule 1303 and for NOx and SOx under Rule 2005. BACT is summarized in the table below.

BACT (LAER) Levels for Chevron Cogen Train D

NOx	CO	VOC	PM_{10}/SOx	NH_3
2.0 ppmvd, @ 15% O_2, 1-hr avg.	2.0 ppmvd, @ 15% O_2, 1-hr avg.	2.0 ppmvd, @ 15% O_2, 1-hr avg.	Pipeline quality natural gas w/ S content ≤ 1 grain/100 scf; Refinery fuel gas w/ total sulfur ≤ 40 ppmv, 1-hr avg. & 30 ppmv, 24-hr rolling avg.	5.0 ppmvd, @ 15% O_2, 1-hr avg.

Note that this BACT determination is not impacted by the proposed installation of PRVS on the fuel system since there is no change in the estimated maximum potential combustion emissions for the unit.

Fugitive Components: The VOC service fugitive components associated with the Cogeneration train, including those VOC service fugitive components being installed with the subject PRVs, are subject to BACT since the increase in fugitive VOC emissions is greater than 1 lb/day. Note that natural gas service fugitive components are not considered to be in VOC service since natural gas contains less than 10% VOC. Therefore, the natural gas service fugitive components are not subject to BACT. The majority of fugitive components being installed, including most of the components related to the subject PRVs, are in natural gas service. BACT for VOC service fugitive components is outlined below.

- 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 S31.20 specifies the requirement to install bellow-sealed (leakless) valves except for the exempt applications listed above. This condition also specifies that Chevron must submit a list of all non-leakless valves to the District prior to the startup of the cogeneration unit. It is also specified that Chevron shall not startup the equipment prior to the Districts approval for the use of all non-leakless valves.

- *Relief Valves*: BACT for emergency pressure relief valves (PRVs) is connection to a closed vent system. The subject PRVs will comply with this requirement since they will be connected to the LSFO VRS.

- *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 Chevron, new process drains for the Cogen Train D 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. Chevron 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.

1303(b) – The following requirements apply to any new or modified source which results in a net emission increase of any nonattainment air contaminant.

1303(b)(1): Modeling - The applicant must substantiate with modeling that the new facility or modification 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. According to 1306(b), the new total emissions for modified sources shall be calculated on a pound per day basis for determination of BACT and modeling applicability. The modeling procedures are discussed in Appendix A to the rule. It is specified in Appendix A of this rule that modeling is not required for VOC. Therefore, under this rule, modeling is required for PM10 only.

As discussed in detail in the engineering evaluation for PC A/N 470782, the Cogeneration Train D passes the screening modeling in Appendix A since the estimated maximum potential PM10 emissions of 5.45 lb/hr for the Cogen Train D is less than the Appendix As screening level of 7.9 lb/hr. The subject PRVs will not cause an increase in PM10 emissions so additional modeling is not required.

1303(b)(2): Offsets – Unless exempt from offsets requirements pursuant to Rule 1304, emission increases shall be offset by either Emission Reduction Credits approved pursuant to Rule 1309, or by allocations from the Priority Reserve. Per District policy, Offsets are required for any increase in emissions that exceeds 0.5 lb per day on a maximum daily basis.

VOC and PM10 offset requirements for construction of the Cogeneration Train D were satisfied under PC A/N 470782. Based on an ERC ratio of 1.2-to-1.0 for facilities in the South Coast Air Basin (SOCAB), Chevron provided 55 lbs of VOC ERCs under PC A/N 470782 to offset the estimated VOC emission increase of 46.1 lb/day for the Cogen Train D. The VOC ERC requirement is re-estimated by adding the 0.34 lb/day VOC emission increase for the PRVS to the 46.1 lb/day of VOC emissions for the Cogen Train D. The resulting 46.44 lb/day is multiplied by the 1.2 ERC ratio to arrive at a VOC ERC requirement of 56 lb/day (55.73 rounded up). Chevron will be required to provide an additional 1 lb of VOC ERC. Note that Chevron is not required to offset the increase in fugitive VOC emissions caused by the change in fugitive VOC emission factors since the issuance of PC A/N 470782.

1303(b)(3) - Sensitive Zone Requirements: This section pertains to Emission Reduction Credits (ERCs) for facilities in the South Coast Air Basin (SOCAB). Except for credits that are obtained from the Priority Reserve, facilities are subject to the Sensitive Zone requirements (H&SC Section 40410.5) for ERCs. A facility in zone 1 may obtain ERCs originated in zone 1 only, and a facility in zone 2A may obtain ERCs from either zone 1 or zone 2A.

The El Segundo Refinery is located in Zone 1. Chevron will utilize ERC certificate no. AQ011196, which is for 112 lb/day of VOC. These ERCs were originally generated from the shutdown of equipment in 1994 at an ALCOA facility (ID. 017418) located in Vernon, which is in Zone 1. The equipment shutdown generated 566 lb/day of VOC ERCs issued as ERC certificates AQ001375 and AQ001497.

1303(b)(4) - Facility Compliance: The facility must be in compliance with all applicable rules and regulations of the District.

This facility is currently in compliance with all applicable rules and regulations. There are no outstanding NOV's and no known violations.

1303 (b)(5) - Major Polluting Facilities: Any new major polluting facility or major modification at an existing major polluting facility must comply with the requirements summarized below. A major modification is defined in 1302(r) as any modification at an existing major source that will cause

- an increase of one pound per day or more, of the facility's potential to emit (PTE) for NOx or VOC if the facility is located in the SOCAB , or
- an increase of 40 tons per year or more, of the facility's PTE for SOx, or
- an increase of 15 tons per year or more, of the facility's PTE for PM_{10}; or,

- an increase of 50 tons per year or more, of the facility's PTE for CO.

Since the total increase in VOC emissions for construction of the Cogen Train D is greater than 1 lb/day, it is considered a major modification at a major polluting facility. Therefore, the project must comply with the following requirements.

(A) 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 PRO Project, which was performed as required by CEQA, was certified on May 9, 2008. An addendum to the FEIR was certified on May 13, 2010. According to Jeff Inabinet of the District's CEQA Group, the FEIR adequately addresses the Cogeneration Train D including the addition of the five PRVs. The requirements of 1303(b)(5)(A) are satisfied.

(B) Statewide Compliance: The applicant must demonstrate that all major stationary sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by the applicant 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 Ms. Susan Worley, the Health, Environmental, and Safety Manager at the El Segundo Refinery, indicating that all major sources owned or operated by Chevron U.S.A. Inc. 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 is contained in engineering file.

(C) Protection of Visibility - A modeling analysis for plume visibility is required if the net emission increase exceeds 15 tons/yr of PM10 or 40 tons/yr 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 the table below.

Federal Class I Area	Threshold Distance	Distance from Chevron Refinery
Agua Tibia	28 km (17.4 miles)	135 km
Cucamonga	28 km (17.4 miles)	71 km
Joshua Tree	29 km (18.0 miles)	178 km
San Gabriel	29 km (18.0 miles)	50.5 km
San Gorgonio	32 km (19.9 miles)	133 km
San Jacinto	28 km (17.4 miles)	135 km

A plume visibility analysis is not required since none of the Federal Class I Areas are closer to the refinery than the distances specified in the table.

(D) Compliance through California Environmental Quality Act- As discussed previously, CEQA requirements have been fulfilled. (See CEQA Evaluation).

RULE 1325: FEDERAL PM2.5 NEW SOURCE REVIEW PROGRAM

This NSR rule for PM2.5 was adopted by the District's Governing Board on June 3, 2011. The Cogen Train D was not subject to this regulation under permit to construct A/N 470782 since the rule was approved subsequent to permit issuance. The requirements of this rule are not triggered by the installation of the subject PRVs since they will not cause an increase in maximum potential PM2.5 emissions.

REGULATION XIV: TOXICS AND OTHER NON-CRITERIA POLLUTANTS

RULE 1401: NEW SOURCE REVIEW OF TOXC AIR CONTAMINANTS

Requirements – Rule 1401 contains the following requirements:

1) *(d)(1) MICR and Cancer Burden* - The cumulative increase in MICR which is the sum of the calculated MICR values for all toxic air contaminants emitted from the new, relocated or modified permit unit will not result in any of the following:
   (A) an increased MICR greater than one in one million (1.0×10^{-6}) at any receptor location, if the permit unit is constructed without T-BACT;
   (B) an increased MICR greater than ten in one million (1.0×10^{-5}) at any receptor location, if the permit unit is constructed with T-BACT;
   (C) a cancer burden greater than 0.5.

2) *(d)(2) Chronic Hazard Index* - The cumulative increase in total chronic HI for any target organ system due to total emissions from the new, relocated or modified permit unit will not exceed 1.0 at any receptor location.
3) *(d)(3) Acute Hazard Index* - The cumulative increase in total acute HI for any target organ system due to total emissions from the new, relocated or modified permit unit will not exceed 1.0 at any receptor location.

Analysis – Under this rule, a health risk assessment (HRA) must be performed for each individual permit unit for which there is an increase in TACs. Under PC A/N 470782, Chevron performed a Tier 4 health risk assessment in accordance with the SCAQMD Risk Assessment Procedures for Rules 1401 and 212 Version 7.0 (July 2005) and the Consolidated Tables of OEHHA/ARB Approved Risk Assessment Health Values (February 2009). The HRA was performed using the CARB HARP model (version 1.4a), which combines US EPA Industrial Source Complex dispersion model with a risk calculation model based on the Air Toxics Hot Spots Program Risk Assessment Guidelines (OEHHA, 2003).

The results from the analysis are shown in the table below. AQMD modeling staff confirmed that Chevron's HRA conformed to the District's applicable requirements.

Results of Rule 1401 Analysis

Parameter	Results	Rule 1401 Requirements	Comply (Y/N)
MICR	0.04EE-06	<1.0EE-06 (no TBACT) <10EE-06 (w/TBACT)	Yes
HIA	0.001	<1.0	Yes
HIC	0.003	<1.0	Yes
Cancer Burden	N/A	Applicable only if MICR >1.0EE-06	N/A

Due to the large margin of compliance with the requirements of this regulation and the insignificance of the small increase in TAC emissions for the subject PRVs relative to the overall TAC emissions for the Cogen Unit, no additional analysis is required.

REGULATION XVII: PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

The PSD program is the federal New Source Review (NSR) program for pollutants for which an area is in attainment with or unclassified with respect to a National Ambient Air Quality Standard (NAAQS) as well as greenhouse gases (GHG).

RULE 1703: PSD ANALYSIS (& ASSOCIATED RULES 1701, 1702, 1704, 1706, 1710 & 1713)

These rules contain the PSD requirements for attainment pollutants and selected unclassified pollutants. As discussed earlier, SOCAB is currently designated as attainment with NAAQSs for SO2, NO2, CO, and Lead. On March 3, 2003, AQMD's PSD delegation was rescinded by EPA. AQMD and EPA signed a "Partial PSD Delegation Agreement" effective July 11, 2007. According to a memo from Mr. Mohsen Nazemi, who is the Deputy Executive Officer of the AQMD Engineering and Compliance Division, this Partial Delegation Agreement is intended to delegate the authority and responsibility to AQMD for issuance of initial PSD permits and for PSD permit modifications where the applicant seeks to use the emissions calculation methodology set forth in AQMD Regulation XVII instead of those promulgated in 40 CFR 52.21 (NSR Reform).

Under PC A/N 470782, it was determined that the requirements of this rule are not applicable for the construction of the Cogeneration Train D since it will not cause a significant emission increase of any attainment air contaminant. A comparison of the estimated maximum CO, NOx and SOx emissions for the Cogen Train D versus the significance thresholds of the regulation is contained in the table below.

Pollutant	Emission Increase (ton/yr)	Significance Threshold (ton/yr)	Significant Increase of Attainment Pollutant?
CO	15	100	**No**
NOx	22	40	**No**
SOx	5	40	**No**

The installation of the subject fuel system PRVs does not impact this PSD analysis since they will not cause an increase in the emission of CO, NOx or SOx under normal operating conditions.

RULE 1714: PREVENTION OF SERIOUS DETERIORATION FOR GREENHOUSE GASES

This rule sets forth preconstruction review requirements for greenhouse gases (GHG), which is defined as an aggregate group of six GHGs: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. This rule was adopted on November 5, 2010, therefore, it did not exist at the time that the permit to construct for the Cogen Train D was issued under A/N 470782.

For the connection of the fuel system PRVS to the LSFO VRS and Flare, the pollutant GHG is subject to requirements under this regulation if either of the following apply:

- A stationary source, which is an existing major stationary source for a regulated non-GHG NSR pollutant, has an emissions increase of at least 75,000 tpy CO_2e and also an emissions increase of a regulated NSR pollutant.
- A stationary source, which is an existing major stationary source that emits or has the potential to emit 100,000 tpy CO_2e, undertakes a physical change or change in the method of operation that will result in an emissions increase of 75,000 tpy CO_2e or more.

The refinery is a major source for all non-GHG pollutants. Therefore, the requirements of this regulation are triggered for any modification with an increase in CO2e greater than 75,000 TPY. According to EPA permitting guidance for GHGs, methane has a global warming potential of 21. Using a worst case assumption that all of the VOC emitted from a permit unit is methane, the requirements of this regulation are triggered for a VOC emission increase of 3571 TPY (75,000 TPY/21) or about 19,500 lb/day.

The increase in VOC emissions for the installation of the fuel system PRVs is only 0.34 lb/day. Therefore, the requirements of this regulation are not applicable.

<u>REGULATION XX: REGIONAL CLEAN AIR INCENTIVES MARKET (RECLAIM)</u>

RECLAIM is a market incentive program designed to allow facilities flexibility in achieving emission reduction requirements for Oxides of Nitrogen (NOx), and Oxides of Sulfur (SOx). The Chevron Refinery (ID 800030) is a Cycle II RECLAIM facility. The proposed cogeneration unit will be subject to the NOx and SOx requirements of this regulation.

As discussed in detail in the engineering evaluation for permit to construct A/N 470782, the Cogeneration Train D will comply with all the requirements of this regulation. The cogeneration unit is being constructed with BACT for NOx and SOx as required by Rule 2005. Installation of the subject fuel system PRVs will not impact compliance with the requirements of this regulation since it does not cause an increase in the Cogen Train D NOx or SOx emissions. The LSFO Flare is exempt from the requirements of this regulation. The gas flare exemption is contained at Rule 2011(i) and 2012(k). The definition of a gas flare, as contained in 2011 Attachment E and 2012 Attachment F is “a combustion equipment used to prevent unsafe operating pressures in process units during shutdowns and startups and to handle miscellaneous hydrocarbon leaks and process upsets”. The LSFO Flare qualifies for this exemption.

REGULATION XXX: TITLE V PERMITS

The initial Title V permit for the refinery was sent to Chevron on September 29, 2009 with an effective date of October 12, 2009. The permits issued for this project will be issued as a revision of the Title V permit. Permit revisions are categorized into the following four types: *administrative, minor, de minimis significant and significant*. The review and distribution requirements for each revision type are summarized in the following table.

Title V Permit Revisions: Review and Distribution Requirements

Revision Type	Permit Review and Distribution Requirements		
	EPA Review (45-day)	Public Notice (30-day)	Send Final Permit to EPA
Administrative	No	No	Yes
Minor	Yes	No	Yes
De Minimis Significant	Yes	No	Yes
Significant	Yes	Yes	Yes

As defined in Rule 3000, a minor Title V permit revision is any revision that:

(1) does not require or change 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;
(2) does not violate a regulatory requirement;
(3) does not require any significant change in monitoring terms or conditions in the permit;
(4) does not require relaxation of any recordkeeping, or reporting requirement, or term, or condition in the permit;
(5) does not result in an emission increase of RECLAIM pollutants over the facility starting Allocation plus nontradeable Allocations, or higher Allocation amount which has previously undergone a significant permit revision process;
(6) does not result in an increase in emissions of a pollutant subject to Regulation XIII - New Source Review or a hazardous air pollutant;
(7) does not establish or change a permit condition that the facility has assumed to avoid an applicable requirement;
(8) is not an installation of a new permit unit 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; and,
(9) is not a modification or reconstruction of an existing permit unit, resulting in new or additional NSPS requirements pursuant to 40 CFR Part 60, or new or additional NESHAP requirements pursuant to 40 CFR Part 61 or 40 CFR Part 63; or,
(10) incorporates an existing general permit, as defined in subdivision (e) of Rule 3004, and its associated requirements, into another Title V permit.

A de minimis significant Title V permit revision meets all of the requirements above with the exception that it does result in an increase in the emission of HAP, CO, VOC or PM10 that is not greater than the respective threshold below and the total cumulative emission increase of HAP, CO, VOC or PM10 for all de minimis Title V revisions during the term of the Title V permit is not greater than the respective threshold:

HAP: 30 lb/day
CO: 220 lb/day
VOC: 30 lb/day
PM10: 30 lb/day

Once the cumulative emission increase of HAP, CO, VOC or PM10 for all de minimis revisions issued during the term of the Title V permit exceeds the respective threshold above, all subsequent Title V permit revisions, with an increase of HAP, CO, VOC or PM10, issued during the term of the Title V permit will be significant revisions. Therefore, the cumulative increase in HAP, CO, VOC and PM10 emissions for de minimis revisions must be tracked for each 5-year Title V permit term. The term of the current Title V permit is from October 12, 2009 until October 11, 2014.

The proposed installation of fuel system PRVS for the Cogeneration Train D is a de minimis significant TV permit revision since it meets all of the requirements of a minor TV revision except that it causes an emission increase of 0.3 lb/day. The table below contains a summary of the HAP, CO, VOC and PM10 emission increases for all de minimis significant revisions issued during the term of the current Chevron El Segundo Refinery Title V Permit. Since the cumulative emission increase of HAP, CO., VOC and PM10 for all de minimis significant revisions issued during the current term of the Chevron Title V permit is less than respective threshold, this revision of the Title V permit is a not a significant revision. The Title V revision will be sent to EPA for a 45-day review. Public notice is not required.

Emission Increases for De Minimis Significant Revisions of Chevron Title V Permit

Equipment Permit Appl. No.	Title V Revision Appl. No.	Emission Increase (lb/day)			
		HAP	CO	VOC	PM10
511207	511206	0	0	1.0	0
435990	516647	0	0	0.3	0
437429	516647	0	0	0.4	0
516645	516647	0	0	1.3	0
526607	526610	0	0	0.3	0
Cumulative (1)		**0**	**0**	**3.3**	**0**

(1) Cumulative emissions increase for all de minimis significant Title V permit revisions since issuance of the initial Title V permit on October 12, 2009.

CONCLUSION / RECOMMENDATION:

Based on the foregoing evaluation, it is expected that the subject applications will comply with all applicable District Rules and Regulations. It is recommended that permits to construct be issued for the proposed Cogen Train D, LSFO VRS and LSFO Flare.

Appendix A: Cogen Train D - Estimate of Criteria Pollutant Emissions During Startup

Pollutant	Elapsed Time (minutes)	Fuel Gas Rate MMBTU/Hr	Basis	Emission Factor	Units	Emission Factor lb/MMBtu	Emissions (lbs)
NOx	0-15	68	Uncontrolled	12.0	ppmv @ 15% O2	0.0449379	0.8
NOx	16-30	135	Uncontrolled	25.0	ppmv @ 15% O2	0.0936205	3.2
NOx	31-45	135	Uncontrolled	25.0	ppmv @ 15% O2	0.0936205	3.2
NOx	46-60	228	Uncontrolled	45.0	ppmv @ 15% O2	0.1685169	9.6
NOx	61-75	415	Uncontrolled	15.0	ppmv @ 15% O2	0.0561723	5.8
NOx	76-90	509	Uncontrolled	15.0	ppmv @ 15% O2	0.0561723	7.1
NOx	91-105	509	Controlled	3.0	ppmv @ 15% O2	0.0112345	1.4
NOx	106-120	509	Controlled, BACT	2.0	ppmv @ 15% O2	0.0074896	1.0
						Total	**32**
SO2	0-15	68	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.0
SO2	16-30	135	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.0
SO2	31-45	135	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.0
SO2	46-60	228	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.0
SO2	61-75	415	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.1
SO2	76-90	509	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.1
SO2	91-105	509	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.1
SO2	106-120	509	Nat. Gas	5.0000	ppmv TRS in Fuel	0.000805	0.1
						Total	**0.50**
VOC	0-15	68	Uncontrolled	25.2	ppmvd @ 15% O2	0.0328242	0.6
VOC	16-30	135	Uncontrolled	6.6	ppmvd @ 15% O2	0.0085968	0.3
VOC	31-45	135	Uncontrolled	6.6	ppmvd @ 15% O2	0.0085968	0.3
VOC	46-60	228	Uncontrolled	15.3	ppmvd @ 15% O2	0.0199290	1.1
VOC	61-75	415	Uncontrolled	7.7	ppmvd @ 15% O2	0.0100296	1.0
VOC	76-90	509	Uncontrolled	8.2	ppmvd @ 15% O2	0.0106809	1.4
VOC	91-105	509	Controlled	4.4	ppmvd @ 15% O2	0.0057312	0.7
VOC	106-120	509	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0026051	0.3
						Total	**5.7**
CO	0-15	68	Uncontrolled	126.0	ppmv @ 15% O2	0.2872115	4.8
CO	16-30	135	Uncontrolled	33.0	ppmv @ 15% O2	0.0754500	2.5
CO	31-45	135	Uncontrolled	33.0	ppmv @ 15% O2	0.0754500	2.5
CO	46-60	228	Uncontrolled	76.5	ppmv @ 15% O2	0.1743784	10.0
CO	61-75	415	Uncontrolled	38.5	ppmv @ 15% O2	0.0877591	9.1
CO	76-90	509	Uncontrolled	41.0	ppmv @ 15% O2	0.0934577	11.9
CO	91-105	509	Controlled	9.0	ppmv @ 15% O2	0.0205151	2.6
CO	106-120	509	Controlled, BACT	2.0	ppmv @ 15% O2	0.0045589	0.6
						Total	**44**
PM10	0-15	68	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.1
PM10	16-30	135	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.2
PM10	31-45	135	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.2
PM10	46-60	228	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.4
PM10	61-75	415	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.7
PM10	76-90	509	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.9
PM10	91-105	509	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.9
PM10	106-120	509	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.9
						Total	**4.5**

Notes and Assumptions:

Uncontrolled NO_x, CO and VOC concentration estimates provided by Fluor.

The duct burners are fired only after the gas turbine is at base load operation.

High Heating Value of Fuel Gas = 1050 Btu/scf; F-factor = 8710 scf/MMBtu; Molar Volume = 379 scf/mole

Appendix B: Cogen Train D - Estimate of Criteria Pollutant Emissions During Shutdown

Pollutant	Elapsed Time (minutes)	Fuel Gas Rate (MMBtu/hr)	Basis	Emission Factor	Units	Emission Factor lb/MMBtu	Emissions (lbs)
NOx	0-15	471.4	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0074896	0.9
NOx	16-30	396.7	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0074896	0.7
NOx	31-45	322.0	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0074896	0.6
NOx	46-60	247.3	Uncontrolled	40	ppmvd @ 15% O2	0.1497928	9.3
NOx	61-75	172.5	Uncontrolled	48	ppmvd @ 15% O2	0.1797514	7.8
NOx	76-90	135.0	Uncontrolled	35	ppmvd @ 15% O2	0.1310687	4.4
NOx	91-105	135.0	Uncontrolled	35	ppmvd @ 15% O2	0.1310687	4.4
NOx	106-120	87.8	Uncontrolled	17	ppmvd @ 15% O2	0.0636620	1.4
						Total	**29**
SO2	0-15	471.4	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.09
SO2	16-30	396.7	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.08
SO2	31-45	322.0	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.06
SO2	46-60	247.3	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.05
SO2	61-75	172.5	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.03
SO2	76-90	135.0	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.03
SO2	91-105	135.0	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.03
SO2	106-120	87.8	Nat. Gas	5	ppmvd TRS in Fuel	0.0008050	0.02
						Total	**0.4**
VOC	0-15	471.4	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0026051	0.3
VOC	16-30	396.7	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0026051	0.3
VOC	31-45	322.0	Controlled, BACT	29.0	ppmvd @ 15% O2	0.0377738	3.0
VOC	46-60	247.3	Uncontrolled	95.0	ppmvd @ 15% O2	0.1237419	7.7
VOC	61-75	172.5	Uncontrolled	116.0	ppmvd @ 15% O2	0.1510954	6.5
VOC	76-90	135.0	Uncontrolled	89.0	ppmvd @ 15% O2	0.1159266	3.9
VOC	91-105	135.0	Uncontrolled	89.0	ppmvd @ 15% O2	0.1159266	3.9
VOC	106-120	87.8	Uncontrolled	45.0	ppmvd @ 15% O2	0.0586146	1.3
						Total	**27**
CO	0-15	471.4	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0045589	0.5
CO	16-30	396.7	Controlled, BACT	2.0	ppmvd @ 15% O2	0.0045589	0.5
CO	31-45	322.0	Uncontrolled	145	ppmvd @ 15% O2	0.3305211	26.6
CO	46-60	247.3	Uncontrolled	474	ppmvd @ 15% O2	1.0804622	66.8
CO	61-75	172.5	Uncontrolled	579	ppmvd @ 15% O2	1.3198051	56.9
CO	76-90	135.0	Uncontrolled	445	ppmvd @ 15% O2	1.0143580	34.2
CO	91-105	135.0	Uncontrolled	445	ppmvd @ 15% O2	1.0143580	34.2
CO	106-120	87.8	Uncontrolled	223	ppmvd @ 15% O2	0.5083187	11.2
						Total	**231**
PM10	0-15	471.4	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.8
PM10	16-30	396.7	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.7
PM10	31-45	322.0	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.6
PM10	46-60	247.3	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.4
PM10	61-75	172.5	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.3
PM10	76-90	135.0	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.2
PM10	91-105	135.0	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.2
PM10	106-120	87.8	NG Emission fact.	0.0071	lbs/MMBTU	0.0071	0.2
						Total	**3.5**

Notes and Assumptions:

Uncontrolled NO_x, CO and VOC concentration estimates provided by Fluor.

Duct burner is shutdown prior to gas turbine shutdown.

Fuel to Gas Turbine prior to shutdown = 508.7 MMBTU/Hr

High Heating Value of Fuel Gas = 1050 Btu/scf; F-factor = 8710 scf/MMBtu; Molar Volume = 379 scf/mole

Appendix C: Cogen Train D - Estimated NOx and SO2 Emissions During Comissioning Period

Day	Operation	Duration (hours)	Fuel Gas Rate (mmbtu/hr)	Basis	Emission Factor	Units	Emission Factor lb/MMBtu	Emissions (lbs)
NOx								
1	Bring to FSNL	0.5	135	Uncontrolled	14.0	ppmvd @ 15% O2	0.05243	3.5
1	OST Check	2.0	135	Uncontrolled	30.0	ppmvd @ 15% O2	0.11235	30.3
1	Shut Down	0.5	90	Uncontrolled	30.0	ppmvd @ 15% O2	0.11235	5.1
2	Bring to FSNL	0.5	135	Uncontrolled	14.0	ppmvd @ 15% O2	0.05243	3.5
2	Sync. Checks	6.0	135	Uncontrolled	30.0	ppmvd @ 15% O2	0.11235	91.0
2	Shut Down	0.5	90	Uncontrolled	30.0	ppmvd @ 15% O2	0.11235	5.1
3	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	35.6
3	Combustion Tuning	10.0	508.7	Uncontrolled	18.0	ppmvd @ 15% O2	0.06741	342.9
3	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	9.0
4	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	35.6
4	Combustion Tuning	10.0	508.7	Uncontrolled	18.0	ppmvd @ 15% O2	0.06741	342.9
4	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	9.0
5	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	35.6
5	Duct Burner Testing	10.0	640.7	Uncontrolled	16.0	ppmvd @ 15% O2	0.05991	383.8
5	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	9.0
6	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	35.6
6	Duct Burner Testing	10.0	640.7	Uncontrolled	16.0	ppmvd @ 15% O2	0.05991	383.8
6	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	9.0
7	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	35.6
7	Duct Burner Testing	10.0	640.7	Uncontrolled	16.0	ppmvd @ 15% O2	0.05991	383.8
7	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	9.0
12	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	35.6
12	NH3 Inj. Testing	22.5	640.7	"Controlled"	16.0	ppmvd @ 15% O2	0.05991	863.6
13	NH3 Inj. Testing	24.0	640.7	"Controlled"	16.0	ppmvd @ 15% O2	0.05991	921.2
13	NH3 Inj. Testing	24.0	640.7	"Controlled"	16.0	ppmvd @ 15% O2	0.05991	921.2
14	NH3 Inj. Testing	24.0	640.7	"Controlled"	16.0	ppmvd @ 15% O2	0.05991	921.2
							Total	**5862**
SO2								
1	Bring to FSNL	0.5	135	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.05
1	OST Check	2.0	135	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.22
1	Shut Down	0.5	90	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.04
2	Bring to FSNL	0.5	135	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.05
2	Sync. Checks	6.0	135	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.65
2	Shut Down	0.5	90	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.04
3	Bring to Base Load	1.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.30
3	Combustion Tuning	10.0	508.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	4.10
3	Shut Down	0.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.09
4	Bring to Base Load	1.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.03
4	Combustion Tuning	10.0	508.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	4.10
4	Shut Down	0.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.09
5	Bring to Base Load	1.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.03
5	Duct Burner Testing	10.0	640.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	5.16
5	Shut Down	0.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.09
6	Bring to Base Load	1.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.03
6	Duct Burner Testing	10.0	640.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	5.16
6	Shut Down	0.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.09
7	Bring to Base Load	1.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.03
7	Duct Burner Testing	10.0	640.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	5.16
7	Shut Down	0.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.09
12	Bring to Base Load	1.5	Varies	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	0.03
12	NH3 Inj. Testing	22.5	640.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	11.60
13	NH3 Inj. Testing	24.0	640.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	12.38
13	NH3 Inj. Testing	24.0	640.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	12.38
14	NH3 Inj. Testing	24.0	640.7	Nat. Gas	5.0	ppmv TRS in Fuel	0.0008050	12.38
15							**Total**	**74**

Appendix C (Cont'd): Cogen Train D - Estimated CO & VOC Emissions During Comissioning Period

Day	Operation	Duration (hours)	Fuel Gas Rate (mmbtu/hr)	Basis	Emission Factor	Units	Emission Factor lb/MMBtu	Emissions (lbs)
Carbon Monoxide								
1	Bring to FSNL	0.5	135	Uncontrolled	151.0	ppmvd @ 15% O2	0.34420	23.2
1	OST Check	2.0	135	Uncontrolled	40.0	ppmvd @ 15% O2	0.09118	24.6
1	Shut Down	0.5	90	Uncontrolled	151.0	ppmvd @ 15% O2	0.34420	15.5
2	Bring to FSNL	0.5	135	Uncontrolled	151.0	ppmvd @ 15% O2	0.34420	23.2
2	Sync. Checks	6.0	135	Uncontrolled	40.0	ppmvd @ 15% O2	0.09118	73.9
2	Shut Down	0.5	90	Uncontrolled	151.0	ppmvd @ 15% O2	0.34420	15.5
3	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	40.8
3	Combustion Tuning	10.0	508.7	Uncontrolled	18.0	ppmvd @ 15% O2	0.04103	208.7
3	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	68.2
4	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	40.8
4	Combustion Tuning	10.0	508.7	Uncontrolled	18.0	ppmvd @ 15% O2	0.04103	208.7
4	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	68.2
5	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	40.8
5	Duct Burner Testing	10.0	640.7	Uncontrolled	17.0	ppmvd @ 15% O2	0.03875	248.3
5	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	68.2
6	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	40.8
6	Duct Burner Testing	10.0	640.7	Uncontrolled	17.0	ppmvd @ 15% O2	0.03875	248.3
6	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	68.2
7	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	40.8
7	Duct Burner Testing	10.0	640.7	Uncontrolled	17.0	ppmvd @ 15% O2	0.03875	248.3
7	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	68.2
12	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	40.8
12	NH3 Inj. Testing	22.5	640.7	"Controlled"	17.0	ppmvd @ 15% O2	0.03875	558.6
13	NH3 Inj. Testing	24.0	640.7	"Controlled"	17.0	ppmvd @ 15% O2	0.03875	595.9
13	NH3 Inj. Testing	24.0	640.7	"Controlled"	17.0	ppmvd @ 15% O2	0.03875	595.9
14	NH3 Inj. Testing	24.0	640.7	"Controlled"	17.0	ppmvd @ 15% O2	0.03875	595.9
							Total	**4270**
Volatile Organic Compounds								
1	Bring to FSNL	0.5	135	Uncontrolled	30.0	ppmvd @ 15% O2	0.03907	2.6
1	OST Check	2.0	135	Uncontrolled	7.9	ppmvd @ 15% O2	0.01029	2.8
1	Shut Down	0.5	90	Uncontrolled	30.0	ppmvd @ 15% O2	0.03907	1.8
2	Bring to FSNL	0.5	135	Uncontrolled	30.0	ppmvd @ 15% O2	0.03907	2.6
2	Sync. Checks	6.0	135	Uncontrolled	7.9	ppmvd @ 15% O2	0.01029	8.3
2	Shut Down	0.5	90	Uncontrolled	30.0	ppmvd @ 15% O2	0.03907	1.8
3	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	4.3
3	Combustion Tuning	10.0	508.7	Uncontrolled	1.9	ppmvd @ 15% O2	0.00247	12.6
3	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	2.3
4	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	4.3
4	Combustion Tuning	10.0	508.7	Uncontrolled	1.9	ppmvd @ 15% O2	0.00247	12.6
4	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	2.3
5	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	4.3
5	Duct Burner Testing	10.0	640.7	Uncontrolled	3.0	ppmvd @ 15% O2	0.00391	25.0
5	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	2.3
6	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	4.3
6	Duct Burner Testing	10.0	640.7	Uncontrolled	3.0	ppmvd @ 15% O2	0.00391	25.0
6	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	2.3
7	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	4.3
7	Duct Burner Testing	10.0	640.7	Uncontrolled	3.0	ppmvd @ 15% O2	0.00391	25.0
7	Shut Down	0.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	2.3
12	Bring to Base Load	1.5	Varies	Uncontrolled	Varies	ppmvd @ 15% O2	Varies	4.3
12	NH3 Inj. Testing	22.5	640.7	"Controlled"	3.0	ppmvd @ 15% O2	0.00391	56.3
13	NH3 Inj. Testing	24.0	640.7	"Controlled"	3.0	ppmvd @ 15% O2	0.00391	60.1
13	NH3 Inj. Testing	24.0	640.7	"Controlled"	3.0	ppmvd @ 15% O2	0.00391	60.1
14	NH3 Inj. Testing	24.0	640.7	"Controlled"	3.0	ppmvd @ 15% O2	0.00391	60.1
							Total	**394**

Appendix D: Cogen Train D - VOC Emission Estimate for Fugitive Components
(without refinery fuel gas system PRVs and associated fugitive components)

Equipment Type	Service	No. of Sources	VOC Emission Factors lbs/yr*	Annual VOC Emission lb/yr
Valves - Sealed Bellow	Gas/Vapor	32	0.00	0.0
	Light Liquid	0	0.00	0.0
Valves - Low emission ≤ 500 ppmv, or Live loaded w/ dual seal system	Gas/Vapor	5	4.55	23
	Light Liquid	0	4.55	0
	Heavy Liquid	0	4.55	0
Flanges	Light Liquid/Vapor	210	6.99	1468
	Heavy Liquid	84	6.99	587
Connectors	Light Liquid/Vapor	66	2.86	189
	Heavy Liquid	24	2.86	69
Pumps	Light Liquid (double seal)	0	46.83	0
	Light Liquid (sealless type)	0	0	0
	Heavy Liquid (single seal)	2	17.21	34
Compressors	Gas/Vapor	0	9.09	0
PRV's	All (To Atmosphere)	0	9.09	0
	All (Closed Vent)	2	0	0
Drains (with p-trap)		6	9.09	55

Total Count:	431	Total (lb/yr)	**2,424**
		Emissions (lbs/day (30-day Average)	**6.73**

* Emission factors based on correlation equations from the *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities* (CARB/CAPCOA - 1999)

Appendix E: Cogen Train D - VOC Emission Estimate for Fugitive Components
(with refinery fuel gas system PRVs and associated fugitive components)

Equipment Type	Service	No. of Sources	VOC Emission Factors lbs/yr*	Annual VOC Emission lb/yr
Valves - Sealed Bellow	Gas/Vapor	36	0.00	0.0
	Light Liquid	0	0.00	0.0
Valves - Low emission ≤ 500 ppmv, or Live loaded w/ dual seal system	Gas/Vapor	8	4.55	36
	Light Liquid	0	4.55	0
	Heavy Liquid	0	4.55	0
Flanges	Light Liquid/Vapor	218	6.99	1524
	Heavy Liquid	84	6.99	587
Connectors	Light Liquid/Vapor	84	2.86	240
	Heavy Liquid	24	2.86	69
Pumps	Light Liquid (double seal)	0	46.83	0
	Light Liquid (sealless type)	0	0	0
	Heavy Liquid (single seal)	2	17.21	34
Compressors	Gas/Vapor	0	9.09	0
PRV's	All (To Atmosphere)	0	9.09	0
	All (Closed Vent)	3	0	0
Drains (with p-trap)		6	9.09	55

Total Count: 465 Total (lb/yr) **2,545**

Emissions (lbs/day **7.07**
(30-day Average)

* Emission factors based on correlation equations from the *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities* (CARB/CAPCOA - 1999)

Appendix F: LSFO VRS - VOC Emission Estimate for Fugitive Components

Equipment Type	Service	No. of Sources	VOC Emission Factors lbs/yr*	Annual VOC Emission lb/yr
Valves - Sealed Bellow	Gas/Vapor	564	0.00	0.0
	Light Liquid	177	0.00	0.0
Valves - Low emission ≤ 500 ppmv, or Live loaded w/ dual seal system	Gas/Vapor	334	4.55	1518
	Light Liquid	0	4.55	0
	Heavy Liquid	0	4.55	0
Flanges	Light Liquid/Vapor	795	6.99	5557
	Heavy Liquid	0	6.99	0
Connectors	Light Liquid/Vapor	2378	2.86	6804
	Heavy Liquid	0	2.86	0
Pumps	Light Liquid (double seal)	5	46.83	234
	Light Liquid (sealless type)	0	0	0
	Heavy Liquid (single seal)	0	17.21	0
Compressors	Gas/Vapor	0	9.09	0
PRV's	All (To Atmosphere)	0	9.09	0
	All (Closed Vent)	2	0	0
Drains (with p-trap)		0	9.09	0

Total Count: 4,255 Total (lb/yr) **14,114**

Emissions (lbs/day **39.2**
(30-day Average)

* Emission factors based on correlation equations from the *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities* (CARB/CAPCOA - 1999)

Appendix G: LSFO Flare - VOC Emission Estimate for Fugitive Components

Equipment Type	Service	No. of Sources	VOC Emission Factors lbs/yr*	Annual VOC Emission lb/yr
Valves - Sealed Bellow	Gas/Vapor	103	0.00	0.0
	Light Liquid	29	0.00	0.0
Valves - Low emission ≤ 500 ppmv, or Live loaded w/ dual seal system	Gas/Vapor	169	4.55	768
	Light Liquid	43	4.55	195
	Heavy Liquid	186	4.55	0
Flanges	Light Liquid/Vapor	637	6.99	4453
	Heavy Liquid	0	6.99	0
Connectors	Light Liquid/Vapor	966	2.86	2764
	Heavy Liquid	384	2.86	1099
Pumps	Light Liquid (double seal)	9	46.83	421
	Light Liquid (sealless type)	0	0	0
	Heavy Liquid (single seal)	2	17.21	34
Compressors	Gas/Vapor	0	9.09	0
PRV's	All (To Atmosphere)	0	9.09	0
	All (Closed Vent)	12	0	0
Drains (with p-trap)		0	9.09	0

Total Count: 2,540 Total (lb/yr) **9,735**

Emissions (lbs/day **27.0**
(30-day Average)

* Emission factors based on correlation equations from the *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities* (CARB/CAPCOA - 1999)

Appendix H: Distance from Cogen Train D to Sensitive Receptors

Receptor No.	Receptor Name	UTME	UTMN	Distance to Cogen D Stack (ft)
SR001	ST ANTHONY'S SCHOOL	369950	3753775	3069
SR002	IMPERIAL SCHOOL	369775	3755100	6719
SR003	EL SEGUNDO MIDDLE	369275	3754500	4563
SR004	EL SEGUNDO PRESCHOOL	369350	3753900	**2601**
SR005	ST JOHNS LUTHERAN	370250	3754850	6516
SR006	CAROUSEL CHRISTIAN	369075	3754200	3649
SR007	1ST BAPTIST CHURCH DAY CARE	369750	3754575	5037
SR008	BEGG SCHOOL	371700	3750625	11345
SR009	LA MARINA	372125	3750600	12410
SR010	MEADOWS AVE SCHOOL	371425	3750500	11051
SR011	PACIFIC ELEMENTARY	370375	3750525	9189
SR012	CENTER SCHOOL	370250	3750475	9192
SR013	AMERICAN MARTYRS SCHOOL	370200	3750725	8366
SR014	GRAND VIEW SCHOOL	369475	3751150	6453
SR015	MANHATTAN HILLS SCHOOL	372025	3749875	13886
SR016	AVIATION HIGH SCHOOL	372875	3750450	14632
SR017	LADERA SCHOOL	369600	3751250	6180
SR018	MED CENTER OF MANHATTAN BEACH	370975	3751200	8345
SR019	MONTESSORI OF MANHATTAN BEACH	371775	3749725	13765
SR020	LITTLE RED SCHOOL HOUSE	371825	3750400	12162
SR021	1ST LUTHERAN CIRCLE OF LOVE	370625	3750275	10271
SR022	MANHATTAN BEACH ELE/MIDDLE	370275	3750425	9374
SR023	CAMP RUNAROUND INC	369600	3751175	6423
SR024	YOUNG VISIONS	369650	3751325	5968
SR025	RAINBOW RIVER	370300	3750375	9556
SR026	CENTER STREET ELEMENTARY	370275	3754500	5585

Note: UTM Coordinates for Cogen Train D Stack are UTME - 369293 and UTMN - 3753109