AIR POLLUTION
CONTROL DISTRICT
COUNTY OF SAN LUIS OBISPO

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Permits Office Air-3
U.S. EPA, Region 9

June 29, 2007

Gerardo Rios
USEPA, Region IX
75 Hawthorne St, Mail Stop (Air-3)
San Francisco, California 94104-3901

Re: ConocoPhillips Santa Maria Facility Title V Permit

45 day review ends 8/17/07

Dear Mr. Rios:

Enclosed is a proposed Title V permit for the ConocoPhillips Santa Maria Facility in response to their application for significant modifications under our application tracking numbers 4229 and 4255. Minor permit modifications are also being made under application numbers 4256, 4318 and 4369. Your receipt of these documents should begin EPA's official 45-day review opportunity allowed under District Rule 216.H.5, EPA Objection. Your acknowledgment that this package has been received, and the date that your review period will be considered to have ended, is requested.

Also enclosed is a copy of the District's staff report, which should be considered its statement-of-basis. Please respond with any comments you may have no later than 45-days following receipt of this material. If you have any questions, feel free to contact me at 805-781-5912.

Sincerely,

Dean Carlson

Dean Carlson
Air Pollution Control Engineer

Enclosures

cc: James O. Anderson, ConocoPhillips Company w/enclosures

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Conventions and Abbreviations

A. The following conventions are used in this permit.

1. The reference for each requirement will be noted in [square brackets]. References that are noted as being "District-only" are not federally-enforceable requirements. All conditions with references in [square brackets] that do not contain the phrase "District-only" must be considered federally-enforceable requirements.

2. In multi-part conditions, the general reference notation at the beginning of the condition will apply throughout, except for those subparts that are followed by a specific reference for which only the specific reference shall apply.

3. Unless otherwise noted, both a "day" and an "operating day" shall be considered a 24 hour period from midnight to midnight (*i.e.*, calendar day).

4. Unless otherwise noted, averaging periods are intended to mean the following.

   a. Daily average for hourly limit, record, or report: total for calendar day divided by twenty-four (24).
   b. Three (3) hour average for concentration: average concentration over a continuous three (3) hour period.
   c. 168 hour average for concentration: average concentration over a continuous 168 hour period.
   d. Quarterly average sulfur content: average of all sulfur content determinations made during the preceding three (3) month period (see additional note a.2 to condition section I.A).

5. The number of values displayed for any given emission or operational limit in this permit is intended to represent the number of significant figures to which test or analysis results are to be rounded. *e.g.*, 2,000 ppm is intended to represent 2.000E3 ppm and any test result greater than 2,000.5 ppm would not comply with that limit.

6. When rounding test and analysis results or recorded and reported values to the correct number of significant figures, any rounding of the value "five (5)" should result in an even number. *e.g.*, 34.65 to three significant figures would be written 34.6. Also when rounding, if the final digit is 0, 1, 2, 3, or 4, the number does not change and, if the final digit is 6, 7, 8, or 9, the number is increased by one.

7. Federal regulation subpart references will typically be indicated by their subpart designation only. The titles of all subparts included here are as follows.

   – 40CFR60 Subpart A, General Provisions (New Source Performance Standards - NSPS)
   – 40CFR60 Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
   – 40CFR60 Subpart J, Standards of Performance for Petroleum Refineries

- 40CFR60 Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984
- 40CFR60 Subpart VV, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry
- 40CFR60 Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries
- 40CFR60 Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems
- 40CFR60, Appendix B, Performance Specification 2, Specifications and Test Procedures for SO_2 and NO_x Continuous Emission Monitoring Systems in Stationary Sources (abbreviated 40CFR60.PS-2)
- 40CFR60, Appendix B, PS-5, Specifications and Test Procedures for TRS Continuous Emission Monitoring Systems in Stationary Sources (abbreviated 40CFR60.PS-5)
- 40CFR60, Appendix B, PS-7, Specifications and Test Procedures for Hydrogen Sulfide Continuous Emission Monitoring Systems in Stationary Sources (abbreviated 40CFR60.PS-7)
- 40CFR61 Subpart A, General Provisions (National Emission Standards for Hazardous Air Pollutants - NESHAP)
- 40CFR61 Subpart M, National Emission Standard for Asbestos
- 40CFR61 Subpart FF, National Emission Standard for Benzene Waste Operations
- 40CFR63 Subpart A, General Provisions (NESHAP for Source Categories - MACT)
- 40CFR63 Subpart CC, National Emission Standard for Hazardous Air Pollutants from Petroleum Refineries
- 40CFR63 Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units
- 40CFR63 Subpart EEEE, National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (non-Gasoline)
- 40CFR63 Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters
- 40CFR64, Compliance Assurance Monitoring
- 40CFR68, Chemical Accident Prevention
- 40CFR82, Protection of Stratospheric Ozone
- 40CFR82 Subpart E, Labeling of Products Using Ozone-Depleting Substances
- 40CFR82 Subpart F, Recycling and Emission Reduction
- 40CFR82 Subpart G, Significant New Alternatives Policy Program

8. District rule numbers only, will be used for the most part in this permit. The titles of all rules referenced are as follows.

   - SIP Rule 106, Standard Conditions
   - Rule 107, Breakdown or Upset Conditions and Emergency Variances
   - Rule 113, Continuous Emissions Monitoring

- SIP Regulation IV, Rule 113, Particulate Matter (abbreviated SIP Rule IV.113)
- SIP Rule 114, Gaseous Contaminants Prohibitions
- Rule 201, Equipment Not Requiring a Permit
- SIP Rule 201.E, Posting of Permit to Operate
- Rule 204, Requirements (a.k.a. New Source Review)
- SIP Rule 205, Conditional Approval
- Rule 206, Conditional Approval
- Rule 210, Periodic Inspection, Testing and Renewal of Permits to Operate
- Rule 216, Federal Part 70 Permits
- Rule 302, Schedule of Fees
- SIP Rule 401, Visible Emissions
- Rule 402, Nuisance
- Rule 403, Particulate Matter Emission Standards
- SIP Rule 404, Sulfur Compounds Emission Standards, Limitations, and Prohibitions
- SIP Rule 406, Carbon Monoxide Emission Standards, and Limitations
- SIP Rule 407, Organic Material Emission Standards, Limitations, and Prohibitions
- Rule 407, Organic Material Emission Standards
- SIP Rule 416, Degreasing Operations
- SIP Rule 419, Petroleum Pits, Ponds, Sumps, Well Cellars, and Wastewater Separators
- SIP Rule 422, Refinery Process Turnarounds
- SIP Rule 424, Gasoline Dispensing Facilities
- Rule 425, Storage of Volatile Organic Compounds
- Rule 430, Control of Oxides of Nitrogen from Industrial, Institutional, Commercial Boilers, Steam Generators, and Process Heaters
- Rule 431, Stationary Internal Combustion Engines
- Rule 433, Architectural Coatings
- Rule 440, Petroleum Coke Calcining and Storage
- SIP Rule 501, General Burning Provisions

9. Federally-enforceable requirements that gain their authority from a court of law will be indicated by their commonly used title plus the court's tracking number. The title of all such requirements included here are as follows.

Consent Decree H-05-0258	US District Court for the Southern District of Texas case number H-05-0258

B. Abbreviations used in this permit are as follows.

Abbreviation	**Description**
40CFR	Chapter 40 to the Code of Federal Regulations
$\geq$50 hp	rated at 50 horsepower or more
acfm	actual cubic feet per minute
ACM	asbestos containing material
APCO	Air Pollution Control Officer
ARB	Air Resources Board
atm	atmosphere
bbl	barrel (42 gallons)
BACT	Best Available Control Technology
CAA	Clean Air Act
CALOSHA	California Occupational Safety and Health Authority
CAM	Compliance Assurance Monitoring
CCR	California Code of Regulations
cf	cubic feet
CMS	continuous monitoring system
CO	carbon monoxide
CS_2	carbon disulfide
CH_3SH	methyl mercaptan
DCS	Distributed Control System
District	San Luis Obispo County Air Pollution Control District
DOC	diesel oxidation catalyst
DPF	diesel particulate filter
EPG	electrical power generation
ERC	emission reduction credit
^oF	degrees Fahrenheit
HAPs	hazardous air pollutant(s)
heat exch	heat exchanger
hp	horsepower
H_2O	water
H_2S	hydrogen sulfide
gph	gallons per hour
gpm	gallons per minute
GHV	gross heating value
g/hr	grams per hr
g/bhph	grams per brake horsepower hour
gr/dscf	grains per dry standard cubic foot
H&SC	California Health and Safety Code
ID	induced draft
inH_2O	inches of water column (pressure)
KO	knock-out (catch point for liquids in a vapor line)
lb	pounds
lb/hr	pounds per hour
lb/mmBtu	pounds per million British thermal units of heat input
lb-stm/hr	pounds of steam per hour
MACT	Maximum Achievable Control Technology
mg/m^3	milligrams per cubic meter
ml/min	milliliter per minute

Abbreviation	**Description**
mmBtu	million British thermal units
mmscfd	million standard cubic feet per day
MVAC	motor vehicle air conditioner
MW	megawatt (electrical)
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_x	oxides of nitrogen
NO_2	nitrogen dioxide
NSPS	New Source Performance Standards
O_2	oxygen
ODS	ozone-depleting substances
OMMP	operating, maintenance, and monitoring plan
P&ID	piping and instrumentation diagram
PM	particulate matter
PM10	particulate matter less than ten (10) microns
ppmv	parts per million by volume
ppmwv	parts per million by volume, wet
PR	photochemically reactive (solvent)
psia	pounds per square inch absolute
psig	pounds per square inch gauge
RACM	regulated asbestos-containing material
RGG	reduced gas generator
RMP	risk management plan
ROU	reverse osmosis unit
RVP	Reid vapor pressure
S	total sulfur
SIC	Standard Industrial Classification
SIP	State of California Implementation Plan
SO_x	oxides of sulfur
SO_2	sulfur dioxide
SSM	startup, shutdown, and malfunction
SSMP	startup, shutdown, and malfunction plan
TABQ	total annual benzene quantity
tpy	tons per year
TEG	triethylene glycol
TRS	total reduced sulfur compounds
TVP	true vapor pressure
VOC	volatile organic compounds
wt%	percent by weight

I. Specific Emission and Operational Limits

A. Emission Limits. The following emission limits shall apply to the identified units:

Unit		Limit			Compl-iance	Notes
B-1,C,D-1	B-2A/B(2) B-62A/B(2) B-102A/B(2) B-504 B-506	1.	NO_x	0.036 lb/mmBtu or 30 ppmv @3% O_2 dry	annual test and oxygen monitor-ing	(d) [Rule 430 & 40CFR60.44b.a.1.i for B-506 and District-only, Rule 430 for all others]
		2.	CO	400 ppmv @3% O_2 dry	annual test	[District-only, Rule 430]
B-1,C	B-2A	3.	SO_2	0.090 lb/mmBtu 6.94 lb/hr	biennial stack test	[District-only, Rule 206]
	B-2B	4.	SO_2	0.091 lb/mmBtu 6.93 lb/hr	biennial stack test	[District-only, Rule 206]
	B-102A/B(2)	5.	SO_2	0.094 lb/mmBtu 7.6 lb/hr each	biennial stack test	[SIP Rule 205]
	B-201A/B(2)	6.	NO_x	0.090 lb/mmBtu 0.29 lb/hr each	annual test	[SIP Rule 205]
		7.	SO_2	0.094 lb/mmBtu 0.3 lb/hr each	biennial stack test	[SIP Rule 205]
D-1	B-507	8.	NOx	0.036 lb/mmBtu or 30 ppmv @ 3% O2 dry	annual test	[District-only Rule 430]
			CO	400 ppmv @ 3% O2 dry		[40CFR63.7500]
			PM	0.03 lb/mmBtu	low sulfur fuel	[40CFR60.43c.e.1]
D-2, EPG boiler	B-505	9.	NO_x	30 ppmv @3% O_2 dry	annual test	[District-only, Rule 430]
		10.	SO_2	100 lb/day	quarterly calculation	(a) [District-only, Rule 204]
		11.	CO	154 ppmv @3% O_2 dry	annual test	[District-only, Rule 206]
		12.	VOC	30 ppmv @3% O_2 dry	biennial test	[District-only, Rule 206]
E-1, K Sulfur Recovery Plant	B-602 A/B(2) B-702	13.	SO2	250 ppmv @0% O2 dry	biennial test and AN-1600 A/B, AN-1707/1709 cont. monitor	(k), (l) [40CFR104.a.2.i]
		14.	TRS	300 ppmv @0% O2 dry		[40CFR104.a.2.ii]
		15.	H2S	10 ppmv @0% O2 dry		[40CFR104.a.2.ii]
H, gas oil rack		16.	VOC	2,300 ppmv	each use test	per load avg [District-only, Rule 206]

Unit		Limit				Compl-iance	Notes
K, tail gas unit	B-702	17.	a.	SO_2	100 ppmv @0% O_2 dry	biennial test and AN-1707/ 1709 continuous monitor	high-fire operation, (i) [SIP Rule 205, 40CFR60.104.a.2.i, 40CFR63.1568.a.1& c.1, and subpart UUU, table 29, item 1.a]
			b.		4.8 lb/hr		[SIP Rule 205]
		18.	a.	TRS	383.5 lb/week		(b) [SIP Rule 205]
			b.		65 ppmv @0% O_2 dry	annual test and AN-1707/ 1709 continuous monitor	168 hour average [SIP Rule 205]
			c.		300 ppmv @0% O_2 dry		instantaneous, low-fire operation, (c)(j) [40CFR60.104.a.2.ii]
		19.		H_2S	10 ppmv @0% O_2 dry		low-fire operation, (c)(i) [40CFR60.104.a.2.ii]
S-2, railcar baghouse		20.	a.	PM	0.30 gr/scf	biennial test	(f) [SIP Rule IV.113.1]
			b.		lb/hr based on SIP Rule IV.113		(f) [SIP Rule IV.113.2]
			c.		0.10 gr/dscf		(g) [District-only, Rule 403.A]
			d.		lb/hr based on Rule 403.B		(g) [District-only, Rule 403.B]
B-1, M	G-51-4 GB-524S GB-1015 GE-522	21.	a.	NO_x	600 ppmv @15% O_2 dry or 30 vol% reduction	periodic test	(e) [District-only, Rule 431.D.3]
			b.	CO	4500 ppmv @15% O_2 dry		
D-1	G-515-3 G-515-4	22.	a.	NOx	3274 g/hr ea.	manufacture specification	[District-only, Rule 206]
			b.	CO	935 g/hr each		
			c.	PM10	39 g/hr each		
			d.	VOC	113 g/hr each		
			e.	SOx	344 g/hr each		

Additional Notes

(a) 1) The SO_2 calculations shall be based on 100% oxidation of fuel gas sulfur in the fuel gas to SO_2. The sulfur content of the fuel gas shall be calculated by multiplying the daily amount of fuel gas burned by the quarterly average sulfur content of the fuel gas.

2) The quarterly average sulfur content of the fuel gas shall be calculated by summing all weekly Tutweiler measurements required under condition III.B.2.d.2 and dividing by the number of weekly readings.

3) The average daily oxides of sulfur (as SO_2) emissions shall be calculated at the end of each quarter.

(b) Total reduced sulfur compounds (TRS) shall be analyzed specifically as COS, CS_2, mercaptans as CH_3SH, and H_2S; and then summed and presented as total reduced sulfur compounds.

(c) Calculated as sulfur dioxide.

(d) The B-2A/B heaters and B-506 boiler are the only units with oxygen monitors.

(e) Applicable to the respective engines upon retrofit or replacement under condition III.C.11.a.
(f) Intentional duplication of condition III.A.1.c.1.
(g) Intentional duplication of condition III.A.1.c.2.
(h) Intentional duplication of condition III.A.1.c.4.
(i) Averaging period is one-hour for both continuous emissions monitoring instrument results and stack testing results.
(j) Averaging period is one-hour for stack testing results.
(k) Not applicable during periods of startup, shutdown or malfunction of the SRP or malfunction of the TGU, or during a scheduled TGU turnaround. Scheduled TGU turnarounds not to exceed 30 days each event, nor two events prior to 12/31/2013.
(l) COP AMP submitted to EPA for approval provides during normal operation that the weighted average of B602 and B702 emissions meet 300 ppm TRS.

23. Process Unit M, Portable Air Compressor GB-1015. The calendar year emission limitations listed in the last row of the following table shall apply. With the exception of SO_2, compliance shall be determined using the emission rates listed in the middle row of the following table, and the total operating hours in the calendar year of interest. Compliance with the SO_2 limit shall be based on a mass balance using average fuel sulfur content and annual fuel usage data. [District-only, Rule 204]

Air Compressor Engine Emission Limitations

	VOC	**CO**	**NOx**	**PM-10**	**SO2**
lb/hr from June 1, 2006 stack test	3.97E-03	8.39E-04	6.09E-01	1.24E-02	1.87E-03
lb/year limitations	17.37	3.67	2,666.85	54.10	8.18

B. **Operational Limits.** The following operational limits shall apply to the specified units. Compliance shall be determined through recordkeeping except as noted: [District-only, Rule 206]

Unit			**Parameter**	**Limit**		**Notes**
1.	refinery		crude oil throughput	a.	48,000 bbl/day	daily total, wet basis [District-only, Rule 206]
				b.	16,220,600 bbl/yr	12 month rolling period, wet basis [District-only, Rule 206]
2.	B-1,C	B-2A	fuel feed (c) and (d)	a.	77.0 mmBtuh	maximum hour [District-only, Rule 206]
		B-2B		b.	76.2 mmBtuh	maximum hour [District-only, Rule 206]
		B-2A/B (2)		c.	529,104 mmBtu each	12 month rolling period [District-only, Rule 204]
		B-62A		d.	16.2 mmBtuh	maximum hour [District-only, Rule 206]
		B-62B		e.	16.0 mmBtuh	maximum hour [District-only, Rule 206]
		B-62A/B (2)		f.	140,160 mmBtu each	12 month rolling period [District-only, Rule 204]
		B-102A/B (2)		g.	80.5 mmBtuh each	maximum hour [District-only, Rule 206]

Unit			Parameter	Limit		Notes
				h.	705,180 mmBtu each	12 month rolling period [District-only, Rule 204]
		B-2A,62A, 102A (3)		i.	156.9 mmBtuh total	daily average [District-only, Rule 206]
		B-2B,62B, 102B (3)		j.	156.9 mmBtuh total	daily average [District-only, Rule 206]
3.	B-1, cooling tower		organic compounds in water	15 mg/l		per sample, weekly test [District-only, Rule 206]
4.	refinery		fuel gas	a.	0.10 gr/dscf H_2S (160 ppmv)	AN-603 continuous monitor, 3 hour average [40CFR60.104.a.1 and 40CFR40b.c for B-506]
				b.	0.50 gr/dscf total S (797 ppmv)	weekly fuel test & annual analytical test, intentional duplication of condition III.A.1.d.2 [SIP Rule 404.e.1]
5.	D-1 boiler plant	B-504,B-506, B507	total steam produced	170,000 lb/hr		daily average [SIP Rule 205]
6.	D-1 boiler plant	ROU standby engine	non-emergency operation	a.	20 hrs/yr	calendar year, intentional duplication of I.B.18.a.1 [District-only, Rule 206]
		G-515-3 G-515-4	non-emergency operation	b.	29 hrs/yr/unit	calendar year, (g) [District-only, 17CCR93115.c.16]
7.	D-2, EPG boiler	B-505	fuel feed	a.	100 mmBtuh	(d), daily average [District-only, Rule 204]
				b.	821,250 mmBtu/yr	(a), yearly total [District-only, Rule 204]
8.	H, gas oil loading rack		truck loading throughput	a.	2,000 bbl/day	[SIP Rule 205]
			pumping rate	b.	500 gpm	[District-only, Rule 206]
			material received	c.	1.0 psia	RVP [District-only, Rule 206]
	H, gas oil loading rack	TK-802	material stored	d.	0.45 psia	RVP [District-only, Rule 206]
				e.	150°F	[SIP Rule 205]
9.	M	GE-522 portable water pump	total hours of operation	a.	5840 hr/yr	[District-only, Rule 206]
		GB-1015 portable air compressor		b.	4,380 hr/yr	[District-only, Rule 204]
10.	U, sulfur pelletizing plant		pelletizer throughput	a.	42.6 tons/hr	[District-only, Rule 206]
			screen throughput	b.	50 tons/hr	[District-only, Rule 206]
			open stockpile storage	c.	25,000 tons	(b) [District-only, Rule 206]
11.	AN-603 H_2S CMS		calibration drift	a.	<15 ppm	(i) [40CFR60.PS-7.6.2]
			relative accuracy	b.	(h)	[40CFR60.PS-7.6.3]

Unit		Parameter	Limit		Notes
12.	AN-1707/1709 TRS CMS	calibration drift	a.	<17.5 ppm	(i) [40CFR60.PS-5.13.1]
		relative accuracy	b.	(h)	[40CFR60.PS-5.13.2]
13.	AN-1600 A/B SO2 CMS	calibration drift	a.	<12.5 ppm	[40CFR60.PS-2.13.1]
		relative accuracy	b.	(h)	[40CFR60.PS-2.13.2]
14.	M, GE-522 Portable Water Pump	hours of operation	5,840 hours per year		[District-only, Rule 206]

Additional Notes

(a) Calendar year basis. The actual fuel usage shall be the summation of each calendar month's total fuel flow rate times the respective month's average fuel gas gross heating value (GHV) used for compliance under condition III.D.6.b below.

(b) Prior approval for additional storage may be obtained from the APCO.

(c) Rolling 12-month basis. The actual fuel usage shall be the summation of the preceding 12-month's total fuel flow rate times the respective month's average fuel gas GHV used for compliance under condition III.D.6.b below.

(d) Daily average basis. The actual fuel usage shall be the summation of the day's total fuel flow divided by twenty-four (24) times the respective month's average fuel gas GHV used for compliance under condition III.D.6.b below.

(g) An emergency is defined as any time a refinery-declared state of emergency exists.

(h) If the average emissions during testing are less than 50% of the emission standard, the applicable emission standard value shall be used in the denominator of the Relative Accuracy (RA) equation 2-6 from 40CFR60.PS-2, as it appeared in the federal regulations as published on July 1, 2001, and the RA shall be no greater than 10%. If the average emissions during testing are greater than or equal to 50% of the emission standard, the average reference method value shall be used in the denominator of the equation and the RA shall be no greater than 20%. [40CFR60.PS-2.13.2]

(i) Maximum drift or deviation on six (6) of seven (7) test days.

(j) District Rule 431.C.2 exempts stationary diesel engines operated less than 200 hours per year from NOx and CO emission limitations.

16. Process W, Diesel Engine Systems

a. Non-Emergency Operation

1) Non-emergency operation shall be limited to maintenance and performance testing only and shall not exceed twenty (20) hours per engine per calendar year. Operation for emissions testing required by the District shall not be limited by this condition. [District-only, 17CCR93115.e.2.B.3.a.I.i and 17CCR93115.g.1]

2) Except for the carbon plant runoff collection pond pump, item II.30.g, an emergency is defined as failure of normal electrical power service that is beyond the control of the permit holder and does not include voluntarily disconnecting from utility grid power. [District-only, 17CCR93115.d.25]

3) For the carbon plant runoff collection pond pump, item II.30.g, an emergency is defined as the pumping of water to prevent the flooding of areas that are down slope from the collection pond. [District-only, 17CCR93115.d.25.C]

II. Facility Description

A. General. This facility is a petroleum refinery having the Standard Industrial Classification (SIC) Code of 2911. Raw petroleum enters the refinery by pipeline. Products leave as semi-refined petroleum by pipeline or tanker truck, as solid petroleum coke by rail or haul truck, and as recovered sulfur by haul truck. The primary processes involve: raw material storage, atmospheric pressure distillation, vacuum distillation, delayed coking of residual solids, , product storage, and product shipping. Secondary processes include: a refinery fuel gas system, a relief flare system, steam production, sulfur recovery, and oily water treatment. Two extraordinary aspects of the operation are worthy of specific note: petroleum storage tanks utilizing domed roofs and vapor recovery, and a six-megawatt electrical power generation system.

Domed roofs with a vapor recovery system were added to several large storage tanks in the early 1990's because of their significant odor potential. This effort was one of many in response to a conditional order of abatement brought by the District's Hearing Board. As the fluid level in a dome-covered tank drops, purchased natural gas is bled into the head space to maintain a positive pressure. As the fluid level rises, that blanket gas, which may now contain odorous compounds, is vented to the refinery's make-gas system where the hydrogen sulfide absorption units remove odorous compounds to produce elemental sulfur.

The power generation system is used to generate electricity from excess fuel gas that is not needed elsewhere in the refinery. With the shutdown of the Guadalupe oil field, where fuel gas was burned to produce enhanced oil recovery steam, and the Battles gas plant, where fuel gas was converted to pipeline quality natural gas, the refinery found itself in the mid-1990's with much more fuel gas than was necessary for crude oil processing. The electrical power generation unit was their solution and consists of the B-505 boiler, which burns the excess gas to produce high quality steam, and a 5.8 megawatt steam turbine. The B-505 boiler emissions were new to the refinery and triggered the need for offsets under the District's New Source Review program. Emission reductions from the Battles gas plant shutdown in nearby Santa Maria were used to satisfy that need. Thus, this project provided the refinery with a more reliable source of electricity without creating an emission increase in the region.

The Santa Maria Facility is a major federal stationary source for criteria air pollutants. It is subject to several New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAPs), and maximum achievable control technology (MACT) standards. Continuous monitoring systems (CMS) keep watch over both the refinery fuel gas system and the sulfur plant system.

The petroleum coke calciner at the facility was permanently shut down on March 13, 2007. This shut down reduced the facility emissions of hazardous air pollutants (HAPs) below the major source level, and also lead to several equipment and operating condition changes in the permit. A new boiler was installed in the Utility Plant at this time to replace steam that was previously produced by the calciner waste heat boiler.

B. Specific Equipment. The equipment descriptions in this section are organized by process. Major emission units are listed but all associated valves, flanges, piping, and minor emission units, which are not explicitly identified, are also included in this permit and subject to their respective major emission unit's requirements. ConocoPhillips is authorized to operate the equipment listed below in the configuration described. [SIP Rule 201]

1. **Process Unit A-1, Petroleum Tank Farm**; consisting of:

TITLE		ID	CAPACITY	DESCRIPTION
a.	gas oil (2)	TK-800,801	76,500 bbl each	welded shell, external floating pontoon roof, single shoe seal, 345.6 foot circumference [District-only, Rule 206]
b.	crude oil (3)	TK-900,901	92,000 bbl each	welded shell, external floating pontoon roof, primary shoe and zero-gap secondary wiper seals, 421 foot circumference [District-only, Rule 425.E.1]
		TK-903	92,000 bbl	welded shell, external floating pontoon roof, primary shoe and zero-gap secondary wiper seals, 421 foot circumference [Rule 425.E.1 & 40CFR60-Kb]
c.	recovered oil (2)	TK-100,101	9,460 bbl each	welded shell, dome roof, vented to Process A-2 [District-only, Rule 425.E.3]
d.	pressure distillate (2)	TK-550,551	52,000 bbl each	welded shell, dome roof, vented to Process A-2 [Rule 425.E.3 & SIP Rule 407.A.2]

2. **Process Unit A-2, Tank Farm Vapor Recovery System**; controlling vapors from Tanks 100, 101, 351, 550, and 551, water treatment system vessels F-821A/B/C, F-824, and F-408/9, and product pumps G-50-1/2; consisting of:

TITLE		ID	CAPACITY	DESCRIPTION
a.	blower suction knock-out drum	F-455		24" D x 5' T
b.	blower suction drip pot	F-456		13" D x 36' T
c.	vapor recovery blower (2)	GB-451	582 acfm	40 hp
d.	blower recycle cooler(2)	E-450		
e.	Tank 351 drip pot	F-353		16" D x 22" T

3. Process Unit B-1, Coking Unit A; consisting of:

	TITLE	ID	CAPACITY	DESCRIPTION
a.	crude fractionating heater	B-2A	65.0 mmBtuh	eight (8) John Zink InfurNOx PSMR-16RM burners with automatic oxygen feedback control
b.	vacuum distillation heater	B-62A	17.2 mmBtuh	three (3) John Zink InfurNOx PSMR-15RM burners
c.	coking heater	B-102A	88.6 mmBtuh	twenty-four (24) John Zink InfurNOx PSMR-13RM burners
d.	coke drums (2)	D-101A, D-102A		
e.	coker fractionator	D-103A		
f.	gas recovery compressor	G-212A	1400 hp	turbine driven compressor with steam supplied by B-201A
g.	gas recovery steam superheater	B-201A	3.2 mmBtuh	
h.	cooling tower			serving Processes B-1 and C
i.	cooling tower spare circ pump	G-51-4	263 hp	Cummins, NT855 diesel engine, manufactured in 1985, equipped with a Mine-X DC12 DOC

4. Process Unit B-2, Coker Steamout System; consisting of:

	TITLE	ID	CAP.	DESCRIPTION
a.	steamout quench tower	F-411		12' & 9' D x 35' T
b.	steamout condensate drum	F-415		6'6" D x 18' T
c.	steamout overhead condenser	E-411	62.4 mmBtuh	heat exch, no atm vent
d.	steamout accumulator	F-412		7' D x 35' T
e.	quench tower circulating pump (2)	G-411	220 gpm each	
f.	heavy recovered oil pump (2)	G-412	40 gpm each	
g.	light recovered oil pump (2)	G-413	330 gpm each	
h.	steamout water pump (2)	G-414	147 gpm each	
i.	coke strainer (2)	F-413		12" D x 28" T
j.	open top, coke cooling water storage tanks (2)	TK-405,6	20,000 bbl each	71' D, manually posi-tioned oil skimmers

5. Process Unit B-3, Gland Oil System; consisting of:

	TITLE	ID	CAP.	DESCRIPTION
a.	gland oil tank	F-115	500 bbl	vented to F-117
b.	gland oil pump (2)	G-112	90 gpm each	
c.	gland oil filters (2)	F-116		12"D x 2'T each
d.	carbon canister (2)	F-117	400 lb carbon each	

6. **Process Unit C, Coking Unit B**; consisting of:

	TITLE	ID	CAP.	DESCRIPTION
a.	crude fractionating heater	B-2B	65.0 mmBtuh	eight (8) John Zink InfurNOx PSMR-16RM burners with automatic oxygen feedback control
b.	vacuum distillation heater	B-62B	17.2 mmBtuh	three (3) John Zink InfurNOx PSMR-15RM burners
c.	coking heater	B-102B	88.6 mmBtuh	twenty-four (24) John Zink InfurNOx PSMR-13RM burners
d.	coke drums (2)	D-101B, D-102B		
e.	coker fractionator	D-103B		
f.	gas recovery compressor	G-212B	1400 hp	turbine driven compressor with steam supplied by B-201B
g.	gas recovery steam superheater	B-201B	3.2 mmBtuh	
h.	coke transfer conveyor system			bridge crane, hopper (2), and convey-or (2) serving Processes B-1 and C

7. **Process Unit D-1, Main Boiler Plant**; consisting of:

	TITLE	ID	CAP.	DESCRIPTION
a.	steam boiler	B-504	125 mmBtuh	Nebraska, 100,000 lb-stm/hr, burner: low-nox North American 4211-140-LE, fuel gas only
b.	steam boiler	B-506	127 mmBtuh	B&W model FM103-97, burner: low-nox North American 4211-116-LE, fuel gas only
c.	steam boiler	B-507	99.9 mmBtuh	B&W model FM103-79, with selective catalytic reduction system, fuel gas only
d.	emergency water pump engines (2)	G-515-3, G-515-4	370 hp each	Caterpillar model 3406B DIT LTS, diesel fueled, manufactured in 2000

8. **Process Unit D-2, Electrical Power Generation (EPG) Plant**; with steam supplied to the EPG turbine and to refinery utilities; consisting of:

	TITLE	ID	CAP.	DESCRIPTION
a.	fuel gas storage (2)		4,000 cf (each) @ 150 psig	pressure vessels
b.	boiler	B-505	70,000 lb-stm/hr & 100 mmBtuh	Babcock and Wilcox with Coen CFP/LN-32 burner, flue gas recirculation, and automatic oxygen feedback control
c.	steam driven turbine	N-970	7935 hp @ 66,000 lb-stm/hr	
d.	electrical generator	GT-970	5.8 MW	

9. **Process Unit E-1, Sulfur Recovery Units A and B**; each of a three (3) stage Claus design with 91 long-ton per day capacity and, except as noted, each consisting of:

TITLE		ID	CAP.	DESCRIPTION
a.	acid gas knock-out drum	F-612		3' D x 10'6" T
b.	acid gas preheater	E-600	0.211 mmBtuh	no vent to atmosphere
c.	process water stripper overhead knock-out drum	F-355		3' D x 8' T
d.	reaction furnace & waste heat boiler	B-600	16.1 mmBtuh	Comprimo burner, no vent to atmosphere
e.	process water stripper knock-out drum cond pump (2)	G-358	30 gpm each	
f.	sulfinol acid gas knock-out drum pump	G-618	30 gpm	
g.	converters (2)	D-603/5		
h.	in-line heaters	B-605		no vent to atmosphere
i.	waste heat condenser	E-611		
j.	air blower (3)	GB-611		driven by: two each steam turbine and one electric
k.	sulfur condensers (4)	E-605/8 & E-610/12		
l.	air demand analyzer (2 total)	AA-601 & AB-601		no vent to atmosphere
m.	sulfur recovery unit incinerator (2 total)	B-602A/B	9 mmBtuh each	normal operation is 750°F
n.	stack flow meters	FI-1600 A/B		EMRC DP-60/75 Mark 2 monitors
o.	incinerator SO2 monitor	AN-1600 A/B		Ametek Model 922 Multi-Gas Analyzer dual span 0-500 ppm and 0-10,000 ppm
p.	sulfur pit (2 total)			vented to B-602A/B

10. Process Unit E-2, Sulfur Recovery Support Units (common to Sulfur Recovery Units A and B); consisting of:

TITLE		ID	CAP.	DESCRIPTION
a.	sulfur plant relief drum	F-617		3'6" D x 7' T
b.	relief drum pump (2)	G-617	15 gpm each	
c.	spare turbine	GB-611		

11. Process Unit G, Oily Water Treatment; consisting of:

	TITLE	ID	CAP.	DESCRIPTION
a.	oily water sewer system			refinery-wide
b.	covered diversion box	F-820		10' H x 10' W x 10' D, atm vent
c.	covered API oil-water separator (3)	F-821A, B,C	535 gpm each	85' L x 12' W x 8' H, natural gas blanket vented to Process A-2
d.	recovered oil surge drum	F-824	110 bbl	fixed roof, natural gas blanket vented to Process A-2
e.	recycled solids tank (2)	F-408,9	120 bbl each	fixed roof, natural gas blanket vented to Process A-2
f.	safety surge tank (2)	TK-822,3	40,000 bbl	floating roof, 120' diameter, 377' circumference, mechanical shoe primary, rim-mounted secondary, roof drain with slotted membrane cover, and under-roof oil skimmer
g.	effluent air cooler	E-801	7.1 mmBtuh heat removal	fin-fan heat exchanger

12. Process Unit H, Gas Oil Loading Rack; consisting of:

	TITLE	ID	CAP.	DESCRIPTION
a.	gas oil tank	TK-802	440 bbl	fixed roof, 12' D x 23'9" T, insulated
b.	loading & unloading rack			submerged top-load or bottom-load
c.	loading pump		40 hp	

13. Process Unit I, Hydrogen Sulfide Absorption Unit A; consisting of:

	TITLE	ID	DESCRIPTION
a.	sulfinol H_2S absorber	D-601	3'7" D x 61' T
b.	sulfinol stripper	D-602	5' D x 62' T
c.	rich sulfinol flash drum	F-600	7' D x 26' L
d.	hydrogen sulfide scrubber	F-616	18" D 13' T
e.	sulfinol storage and handling system		
f.	carbon filtration system		

14. Process Unit J, Hydrogen Sulfide Absorption Unit B; consisting of:

	TITLE	ID	DESCRIPTION
a.	sulfinol H_2S absorber	D-601	
b.	sulfinol stripper	D-602	
c.	fuel gas H_2S analyzer	AN-603	Del Mar Sulfur Smart model 3200, span is 300 ppm H_2S, monitors output of both Units I & J
d.	rich sulfinol flash drum	F-600	7' D x 26' L
e.	hydrogen sulfide scrubber	F-616	18" D 13' T
f.	sulfinol storage and handling system		
g.	carbon filtration system		

15. Process Unit K, Tail Gas Treating Unit; utilizing a vanadium-based liquid solution and consisting of:

TITLE			ID	DESCRIPTION
a.	reduced gas generator		B-701	
b.	hydrogenation reactor		D-701	
c.	contact condenser/desuperheater		D-702	
d.	absorber/reaction tank		F-704	
e.	tail gas combustor		B-702	discharge to atmosphere, 12 mmBtuh, normal operation is 600°F
f.	three-stage oxidizer system		F-701/2/3	Claus reaction
g.	tail gas emissions monitor		AN-1707/1709	EmersonProcess-Daniel model 1000 flame photometric detector gas chromatograph system with model 2350A controller, span is 20 ppm H_2S & 350 ppm TRS
h.	sulfur melt pit		F-716	inactive
i.	sulfur froth handling system			
	1)	froth tank	F-712	25' D x 18 ' T
	2)	Verti-press filter	ME-701	with bagging system

16. Process Unit L, Product Pump System; consisting of:

TITLE	ID	DESCRIPTION
electrically driven pump (2)	G-50	tandem barrier-fluid seals vented to Process A-2

17. Process Unit M, Compressor and Pump Engines; consisting of:

TITLE	ID	CAP.	DESCRIPTION
spare plant-air compressor engine	GB-524S	270 hp	Caterpillar, 3306 BDITA diesel engine, manufactured in 1974, equipped with a Mine-X DC10 DOC
portable water pump	GE-522	225 hp	John Deere, model 6081AF001, diesel engine; manufactured in 1999 with turbocharger on the inlet, catalyzed particulate filter on the exhaust, and Claire Longview backpressure monitoring system
portable air compressor system	GB-1015	115 hp	John Deere, 4045TF275 Tier 2 diesel engine, manufactured in 2004, Harco catalyzed particulate filter, model SUD-CHEMIE EnviCat

18. Process Unit N, Portable Abrasive Blasting Equipment; consisting of:

TITLE		CAP/	DESCRIPTION
a.	sandpot	250 lb	portable, Schmidt 24L-144
b.	sandpot	500 lb	portable, Kelco, model 124
c.	blast guns		Kelco, model 24-36-W with nozzle numbers 5 through 10, and Schmidt nozzle number 5
d.	blasting containment structure		24' x 20' x 15'

19. Process Unit O, Hydrocarbon Relief and Recovery System; consisting of:

Title		ID	CAP.	DESCRIPTION
a.	relief drum	F-451		8' D x 32' L
b.	quench tower	D-451		11' D x 28'6" T
c.	blower suction knock-out drum	F-452		24" D x 5' T
d.	blower suction drip pot	F-453		12" D x 36" T
e.	vapor recovery blower	GB-455	833 mmscfd	40 hp
f.	blower recycle cooler	E-452	47.4 mBtuh	heat exch, no atm vent
g.	blower discharge cooler	E-458	0.45 mmBtuh	heat exch, no atm vent
h.	blower discharge knock-out drum	F-458		30" D x 6' T
i.	discharge knock-out drum pump	G-458	10 gpm	
j.	light recovered oil pump (2)	G-454	100 gpm each	
k.	flare stack and seal drum	C-451		24" D x 200' H, steam-assisted
l.	flare gas flowmeter			Panametric, model 7168, ultrasonic
m.	flare stack sampling system to determine flared gas heat content		auto sample after 5 minutes of flared gas flow	Welker Engineering, downstream of D-451 quench tower
n.	heavy recovered oil pump (2)	G-453	250 gpm each	
o.	quench tower bottoms pump (2)	G-452	250 gpm each	
p.	recovered oil cooler	E-451	30 mmBtuh	heat exch, no atm vent

20. Process Unit P, Process Water System; consisting of:

Title		ID	CAP.	DESCRIPTION
a.	process water stripper	D-351		5' D x 93' T
b.	process water tank	TK-351	40,000 bbl	domed roof, vent to Process A-2
c.	feed/effluent exchanger	E-351	12.0 mmBtuh	heat exch, no atm vent
d.	stripper reboiler	E-353	24.7 mmBtuh	heat exch, no atm vent
e.	stripper overhead condenser	E-352	17.6 mmBtuh	heat exch, no atm vent
f.	stripper water cooler	E-354	5.4 mmBtuh	heat exch, no atm vent
g.	feed pump (2)	G-351	265 gpm each	
h.	stripper water pump (2)	G-352	280 gpm each	
i.	stripper reflux pump (2)	G-353	50 gpm each	

Title		ID	CAP.	DESCRIPTION
j.	skim oil pump	G-354	20 gpm	
k.	tank block sump pump (2)	G-357	20 gpm each	
l.	stripper feed filters	F-352		18" D x 3' T
m.	caustic storage tank	F-354		10' D x 17' H
n.	caustic circulation pump	G-356	5 gpm	
o.	caustic injection pump	G-355	30 gph	

21. Process Unit Q, Green Coke Handling System; consisting of:

TITLE		CAP.	DESCRIPTION
a.	stock-piles	five (5) grades	green coke receipts, plus 1/4" kilnfeed, 1/4" x 1", 1/4" x 6 mesh, & minus 6 mesh (fines)
b.	runoff collection pond pump		electrically driven pump

22. Process Unit S-1, Calcined Coke Storage and Handling; consisting of:

TITLE		CAP.	DESCRIPTION
a.	storage silo	1,270 ton total	four compartment
b.	steel reclaim hopper		8' W x 16' L x 5' T, discharge to load-out conveyor
c.	covered load-out conveyor		24" W x 231' L
d.	loading chute and shroud		

23. Process Unit S-2, Calcined Coke Loading Control System; consisting of:

TITLE	CAP.	DESCRIPTION
baghouse	12,200 cfm, 75 hp	Western Precipitation Pulsflo model PF 4595-216, 2315 sq.ft. bag surface area

24. Process Unit S-3, Calcined Coke Portable Handling Equipment; consisting of:

Title		ID	CAP.	DESCRIPTION
a.	hopper (2)	4005,6	10 ton each	used for stockpiling, blending, or feeding calcined or green coke or elemental sulfur as needed
b.	stacker conveyor (2)	4137,8		used for stockpiling, blending, or feeding calcined or green coke or elemental sulfur as needed
c.	semi-portable hopper and conveyor	4004	10 ton	hopper: 16' L x 9' W x 12' H, conveyor: 24" W x 19' L, used for green coke blending and emergency green coke feed upon failure of normal vibratory feeder

25. Process Unit U, Sulfur Pelletizing Plant; consisting of:

TITLE		ID	CAP.	DESCRIPTION
a.	sulfur pump	6000	10 hp	
b.	pelletizing nozzle	6007		
c.	hopper with delumper	6026		
d.	conveyor (short)	6027		between c and e
e.	conveyor (long, inclined)	6028		between d and f
f.	rod deck screen	6030	7.5 hp	4' x 8', Symon
g.	screen delumper			
h.	screened product silo (truck loading hopper)			
i.	sulfur storage pit			16' W x 16' L x 13.5' D, below grade

26. Process Unit W, Diesel Engine Systems; consisting of:

a. Backup electrical generator for the Wet Plant consisting of: one 230 kW Kohler, Model 230R0ZD71, generator driven by a 370 hp, diesel fueled, Detroit Diesel, Model 6V92T engine, turbocharged, ConocoPhillips ID# NE-800. Manufactured in 1996 with run-time of 26.9 hours on February 27, 2004.

b. Backup electrical generator for the coker control room consisting of: one 180 kW Kohler, Model 180R0ZD71, generator driven by a 300 hp, diesel fueled, John Deere, Model 6076AF011 engine, turbocharged, ConocoPhillips ID# NE-503. Manufactured in 1996 with run-time of 88.2 hours on February 27, 2004.

c. Backup electrical generator for the maintenance and administration operation consisting of: one 150 kW Kohler, Model 150R0ZD71, generator driven by a 250 hp, diesel fueled, John Deere, turbocharged, Model 6076AF010 engine, ConocoPhillips ID# NE-504. Manufactured in 1996 with run-time of 30.4 hours on February 27, 2004.

d. Backup electrical generator for the Reverse Osmosis Unit consisting of: one 355 kW Kohler, Model 350RE0ZD, generator driven by a 550 hp, diesel fueled, Detroit Diesel, Model 6063TK35 engine, turbocharged. Engine family YDDXL12.7TGD, manufactured in 2000 with run-time of 56.6 hours on February 27, 2004.

e. Backup electrical generator for the carbon plant control room consisting of: one 75 kW Onan-DYC, Model 750-DYC 15R21175K, generator driven by a 162 hp, diesel fueled, Allis Chalmers, Model 670T engine, turbocharged, ConocoPhillips NE-4108. Manufactured in 1978 with run-time of 915.4 hours on March 9, 2004.

f. Backup water pump for the carbon plant runoff collection pond consisting of: one 82 hp, diesel fueled, Perkins, Model 1004-42 engine, ConocoPhillips BK-699. Engine family 1PKXL04.2AR1, manufactured in 2001 with run-time of 564.5 hours on March 9, 2004.

g. Portable welding unit consisting of: one Lincoln Welder driven by a 71 hp, diesel fueled, Perkins, model K1278-5, Serial C102090053, ConocoPhillips ID 7975. Manufactured in 1999 with a run time of 750 hours on December 9, 2005.

h. Portable welding unit consisting of: one ARC Welder Trailer driven by a 71 hp, diesel fueled, Perkins, model SAE-400 4.236, Serial 944059, ConocoPhillips ID 1485. Manufactured in 1975 with a run-time meter installed on March 9, 2006.

i. Portable welding unit consisting of: one Diesel Welder SAE driven by an 80 hp, diesel fueled, Perkins, model SAE-400 4.236, ConocoPhillips ID 7970. Manufactured in 1985.

27. **Process Unit X, Emission Control Devices for Mobile Equipment;** consisting of:

a. One (1) MINE-X DC14 oxidation catalyst controlling the emissions from a Caterpillar 924-C Dozer, 310 hp, manufactured in 1984.

b. One (1) MINE-X DC14 oxidation catalyst controlling the emissions from a Caterpillar D8L Dozer, 335 hp, manufactured in 1985.

c. One (1) MINE-X DC14 oxidation catalyst controlling the emissions from a Caterpillar 988B Loader, 375 hp, manufactured in 1985.

d. One (1) MINE-X DC14 oxidation catalyst controlling the emissions from a Caterpillar 988B Loader, 375 hp, manufactured in 1986.

C. **Insignificant Equipment.** The following equipment and equipment types are considered environmentally insignificant. This equipment is not subject to the provisions of this permit except for those units that are subject to a federally-enforceable, generally applicable requirement as listed in section III.A.1, and diesel engines rated at <50 bhp that become subject to the requirements of 17CCR93115, Airborne Toxic Control Measure for Stationary Compression Ignition Engines.

Description	Basis for Insignificance
chemical laboratory analytical equipment	Rule 201.A.1
internal combustion engines rated <50 bhp	Rule 201.B.1
restroom water heaters	Rule 201.B.2
coke handling mobile equipment	Rule 201.C.1
diesel storage tanks used for vehicle fueling	Rule 201.I.4
gasoline storage tanks used for vehicle fueling	Rule 201.I.9
architectural coating spray guns	Rule 201.J.1
cold solvent cleaners	Rule 201.J.2
comfort air conditioning	Rule 201.M.1
comfort space heating	Rule 201.M.5
welding equipment	Rule 201.N.2
bead blaster	Rule 201.A.1
dedusting system	Rule 201.A.1
a. two (2) 2 gpm dedust oil pumps	
b. two (2) screw conveyors	
c. oil spray nozzles	
d. one (1) steam-heated 10,000 gal. oil storage vessel	
tail gas unit regenerative crystallizer system	Rule 201.A.1

III. CONDITIONS

A. STANDARD CONDITIONS

1. **Generally Applicable Requirements.** For the purposes of this permit, all requirements shall be based on standard atmospheric conditions of sixty degrees Fahrenheit (60°F) and 14.7 psia. [SIP Rule 106]

   a. Visible emissions shall not exceed any of the following, except for open outdoor fires that have been approved by the APCO for the purposes of employee instruction in fire fighting methods: [SIP Rule 401.B.3]
      1) Ringlemann #2 or forty percent (40%) opacity for a period exceeding three (3) minutes aggregated in any sixty (60) minute period of time; or [SIP Rule 401 and District-only, H&SC 41701]
      2) Ringlemann #1 or twenty percent (20%) opacity for a period exceeding three (3) minutes aggregated in any sixty (60) minute period of time. [District-only, Rule 401.A]

   b. If the APCO determines that the operation of this equipment is causing a public nuisance, ConocoPhillips shall take immediate action and eliminate the nuisance. [District-only, Rule 402]

   c. Particulate matter emissions shall not exceed any of the following:
      1) For all emission units:
         i. 0.30 gr/scf, on an hourly basis, and [SIP Rule IV.113.1]
         ii. that lb/hr amount identified in Table I of SIP Rule 113 depending on process rate; [SIP Rule IV.113.2]
      2) For all emission units, except combustion devices and internal combustion engines:
         i. 0.10 gr/dscf, on an hourly basis, and [District-only, Rule 403.A]
         ii. that lb/hr amount identified in Rule 403.B depending on process rate; [District-only, Rule 403.B]
      3) For combustion devices:
         i. 0.30 gr/scf corrected to three percent (3%) O_2, wet, and [SIP Rule IV.113.4]
         ii. 0.120 lb/mmBtu of fuel input, except for internal combustion engines. [District-only, Rule 403.C.1]

   d. Sulfur compound limitations.
      1) Sulfur compound emissions shall not exceed 0.20 percent by volume of sulfur compounds calculated as sulfur dioxide, excluding units B-602A/B, which are exempt under SIP Rule 114.1.c [SIP Rule 114.1.a]
      2) Gaseous fuel sulfur content shall not exceed 50 gr/100 dscf (797 ppmv) total sulfur (as H_2S at standard conditions). [SIP Rule 404.E.1]
      3) Liquid fuel sulfur content shall not exceed 0.50 wt% sulfur. [SIP Rule 404.E.1]
      4) ConocoPhillips shall not burn liquid fuel in the following combustion devices: [Consent Decree H-05-0258, condition 117]
         i. B-2A&B

ii. B-102A&B
iii. B-504, B-505, & B-506

e. Carbon monoxide emissions shall not exceed 2000 ppmv at standard conditions. This condition shall not apply to internal combustion engines. [SIP Rule 406]

f. Metal surface coatings shall not be thinned or reduced with photochemically reactive solvents, as defined in SIP Rule 407. [SIP Rule 407.H.2]

g. Architectural coatings, which are purchased in containers of one (1) quart capacity or larger, shall not contain photochemically reactive solvents nor shall they be thinned or reduced with photochemically reactive solvents. [SIP Rule 407.H.3]

h. No photochemically reactive solvent, or any material containing that amount of photochemically reactive solvent, may be evaporated during the disposal of that solvent or material. [SIP Rules 205 and 407.H.4]

i. ConocoPhillips shall not vent organic compounds to the atmosphere during the depressurization, or vessel purging, steps of a refinery process turnaround. Compliance shall be accomplished by venting all uncondensing organic gases to a fuel gas system or to a flare. [SIP Rule 422]

j. This facility shall comply with all applicable provisions of the Air Toxic "Hot Spots" Act as set forth in Health and Safety Code Section 44300 (et seq.). [District-only, H&SC 44300 (et seq.) and, District-only, Rule 204.F.1]

k. All abrasive blasting shall be conducted in accordance with Title 17 of the California Code of Regulations (CCR). [District-only, CCR92000 (et seq.)]
1) Each operator of this equipment shall be supplied with a copy of the abrasive blasting provisions of Title 17 and the APCO prepared summary of Title 17. [District-only, Rule 206]
2) Abrasive blasting of items smaller than eight feet (8') shall be conducted within an enclosure or indoors. [District-only, CCR92000 (et seq.)]
3) All dry, unconfined blasting shall utilize ARB certified abrasives. [District-only, CCR92000 (et seq.)]
4) Areas surrounding the blasting operation shall be periodically washed, swept, vacuumed, or otherwise cleaned to prevent re-entrainment of dust. [District-only, Rule 206]

l. This equipment shall be operated consistent with the information provided in the application under which this permit, or previous versions of this permit and all previous permits issued for this equipment, were issued; and shall be maintained on-line and in good working order at all times during the operation of their respective process and in such a manner as to minimize the emission of air contaminants. [SIP Rule 201]

m. The APCO shall be notified in writing before any changes are made in the design, construction, or method of operation of this equipment, or any modifications are made to process conditions that might increase the emission of air contaminants in excess of existing permit limits, for those emission unit and pollutant combinations with such limits, or that might increase the potential to emit of any air contaminant, for those emission unit and pollutant combinations without current limits. [SIP Rule 201]

n. Spilled petroleum material shall be cleaned up as soon as possible to minimize hydrocarbon emissions and odors. Clean up materials shall be stored in closed containers in accordance with applicable regulations and disposed of as hazardous material in compliance with federal, state, and local regulation. [District-only, Rule 206]

o. Any gasoline transfer to a stationary storage tank shall utilize a permanently installed submerged fill pipe and a tight-fitting nozzle. [SIP Rule 407.C.1.a]

p. ConocoPhillips shall follow good operating practices when storing or transferring gasoline including: [SIP Rule 424.B.5]

    1) preventing spills;
    2) utilizing closed storage containers; and
    3) disposing of any gasoline in compliance with all applicable federal, state, and local regulations.

q. ConocoPhillips shall ensure that cold solvent metal cleaning devices, with the exception of wipe clean operations:

    1) utilize: [SIP Rule 416.B]
        i. a container for the solvent and the articles being cleaned;
        ii. a cover, easily operated with one hand, which prevents the solvent from evaporating when the cleaning device is not in use;
        iii. a shelf for draining cleaned parts such that the drained solvent is returned to the solvent storage container;
        iv. a permanent, conspicuous label, which lists all applicable operating requirements; and
        v. a freeboard ratio equal to or greater than 0.75, if the solvent surface area is greater than or equal to 5.4 square feet; and

    2) are operated as follows. [SIP Rule 416.C]
        i. All degreasing equipment and emission control equipment shall be operated and maintained in good working order.
        ii. No solvent may be allowed to leak from the degreasing equipment.
        iii. All solvent shall be stored and disposed of in a manner that prevents its evaporation to the atmosphere.
        iv. The cover of any cleaning device shall not be removed unless that device is in use or undergoing maintenance.
        v. The operator shall drain parts for at least fifteen (15) seconds after cleaning or until dripping ceases.
        vi. Flowing solvent shall consist of a liquid stream and not a fine, atomized, or shower type spray; and the motive pressure for that

solvent flow shall be sufficiently low to prevent the splashing of solvent beyond the container.

r. ConocoPhillips shall not ignite or maintain an open outdoor fire except as approved by the APCO for the purposes of employee instruction in fire fighting methods. [SIP Rule 501.A]

s. All subject processes shall comply with applicable provisions of 40CFR61, National Emission Standards for Hazardous Air Pollutants, subpart A, General Provisions, and all of the provisions of subpart M, Asbestos. [40CFR61.05.c and subpart M]

1) General Provisions. ConocoPhillips shall:
   i. not fail to report, revise reports, or report source test results as required by subpart M; [40CFR61.05.d]
   ii. ensure that any change to the information provided in the initial notification under 40CFR61.10.a shall be submitted to the APCO no later than thirty (30) calendar days after that change; [40CFR61.10.c]
   iii. ensure that each subject process shall be maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions; [40CFR61.12.c]
   iv. ensure that regulated asbestos containing material (RACM) workers are adequately trained in accordance with 40CFR60.145.c.8; and [40CFR61.145.c.8]
   v. not install or reinstall RACM. [40CFR61.148]

2) Applicability. The notification and procedural requirements of subpart M apply to demolition and renovation activity of regulated asbestos-containing material (RACM) involving: [40CFR61.145.a.1]
   i. at least 260 linear feet of RACM on pipes,
   ii. at least 160 square feet of RACM on other components, or
   iii. at least thirty-five (35) cubic feet of RACM that has been removed from refinery components and is no longer otherwise measurable in the above units.

3) Notifications. ConocoPhillips shall submit the following notifications to the APCO and CALOSHA. [District-only, Rule 206 for the requirement to notify CALOSHA]

   i. No later than ten (10) working days prior to any renovation or demolition involving that amount of RACM identified in condition III.A.1.s.2 and using a form similar to that shown in figure 3 to subpart M: [40CFR61.145.b.4]
      (a) identify the notification as either an original or a revision;
      (b) name, address, and telephone numbers of both the facility and the contractor, if appropriate;
      (c) identify the activity as either demolition or renovation;
      (d) location and description of the affected part of the facility including the affected part's size, age, and use;

(e) procedure used to detect the presence of RACM;
(f) the estimated amount of RACM involved and the basis for that estimate;
(g) scheduled starting and completion dates of the RACM work;
(h) description of RACM work, including the work practices, engineering controls, and waste-handling procedures to be used to comply with subpart M;
(i) name, location, and telephone number of the waste transporter and disposal site;
(j) certification that al least one properly trained person will supervise the activity; and
(k) description of procedures to be followed in the event that unexpected RACM is found or that Category II nonfriable asbestos containing material becomes crumbled, pulverized, or reduced to powder.

ii. If an RACM activity start date is after the date given in the original notification, provide verbal notification of the new date as soon as possible before the original date and a written notification as soon as possible, but no later than the original start date. [40CFR61.145.b.3.iv.A]

iii. If an RACM activity start date is earlier than the date given in the original notification, provide written notification at least ten (10) working days before the new start date. [40CFR61.145.b.3.iv.B]

iv. Update any previously provided notice, if the amount of RACM involved changes by at least twenty percent (20%) or if the start or end date of any activity changes. [40CFR61.145.b.2]

4) Emission Controls. ConocoPhillips and/or their contractor(s) shall comply with the procedures for asbestos emission control identified in 40CFR61.145.c. [40CFR61.145.c]

5) Waste Disposal. ConocoPhillips shall:
i. not discharge any visible emissions to the ambient air during the collection, processing, packaging, or transporting of asbestos-containing material (ACM), except as allowed by 40CFR61.150.a; [40CFR61.150.a]
ii. ensure that all ACM is properly disposed of as soon as practicable; [40CFR61.150.b]
iii. ensure that vehicles used to transport ACM are marked with visible signs in accordance with 40CFR61.149.d; [40CFR61.150.c]
iv. provide a copy of the ACM waste shipment record, as required under condition III.B.1.w, to the disposal site operator when the waste is delivered to their site; [40CFR61.150.d.2]
v. if a copy of a waste shipment record is not received within thirty-five (35) calendar days of the date that ACM waste was accepted by an initial transporter, contact the transporter(s) or the

owner/operator of the designated waste disposal site to determine the status of the waste shipment; and [40CFR61.150.d.3]

vi. if a copy of a waste shipment record is not received within forty-five (45) calendar days of the date that ACM waste was accepted by an initial transporter, provide a written report to the APCO and CALOSHA which includes the waste shipment record of concern and details ConocoPhillips' efforts to determine the shipment's status. [40CFR61.150.d.4]

t. All subject processes shall comply with the provisions of 40CFR61, <u>National Emission Standards for Hazardous Air Pollutants</u>, subpart A, <u>General Provisions</u>, and subpart FF, <u>Benzene Waste Operations</u>. [40CFR61.05.c and subpart FF]

1) General Provisions

i. Tosco shall not fail to report, revise reports, or report source test results as required by subpart FF. [40CFR61.05.d]

ii. Any change to the information provided in the initial notification under 40CFR61.10.a shall be submitted to the APCO no later than thirty (30) calendar days after that change. [40CFR61.10.c]

iii. Each subject process shall be maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions. [40CFR61.12.c]

2) ConocoPhillips shall determine the total annual benzene waste quantity (TABQ) generated using the procedures in 40CFR61.355: [40CFR61.355.a]

i. annually for the preceding calendar year, and [40CFR61.355.a]

ii. whenever there is a change in the process generating the waste that could cause the TABQ to increase to ten (10) megagrams per year or more. [40CFR61.355.a.4.ii]

3) Whenever a TABQ determination is made under condition III.A.1.t.2.ii above, ConocoPhillips shall submit an update of their original report under 40CFR61.357.a to the APCO, with a copy to the EPA Region IX administrator. [40CFR61.357.c]

u. ConocoPhillips shall comply with all applicable provisions of 40CFR82, <u>Protection of Stratospheric Ozone</u>. [40CFR82.1.b]

1) ConocoPhillips shall comply with the ozone-depleting substance (ODS) labeling standards of 40CFR82 subpart E. No person may modify, remove, or interfere with a required warning statement, except as described in 40CFR82.112. [40CFR82.112.a]

2) ConocoPhillips shall comply with the recycling and emissions reduction standards of 40CFR82 subpart F. [40CFR82.150.b]

i. ConocoPhillips shall comply with 40CFR82.156 when opening any appliance for maintenance, service, repair, or disposal.

ii. ConocoPhillips shall ensure that recycling and recovery equipment used during the maintenance, service, repair, or disposal of appliances complies with 40CFR82.158.

iii. ConocoPhillips shall ensure that any person performing maintenance, service, or repairs on, or disposing of, appliances is currently certified under a technician certification program that has been approved under 40CFR82.161.

iv. ConocoPhillips shall comply with the recordkeeping requirements of 40CFR82.166 when disposing of small appliances or motor vehicle air conditioner (MVAC)-like appliances.

v. ConocoPhillips shall comply with the leak repair requirements of 40CFR82.156.

vi. ConocoPhillips shall maintain a record of refrigerates purchased and added to the coker control room chiller, which contains fifty (50) pounds or more of refrigerate, as required by 40CFR82.166.

3) ConocoPhillips shall not perform maintenance, service, or repairs on MVACs. [SIP Rule 205]

4) For any given equipment, ConocoPhillips may at any time, and without prior notification to the APCO, switch from the use of an ODS to an alternative substance, which has been approved under the Significant New Alternatives Program of 40CFR82 subpart G, and shall comply with any use restriction for that alternative substance which was set by the applicability decision. [40CFR82.174.c]

v. A copy of the State certification must be readily available for any portable equipment that operates at ConocoPhillips' Santa Maria Facility and is registered with ARB pursuant to CCR Title 13, section 2450 (et seq.). [SIP Rule 205]

w. This facility shall comply with all applicable provisions of District Rule 433, Architectural Coatings. [District-only, Rule 433]

2. Compliance with Permit Conditions

a. ConocoPhillips shall comply with all terms and conditions of this permit. Non-compliance constitutes a violation of the federal Clean Air Act. Continuing non-compliance with any federally-enforceable permit condition is grounds for permit termination, revocation and reissuance, modification, enforcement action, or denial of permit renewal. [Rule 216.F.1.f for all "federally-enforceable" conditions and, District-only, Rule 206 for "District-only" enforceable conditions]

b. The need to halt or reduce a permitted activity in order to maintain compliance shall not be used as a defense for noncompliance with any permit condition. [Rule 216.F.1.g]

c. This permit may be reopened by the APCO at any time for cause. For the purposes of this permit, the following circumstances shall constitute cause. [Rule 216.K.1]

1) ConocoPhillips becomes subject to an additional federally-enforceable requirement, the remaining term of this permit is three years or more, and the effective date of that requirement is not later than the date on which this permit is due to be reissued. [Rule 216.K.1.a]
2) The APCO or the EPA determines that this permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards, terms, or conditions of the permit. [Rule 216.K.1.c]
3) The APCO determines that this permit must be revised or revoked to assure compliance with any applicable requirement, or EPA determines that the permit must be revised or revoked to assure compliance with any federally-enforceable requirement. [Rule 216.K.1.d]
4) A TABQ equal to or exceeding ten (10) megagrams in any given year, as determine under 40CFR61 subpart FF and condition III.A.1.t to this permit, shall be considered cause for reopening this permit. [40CFR61.342.b]

d. This permit does not convey property rights or exclusive privilege of any sort. [Rule 216.F.1.i]

e. Within a reasonable time period, ConocoPhillips shall furnish any information requested by the APCO, for the purpose of determining:

1) compliance with this permit; [Rule 216.F.1.j.2]
2) air contaminant emissions; [SIP Rule 205]
3) whether or not cause exists to modify, revoke, reissue, or terminate this permit; or [Rule 216.F.1.j.1]
4) whether or not cause exists for an enforcement action. [Rule 216.F.1.j.2]

f. If ConocoPhillips is not in compliance with any federally-enforceable requirement, they shall submit to the APCO a schedule of compliance, which has been approved by the Hearing Board. [Rule 216.F.2.c]

g. A pending permit action, or notification of anticipated noncompliance, does not stay any condition of this permit. [SIP Rule 205]

h. All terms and conditions of this permit are enforceable by the EPA Administrator and citizens of the United States under the federal Clean Air Act unless referenced as being based on a District-only requirement. All terms and conditions of this permit, including those referenced as being based on a District-only requirement, are enforceable by the APCO. [Rule 216.F.3]

i. This permit, or a true copy, shall be made readily accessible at ConocoPhillips' Santa Maria Facility and shall not be altered or defaced in any way. [SIP Rule 201.E&F]

j. The terms and conditions of this permit shall apply to the equipment listed herein, which is operated by either ConocoPhillips or their contractor(s), and located at 2555 or 2565 Willow Road, Arroyo Grande, California, or on contiguous properties to those addresses, which are owned and controlled by ConocoPhillips. [SIP Rule 205]

k. A permit revision shall not be required to implement processes changes, economic incentives, marketable permits, emissions trading and other similar programs that are provided for elsewhere in this permit. [Rule 216.F.1.l]

3. **Emergency Provisions.** ConocoPhillips shall comply with the requirements of District Rule 107, Upset and breakdown Conditions. [Rule 107]

4. **Federal Regulation and District Compliance Plans**

a. ConocoPhillips will continue to comply with those permit conditions with which it is in compliance, as identified in this permit. [Rule 216.F.1.f & L.2.b]

b. ConocoPhillips shall comply with all federally-enforceable requirements that become applicable during the permit term, in a timely manner, as identified in this permit. [Rule 216.F.1.f & L.2.c]

c. ConocoPhillips shall comply with all APCO approved compliance plans. [District-only, Rule 206]

d. No later than sixty (60) calendar days after the completion of an engine retrofit or replacement under condition III.C.11.a.2, ConocoPhillips shall submit an Engine Operator Inspection Plan for the APCO's approval. At a minimum, that Plan shall include the following. [District-only, Rule 431.E]

1) The manufacturer, model number, horsepower, and combustion type of the engine.
2) A description of the NO_x control system installed on the engine, including type and manufacturer, as well as a description of any ancillary equipment related to the control of emissions.
3) The facility-defined equipment identification number and the location of the engine on a map or plot plan of the affected facility.
4) A specific engine inspection procedure to ensure that the engine is operated in compliance with the provisions of Rule 431. That procedure shall include an inspection schedule and the inspection log format as required by Section G of Rule 431. Inspections shall be conducted every quarter or after every 2,000 hours of engine operation. In no event shall the frequency of inspection be less than once per year.
5) A description of each preventive or corrective maintenance procedure or practice that will be used to maintain the engine and NO_x control system in compliance with the provisions of Rule 431.

5. **Right of Entry.** The Regional Administrator of U.S. Environmental Protection Agency, the Executive Officer of the California Air Resources Board, the APCO, or their authorized representatives, upon the presentation of credentials, shall be permitted to enter upon the premises and, at reasonable times, be permitted to: [Rule 216.F.2.a].

a. inspect the stationary source, including equipment, work practices, operations, and emission-related activity; and

b. inspect and duplicate records required by this Permit to Operate; and

c. sample substances or monitor emissions from the source or other parameters to assure compliance with the permit or applicable requirements. Monitoring of emissions can include source testing.

6. **Severability.** The provisions of this Permit to Operate are severable, and, if any provision of this Permit to Operate is held invalid, the remainder of this Permit to Operate shall not be affected thereby. [Rule 216.F.1.e]

7. **Circumvention.** ConocoPhillips shall not build, erect, install, or use, any article, machine, equipment, or process subject to an applicable standard, if the use of which conceals an emission that would otherwise constitute a violation of that standard. [40CFR60.12, 61.19, & 63.4.b]

8. **Permit Life.** This Permit to Operate shall become invalid five (5) years from the original effectiveness date unless a timely and complete renewal application is submitted to the District. ConocoPhillips shall apply for renewal of this permit no later than six (6) months before the date of expiration. Upon submittal of a timely and complete renewal application, this Permit to Operate shall remain in effect until the APCO issues or denies the renewal application. [Rule 216.I.1, I.2, & I.4]

9. **Payment of Fees.** ConocoPhillips shall remit Title V compliance determinations fees to the District in response to the District's invoice on a timely basis. Failure to remit fees in accordance with District Rule 302 shall result in forfeiture of this Permit to Operate. Operation without a permit to operate subjects the source to potential enforcement action by the District and the U.S. EPA pursuant to section 502(a) of the Clean Air Act. [Rule 216.F.1.k]

B. Specific Recordkeeping, Inspection, and Reporting Requirements. All records shall be retained for a minimum of five (5) years and be made available to the APCO upon request. For the purposes of this permit, records shall be considered all calibration and maintenance records, all original strip-chart or electronic recordings for continuous monitoring and instrumentation, all records specifically required to be maintained herein, and copies of all reports required to be submitted herein. [District-only, Rule 206, for "District-only" records; Rule 216.F.1 for all other records; for B-505, 40CFR60.48c.i; and for subpart UUU provisions, 40CFR63.10.b.1&1576.h]

1. Recordkeeping. ConocoPhillips shall record the following.

a. All AN-1707/1709 tail gas CMS data as follows:

1) any measurement made, except that the concentration of CS_2 may be added to the concentration of mercaptans as CH_3SH and recorded as mercaptans; [40CFR60.7.f]
2) relative accuracy tests performed in accordance with EPA Method 15; [40CFR60.7.f]
3) calibration drift test results as required by 40CFR60.PS-5; [40CFR60.7.f]
4) daily records of the calibration including the date, zero and span values, and calibration drift; [40CFR60.7.f]
5) records of all maintenance: [40CFR60.7.f and 40CFR63.10.b.2.iii]
   i. date, place, and time of maintenance activity;
   ii. operating conditions at the time of maintenance activity;
   iii. date, place, name of company or entity that performed the maintenance activity and the methods used; and
   iv. results of the maintenance;
6) all data sufficient to report excess emissions and CMS downtime as required by 40CFR60.105.e.4.ii and 40CFR60.7.c; and [40CFR60.7.f]
7) the original FQI-1721/FQI-1759 "Combined CEM Recorder" strip chart which shows tail gas H2S and TRS, combustor duty, and fuel gas sulfur content as the preferred record, with DCS data as an approved alternative to the FQI-1721/FQI-1759 chart. [District-only, Rule 206]

b. Data from the AN-603 fuel gas hydrogen sulfide CMS, and the AN-1600 A/B B-602 sulfur dioxide CMS as follows:

1) any measurement made; [40CFR60.7.f]
2) relative accuracy tests performed in accordance with EPA Method 15; [40CFR60.7.f]
3) calibration drift test results as required by 40CFR60.PS-7; [40CFR60.7.f]
4) daily records of the calibration including the date, zero and span values, and calibration drift; [40CFR60.7.f]
5) records of all maintenance: [40CFR60.7.f]
   i. date, place, and time of maintenance activity;
   ii. operating conditions at the time of maintenance activity;
   iii. date, place, name of company or entity that performed the maintenance activity and the methods used; and
   iv. results of the maintenance; and

6) all data sufficient to report excess emissions and CMS downtime as required by 40CFR60.105.e.3.ii and 40CFR60.7.c. [40CFR60.7.f]

c. Boilers B-504, B-505, B-506 and B-507 fuel usage continuously, including an hourly summary, with the Distributed Control System (DCS) and at least once per shift in an operating log.
[District-only Rule 206 for B-504, B-507 DCS records,
SIP Rule 205 and 40CFR60.48c.g for B-505 DCS records, and
SIP Rule 205 and 40CFR60.49b.c.3 for B-506 DCS records; and
District-only, Rule 206 for all unit operating logs]

d. Boilers B-504, B-505, B-506 and B507 steam production continuously, including an hourly summary, with the DCS and at least once per shift in an operating log.
[SIP Rule 205 and 40CFR60.49b.c for B-506 DCS records,
District-only Rule 206 for all other unit DCS records,
and District-only, Rule 206 for all unit operating logs]

e. The following parameters for the B-2A/B, B-62A/B, and B-102A/B heaters. The fuel gas heat content shall be based on the average results of the most recent three months of fuel gas GHV testing, except as otherwise allowed under condition III.D.8. [District-only, Rule 206]

1) Hourly heat input for each heater in terms of mmBtuh.
2) Monthly heat input for each heater in terms of mmBtu per month.
3) Hourly heat input for the B-2A, B-62A, and B-102A heaters combined, and for the B-2B, B-62B, and B-102B heaters combined, on a daily average and in terms of mmBtuh.
4) Cumulative heat input for each heater in terms of mmBtu, on a monthly basis, for the most recent 12-month rolling period.

f. The following parameters for the B-505 boiler. For the purposes of this condition, the fuel gas heat content shall be based on the results of the most recent compliance testing. [District-only, Rule 206]

1) Hourly heat input, on a daily average and in terms of mmBtuh.
2) Cumulative heat input, in terms of mmBtu, for the current calendar year.
3) During any period when steam from the B-505 boiler is being supplied to the utility plant, the start and stop time of that period and the combined steam production of the B-504, B-506, and B-507 boilers on an hourly basis in an operating log.

g. The total daily crude oil feed to the refinery in barrels and, at the end of each calendar month, the cumulative total crude oil feed for the preceding 12-month rolling period. [District-only, Rule 206]

h. The daily amount of sulfur pelletizing plant production and shipping, when operation occurs during any part of a day. That record shall also include a running balance of stockpiled sulfur. [District-only, Rule 206]

i. Gas oil loading and unloading at the gas oil loading rack. [District-only, Rule 206]

j. Calcined coke handling, storage, and loading equipment inspection dates and results. Equipment repair date and description, if applicable, shall also be included. [District-only, Rule 206]

k. Sulfur pit air sweep quarterly air flowrate results performed under condition III.B.2.f below. [District-only, Rule 206]

l. Inspection results, adjustments, and repairs made to any floating roof storage tank seal. [for Tanks 800, 801, 822, 823, 900, & 901 District-only, Rule 206 and for Tank 903, SIP Rule 205 and 40CFR60.116b.a]

m. The location, date, and corrective action taken for the following units subject to 40CFR60, subpart QQQ, Waste Water Systems: [40CFR60.697.b thru e]

1) drains, if a water seal is found dry, a drain cap or plug is found missing, or any other problem is identified that could result in VOC emissions;
2) junction boxes, if a broken seal, gap, or any other problem is identified that could result in VOC emissions;
3) sewer lines, if any problem is identified that could result in VOC emissions;
4) oil-water separators, if any problem is identified that could result in VOC emissions; and
5) closed vent systems, if a leak is measured or any problem is identified that could result in VOC emissions. In addition, the background level and the maximum level of VOC concentration shall be recorded if a leak is measured;
6) if repairs cannot be performed without process unit shutdown, the reason for delay, the expected date of repair, the signature of the person responsible for the delay, and the date of successful repair shall be recorded.

n. For the life of the refinery, ConocoPhillips shall maintain a copy of the design pecification used to comply with 40CFR60, subpart QQQ, Waste Water Systems. [40CFR60.697.f]

o. For the life of the refinery, ConocoPhillips shall maintain plans and specification as necessary to qualify for the exclusions allowed under 40CFR60, subpart QQQ, Waste Water Systems, as follows: [40CFR60.697.g thru j]

1) capped or plugged inactive drain location; and
2) stormwater sewer, ancillary equipment, and non-contact cooling water separation from the oil water drain system.

p. All records required under 40CFR60, subpart GGG. [in addition to the references cited below, the following reference(s) shall apply to each requirement: 40CFR60.592.e and, for all naphtha stream components, 40CFR63.648.a]

1) A list of all subject components categorized by type of service. [40CFR60.486.e.1]
2) A list, which has been signed by the owner or operator, of all components designated as having no detectable emissions. [40CFR60.486.e.2]
3) For each compliance test to determine no detectable emissions, the following data: [40CFR60.486.e.4]
   i. the beginning date of the test,
   ii. the measured background level, and
   iii. the maximum instrument reading.

4) A list of all valves designated as unsafe-to-monitor or difficult-to-monitor, including an explanation for that designation and a plan for monitoring each valve. [40CFR60.486.f]
5) If a leak is detected, log the following data: [40CFR60.486.c]
   i. the instrument, operator, and equipment identification numbers;
   ii. the dates of detection and each repair attempt;
   iii. the method of each repair attempt;
   iv. the phrase "above 10,000," if the maximum instrument reading after an attempt at repair is equal to or greater than 10,000 ppm; and
   v. the date of successful repair of the leak.
6) If a leak is not repaired within fifteen (15) calendar days of detection, log the following data: [40CFR60.486.c]
   i. the phrase "repair delayed," the reason for the delay, and the expected date of repair;
   ii. the printed name of the owner or operator whose decision is was that a repair must be delayed, if the reason for delay is that the repair could not be affected without a process shutdown;
   iii. the date(s) of the respective process unit's shutdown that occur while the equipment is not repaired.
7) For closed vent systems, the relief and recovery system, and the flare system: [40CFR60.486.d]
   i. detailed schematics, design specifications, and P&ID drawings;
   ii. the date(s) and description(s) of any changes in the design specifications;
   iii. the description of the parameter(s) monitored to ensure that the systems are operated and maintained in accordance with their design and an explanation of why each parameter was selected for monitoring; and
   iv. a log of:
      (a) periods when the systems are not operating as designed, including when the flare pilot flame is extinguished; and
      (b) dates of startup and shutdown of the systems.

q. All records required under 40CFR61 subpart M. For all asbestos containing material (ACM) transported away from the Santa Maria Facility, and using a form similar to that shown in figure 4 to subpart M, record the following. [40CFR61.150.d.1]

1) The name, address, and telephone number of the waste generator.
2) The District's name and address as the local agency responsible for administering the asbestos NESHAP program.
3) The approximate quantity of ACM in cubic yards.
4) The name and telephone number of the disposal site operator.
5) The name and physical location of the disposal site.
6) The date transported.
7) The name, address, and telephone number of the transported.
8) A certification the ACM are fully and accurately described; are classified, packed, marked, and labeled; and are in all respects in proper condition for transport.

r. All records required under 40CFR61 subpart FF. [in addition to the references cited below, the following reference shall apply to each requirement: 40CFR61.355.a.4.i]
   1) A record that identifies each waste stream that is subject to subpart FF. [40CFR61.356.b]
   2) For each waste stream which is subject to subpart FF, a record which includes all test results, measurements, calculations, and other documentation used to determine the following information for that waste stream: [40CFR61.356.b.1]
      i. waste stream identification,
      ii. water content,
      iii. whether of not the waste stream is a process water stream,
      iv. annual waste quantity,
      v. benzene concentration range,
      vi. annual average flow-weighted benzene concentration, and
      vii. annual benzene quantity.
   3) When the annual waste quantity for process unit turnaround waste is determined by selecting the highest annual quantity of waste managed from historical records representing the most recent five (5) years of operation, a record which includes all test results, measurements, calculations, and other documentation used to determine the following information: [40CFR61.356.b.5]
      i. identification of the process units undergoing turnaround,
      ii. most recent turnaround date for each unit,
      iii. identification of each process unit turnaround waste,
      iv. water content of the waste,
      v. annual waste quantity,
      vi. benzene concentration range of the waste,
      vii. annual average flow-weighted benzene concentration of the waste, and
      viii. annual benzene quantity.

s. The manufacturer's brand name and designation of each solvent used to thin or reduce any coating that is applied to a metal surface by either ConocoPhillips or any contractor employed by ConocoPhillips. Purchase records will be sufficient to satisfy this recordkeeping requirement. Material Data Safety Sheet information sufficient to determine the non-photochemical reactivity of those solvents shall be maintained within easy access of this record. [Rule 216.F.1.c.1]

t. The manufacturer's brand name and designation of each architectural coating used in containers of one quart capacity or larger, and the solvent used to thin or reduce those coatings, which is applied by either ConocoPhillips or any contractor employed by ConocoPhillips. Purchase records will be sufficient to satisfy this recordkeeping requirement. Material Data Safety Sheet information sufficient to determine the non-photochemical reactivity of those coatings and solvents shall be maintained within easy access of this record. [Rule 216.F.1.c.1]

u. The following information during startup, shutdown, and malfunction (SSM) periods.

1) The title of the federal standard for which the approved SSM plan is activated. [SIP Rule 205]
2) The process equipment and/or air pollution control equipment involved. [SIP Rule 205]
3) The occurrence and duration of each SSM of that operation; in other words, the process equipment. [40CFR63.10.b.2.i]
4) The occurrence and duration of each malfunction of the required air pollution control and monitoring equipment. [40CFR63.10.b.2.ii]
5) Actions taken during periods of SSM, including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation, when such actions are different from the procedures specified in the affected emission unit's SSMP. [40CFR63.10.b.2.iv]
6) All information necessary to demonstrate conformance with the affected emission unit's SSMP when all actions taken during periods of SSM, including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation, are consistent with the procedures specified in such plan. [40CFR63.10.b.2.v]
7) When actions taken by ConocoPhillips during a SSM, including actions taken to correct a malfunction, are consistent with the procedures specified in the affected emission unit's SSMP, ConocoPhillips must keep records for that event which demonstrate that the procedures specified in the plan were followed. [40CFR63.6.e.3.iii]
8) ConocoPhillips must keep records as specified in 40CFR63.10(b), including records of the occurrence and duration of each startup, shutdown, or malfunction of operation and each malfunction of the air pollution control and monitoring equipment. [40CFR63.6.e.3.iii]

v. Maintain a list of stationary diesel engines rated at ≤50 hp that began initial operation after January 1, 2005, and the emission limits with which they comply from the Off-Road Compression-Ignition Engine Standards found in 13CCR2423. [District-only, Rule 206]

w. The following records shall be maintained on a monthly basis for any engine having undergone retrofit or replacement under condition III.C.11.a. [District-only, Rule 431.G.1]

1) date and results of each engine inspection,
2) a summary of any preventive or corrective maintenance taken,
3) the total hours of operation,
4) the type and quantity of fuel used, and
5) any additional information required in the Engine Operator Inspection Plan.

x. Non-mobile diesel engine systems rated at ≥50 hp [District-only, Rule 206, and 17CCR93115.e.4.I.1 for emergency standby engines]

1) ConocoPhillips shall retain a copy of the purchase invoice for each delivery of fuel to the tanks supplying stationary diesel engines rated at >50 hp. Each invoice must indicate: [District-only, 17CCR93115.e.4.I.1.g]
   i. whether or not the fuel qualifies as CARB diesel fuel,
   ii. amount of fuel purchased,
   iii. date when the fuel was purchased,
   iv. signature of the person who received the fuel, and
   v. signature of fuel provider indicating that the fuel was delivered.

2) ConocoPhillips shall maintain a daily operational log of the following information for diesel engine systems.
   i. Operating mode: emergency, maintenance, District required testing, or, prime mover
   ii. Engine run-time hour meter reading at initial start-up for the day,
   iii. Engine run-time hour meter reading at final shutdown for the day,
   iv. Total operating hours for the calendar day based on run-hour meter readings,
   v. Running total calendar year to date operating hours,
   vi. Running total calendar year to date operating hours in maintenance mode,
   vii. Running total calendar year to date operating hours in emergency mode,
   viii. Any significant maintenance performed that might affect the engine's emissions,
   ix. For the following engine systems, running total calendar year to date operating hours in prime mover mode,
      (a) GB-1015, portable air compressor,
      (b) G-51-4, cooling tower pump,
      (c) GB-524S, plant air compressor, and
      (d) GE-522, coke pile water pump,

y. For the GE-522, coke pile water pump, GB-1015, portable air compressor, and BK-699, runoff pond backup pump,

1) list of operating locations,

2) plot map showing those locations, and
3) the beginning and ending dates of operation at those locations,
   i. For the GB-1015, portable air compressor, those back-pressure monitor indications that show adequate diesel particulate filter operation,
   ii. Estimated fuel use for the day in gallons,
   iii. Running total calendar year to date fuel use in gallons, and
   iv. Fuel supplied in gallons.

z. Emergency Water Pump Engines, G-515-3 and G-515-4. An operating and inspection log for the G-515 engines shall be maintained on a monthly basis and on any day the engines are operated that includes the following data: [District-only, Rule 206]

1) date and results of each engine inspection, if newly performed since last entry,
2) a summary of any preventive or corrective maintenance taken,
3) the total minutes of operation for each engine and whether the operation was for maintenance or emergency,
4) the quantity of fuel used, and
5) any additional information required in the Engine Operator Inspection Plan.

aa. Process Unit Q, Green Coke Storage, 225 hp John Deere Portable Water Pump. [District-only, Rule 206]

1) An inspection log shall be maintained that includes the following data:
   i. date and results of each engine inspection,
   ii. results of any check of the backpressure monitoring system used to ensure proper diesel particulate filter operation, and
   iii. a summary of any preventative or corrective maintenance taken during and since the last inspection.

ab. Refinery MACT II, 40CFR63, subpart UUU. ConocoPhillips shall maintain the following records in a form suitable and readily available for expeditious review. [40CFR63.1576.a&g and 63.10.b.1]

1) A copy of each notification and report submitted to comply with this subpart, including all documentation supporting any initial notification or Notification of Compliance Status submitted. [40CFR63.10.b.2.xiv and 63.1576.a.1].

2) Records of performance tests, performance evaluations, and opacity and visible emission observations. [40CFR63.10.b.2.viii and 63.1576.a.3]

3) The following information for the AN-1707/1709 continuous emission monitoring system. This is separate requirement from condition III.B.1.a. [40CFR63.8.d,10.b,&10.c and 1576.b]
   i. Records described in 40CFR63.10.b.2.vi through xi.

ii. Records described in 40CFR63.10.c.1 through 6 and 9 through 14.
iii. Previous versions of the performance evaluation plan as required in 40CFR63.8(d)(3).
iv. Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period.

4) The following information to ensure continuous compliance. [40CFR63.1576.d]
   i. Hourly average TRS monitoring data in accordance with 40CF63.1572.a for the AN-1707/1709. This is separate requirement from condition III.B.1.a. [40CFR63, subpart UUU, table 34, item 3]
   ii. The date, time, and duration of any bypass from either Sulfur Recover Plant to their respective B-602 incinerator. [40CFR63.1569.c.1 and subpart UUU, table 39, item 5]
   iii. The date, time, and duration of any bypass from either H_2S Absorption Plant to the Hydrocarbon Relief and Recover System through their respective PCV-657 valve. [40CFR63.1569.c.1 and subpart UUU, table 39, item 5]
   iv. Whether or not any bypass was the result of a startup, shutdown, or malfunction and the process unit involved. [SIP Rule 205]
   v. At least as frequently as on an hourly basis, whether the PCV-657A/B valve position indicators are operating properly and whether flow is present in the line. [40CFR63.1569.c.1 and subpart UUU, table 39, item 1]
   vi. At least as frequently as on a monthly basis, whether the Sulfur Recovery Plant to B-602 incinerator bypass line valves are locked in the closed position and whether flow is present in the line. [40CFR63.1569.c.1 and subpart UUU, table 39, item 2]

5) A copy of the current operation, maintenance, and monitoring plan and records to show continuous compliance with the procedures in that plan. [40CFR63.1576.e]

6) A record of any changes that affect emission control requirements. [40CFR63.1576.f]

ac. An inspection log shall be maintained for the 115 hp John Deere portable air compressor, GB-1015, that includes the following data: [District-only, Rule 206]

1) date and results of each engine inspection,
2) results of any check of the backpressure monitoring system used to ensure proper diesel particulate filter operation, and
3) a summary of any preventative or corrective maintenance taken during and since the last inspection.

2. **Inspections, calibrations, and sampling.** ConocoPhillips shall inspect, calibrate, or sample, the following processes as indicated. The results shall be recorded in an operational log or as specified. [SIP Rule 205 and, for "District-only" inspections, District-only, Rule 206]

   a. On an hourly basis, determine that the position indicator systems for the Sulfur Recovery Unit bypass line blocking valves, PCV-657A/B, are operating properly and that there is no flow in the respective bypass line. [40CFR63.1569.c.1 and subpart UUU, table 39, item 1]

   b. On a **Per Shift** Basis

Process	Desc/ID	Parameter
B-2-j	TK-405 & 406	1) Visually inspect for floating oil. Record the date, time, staff initials, and surface area appearance in oil percentage, and tank activity at the time of observation. [District-only, Rule 206] i. ConocoPhillips shall take immediate action to reposition the installed oil skimmer to maximize oil collection for either tank in which greater than fifty percent (50%) of oil coverage is observed. Following such an observation, the oil coverage shall be monitored at least every half-hour, and the installed oil skimmer repositioned as necessary, until the observed oil coverage is less than fifty percent (50%). ii. The final observation during a greater than 50% oil coverage episode shall be logged and the length of that episode noted.
A-1,A-2, B-1,B-2, B-3,C, D-1,E-1, E-2,G,H, I,J,K,L,	O,P, fugitive emissions program	2) On a continual basis and by using visual, audible, or olfactory means, monitor all pumps and valves in heavy liquid service, pressure relief valves in light liquid or heavy liquid service, and flanges and other connectors for leaks. Within five (5) calendar days of detecting evidence of a leak, the suspected component shall be monitored with an instrument. [40CFR60.482-1 through 482-10] i. A leak is defined as an instrument reading of 10,000 ppm or greater. ii. A leaking component shall be affixed with a weatherproof tag that displays the respective equipment's identification number. This tag may be removed upon repair, except for valves that must be monitored for two (2) successive months following repair and found to not leak before their tag may be removed. [40CFR60.486.b] iii. Any leak shall be repaired as soon as practicable, with the first repair attempt occurring within five (5) calendar days and the final repair not later than fifteen (15) calendar days after detection, except as allowed under condition III.B.3.i.
A-1,A-2, B-1,B-2, B-3,C, D-1,E-1, E-2,G,H, I,J,K,L, O,P,	fugitive emissions program	3) On a continual basis and by using visual, audible, or olfactory means, monitor all pressure relief devices that relieve to the atmosphere in VOC gas/vapor service for leaks. As soon as practicable after detecting evidence of a leak, the suspected component shall be monitored with an instrument according to EPA Method 21. [District-only, Rule 206] i. A leak is defined as an instrument reading of 500 ppm or greater (intentional duplication of condition III.C.1.d.1). ii. A leaking component shall be affixed with a weatherproof tag that displays the respective equipment's identification number. This tag may be removed following repair and found to not leak. iii. Any leak shall be repaired as soon as practicable.

c. On A **Daily** Basis

	Process	Description	Parameter
1)	B-1-h	cooling tower	Visually inspect for floating oil. [District-only, Rule 206]
2)	J	AN-603	Analyzer calibration. [40CFR60.13.d.1]
3)	K	AN-1707/1709	Analyzer calibration. [40CFR60.13.d.1]

d. On A **Weekly** Basis

	Process	Description	Parameter
1)	B-1-h	cooling tower	Sample for floating oil using current EPA method for determining oil and grease in water. [District-only, Rule 206]
2)	I,J	fuel gas	Fuel gas shall be sampled for hydrogen sulfide by using the drager tube method and total sulfur content using the Tutweiler test method. [Rule 216.F.1.c.1 and SIP Rule 404.E.1 for total sulfur]
3)	I,J	sulfinol	The concentration of Sulfolane W in the D601A and D601B H_2S absorbers shall be sampled using a method subject to the approval of the APCO and recorded. [District-only, Rule 204]
4)	A-1,A-2,B-1, B-2,B-3, C, D-1,E-1,E-2, G,H,I,J,K,L,O, P,	fugitive emissions program	Inspect each pump in light liquid service for leaks, except those designated as having no detectable emissions. A "leak" is defined as liquid dripping from the pump seal. See condition III.B.2.b.2 above for tagging and repair requirements. [40CFR60.482-2.a.2, 40CFR60.482-2.d.4, and, for all naphtha stream components, 40CFR63.648.a]

e. On A **Monthly** Basis (a)

	Process	Description	Parameter
1)	A-2,E-1,E-2, G,I,J,L,O,P	active drains, drain hubs, and catch basins	Inspect each drain, drain hub, and catch basin for indications of low water level, or other condition that would reduce the effectiveness of the water seal control. [40CFR60.692-2.a.2] i. Water shall be added if low water level is found. ii. All other abnormal conditions shall be repaired as soon as practicable, but not later than twenty-four (24) hours after detection, except as allowed under condition III.B.3.i.
2)	S-1,S-2,S-3	calcined coke handling, storage, and loading	Inspect all equipment to verify proper operation. All deficiencies shall be repaired within forty-eight (48) hours. [District-only, Rule 206]
3)	A-1,A-2,B-1, B-2,B-3,C, D-1,E-1,E-2, G,H,I,J,K,L,O, P	fugitive emissions program	Monitor each pump in light liquid service for leaks, except for those with dual mechanical seals or those designated as having no detectable emissions. See condition III.B.2.b.2 above for tagging and repair requirements and the definition of "leak." [40CFR60.482-2.a.1 and, for all naphtha stream components, 40CFR63.648.a]
4)	E-1	Tail Gas Unit bypass valves	Confirm that the Tail Gas Unit bypass valves to the B-602A/B incinerators are locked closed by a car-seal device and that there is no flow in the respective bypass line. [40CFR63.1569.c.1 and subpart UUU, table 39, item 2]
5)	A-1	TK-900, 901, & 903	Inspect all openings and fittings for closure and the secondary seal for integrity and gaps. [40CFR60.113b.b.1.ii and Rule 425.I.1 for Tank 903 and District-only, Rule 425.I.1 for Tanks 900 & 901]

Note (a) See condition III.D.8.a for monthly fuel gas sampling requirements.

f. On A **Quarterly** Basis

Process		Description	Parameter
1)	E-1, E-2	sulfur pits	Inspect the air intake sweeps for both the A and B side sulfur pits for proper operation of the pit vent system and quantitatively measure the air flowrate through each sweep. [District-only, Rule 206]
2)	B-1, M	diesel engines	Inspect subject units in accordance with the Engine Operator Inspection Plan approved under condition III.A.4.e. [District-only, Rule 431.E.4]
3)	D-1	G-515-3 G-515-4	Inspect subject units in accordance with the Engine Operator Inspection Plan submitted on March 18, 2002, under application number 3111. [District-only, Rule 206]
4)	M	GB-1015	Inspect the subject unit in accordance with the Engine Operator Inspection Plan submitted on May 1, 2006, under application number 3875. [District-only, Rule 206]

g. On A **Semi-annual** Basis

Process	Description	Parameter
A-2,E-1, E-2,G,I, J,L,O,P	inactive drains	1) Inspect each plugged or capped drain to ensure that the plug or cap is in place and properly installed. Any abnormal condition shall be repaired as soon as practicable, but not later than twenty-four (24) hours after detection, except as allowed under condition III.B.3.i. [40CFR60.692-2.a.4]
	junction boxes and manholes	2) Inspect each junction box and manhole to ensure the cover is in place and that the edge is tightly sealed. Any abnormal condition shall be repaired as soon as practicable, but not later than fifteen (15) calendar days after detection, except as allowed under condition III.B.3.i. [40CFR60.692-2.b.3]
	F-821A,B,& C,F-824, F-408&9	3) Inspect each oil-water separator, oily solids tank, and the slop oil tank to ensure there are no cracks or gaps in any seal and that all access doors and other openings are closed and gasketed properly. Any abnormal condition shall be repaired as soon as practicable, but not later than fifteen (15) calendar days after detection, except as allowed under condition III.B.3.i. [40CFR60.692-3.a.4]
	closed vent systems	4) Inspect each closed vent system for leaks. A "leak" shall be defined as an instrument reading of 500 ppm as methane. Any leak shall be repaired as soon as practicable, but not later than thirty (30) calendar days after detection, except as allowed under condition III.B.3.i. [40CFR60.692-5.e.1]
	unburied sewer lines	5) Inspect each unburied sewer line for cracks, gaps, or other problems. Any abnormal condition shall be repaired as soon as practicable, but not later than fifteen (15) calendar days after detection, except as allowed under condition III.B.3.i. [40CFR60.692-2.c.2]
G	TK-822,823	6) Inspect all access doors and other openings to ensure that there is a tight fit around the edges and to identify other problems that could result in VOC emissions. [District-only, Rule 206]

h. On An **Annual** Basis

	Process	Description	Parameter
1)	A-1	TK-900, 901,903	Inspect the primary seal at four (4) locations to be selected by the APCO. [District-only Rule 425.G.6 for Tanks 900 & 901, federally-enforceable 40CFR60.113b.b.1.i and Rule 425.G.6 for Tank 903]
2)	G	TK-822,823	Inspect the secondary seal. [District-only, Rule 206]
3)	A-1,A-2,B-1, B-2, B-3,C, D-1,E-1,E-2, G,H,I,J,K,L, O,P,	fugitive emissions program	Within one week's time, monitor all valves in gas/vapor or light liquid service for leaks. See condition III.B.2.b.2 above for tagging and repair requirements and the definition of "leak." [40CFR60.483-1.b.2, 40CFR60.483-1.c.1 and, for all naphtha stream components, 40CFR63.648.a]
4)			Monitor each component for leaks that has been designated as having no detectable emissions as follows. "No detectable emissions" is defined as an instrument reading of less than 500 ppm above background. See conditions III.B.2.b.2&3 above for tagging and repair requirements and the definition of "leak": [for all naphtha stream components, 40CFR63.648.a] i. pumps in light liquid service [40CFR60.482-2.e.3] ii. compressors [40CFR60.482-3.i.2] iii. closed vent systems [40CFR60.482-10.f.2] iv. pressure relief devices in gas/vapor service [District-only Rule 206].

i. On an **annual** basis, calibrate the following recording or indicating devices. Upon successful calibration, a notation shall be made on the cover glass of each device, or other such readily visible location, that includes the date of calibration and the individual's initials that performed the calibration. [40CFR64.3.b.2 for process R-2 and District-only Rule 206 for all others]

	Process	Description	Parameter
1)	D-1	B-504, 506, 507	i. Individual boiler inlet fuel flow instruments [40CFR60.49b.c for B-506 and District-only, Rule 206 for B504]
			ii. Individual boiler steam production instruments [40CFR60.49b.c for B-506 and District-only, Rule 206 for B504]

j. At Least Once **Every Five Years**

Process	Description	Parameter
A-1	TK-800,801	Inspect the primary seal for gaps and physical condition. [District-only Rule 425.I.1]
G	TK-822,823	

k. At Least Once **Every Ten Years**

Process	Description	Parameter
A-1	TK-900,901,903	Inspect the primary seal for gaps and physical condition. [Rule 425.I.1 for Tank 903 and District-only, Rule 425.I.1 for Tanks 900 & 901]

3. Unusual Operating Conditions, Actions, and Reporting.

a. AN-603 Fuel Gas Analyzer Operation

1) Any instantaneous exceedance of 160 ppmv H_2S in the fuel gas shall be reported immediately to the District, and strip charts for periods of exceedance included in the monthly report, under condition III.B.4.a. [District-only, Rule 206]

2) Any exceedance of 160 ppmv H_2S, averaged over three (3) hours, shall be included with the monthly report under condition III.B.4.a and shall include: the magnitude of emissions due to excess H_2S, conversion factors used, and date and time of commencement and completion of each time period of excess emissions. [40CFR60.105.e.3.ii]

3) Specific identification of any exceedance of 160 ppmv H_2S, averaged over three (3) hours, that occurs during start-up, shutdown, or malfunction of the gas sweetening systems shall be included with the monthly report under condition III.B.4.a and shall include the nature and cause of any malfunction and corrective action taken. [District-only, Rule 206]

4) The date and time identifying each period during which the CMS was inoperative, other than for daily calibration, and the nature of system repairs and adjustments shall be logged and reported to the APCO in accordance with the provisions of District Rules 107 and 113. A summary report of this information shall be included with the quarterly report as required in condition III.B.4.b. [40CFR60.7.b&c]

b. Failure of either the AA-601 or the AB-601 air demand analyzers, or their associated AI-601 A/B indicator instruments, shall be reported to the APCO as soon as reasonably possible but in any case within one (1) hour after the start of the next regular business day. A written report of analyzer failure shall be filed within ten (10) working days that includes the reason for failure, the corrective action taken, and the affect on plant operations. [District-only, Rule 206]

c. AN-1707/1709 Tail Gas Analyzer Operation

1) The date and time identifying each period during which the CMS was inoperative, other than for daily calibration, and the nature of system repairs and adjustments shall be logged and reported to the APCO in accordance with the provisions of District Rules 107 and 113. A summary report of this information shall be included with the quarterly report as required in condition III.B.4.b. [40CFR60.7.b&c]

2) Any exceedance of 300 ppmv TRS, averaged over twelve (12) hours, shall be included with the monthly report under condition III.B.4.a and shall include: the magnitude of emissions due to excess TRS, conversion factors used, and date and time of commencement and completion of each time period of excess emissions. [40CFR60.105.e.4.ii]

d. AN-1600 B-602 Incinerator SO2 Analyzer:

1) The date and time identifying each period during which the CMS was inoperative, other than for daily calibration, and the nature of system repairs and adjustments shall be logged and reported to the APCO in accordance with the provisions of District Rules 107 and 113. A summary report of this information shall be included with the quarterly report as required in condition III.B.4.b. [40CFR60.7.b&c]

2) Any exceedance of 250 ppmv SO2, averaged over twelve (12) hours, shall be included with the monthly report under condition III.B.4.a and shall include: the magnitude of emissions due to excess SO2, and the date and time of commencement and completion of each time period of excess emissions. [40CFR60.105.e.4.iii]

e. Flaring

1) Flaring as a result of either G-212 compressor being inoperative or flaring in excess of sixty (60) minutes cumulative in any given day, for whatever reason, shall be considered an upset under District Rule 107 and may be a violation of this condition unless relief is granted in accordance with the provisions of that rule. The written report shall include, in addition to those items required by Rule 107, the volume and heat content of the flared gas. [District-only, Rule 206]

2) All incidences of flaring less than sixty (60) minutes cumulative in any given day shall be logged and reported to the APCO in accordance with the provisions of District Rule 107 and shall also include the information required in condition III.B.3.d.1 above. These incidences of flaring are not considered a breakdown or upset condition. [District-only, Rule 206]

3) Flaring during maintenance, testing of the flare system, or turnarounds shall be logged. These incidents of flaring are not considered a breakdown or upset condition. [District-only, Rule 206]

f. Tail Gas Unit Desalting Plant. Any failure of the tail gas unit regenerative crystallizer system that causes the release of an air contaminant shall be considered an upset under District Rule 107 and shall be a violation of this Condition unless breakdown relief is granted in accordance with the provisions of that rule. [District-only, Rule 206]

g. Any deviation from any requirement in this permit, excluding those reported under District Rule 107, <u>Breakdown and Upset Conditions</u> as required by condition III.A.3, shall be reported to the APCO as follows: [Rule 216.F.1.o]

1) As soon as reasonably possible, but in any case within four (4) hours, after its detection.
2) As soon as the occurrence has been corrected, but no later than ten (10) calendar days after the event, through a written report which includes the

probable cause of the deviation and the corrective actions or preventative measures taken.

h. At least ten (10) working days before asbestos stripping or removal work, the APCO shall be notified as required by section 61.145.b.3.i of 40CFR61 subpart M, National Emission Standard for Asbestos. [40CFR61.145.b.3.i]

i. The repair of any component subject to 40CFR60 subparts QQQ or GGG may be postponed until the next refinery or respective process unit shutdown if that repair is technically impossible without complete or partial refinery or process unit shutdown. Additional delay of repair provisions for subpart GGG components appear in 40CFR60.482-9. [40CFR60.692-6 and 482-9]

j. Emergency use of the carbon plant runoff collection pond pump, BK-699, that exceeds 48 hours in any calendar month shall be reported to the APCO as soon as reasonably possible, but in any case within four (4) hours. [District-only, Rule 206]

1) The initial notification shall include the nature of the emergency and whether or not the electrically-driven collection pond pump is also in use. If the electric pump is not in use, the initial report shall include the reason and the estimated time period before it can be put into use.

2) As soon as the emergency use is no longer occurring, but no later than ten (10) calendar days after the initial notification, ConocoPhillips shall submit a written report which includes the nature of the emergency, the status of the electric pump during the emergency, and, if the electric pump was not in use during all or part of the emergency, those steps to be taken to ensure that the electric pump is available during future emergencies.

4. **Reporting.** Each report, due on the date indicated in the following table, should include data for the respective time periods in any given year unless otherwise indicated. [SIP Rule 205]

Due Date	Monthly Data	Quarterly Data	Semi-annual Data	Annual Data
January 31	December	October 1 through December 31	July 1 through December 31	
March 1				January 1 through December 31
April 30	March	January 1 through March 31		
July 31	June	April 1 through June 30	January 1 through June 30	
October 31	September	July 1 through September 30		

a. On a calendar **monthly** basis, ConocoPhillips shall submit a report to the APCO. That report shall be submitted no later than ten (10) business days after the end of the month and shall include the following for the respective calendar month. [SIP Rule 205]

1) Daily steam records kept under condition III.B.1.d. [District-only, Rule 206]
2) Results of hydrogen sulfide and total sulfur samples drawn on the fuel gas under condition III.B.2.d.2. [Rule 216.F.1.c.1]
3) Daily average AN-1707/1709 tail gas monitoring results, including the daily average TRS concentration as SO_2. [40CFR60.7.c]
4) Copies of records, including strip charts as identified under condition III.B.3.a.1 above, and an explanation for any unusual event that either affects the normal operation of the B-702 tail gas combustor or causes the fuel gas sulfur content to exceed an instantaneous value of 160 ppm H_2S. [District-only, Rule 206]
5) The daily average SO2 concentration results from the AN-1600 A/B monitors, and an explanation for any unusual event that either affects the normal operation of the B-602 incinerators or causes the SO2 concentration to exceed 250 ppmv. [40CFR60.7.c]
6) A summary of flaring that occurs as a result of maintenance, testing of the flare system, or turnarounds. [District-only, Rule 206]
7) If the gas oil loading rack is used to load or unload material: [District-only, Rule 206]
   i. the maximum daily loading rate in barrels per day,
   ii. the maximum pumping rate in gallons per minute, and
   iii. the maximum RVP of material received.

8) A list of all floating roof storage tanks which were emptied and degassed and/or whose roof was landed on its support legs. The reason for that activity for each tank and results of all inspections required by this permit

shall also be included. [SIP Rule 205 for Tank 903 and District-only, Rule 206 for all other tanks]

9) The amount of open coke storage determined under Condition III.E.14.e. [District-only Rule 440]

10) The results of the fuel gas GHV analysis for the given month, and the average value to be used to determine compliance. If a fuel gas GHV was not determined for the given month, an explanation shall be included. [District-only, Rule 206]

b. On a **quarterly** basis, ConocoPhillips shall submit a report to the APCO, with a copy to the EPA Region IX Administrator. Each report shall be submitted no later than January 31, April 30, July 31, and October 31 of any given year, shall be certified to be true, accurate, and complete by a responsible official, and shall include the following data. [SIP Rule 205]

1) Summary information of the hydrogen sulfide concentration in the refinery fuel gas based on records maintained under condition III.B.1.b.1. [40CFR60.7.c]
2) Average sulfur content of the fuel gas supplied to the B-505 boiler. [District-only, Rule 206]
3) Those dates, if applicable, in the preceding quarter when the daily oxides of sulfur emissions from the B-505 boiler exceeded 100 lbs. [District-only, Rule 206]
4) Report excess emissions as indicated by, or CMS downtime of, AN-603, Fuel Gas CMS, AN-1707/1709, Tail Gas CMS, and AN-1600 A/B B-602 CMS using the summary report form that appears in 40CFR60.7, Figure One (1). If the total duration of excess emissions is less than one percent (1%) and the CMS downtime is less than five percent (5%) of the total operating time, only the summary report form, with a statement that no excess emissions and/or no CMS downtime occurred, need be submitted. If the excess emissions or CMS downtime exceeds either of those times, the summary report shall be accompanied by a report that includes: [40CFR60.7.c and SIP Rule 205]
   i. The magnitude of excess emissions, conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.
   ii. The process operating time during the reporting period.
   iii. Whether the excess emissions occurred during start-up, shutdown, or malfunction.
   iv. The nature and cause of any malfunction, the corrective action taken, or preventive measures adopted.
   v. The date and time of CMS downtime, except for zero and span checks, and the nature of system repairs or adjustments.

c. On a **semi-annual** basis, ConocoPhillips shall submit a report to the APCO, with a copy to the EPA Region IX Administrator. Each report shall be submitted no later than January 31 and July 31 of any given year, shall be certified to be true, accurate, and complete by a responsible official, and shall include the following. [Rule 216.F.1.c.3]

1) Certification that all of the required inspections have been carried out in accordance with 40CFR60, subpart QQQ. That report shall also summarize all inspections when a water seal was dry or otherwise breached; when a drain cap or plug was missing or improperly installed; or cracks, gaps, or other problems were identified that could result in VOC emissions. [40CFR60.698.b.1 & c]
2) A fugitive emission program summary in accordance with 40CFR60, subparts GGG and VV, which contains the following. [40CFR60.487.c and, for all naphtha stream components, 40CFR63.648.a]
    i. A list of leaking components by month including those whose repaired was delayed and justification for that delay.
    ii. Process unit shutdown dates.
    iii. Revisions to the component count list.
    iv. A calculation of the percentage of valves in gas/vapor and light liquid service, which have been found to leak, in accordance with 40CFR60.483-1.c.3. [SIP Rule 205]
3) A summary of deviations from requirements in this permit. [Rule 216.F.1.c.3.i]
4) If ConocoPhillips is not in compliance with any federally-enforceable requirement, include a progress report on the schedule of compliance that has been approved by the District Hearing Board. That report shall include: [Rule 216.F.2.c]
    i. dates for achieving the activities, milestones, or compliance required in the schedule of compliance, and dates when such activities, milestones or compliance were achieved; and
    ii. an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.
5) For each of the preceding six months, the 12-month rolling period totals for:
    i. individual fuel heat input in mmBtu for the B-2A, B-2B, B-62A, B-62B, B-102A, B-102B heaters; and [SIP Rule 205]
6) The maximum hourly heat input rate, in terms of a single mmBtuh-value each, for the B-2A, B-2B, B-62A, B-62B, B-102A, and B-102B heaters. [District-only, Rule 206]
7) The maximum hourly heat input rate, on a daily average and in terms of mmBtuh, for the B-2A, B-62A, and B-102A heaters combined and for the B-2B, B-62B, and B-102B heaters combined. [District-only, Rule 206]
8) For the B-505 boiler: [District-only, Rule 206]
    i. the maximum hourly heat input rate on a daily average and in terms of a single mmBtuh-value;
    ii. for the July 31 report, the cumulative subtotal heat input for the first six months of the current calendar year, in terms of mmBtu;
    iii. for the January 31 report, the cumulative total heat input for the preceding calendar year, in terms of mmBtu/yr; and

iv. for any period when steam is supplied to the utility plant, the start and stop time of that period and the maximum combined steam production of the B-504 boiler, the B-506 boiler and the B-507 boiler during that period.

9) The maximum daily crude oil feed to the refinery in barrels and, for each of the preceding six (6) months, the 12-month rolling period totals for crude oil feed. [District-only, Rule 206]

10) Startup, shutdown, and Malfunction Report. [40CFR63.10.d.5.i for subpart CC and SIP Rule 205 for subpart UUU, except as noted]

i. If an approved SSM plan is activated and that plan was correctly implemented, include a statement to that effect.

ii. If an approved SSM plan is activated for a malfunction and correctly implemented, but an applicable emission limitation is exceeded, include the number, duration, and a brief description for each type of malfunction.

iii. If an approved SSM plan is activated and the action taken is not consistent with that plan, but no applicable emission standard is exceeded, include a statement to that effect and the response taken. [40CFR63.1575.h.2 for subpart UUU]

11) Information in accordance with 40CFR63.1575.c and subpart UUU, table 43, item 1. [40CFR63.1575.a,b,&c]

i. If there were no deviations from any emission limitation or work practice standard, include a statement that there were no deviations from the emission limitations or work practice standards during the reporting period and that no continuous emission monitoring system was inoperative, inactive, malfunctioning, out-of-control, repaired, or adjusted. [40CFR63.1575.c.4]

ii. Deviations from emission limitations and work practice standards shall be reported in accordance with 40CFR63.1575.d&e. For the AN-1707/1709, this is a separate requirement from condition III.B.4.b.6. [40CFR63.1570.f and 63.1575.d&e.]

iii. Include a copy of any performance test done during the reporting period on any affected unit. [40CFR63.1575.f.1]

d. On an **annual** basis, no later than March 1 of each year, ConocoPhillips shall submit the following.

1) A Compliance Certification Report to the APCO pursuant to District Rule 216.L.3. This report shall identify each federal applicable requirement in this permit, the compliance status of each subject process unit, whether the compliance was continuous or intermittent since the last certification, and the method(s) used to determine compliance. In addition, ConocoPhillips shall certify that the refinery is in compliance with 40CFR68, Chemical Accident Prevention Provisions. Each report shall be certified to be true, accurate, and complete by a responsible official and a copy of this portion of the annual report shall also be submitted to the EPA Region IX Administrator. [Rule 216.L.3 and 40CFR68.215.a]

2) Total Annual Benzene Quantity (TAB-Q) as required by 40CFR61.357.c. A copy of this portion of the annual report shall also be submitted to the EPA Region IX Administrator. [40CFR61.357.c]

3) Summaries of automatic and manual calibration data and internal audits of the AN-1707/1709 tail gas plant monitor. [SIP Rule 205]

4) The location and current use of the calcined coke portable handling equipment, Process S-3. A plot plan of the facility, with equipment locations indicated, shall be included. [District-only, Rule 206]

5) For any diesel engine having undergone retrofit or replacement under condition III.C.11.a, the actual annual fuel usage and operating hours for the respective engine. The report shall also include the engine manufacturer, model number, facility-defined equipment identification number, and a summary of the maintenance record maintained under condition III.B.1.ae above. [District-only, Rule 431.H]

6) The following information for the preceding calendar year. [District-only, Rule 206]

	UNIT	INFORMATION
i.	GB-1015, portable air compressor G-51-4, cooling tower pump GB-524S, plant air compressor GE-522, coke pile water pump BK-699, runoff pond backup pump G-515-3, emergency water pump G-515-4, emergency water pump NE-4108, carbon plant control room generator NE-503, coker control room generator NE-504, administration generator NE-800, wet plant generator ROU, utility plant generator	(a) maintenance operating hours (b) emergency operating hours (c) District required testing operating hours (d) total engine operating hours (e) total fuel usage (f) copies of all fuel purchase records
ii.	GB-1015, portable air compressor G-51-4, cooling tower pump GB-524S, plant air compressor GE-522, portable water pump	prime use operating hours
iii.	GE-522, coke pile water pump BK-699, runoff pond backup pump GB-1015, portable air compressor	(a) list of operating locations (b) plot map showing those locations (c) the beginning and ending dates of operation at those locations
iv.	<50hp diesel engines that have undergone initial operation after January 1, 2005	the emission limits with which each engine complies from the Off-Road Compression-Ignition Engine Standards found in 13CCR2423

e. On an **annual** basis at least ten (10) working days before the end of the calendar year, the APCO shall be notified of the predicted asbestos renovations for the following year, if the total amount of RACM is estimated to be in excess of those amounts identified in condition III.A.1.s.2. [40CFR61.145.b.3.ii]

f. For Tanks 800, 801, 822, 823, 900, 901, and 903, a report of any excessive seal gap repair action shall be made to the APCO within thirty (30) calendar days of the repair. That report shall include the date of discovery and either: the date of repair; or, in the case of a delayed repair, the date of anticipated repair and reason for delay. That report shall also include the results of a post-repair inspection for compliance. [SIP Rule 205 for Tank 903 and District-only, Rule 206, for all others]

g. For Tanks 900, 901, and 903, a report of any seal gap inspection performed under conditions III.B.2.h.1.ii & iii and III.B.2.k shall be made to the APCO within thirty (30) calendar days of the inspection. That report shall include the tank inspected, the date of the inspection, the tank and seal inspected, and a summary of the inspection results. [Rule 425.I.2 for Tank 903 and, District-only, Rule 425.I.2 for Tanks 900 & 901]

h. For Tanks 100, 101, 550, 551, 800, 801, 822, 823, 900, 901, and 903, the tank cleaning plan required under III.C.5.a.4.ii shall be submitted to the APCO for his approval no less than fifteen (15) calendar days prior to the initiation of cleaning. [District-only, Rule 206]

i. If an approved SSM plan is activated, the action taken is not consistent with that plan, and an applicable emission standard is exceeded or a work practice standard is not met, ConocoPhillips shall report the action taken within two (2) working days after commencing such action, followed by a letter no later than seven (7) working days after the event. That report shall include the following information. [SIP Rule 205]

1) name, title, and signature of the responsible official who is certifying to the report's accuracy,
2) the circumstances of the event,
3) the reasons for not following the SSM plan, and
4) a description of any excess emissions and/or parameter monitoring exceedances that are believed to have occurred.

C. Conditions Common To More Than One Process Unit

1. Inspection and Maintenance Program for Fugitive VOC Emissions

Subject Process	Condition
A-1,A-2,B-1, B-2,B-3,C, D-1,D-2,E-1, E-2,G,H,I,J, K,L,O,P,	a. Each subject process shall be inspected and maintained on a schedule that satisfies the provisions of 40CFR60, subpart GGG, <u>Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries</u>. Conditions III.B.2 and III.B.4 to this permit shall respectively govern the timing of periodic inspections and reporting. [40CFR60-GGG and, for all naphtha stream components, 40CFR63.648.a]
	b. A leak, as referenced in subpart GGG, detected by the APCO or his designee shall constitute a violation of this condition with the exception of those components previously identified by ConocoPhillips that are awaiting repair. [District-only, Rule 206]
	c. The percentage of valves in gas/vapor and light liquid service that leak shall not exceed two percent (2.0%). [40CFR60.483-1.d]
	d. All pressure-vacuum relief valves shall be maintained in a leak-free condition except when the operating pressure exceeds the valve pressure setting or during testing. [40CFR60.482-4] 1) Leak-free is defined as an instrument reading of less than 500 ppm above background. 2) After the lifting of any pressure-vacuum relief valve, that valve shall be returned to leak-free condition as soon as practicable, but not later than five (5) calendar days after the release, except as allowed under condition III.B.3.i. 3) No later than five (5) calendar days after the lifting of any pressure-vacuum relief valve, that valve shall be monitored to determine that it is leak-free.
	e. Each pump, which is equipped with a dual mechanical seal employing a barrier fluid system, shall: [40CFR60.482-2.d] 1) operate with the barrier fluid at a pressure that is greater than the pump stuffing box pressure; 2) employ a barrier fluid that is a heavy liquid; 3) employ a barrier fluid system which has a sensor to detect failure of the seal system, the barrier fluid system, or both and that sensor employs an audible alarm or the system is checked daily; 4) A "leak" is defined as liquid dripping from the pump seal. See condition III.B.2.b.2 above for tagging and repair requirements.
A-1,A-2,B-1, B-2,B-3,C, D-1,D-2,E-1, E-2,G,H,I,J, K,L,O,P	f. Each compressor shall be equipped with a seal system that includes a barrier fluid system, which shall: [40CFR60.482-3] 1) operate with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure, or 2) employ a barrier fluid system that is connected by a closed vent system to a control device; 3) employ a barrier fluid that is a heavy liquid; 4) employ a barrier fluid system which has a sensor to detect failure of the seal system, the barrier fluid system, or both; and 5) that sensor employs an audible alarm or the system is checked daily. 6) A "leak" is defined as a failure of the seal system or the barrier fluid system. See condition III.B.2.b.2 above for tagging and repair requirements.

Subject Process	Condition
	g. Each sampling system, which is not an in-situ system, shall be equipped with a closed purge, closed loop, or closed vent system, which shall: [40CFR60.482-5] 1) return the purged process fluid directly to the process line, or 2) collect and recycle the purged process fluid, or 3) capture and transport all purged process fluid to a control device.
	h. Each open ended valve or line shall: [40CFR60.482-6] 1) be equipped with a cap, blind flange, plug, or secondary valve which seals the open end at all times except during operations requiring process fluid flow through the valve or line; and 2) if a secondary valve is used, be operated in such a manner that the valve on the process fluid end is closed before the secondary valve is closed; and 3) if a double block-and-bleed system is used, be allowed to operated with the bleed valve open during operations requiring venting of the line between the block valves but shall comply with this condition III.C.1.h at all other times.
	i. Closed vent system requirements [40CFR60.482-10] 1) Vapor recovery system shall be operated to recover VOC emissions with an efficiency of ninety-five percent (95%) or greater. 2) All control devices shall be monitored to ensure that they are operated and maintained in accordance with their design specifications. 3) Closed vent systems shall be operated with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background and visual inspections. 4) Closed vent systems and control devices shall be operated at all times when emissions may be vented to them.

2. Waste Water Systems.

Process	Condition
A-2,B-2,B-3, D-2,E-1,E-2, G,I,J,L,O,P	Each subject oily water sewer, installed or modified after May 4, 1987, shall be inspected and maintained on a schedule that satisfies the provisions of 40CFR60, subpart QQQ, <u>Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems</u>. Conditions III.B.2 and III.B.4 to this permit shall respectively govern the timing of periodic inspections and reporting. [40CFR60-QQQ] a. All process drains connected to the first downstream junction box common to a new, modified, or reconstructed individual drain system or oil-water separator are included. [40CFR60.691, definition of "individual drain system"] b. The loss of a system water seal, for whatever reason, detected by the APCO or his designee shall constitute a violation of this condition with the exception of those components previously identified by ConocoPhillips that are awaiting repair. [District-only, Rule 206]

3. Fuel Gas Combustion.

Process	Condition
B-1,C,D-1, D-2,K,O	Each subject process shall be inspected and maintained on a schedule that satisfies the provisions of 40CFR60, subpart J, <u>Petroleum Refineries</u>. Conditions III.B.2 and III.B.4 to this permit shall respectively govern the timing of periodic inspections and reporting. [40CFR60-J]

4. Floating Roof Tanks.

Process		Condition
A-1,G	a.	Single seal tanks shall not be used to store organic liquids with a true vapor pressure of 0.5 psia or greater. [District-only, Rule 206 for Tanks 822 & 823 and District-only, Rule 425 for all others]
	b.	Double seal tanks shall not be used to store organic liquids with a true vapor pressure of eleven (11) psia or greater. [SIP Rules 205 & 407.A.2]
	c.	There shall be no holes, tears, or other openings in the primary seal, the secondary seal, seal fabric, or seal envelope which allow the emission of volatile organic compounds to the atmosphere, except when the storage tanks are empty and out of service. [District-only, Rule 206 for Tanks 822 & 823 and District-only, Rule 425 for all others]
	d.	The secondary seal shall not extend above the top edge of the tank wall. [District-only, Rule 206 for Tanks 822 & 823 and District-only, Rule 425 for all others]
A-1,G	e.	All roof openings, except pressure-vacuum relief valves and automatic bleeder vents, shall provide a projection of at least two inches (2") below the stored liquid surface. [District-only, Rule 206 for Tanks 822 & 823 and District-only, Rule 425 for all others]
	f.	All openings and fittings shall be covered and shall have gaskets with no visible gaps. [District-only, Rule 206 for Tanks 822 & 823 and District-only, Rule 425 for all others]
	g.	Any excessive seal gap shall be repaired within thirty (30) calendar days. A thirty (30) calendar day extension may be requested from the APCO if repairs cannot be completed within thirty (30) calendar days because they are technically not possible without complete or partial shutdown of the refinery. [District-only, Rule 206]
	h.	Each time a storage tank is emptied and degassed, the roof fittings and primary and secondary seals shall be inspected for compliance with this permit. [SIP Rule 205&40CFR60.113b.b.6 for Tank 903 and District-only Rule 206 for all others]
	i.	Each time a storage tank roof is refloated after having been on its support legs, the primary and secondary seals shall be inspected for compliance with gap criteria of this permit. If a maintenance activity involves multiple flotation cycles, a single inspection may be performed after the last cycle. [SIP Rule 205 and 40CFR60.113b.b.1.i for Tank 903]
	j.	Storage tank seal inspections shall use 1/8", 1/4", 1/2", and 1-1/2"gap measuring rods, at least fifty-four inches (54") in length, constructed with a calibrated cross section in the measuring area to quantify gaps encountered. [SIP Rule 205 and 40CFR60.113b.b.2 for Tank 903] 1) The gap measuring technique shall consist of an attempt to insert a rod of a known dimension between the metallic shoe seal or the wiper seal, as appropriate, and the storage tank wall. The rod should be held vertically and inserted with a firm pressure but not with enough force to deflect the seal. If the rod can be inserted its full length without significant resistance, the gap should be considered greater than the rod diameter. If the rod will not go past the seal, or if significant resistance is encountered, the gap should be considered equal to or less than the diameter of the rod. 2) Wherever the 1/8" gap measuring rod passes the seal freely, without forcing or binding against the seal, the gap width and length shall be further evaluated sufficient to determine compliance with the requirements of condition III.E.1.a. For Tanks 822, 823, and 903, the total gap width and perimetrical distance combination shall be determined for the length of the gap such that a square inches of gap per foot of tank perimeter value may be quantified.

5. Domed and Floating Roof Tanks.

Process	Condition
A-1,G,P	a. Potential nuisances caused by excessive odor ladened vapor emissions shall be mitigated during open tank work by: [District-only, Rule 206] 1) placing materials which are contaminated with stored product, such as seal material, fabric, etc., into closed containers for handling and disposal in accordance with applicable regulations, and 2) generally maintaining clean work areas. 3) Vacuum truck pump discharge gases shall be vented to an emission control device capable of reducing volatile organic compound (VOC) emissions by ninety-five percent (95%) during all tank cleaning material removal. Fresh, activated carbon of sufficient capacity to prevent breakthrough of VOC emissions will be considered to achieve at least ninety-five percent (95%) control for the purposes of this condition. The air pollution control device shall be subject to the APCO's approval on a case-by-case basis prior to the beginning of work. 4) During tank cleaning, ConocoPhillips shall: i. adhere to the general Tank Cleaning Plans, and ii. submit a specific tank cleaning plan, which may reference the general Plans, to the APCO for any tank cleaning process that may emit nuisance odors to the atmosphere. That plan shall be submitted to the APCO at least fifteen (15) calendar days prior to cleaning and shall describe the procedures to be employed to minimize potential nuisance odors.
A-1,G	b. All gauging and sampling ports shall remain tightly closed and gas-tight except when gauging or sampling is taking place. [Tanks 100 & 101, District-only, Rule 425.E.3.a; Tanks 800, 801, 900, & 901, District-only, Rule 425.F.4.b; Tanks 550 & 551, SIP Rule 407.A.2: Tanks 822 & 823, District-only, Rule 206, and Tank 903, Rule 425.F.4.b]
A-1,P	c. The lifting of a relief valve except during testing shall be considered an upset under District Rule 107, <u>Breakdown or Upset Conditions and Emergency Variances</u>, and shall be a violation of this condition unless relief is granted in accordance with the provisions of that rule. [District-only, Rule 206]
	d. The pressure regulation, alarm, and relief set-points shall be as follows. [District-only, Rule 206] 1) pressure regulation: +0.5 to +1.5 inH_2O 2) audible and visual alarms: 0.0 and +2.5 inH_2O 3) pressure-vacuum valve protection: +3.0 and -1.0 inH_2O respectively. 4) emergency vent manhole lid protection: +4.0 inH_2O.
A-1	e. Testing to determine the vapor pressure of stored materials shall be conducted as directed by the APCO. [District-only, Rule 206]

6. New Source Performance Standard General Provisions

Process		Condition
A-2,B-1, B-2,B-3,C, D-1,D-2, E-1,E-2,G, I,J,K,L,O,P	a.	Each subject process shall comply with the notification, recordkeeping, and reporting requirements as specified in 40CFR60.7. All notifications and reports shall be submitted to the APCO with a copy submitted to the EPA Region IX Administrator. Such action shall include the following. [40CFR60.7] 1) Written notification of the anticipated date of any physical or operational change that may increase emissions, no less than sixty (60) calendar days prior to that date. 2) Maintaining records of the occurrence and duration of any startup, shutdown, or malfunction, except for fugitive emission components as allowed under 40CFR60.486.k. 3) Maintaining a file of all measurements and performance evaluations for a minimum of five (5) years.
	b.	Each subject process shall be maintained and operated in a manner consistent with good air pollution control practice for minimizing emissions. [40CFR60.11.d]

7. Fuel Gas System

Process		Condition
B-1,C, D-2,I,J	a.	Provisions for extracting refinery fuel gas samples shall be provided and maintained. [SIP Rule 205 for B-62A/B heaters and process units I & J and District-only, Rule 206 for all others]
I,J	b.	In the event of a breakdown or upset of either unit, ConocoPhillips shall reduce crude oil throughput to a level such that the fuel gas produced by the remaining operating H_2S absorption unit will continue to meet the limits of Condition I.B.4. [District-only, Rule 206]
	c.	Specific operating conditions added as a BACT finding for the B-505 boiler, application number 1916. Except during start-up and shutdown periods: [District-only, Rule 204] 1) The concentration of Sulfolane W in the H_2S absorbers D-601A and D-601B shall be maintained at twenty percent (20%) or greater by weight. 2) The temperature of the stripper bottoms of units D-602A and D-602B shall be maintained between 250 degrees and 280 degrees F.

8. Fuel Gas Monitoring

Process		Condition
I,J	a.	The instrument for continuously monitoring and recording concentrations of hydrogen sulfide in the fuel gas, AN-603, shall be calibrated, on-line, and operational whenever fuel gas is being combusted, and maintained in accordance with the provisions of 40CFR60, subpart J. [40CFR60.105.a.4]
	b.	Except for system breakdowns, repairs, calibration checks, and zero or span adjustments, the AN-603 system shall be in continuous operation. [40CFR60.13.e]
	c.	In the event of a breakdown or upset of AN-603, which will last eight (8) hours or longer, a sample of the sweet gas shall be analyzed for hydrogen sulfide by the Drager tube method or other approved method. [District-only, Rule 206]

9. Visible Emissions

Process	Description	Condition	
Q, item II.B.21.a only S-1 U (a)	fugitives	a.	Visible emissions shall not exceed Ringlemann ½ or ten percent (10%) opacity for a period exceeding three (3) minutes aggregated in any sixty (60) minute period of time. [SIP Rule 205 for process Q and District-only, Rule 206 for all others]
D-1	G-515-3 G-515-4	b.	Visible emissions shall not exceed Ringlemann No. ¼ or five percent (5%) opacity for periods aggregating more than three (3) minutes in any hour. [District-only, Rule 206]

Note: (a) The fall of material from the pelletizer spray shall not be evaluated as visible emissions if it drops to the ground within the staging area.

10. Refinery MACT Standard. All subject processes shall comply with the provisions of 40CFR63, National Emission Standards for Hazardous Air Pollutants, subpart A, General Provisions, and subpart CC, Petroleum Refineries. [40CFR63.640.a and in addition to the references cited below, the following references shall apply to each requirement: 40CFR63.1.c.1 & 63.4.a.1]

a. For all naphtha stream components, compliance with the requirements of 40CFR60 subpart VV shall be deemed compliance with 40CFR63 subpart CC. [40CFR63.648.a]

b. ConocoPhillips shall implement the APCO approved startup, shutdown, and malfunction (SSM) plan. [40CFR63.6.e.3, except for the need for APCO approval, which is based on SIP Rule 205]

1) During SSM periods for all naphtha stream components, ConocoPhillips shall operate and maintain the refinery in accordance with the approved SSM plan.

2) Malfunctions shall be corrected as soon as practicable after their occurrence. [40CFR63.6.e.1.ii]

3) If the SSM plan is revised, the previous version shall be retained for a minimum of five (5) years from the date of revision and shall be made available to the APCO upon request.

4) If it is found that the SSM plan fails to address a malfunction not initially included in that plan, ConocoPhillips shall submit a revised plan to the APCO for his approval within forty-five (45) calendar days of that discovery.

c. The following specific provision shall apply.

1) ConocoPhillips shall not fail to report, revise reports, or report source test results as required by 40CFR63, subpart CC. [40CFR63.4.a.2]

2) At all times, including periods of startup, shutdown, and malfunction, ConocoPhillips shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. [40CFR63.6.e.1.i]

i. During a period of startup, shutdown, or malfunction, this general duty to minimize emissions requires that ConocoPhillips reduce emissions from the affected source to the greatest extent which is consistent with safety and good air pollution control practices.

ii. The general duty to minimize emissions during a period of startup, shutdown, or malfunction does not require ConocoPhillips to achieve emission levels that would be required by 40CFR63, subpart CC, at other times if this is not consistent with safety and good air pollution control practices, nor does it require ConocoPhillips to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved.

3) The non-opacity emission standards under 40CFR63, subpart CC, shall apply at all times except during periods of startup, shutdown, and malfunction, and as otherwise specified that subpart. If a startup, shutdown, or malfunction of one portion of an affected source does not affect the ability of particular emission points within other portions of the affected source to comply with the non-opacity emission standards set forth in that subpart, then that emission point must still be required to comply with the non-opacity emission standards and other applicable requirements. [40CFR63.6.f.1]

4) A copy of all reports submitted to the APCO pursuant to 40CFR63, subparts A and CC, shall be submitted to the EPA Region IX Administrator. [40CFR63.10.a.4.ii]

5) ConocoPhillips shall identify, either by list or location, equipment in naphtha service less than 300 hours per calendar year. [40CFR63.654.d.5]

11. Diesel Engine Air Toxic Control Measures.

a. Stationary Diesel Engines. ConocoPhillips shall comply with all applicable provisions of 17CCR93115, Airborne Toxic Control Measure for Stationary Compression Ignition Engines. [District-only, 17CCR93115]

1) Any stationary diesel engine rated at ≤50 hp that begins initial operation after January 1, 2005, shall not emit air contaminants in excess of the current Off-Road Compression-Ignition Engine Standards found in 13CCR2423 for off-road engines of the same maximum rated power. [District-only, Rule 206]

2) An application to install, retrofit, or replace any stationary diesel engine rated at ≥50 hp shall be submitted to the APCO no later than sixty (60) calendar days prior to the performance of that work. [District-only, Rule 431.J.3; 17CCR93115.e.2.A&C, e.4.A.1, & e.4.D.1; and Rule 202.A]

3) Stationary diesel engines rated at >50 hp shall not be operated unless they have a non-resettable, calibrated, on-line, and operational engine run-time hour meter that is maintained in accordance with the manufacturer's recommendations. [District-only, 17CCR93115.e.4.G.1]

4) ConocoPhillips shall notify the APCO immediately upon detection of any violation of the provisions of 17CCR93115.e.2. [District-only, 17CCR93115.e.4.E]

5) ConocoPhillips shall operate and maintain a diesel oxidation catalyst that achieves at least a 30% reduction in particulate matter emissions on the following emission units: [District-only, 17CCR93115.e.2.D.1.c and 93115.g.2]
    i. G-51-4, cooling tower recirculation pump, and
    ii. GB-524S, spare plant air compressor.

b. Portable Diesel Engines. ConocoPhillips shall comply with all applicable provisions of 17CCR93116, Airborne Toxic Control Measure for Diesel Particulate Matter from Portable Engines Rated at 50 Horsepower and Greater. [District-only, 17CCR93116]

1) The exemption from authority to construct provided in District Rule 201.L.3 for the identical replacement of portable diesel engines rated at $\geq$50 hp is disallowed under section 201.A.1.b of that same rule, because emissions of diesel particulate matter are involved. An application to install, retrofit, or replace any non-mobile, portable diesel engine rated at $\geq$50 hp shall be submitted to the APCO no later than sixty (60) calendar days prior to the performance of that work. [District-only, Rule 202.A]
2) Portable diesel engines rated at $\geq$50 hp shall not be operated unless they have a non-resettable, calibrated, on-line, and operational engine run-time hour meter that is maintained in accordance with the manufacturer's recommendations. [District-only, Rule 206]

c. Non-mobile diesel engines rated at $\geq$50 hp shall only use CARB diesel fuel. [District-only, 17CCR93115.e.1 for stationary engines and 17CCR93116.3.a.1 for portable engines]

12. **Sulfur Recovery Unit MACT Standard.** All subject emission units shall comply with the provisions of 40CFR63, National Emission Standards for Hazardous Air Pollutants, subpart A, General Provisions, and subpart UUU, Petroleum Refineries: Sulfur Recovery Units. [40CFR63.1563.b and, in addition to the references cited below, the following references shall apply to each requirement: 40CFR63.1.c.1 & 63.4.a.1]

a. The following emission units are subject to this standard.
    1) Sulfur Recovery Units A and B, process E-1. [40CFR63.1562.b.3]
    2) Sulfur Recovery Unit Bypass Lines to the Hydrocarbon Relief and Recovery System and the B-602A/B Incinerators. [40CFR63.1562.b.4]
    3) Tail Gas Unit, process K. [40CFR63.1562.b.3]

b. Sulfur Recovery Units A & B, process E-1, and Tail Gas Unit, process K
    1) The emissions of total reduced sulfur (TRS) compounds from the Tail Gas Unit shall not exceed 300 ppmv, calculated as SO_2@0%O_2dry, when the B-702 combustor is on low-fire. The averaging period is one-hour for both continuous emissions monitoring instrument results and stack testing. This is a separate requirement from condition I.A.18.c. [40CFR63.1568.a.1, 63.1568.c.1, and subpart UUU, table 29, item 1.b]
    2) The emissions of SO_2 from the Tail Gas Unit shall not exceed 100 ppmv @0%O_2dry when the B-702 combustor is on high-fire. The averaging

period is one-hour for both continuous emissions monitoring instrument results and stack testing. This is an intentional duplication of condition I.A.17.a. [SIP Rule 205, 40CFR60.104.a.2.i , 40CFR63.1568.a.1&c.1, and subpart UUU, table 29, item 1.a]

3) Operate and maintain the AN-1707/1709 instrument in accordance with condition III.E.11.a and related provisions of this permit. [40CFR63.1568.b.1, 63.1572.a.1, and subpart UUU, table 31, item 1]

   i. ConocoPhillips shall maintain and operate the AN-1707/1709 TRS analyzer in a manner consistent with good air pollution control practices. [40CFR63.8.c.1]

      (a) The analyzer shall be maintained and operated in accordance with condition III.C.12.g.

      (b) ConocoPhillips shall keep the necessary parts for routine repairs of the analyzer readily available.

      (c) ConocoPhillips shall develop, submit for APCO approval, and implement a written startup, shutdown, and malfunction plan for analyzer as specified in 40CFR63.6.e.3. [SIP Rule 205 for submittal to APCO]

   ii. The AN-1707/1709 shall be installed such that representative measures of emissions from the tail gas unit are obtained and shall be located according to procedures contained 40CFR60, performance specification 5. [40CFR63.8.c.2.i]

   iii. ConocoPhillips shall ensure the AN-1707/1709 data indications that are required for compliance with the emission standards contained in conditions I.A and III.C.12.b are readily accessible on site for operational control or inspection by the operator of that analyzer. [40CFR63.8.c.2.ii]

c. Sulfur Recovery Unit Bypass Lines to the Hydrocarbon Relief and Recovery System and the B-602A/B Incinerators

1) The bypass line blocking valves for each of the two Sulfur Recovery Unit to Tail Gas Unit process streams, and the bypass line blocking valves for each of the two acid gas stripper overhead receivers to the Sulfur Recovery Unit process streams, shall remain closed, except as necessary during periods of startup, shutdown, or malfunction. [SIP Rule 205]

2) The bypass line blocking valve for the Sulfur Recovery Unit A to Tail Gas Unit process stream must be maintained in a closed position by a manual locking car seal system and shall be physically connected to vent to the B-602A incinerator when open. [40CFR63.1569.a.1.ii and subpart UUU, table 36, item 2 for the locking system; and SIP Rule 205 for the vent path]

3) The bypass line blocking valve for the Sulfur Recovery Unit B to Tail Gas Unit process stream must be maintained in a closed position by a manual locking car seal system and shall be physically connected to vent to the B-602B incinerator when open. [40CFR63.1569.a.1.ii and subpart UUU, table 36, item 2 for the locking system; and SIP Rule 205 for the vent path]

4) The bypass line blocking valve for the acid gas stripper overhead receiver F-603A to Sulfur Recovery Unit A process stream must be maintained in a

closed position, as indicated by an automated electronic valve position monitor, and shall be physically connected to vent to the Hydrocarbon Relief and Recovery System when open. [40CFR63.1569.a.1.i and subpart UUU, table 36, item 1 for the valve position monitor; and SIP Rule 205 for the vent path]

5) The bypass line blocking valve for the acid gas stripper overhead receiver F-603B to Sulfur Recovery Unit B process stream must be maintained in a closed position, as indicated by an automated electronic valve position monitor, and shall be physically connected to vent to the Hydrocarbon Relief and Recovery System when open. [40CFR63.1569.a.1.i and subpart UUU, table 36, item 1 for the valve position monitor; and SIP Rule 205 for the vent path]

d. Maintain and operate all subject emission units in accordance with the procedures in the operation, maintenance, and monitoring plan (OMMP) that has been approved by the APCO under 40CFR63.1574.f. Until any requested change to the OMMP is approved, ConocoPhillips shall continue to maintain and operate all subject emission units in accordance with the originally approved plan. [40CFR63.1568.a.3, 63.1569.a.3, and 63.1574.f]

e. ConocoPhillips shall implement the APCO approved startup, shutdown, and malfunction (SSM) plan for subject equipment. [40CFR63.6.e.3 and 63.1570.d, except for the need for APCO approval, which is based on SIP Rule 205]

1) During SSM periods, ConocoPhillips shall operate and maintain the refinery in accordance with the approved SSM plan. [40CFR63.6.e.3.ii and 63.1570.e]
2) Malfunctions shall be corrected as soon as practicable after their occurrence. [40CFR63.6.e.1.ii]
3) If the SSM plan is revised, the previous version shall be retained for a minimum of five (5) years from the date of revision and shall be made available to the APCO upon request. [SIP Rule 205]
4) If it is found that the SSM plan fails to address a malfunction not initially included in that plan, ConocoPhillips shall submit a revised plan to the APCO for his approval within forty-five (45) calendar days of that discovery. [40CFR63.6.e.3.viii]

f. ConocoPhillips shall not fail to report, revise reports, or report source test results as required by 40CFR63, subpart UUU. [40CFR63.4.a.2]

g. At all times, including periods of startup, shutdown, and malfunction, ConocoPhillips shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. [40CFR63.6.e.1.i and 63.1570.c]

1) During a period of startup, shutdown, or malfunction, this general duty to minimize emissions requires that ConocoPhillips reduce emissions from the affected source to the greatest extent which is consistent with safety and good air pollution control practices.

2) The general duty to minimize emissions during a period of startup, shutdown, or malfunction does not require ConocoPhillips to achieve emission levels that would be required by 40CFR63, subpart UUU, at other times if this is not consistent with safety and good air pollution control practices, nor does it require ConocoPhillips to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved.

h. The non-opacity emission standards under 40CFR63, subpart UUU, shall apply at all times except during periods of startup, shutdown, and malfunction, and as otherwise specified that subpart. If a startup, shutdown, or malfunction of one portion of an affected source does not affect the ability of particular emission points within other portions of the affected source to comply with the non-opacity emission standards set forth in that subpart, then that emission point must still be required to comply with the non-opacity emission standards and other applicable requirements. [40CFR63.6.f.1 and 63.1570.a]

i. A copy of all reports submitted to the APCO pursuant to 40CFR63, subparts A and UUU, shall be submitted to the EPA Region IX Administrator. [40CFR63.10.a.4.ii]

13. Boiler B-507 MACT Standard. All subject processes shall comply with the provisions of 40CFR63, National Emission Standards for Hazardous Air Pollutants, subpart A, General Provisions, and subpart DDDDD, Industrial, Commercial, and Institutional Boilers and Process Heaters. [40CFR63.7490.a and in addition to the references cited below, the following references shall apply to each requirement: 40CFR63.1.c.1 & 63.4.a.1]

a. The emissions of Carbon Monoxide (CO) from Boiler B-507 shall not exceed 400 ppmv @ 3% O2 dry, based on a 3-run test average. [40CFR63.7500.a.1]

b. ConocoPhillips shall implement the APCO approved startup, shutdown, and malfunction (SSM) plan. [40CFR63.6.e.3, except for the need for APCO approval, which is based on SIP Rule 205]

1) During SSM periods for the B-507 Boiler, ConocoPhillips shall operate and maintain the refinery in accordance with the approved SSM plan.
2) Malfunctions shall be corrected as soon as practicable after their occurrence. [40CFR63.6.e.1.ii]
3) If the SSM plan is revised, the previous version shall be retained for a minimum of five (5) years from the date of revision and shall be made available to the APCO upon request.
4) If it is found that the SSM plan fails to address a malfunction not initially included in that plan, ConocoPhillips shall submit a revised plan to the APCO for his approval within forty-five (45) calendar days of that discovery.

c. The following specific provisions shall apply.

1) ConocoPhillips shall not fail to report, revise reports, or report source test results as required by 40CFR63, subpart DDDDD. [40CFR63.4.a.2]
2) At all times, including periods of startup, shutdown, and malfunction, ConocoPhillips shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. [40CFR63.6.e.1.i]
   i. During a period of startup, shutdown, or malfunction, this general duty to minimize emissions requires that ConocoPhillips reduce emissions from the affected source to the greatest extent which is consistent with safety and good air pollution control practices.
   ii. The general duty to minimize emissions during a period of startup, shutdown, or malfunction does not require ConocoPhillips to achieve emission levels that would be required by 40CFR63, subpart DDDDD, at other times if this is not consistent with safety and good air pollution control practices, nor does it require ConocoPhillips to make any further efforts to reduce emissions if levels required by the applicable standard have been achieved.

3) The non-opacity emission standards under 40CFR63, subpart DDDDD, shall apply at all times except during periods of startup, shutdown, and malfunction, and as otherwise specified that subpart. [40CFR63.6.f.1]
4) A copy of all reports submitted to the APCO pursuant to 40CFR63, subparts A and DDDDD, shall be submitted to the EPA Region IX Administrator. [40CFR63.10.a.4.ii]

D. Compliance Testing Conditions

1. Monitoring Procedures and Records.

a. All testing shall be conducted in accordance with the District's Source Test Policy with results being reported to the APCO within forty-five (45) calendar days of testing. [District-only, Rule 210.B.1]

b. A record of compliance testing shall be maintained and shall include at least the following information. [Rule 216.F.1.c.3 for all "federally-enforceable" conditions and, District-only, Rule 206 for "District-only" enforceable conditions]

1) The date, place as defined in this permit, and time of sampling or measurements;
2) The date(s) analyses were performed;
3) The company or entity that performed the analyses;
4) The analytical techniques or methods used;
5) For combustion devices, those burners that are out-of-service during a compliance test and the reason for that condition; [District-only, Rule 206]
6) The results of such analyses; and
7) The operating conditions as existing at the time of sampling or measurement.

2. Annual Refinery Compliance Testing. ConocoPhillips shall contract with an independent, or other District-approved, laboratory to conduct the following tests at least once each calendar year using methods approved by the District.

Process		Condition
B-1,C, D-1,D-2	a.	Determination of oxides of nitrogen (NO_x) emissions, calculated as NO_2, oxygen (O_2), carbon monoxide, and carbon dioxide from the: [SIP Rule 205 for B-506 & B-201A/B NO_x and O_2; and District-only, Rule 206 for all others] B-504 boiler, B-505 boiler, B-506 boiler, [in addition, 40CFR60.48b.g.2 for NO_x & O_2] B-507 boiler crude heaters (B-2A/B), vacuum heaters (B-62A/B), coker heaters (B-102A/B), and steam superheaters (B-201A/B).
	b.	Determination of total sulfur content of the fuel gas, including hydrogen sulfide, mercaptan, and other related fuel gas constituents, supplied to the: [Rule 216.F.1.c.1] B-504, 506 and B-507 boilers, B-505 boiler, and Coking Unit A and B process heaters.

Process		Condition
B-1,C, D-1,D-2	c.	Determination of the gross heating value on a dry basis of the fuel gas supplied to the coking unit heaters, the fuel gas supplied to the B-505 boiler, and the fuel gas supplied to the utility plant boilers. [District-only, Rule 210.B.1] 1) The gross heating value of the supplied fuel gas shall be determined each time a heater is tested for compliance. [District-only, Rule 206] 2) The analysis of gross heating value samples shall be expedited and the results shall be reported to the APCO separately from the complete source test report as soon as possible after the results are received by ConocoPhillips. [District-only, Rule 206] 3) Compliance with the heat input limits of this permit during emission compliance testing shall be based on the fuel gas heating value sampling and analysis conducted concurrently with that testing, rather than the average of the most recent three monthly samples as required by condition III.D.8.b below. [District-only, Rule 206]
	d.	Determination of sulfur and total HAP content of crude oil feed to refinery on a single day, weight percent basis. [District-only, Rule 210.B.1 for sulfur content and SIP Rule 205 for HAP content]
	e.	Determination of the hourly heat input rate to the following heaters and boiler in terms of mmBtuh: [District-only, Rule 210.B.1] B-2A/B, B-62A/B, B-102A/B, and B-505.
	f.	The heat input limits in conditions I.B.3.a, b, d, e, and g above may be exceeded during APCO approved testing, but compliance with the emission limits of conditions I.A.1 through 5 shall be shown concurrently.

3. Annual Refinery Performance Audits.

Process	Condition
J,K	ConocoPhillips shall conduct or cause to be conducted a performance audit at least once each calendar year for the: [Rule 210.B.1 and 40CFR60.13.c] AN-603 fuel gas monitor, AN-1707/1709 tail gas monitor, and AN-1600 A/B B602 SO2 monitor Such testing shall be conducted in compliance with the requirements of 40CFR60.105(a).

4. Biennial Refinery Compliance Testing.

Process	Condition
B-1,C, D-2,K	At least once every two calendar years, ConocoPhillips shall contract with an independent, or other District-approved, laboratory to conduct tests to determine the: a. sulfur dioxide emissions in 2008, 2010, and 2012 from the: [District-only, Rule 206 for B-2A/B and SIP Rule 205 for all others] crude heaters (B-2A/B), coker heaters (B-102A/B), and steam superheaters (B-201A/B); b. volatile organic compound emissions in 2008, 2010, and 2012 from the B-505 boiler; [District-only, Rule 210.B.1] c. hydrogen sulfide and reduced sulfur compounds in 2008, 2010, and 2012 in the B-702 stack gas with the combustor on low fire; [CAA 114.a.1.D] d. sulfur dioxide emissions in 2008, 2010, and 2012 in the B-602 A/B incinerators and in the B-702 stack gas with the combustor on high fire; and [CAA 114.a.1.D] e. oxygen levels for at least a three (3) calendar day period in, 2008, 2010, and 2012 at the AN-1707/1709 monitor sampling point. [CAA 114.a.1.D]

5. Biennial Carbon Plant Compliance Testing.

Process	Condition
S-2	During 2007 and 2009, ConocoPhillips shall contract with an independent, or other District-approved, laboratory to conduct tests to determine the rail car loading baghouse emissions of particulate matter. [Rule 210.B.1]

6. Fuel Gas Testing

a. If the refinery is operating normally, and except during months when APCO approved formal compliance testing that includes a fuel gas heating value determination is scheduled to occur, a representative sample of the fuel gas supplied to the coking unit heaters shall be drawn from a location subject to the APCO's approval between the hours of 10 a.m. and 1 p.m., except in the event that a coke drum-switch occurs during that time period in which case the sampling window shall be extended until 3 p.m. [District-only, Rule 206]

1) The sampling shall occur within the first five (5) business days of each calendar month.
2) The sample shall be analyzed for gross heating value (GHV) at 60°F using ASTM D-1946/3588.
3) During any month when a formal compliance testing determination of fuel gas GHV occurs, that determination shall substitute for the normal monthly sampling.
4) As used here,
   i. formal compliance testing is intended to mean an APCO approved stack test designed to determine compliance with the NO_x emission limitations of condition I.A.1; and
   ii. drum-switch is intended to include any preheating that normally occurs prior to switching the feed stream from one coke drum to another.

b. Beginning on the first calendar day and ending at midnight of the last calendar day during months when formal compliance testing does not occur, and up until the first formal compliance testing sample is drawn in months when such testing does occur, the average of the fuel gas GHV analysis results for the most recent three monthly samples, or formal compliance testing determinations in previous months as applicable, shall be used to determine compliance with all process heater heat input limits of this permit (*e.g.*, the average GHV results for months 1, 2, & 3 shall be used for compliance in month 4). [District-only, Rule 206]

c. Beginning the next hour after a fuel gas sample starts during formal compliance testing, and during any succeeding months, the GHV determination made as part of that compliance test shall be used to determine compliance with all process heater heat input limits of this permit until such time as ConocoPhillips notifies the APCO of a new average GHV which includes the compliance testing results. Upon such notification, the reported average GHV shall be used to determine compliance with all process heater heat input limits of this permit until a new average is established as allowed in condition III.D.8.b above. [District-only, Rule 206]

d. The results of the fuel gas GHV analysis for any given month and the average value to be used to determine compliance with all process heater heat input limits of this permit shall be recorded and included in the monthly report required under condition III.B.4.a above which is due in the same month of the analysis (*e.g.*, the analysis results of a sample drawn in January are to be included in the monthly report due in January). [District-only, Rule 206]

1) If the results of a formal compliance testing determination are used in place of a normal monthly sample, the results of that determination and the average value to be used for compliance purposes shall be reported as soon as possible after the analysis results are received by ConocoPhillips.
2) If a monthly sample is not drawn and analyzed (*e.g.*, the refinery was not operating normally or a formal compliance determination is scheduled), the reason shall be recorded and included in the monthly report.
3) All records associated with each fuel gas GHV analysis shall be maintained for a minimum of five (5) years.

7. **Diesel Engines.** Subsequent to having undergone retrofit or replacement under condition III.C.11.a, if that engine's operation has exceeded 200 hours in any calendar year since November 13, 1996, the G-51-4 and GB-524Sdiesel engines shall be tested to verify compliance with the emission limitations therein at least once every 8,760 hours of engine operation, not to exceed thirty-six (36) months between verifications, and using the following test methods and procedures. [District-only, Rule 431.D.5&F]

a. NO_x and CO emissions, and O_2 content shall be determined by using ARB Method 100.
b. Percentage NO_x reductions shall be determined by measuring concurrently at the inlet and outlet of the emission control device. For engines not employing emission control devices, percentage NO_x reductions shall be determined by measuring the uncontrolled NO_x emissions prior to modification and comparing with NO_x emissions after engine modification.

c. Source test data point intervals shall be no greater than five (5) minutes and data points shall be averaged over fifteen (15) consecutive minutes.

8. Verification of Offsets. The green coke pile water pump, GE-522, and portable air compressor, GB-1015, shall be tested to verify compliance with the offset requirements of District Rule 204.B at least once every 8,760 hours of operation, not to exceed thirty-six (36) months between verifications, and using the following test methods and procedures. [District-only, Rule 204]

a. NO_x, CO, and VOC emissions, and O_2 content shall be determined by using ARB Method 100. Gaseous pollutant test data point intervals shall be no greater than five (5) minutes and data points shall be averaged over fifteen (15) consecutive minutes.

b. PM emissions shall be determined by measuring at the outlet of the emission control device using ARB Method 5, including condensibles. PM10 emissions shall be deemed equivalent to PM emissions for the purposes of this condition III.D.10.b.

c. The emissions test report for the GE-522 shall include a comparison of ConocoPhillips' offset liability based on current testing and the offsets provided from ERC certificate number 780-Z1 on May 20, 2004, which were as follows.

tons per year	VOC	CO	NO_x	PM-10	SO_2
emission offsets	0.20	0.0047	1.72	0.053	0.23

d. The emissions test report for the GB-1015 shall include a comparison of ConocoPhillips' offset liability based on current testing and the offsets provided from ERC certificate number 780-Z6 on October 16, 2006, which were as follows.

tons per year	VOC	CO	NO_x	PM-10	SO_2
emission offsets	0.009	0.002	1.333	0.027	0.004

9. Test Methods. The following methods shall be used for compliance testing and performance audits. Alternate methods may be used subject to the APCO's approval, except that any alternate method used to support or determine compliance with a federally-enforceable requirement must have previously been approved for inclusion into the SIP by EPA. The most recent version of the list of alternate methods published by ARB at their web-site *http://www.arb.ca.gov/fcaa/tv/tvinfo/accp_mth.htm*, which is included here as Appendix B, may be used as a guideline.

Parameters/Requirement	**Method**
sample and velocity traverses	EPA 1 or ARB 1
velocity and volumetric flowrate	EPA 2 or ARB 2
CO, CO_2, O_2, excess air, and molecular weight	EPA 3, ARB 3, or ARB 100
moisture content	EPA 4 or ARB 4
particulate matter	ARB 5
SO_x – refinery	ARB 6, 8, or 100
NO_x	EPA 7E or ARB 100
visible emissions	EPA 9
visible emissions from flare	EPA 22

Parameters/Requirement	Method
total reduced sulfur	EPA 15A or ARB 15A
AN-1707/1709 calib. check & relative accuracy	40CFR60.PS-5
H_2S	EPA 15 or ARB 15
AN-603 calib. check & relative accuracy	40CFR60.PS-7
H_2S in fuel gas – during AN-603 breakdown	length of stain tube [District-only]
total sulfur in fuel gas – weekly check	ARB-16A, Tutweiler option, or SC-307-91
total sulfur in fuel gas – annual check	ASTM D-5504 GC/SCD
total sulfur in crude oil	ASTM D-4294 [District-only]
total HAP in crude oil	ASTM 2892
fuel gas heat content	ASTM D-1946/3588
pH	EPA 150.1
fugitive VOC	EPA 21
total sulfur in green coke - annual check	ConocoPhillips AP.6.0
total moisture in green coke - annual check	ConocoPhillips AP.1.0

E. Conditions Specific To The Identified Process

1. Process Unit A-1, Petroleum Tank Farm

a. Floating roof storage tank seal limits
[District-only Rule 206 for Tanks 800 & 801,
District-only Rule 425 for Tanks 900 & 901, and
federally-enforceable 40CFR60 subpart Kb and Rule 425 for Tank 903]

1) The cumulative length of gaps between the tank shell and the primary seal: [40CFR60.113b.b.4 and Rule 425.G.5.a for Tank 903]
   i. exceeding one-half inch (½") shall not be more than ten percent (10%) of the tank circumference, and
   ii. exceeding one-eighth inch (1/8") shall not be more than forty percent (40%) of the tank circumference.

2) No gap between the tank shell and the primary seal shall exceed one and one-half inches (1½") and no continuous gap greater than one-eighth inch (⅛") shall exceed ten percent (10%) of the tank circumference. [40CFR60.113b.b.4 and Rule 425.G.5.a for Tank 903]
3) The gap between the primary shoe seal and tank wall shall not exceed three inches (3.0") for a welded tank at any point from the liquid surface to eighteen inches (18.0") above it. [40CFR60.113b.b.4 and Rule 425.F.7.b for Tank 903]
4) There shall be no visible or measurable gap between the tank shell and the secondary seal, excluding gaps that occur within two inches (2.0") of a vertical weld seam. No gap within two inches (2.0") of a vertical weld seam shall exceed one-half inch (½"). [40CFR60.113b.b.4 and Rule 425.G.5.b for Tank 903]

b. Tanks 900, 901, and 903 shall comply with the construction and maintenance requirements of District Rule 425, <u>Storage of VOC</u>.

1) Tanks 900, 901, and 903 shall utilize: [District-only, Rule 425.F]
   i. both a primary and secondary seal; [40CFR60.112b.a.2 and Rule 425.E.1 for Tank 903 and, District only, Rule 425.E.1 for Tanks 900 & 901]
   ii. a secondary seal that extends from the roof to the tank shell, is not attached to the primary seal, and is not shoe-mounted;
   iii. roof openings, except pressure-vacuum relief valves and automatic bleeder vents, which provide a projection at least two inches (2.0") below the liquid surface;
   iv. openings and fittings that are covered at all times and have gaskets with no visible gap, except when in use; [40CFR60.112b.a.2.ii and Rule 425.F.2 for Tank 903]
   v. sampling and gauging wells, and similar fixed projections through the floating roof, such as an anti-rotational pipe, which meet the requirements of District Rule 425.F.4 and F.5, except that the seals for the anti-rotation pipe for Tank 903 shall have no visible gap; [40CFR60.112b.a.2.ii and Rule 425.F.4.b for Tank 903]

vi. emergency roof drains that drain back to the stored liquid and which utilize a slotted membrane fabric cover, or equivalent, that covers at least ninety percent (90%) of the area of the opening; and

vii. a metallic shoe-type seal with one end of the shoe extending at least two inches (2.0") into the stored liquid and the other end extending a minimum vertical distance of twenty-four inches (24") above the liquid surface.

2) If a secondary seal is voluntarily removed by ConocoPhillips, the primary seal shall be made available for inspection at that time. ConocoPhillips shall provide notification to the APCO no less than seventy-two (72) hours prior to voluntary removal of a secondary seal. [District-only, Rule 425.G.7.c]

3) Each tank's external floating roof shall be floating on the stored liquid's surface at all times except during maintenance or repair as allowed under Rule 425.C. [District-only, Rule 425.E.1]

4) When each tank's external floating roof is resting on its leg supports, the process of filling, emptying, and refilling shall be continuous. [District-only, Rule 425.C.3.b]

2. **Process Unit A-2, Tank Farm Vapor Recovery System**

a. The compressors barrier-fluid seals shall be in-place, maintained, and operated to prevent leakage of the working fluids or gases to the atmosphere. [40CFR60-GGG&VV]

b. A spare compressor of equivalent capacity to compressor GB-451, with equivalent seal design, shall be permanently installed. [District-only, Rule 206]

c. The blanketing gas used for this system shall be pipeline quality natural gas fuel supplied from a California Public Utility Commission regulated company and shall contain less than one (1) gram per 100 cubic foot of sulfur compounds calculated as hydrogen sulfide. [District-only, Rule 206]

d. The vapor recovery system shall be operated as designed and to recover all VOC emissions vented to it with an efficiency of at least ninety-five percent (95%). [40CFR60.692-5.b]

3. **Process Unit B-1, Coking Unit A.** Chromium based water treatment chemicals shall not be used in the cooling tower system. [District-only, Rule 413.C.2]

4. **Process Unit B-2, Coker Steamout System.** [District-only, Rule 206]

a. Standing oil in water settling Tanks TK-405 and TK-406 shall be minimized at all times.

b. At least one oil skimmer each for Tanks TK-405 and TK-406 shall be in-place, maintained, and operated at all times to collect floating oil.

5. **Process Unit D-1, Boiler Plant**

a. If NOx emissions from boiler B-507 exceed 21 ppmv @ 3% O2 dry, then COP shall submit a written evaluation of the feasibility of installing a NOx Continuous Emission Monitor (CEM) within 30 days. [District-only Rule 206]b. Any changes in equipment that would increase the steam generating capacity or decrease steam generating efficiency of boilers B-504 or B-506 shall be reviewed and approved by the APCO prior to implementation of the proposed change. [District-only, Rule 206]

b. The Distributed Control System shall monitor and record the fuel flow and steam production from boilers B-504, B-506 and B-507. All monitoring and recording instruments shall be calibrated and on-line whenever fuel is being combusted in either unit and maintained in good operating order. [SIP Rule 205]

c. At least two (2) District approved sampling ports located ninety degrees (90^o) apart as well as adequate sampling access and services for operating sampling and testing equipment shall be maintained on the boiler plant exhaust stack. [District-only, Rule 206]

d. Emergency Water Pump Engines, G-515-3 and G-515-4 [District-only, Rule 206]

1) Within 90 days of the applicable calendar year and subject to the APCO's approval, emission offsets or mitigation must be provided for any NOx, VOC, PM10, CO, and SOx emissions resulting from engine operation, including emergency and non-emergency hours, in excess of 100 hours per calendar year per engine. Calculations shall be based on the G-515 emission limits in condition I.A.22 above.

6. Process Unit D-2, Electrical Power Generation Plant. [District-only, Rule 206]

a. A dedicated APCO approved fuel gas meter shall be calibrated and on-line whenever fuel is being combusted, maintained, and operated on the boiler at all times.

b. Emission reduction credits in the following amounts were provided for this permit to operate the electrical power generation plant.

VOC	NO_x	SO_x	CO	PM10
5.22 tpy	14.78 tpy	18.25 tpy	47.0 tpy	4.11 tpy

c. Steam from the B-505 boiler shall not be used to supply steam to the utility plant, unless the combined steam production of the B-504 boiler, B-506 boiler and B-507 boiler is less than 170,000 lb/hr.

d. The Distributed Control System shall monitor and record the fuel flow and steam production from boiler B-505. All monitoring and recording instruments shall be calibrated and on-line whenever fuel is being combusted and maintained in good operating order.

7/8. Processes E-1 and E-2, Sulfur Recovery Units and Support Units. [District-only, Rule 206]

a. The instruments for the continuous monitoring and recording of concentrations of sulfur dioxide in the gases discharged to the atmosphere from the B-602 A/B incinerators, AN-1600 A/B, shall be installed such that representative measurements of emissions or process parameters are obtained; shall be in continuous operation, except for instrument breakdowns, repairs, calibration checks, and zero or span adjustments; and shall be calibrated and on-line whenever gas is being emitted from the incinerators; and shall be operated and maintained in accordance with 40CFR60, subpart J. [40CFR60.105.a.5, 60.13.e, and 60.13.f]

b. Each B-600 reaction furnace shall employ an operating optical pyrometer, for the purposes of monitoring proper combustion, and both audible and visual control room alarms, indicating either high or low temperature.

c. The AA-601 and AB-601 air demand analyzers, and their associated AI-601 A/B indicator instruments, shall be maintained in good operating condition and shall be calibrated and on-line whenever their respective sulfur recovery unit is on-line. Components from one analyzer may not be used to repair the other analyzer except in situations where the respective sulfur plant for the off-line analyzer is also off-line.

d. The sulfur pit vents shall be routed to the B-602 incinerators except during incinerator or sulfur pit vent system maintenance or repair.

e. The sulfur pit vent system shall be maintained in a leak free condition.

9. Process Unit G, Oily Water Treatment

a. A preventative maintenance inspection program for Tanks 822 and 823 shall be performed on the schedule identified in section III.B.2 above and which includes the following elements. [District-only, Rule 206]

1) Gap width between the tank wall and primary seal, and at the roof centering device, shall not exceed 1½" at any point. Gap width between the secondary seal and the tank wall shall not exceed ½" at any point. The total gap between the primary or secondary seal and the tank wall shall not exceed 3.2 in^2/ft of tank wall perimeter or 0.32 in^2/ft of tank wall perimeter respectively. Each tank's circumference shall be considered to be 377 feet for the purposes of this condition. [District-only, Rule 206]

   i. Any gap that exceeds the amount allowed above shall be repaired within thirty (30) calendar days with the exception of any gap in the secondary seal exceeding ½" which shall be repaired immediately.

   ii. Adjustments and repairs made to any seal shall be noted in the inspection record.

   iii. The APCO shall be notified by telephone immediately upon initiation of any repair.

2) Repairs may be delayed if they are technically impossible without complete or partial shutdown of the refinery or process unit. [District-only, Rule 206]

3) The general physical condition of the seal and any unusual physical or operational conditions shall be noted during all inspections. [District-only, Rule 206]

4) A gap that exceeds the criteria above detected by the APCO or his designee shall constitute a violation of this condition with the exception of those components previously identified by ConocoPhillips that are awaiting repair. [District-only, Rule 206]

b. The following units shall be continuously vented to Process A-2, Tank Farm Vapor Recovery System:

1) three oil-water separators, F-821A,B,&C [SIP Rule 419.D.4.a and 40CFR60.692-3.b];
2) recovered oil surge drum, F-824 [SIP Rule 205 and 40CFR60.692-3.a]; and
3) two recycled solids tank, F-408&9, [SIP Rule 205 and 40CFR60.692-3.a].

c. Closed vent systems shall be operated and maintained in a leak free condition. [40CFR60.692-5.e.1]

1) For the purposes of this condition and compliance with 40CFR60, subpart QQQ, a leak shall be defined as an instrument reading of 500 ppm or more above background. [40CFR60.692-5.e.1]
2) A leak detected by the APCO or his designee shall constitute a violation of this condition with the exception of those components previously identified by ConocoPhillips that are awaiting repair. [40CFR60.692-5.e.1 and District-only, Rule 206]

10. **Process Unit H, Gas Oil Loading Rack.** [District-only, Rule 206]

a. A continuously accumulating metering device or equivalent shall be in place, calibrated, on-line whenever gas oil is being loaded, and maintained in good operating order on the truck loading and unloading lines of the shipping rack.
b. The APCO shall be notified no less than three (3) working days prior to the use of this equipment.

11. **Process Unit K, Tail Gas Treating Unit**

a. The instrument for the continuous monitoring and recording of concentrations of total reduced sulfur in the gases discharged to the atmosphere from the tail gas unit, AN-1707/1709, shall be installed such that representative measurements of emissions or process parameters are obtained; shall be in continuous operation, except for breakdowns, repairs, calibration checks, and zero or span adjustments; and shall be calibrated and on-line whenever gas is being processed in the tail gas unit; and shall be operated and maintained in accordance with 40CFR60, subpart J. [40CFR60.105.a.6, 60.13.e, and 60.13.f]
b. The District approved sampling platform, electrical service, and sampling ports shall be maintained in good condition. [District-only, Rule 210.b.1]

12. **Process Unit M, Compressor Engines.** [District-only, Rule 206]

a. The diesel engine shall be tuned so that particulate emissions are not visible, except during start-up.
b. Provisions for fuel oil sampling shall be maintained and available upon District request.
c. If the 115 hp John Deere portable air compressor, GB-1015, remains at any one location for more than 365 consecutive days, operates at that location at any given time, and has operated 200 hours or more during any calendar year since it first began operation at the Santa Maria Facility, then it will be subject to the new

engine requirements of District Rule 431, Stationary Internal Combustion Engines, as follows: [District-only, Rule 431]

1) NOx emissions shall not exceed 600 ppmv dry at 15% O2.
2) CO emissions shall not exceed 4,500 ppmv dry at 15% O2.

13. Process Unit O, Hydrocarbon Relief and Recovery System

a. The compressor's barrier-fluid seals shall be in-place and maintained to prevent leakage of the working fluids or gases to the atmosphere. [40CFR60.482-3.a]
b. A spare compressor of equivalent capacity to compressor GB-455, with equivalent seal design, shall be available in storage at the refinery unless the spare compressor is in service. [District-only, Rule 206]
c. The relief and recovery system shall be on-line whenever gas is present in any line or vessel that is vented to the system, and operated so as to minimize flaring. [District-only, Rule 206]
d. ConocoPhillips shall operate and maintain the flare in accordance with the manufacturer's design and the provisions of 40CFR60.18. [40CFR60.18 and 40CFR60.482-10.d]

1) There shall be no visible emission except for periods not to exceed a total of five (5) minutes during any two (2) consecutive hours. [40CFR60.18.c.1]
2) A pilot flame at the flare tip shall be maintained at all times as indicated by a minimum flame sensor temperature of 350° F or visible flame. [40CFR60.18.c.2 and 40CFR60.695.a.4]
3) The flare system shall be on-line and in operation at all times when emissions may be vented to it. [40CFR60.18.e]
4) The flare stack mass flow instrument shall be calibrated and on-line at all times when emissions may be vented to the flare system and maintained and operated in accordance with the manufacturer's design. [District-only, Rule 206]

14. Process Unit Q, Green Coke Handling System. [District-only, Rule 206]

a. If it is found that the emissions from the equipment or stockpiles covered by this permit are the cause of an excessive concentration of air contaminants anywhere beyond the facility's property line, corrective steps shall be taken to control the emissions.
b. ConocoPhillips will, upon notification by the APCO, provide such information and analysis as will disclose the extent and degree of contamination that the equipment or stockpiles cause or may cause in the ambient atmosphere, or at the option of the APCO provide facilities for, and allow access to, the equipment by Air Pollution Control District personnel or agents for inspection and/or emission testing.
c. Operation of the 225 hp John Deere portable water pump shall be subject to the following:

1) If the engine remains at any one location for more than 365 consecutive days and operates at that location at any given time, then it will be subject

to the new engine requirements of District Rule 431, Stationary Internal Combustion Engines, as follows:

i. Oxides of nitrogen (NOx) emissions shall not exceed 600 ppmv dry at 15% O2.

ii. Carbon monoxide (CO) emissions shall not exceed 4,500 ppmv dry at 15% O2.

d. ConocoPhillips shall maintain and operate the permanently installed APCO approved diesel oxidation catalyst on two bulldozers and two front-end loaders involved in green coke pile operations under Process Unit X to this permit.

e. The open storage of petroleum coke at the Santa Maria Facility shall not exceed the volume of coke stored on-site as of January 1, 2006. The on-site open coke storage volume shall be determined monthly using the December 2005 Greenwell survey and the monthly amounts of coke produced and shipped since January 1, 2006.

15. Process Unit S-1, Calcined Coke Storage and Handling. [District-only, Rule 206]

a. All equipment except the by-pass bin and the reclaim hopper shall be vented to an approved air pollution control system.

b. This equipment shall be on-line and maintained in proper operating order. Ducts used to vent the coke sizing screen equipment shall have not more than ¼" of material build-up on the interior surface. ConocoPhillips shall supply access to the duct interior upon the District's request.

16. Process Unit S-3, Calcined Coke Portable Handling Equipment. [District-only, Rule 206]

a. The APCO shall be notified before the calcined coke portable handling equipment is modified or removed from service.

b. This equipment shall not be used offsite without prior approval of the APCO. Any use offsite may require submittal of an application for modification or change of location.

c. All hoppers shall be fed by a front-end loader.

17. Process Unit U, Sulfur Pelletizing Plant. The staging area shall be kept free of sulfur to minimize fugitive emissions associated with vehicular traffic around the sulfur pelletizing plant. The staging area shall be defined as any area where equipment and/or trucks operate within the sulfur pelletizing plant area including the roadway to the coke plant. Stockpiles, including a ten foot (10') strip around the base, are not considered the staging area. [District-only, Rule 206]

18. Process Unit V, Product Elevator Bypass System. The bypass conveyor system shall be used only under the following conditions: [District-only, Rule 206]

a. periodically to verify front-loader product scales,

b. during upset periods of extreme high coke temperature excursion in the product cooler where coke temperature has the potential to exceed 400°F,

c. during upset periods of product elevator failure, or

d. any emergency condition that could result in the shut down of the plant.

19. Process Unit W, Diesel Engine Systems. The electrically-driven carbon plant runoff collection pond pump shall be available for use at all times and shall be used preferentially to the internal combustion engine-driven pump, BK-699, to prevent flooding of areas that are down slope from the collection pond. [District-only, Rule 206]

F. Future Effective Conditions. The following conditions will become effective upon completion of the respective Authorities to Construct or upon the date as indicated.

1. Diesel Engine Air Toxic Control Measures

a. Stationary Diesel Engines. ConocoPhillips shall comply with all future applicable provisions of 17CCR93115, Airborne Toxic Control Measure for Stationary Compression Ignition Engines. [District-only, 17CCR93115]

1) Effective January 1, 2008, ensure that the diesel particulate filter on the GE-522 water pump either reduces particulate emissions by at least 85% or achieves a particulate matter emission rate of 0.01 g/bhph or less. [District-only, 17CCR93115.e.2.D.1.a&b and 93115.g.2]
   i. The GE-522 diesel particulate filter shall employ a backpressure monitor, which shall be calibrated, on-line, operational, and maintained in accordance with the manufacturer's recommendations whenever the engine is in operation. [District-only, 17CCR93115.e.4.G.2]

2) Effective July 1, 2011, ensure that the following emission units utilize an engine that meets or exceeds the tier 4 offroad emission standards of 13CCR2423: [District-only, 17CCR93115.e.2.D.1.c]
   i. G-51-4, cooling tower recirculation pump, and
   ii. GB-524S, spare plant air compressor.

b. Portable Diesel Engines. ConocoPhillips shall comply with all future applicable provisions of 17CCR93116, Airborne Toxic Control Measure for Diesel Particulate Matter from Portable Engines Rated at 50 Horsepower and Greater. [District-only, Rule 206 and 17CCR93116]

1) No later than July 1, 2009, submit a compliance plan for all subject engines that includes at least the following information: [District-only, 17CCR93116.3.b.1]
   i. ConocoPhillips assigned engine designation;
   ii. engine manufacturer, model, and model year;
   iii. if certified to an EPA non-road emission standard, the engine family identification;
   iv. whether the engine is in standby or prime mover use;
   v. whether an emergency or low-use status is requested and, if so, a justification for the same,
   vi. the control strategy to be used for each engine; and
   vii. the timing of that control strategy.

G. Permit Shield. The following federally-enforceable limits are subsumed by the conditions of this permit. The subsumed limit is listed first and then the permit condition(s) subsuming that limit is listed in [square brackets]. Violation of a streamlined limit, *i.e.,* those in [square brackets], may also trigger enforcement action against a subsumed emission limit to the extent that a violation of that emission limit is documented. Through this action, streamlined requirements that were previously District-only requirements become federally-enforceable if any subsumed requirement is federally-enforceable. All monitoring, recordkeeping, and reporting requirements that are associated with any subsumed requirement are also subsumed and shall not apply except as identified elsewhere in this permit.

1. The following storage tank requirements are subsumed and shall not apply.

   a. For Tanks 550 and 551, process A-1, the SIP Rule 407.A.2 requirement for a vapor recovery system and that all gauging and sampling ports be maintained gas-tight. [conditions II.B.1.d and III.C.5.b]
   b. For Tank 903, process A-1,

      1) the 40CFR60.113b.b.4 primary and secondary seal gap requirements, [condition III.E.1.a.1]
      2) the 40CFR60.112b.a.2 requirement for floating roof with double seals, [condition III.E.1.b.1.i]
      3) the 40CFR60.113b.b.1.i and 113b.b.6 seal inspection requirements, and [conditions III.C.4.i & h respectively]
      4) the 40CFR60113b.b.2 inspection technique requirements. [condition III.C.4.j]

2. The 40CFR60.104.a.2.i and 40CFR63.1568.a.1 requirements that the tail gas unit, process K, sulfur dioxide emissions not exceed 250 ppmv (dry) corrected to zero percent (0%) O_2 is subsumed and shall not apply. [condition I.A.17]
3. The 40CFR60.44b.a.1.ii requirement that the B-506 boiler NO_x emissions not exceed 0.2 lb/mmBtu is subsumed and shall not apply. [condition I.A.1]
4. The 40CFR60.48b.g.2 requirement for a predictive NO_x program, with the exception of the hourly fuel usage monitoring of 60.49b.c.3, is subsumed and shall not apply. [conditions III.B.1.c, III.B.1.d, III.B.2.i, & III.D.2]

H. **Alternative Operating Scenarios.** ConocoPhillips is allowed to operate under the alternative scenario(s) listed below and must maintain a record of all changes in operating scenarios. An Authority to Construct pursuant to District Rule 202 may be required for any given alternative scenario. [Rule 216.G.2]

I. **Tank Farm Vapor Recovery Temporary Flare System.** During common turnarounds when both refinery process lines A and B are shutdown and undergoing maintenance, a temporary flare system may be used to incinerate off-gas from the tank farm vapor recovery system, Process A-2.

   a. Temporary flare system equipment description:

      1) SulfaTreat HP scrubber
      2) backup scrubber system with activated carbon
      3) flared gas H_2S analyzer, AE-457
      4) smokeless flare, 4 inch diameter, 1000 scfm, natural gas continuous pilot.

   b. Conditions specific to the temporary flare system:

      1) The temporary flare shall not be used to incinerate gas with a H_2S content greater than 0.10 gr/dscf (160 ppmv), three-hour average and as measured

by the AE-457 H_2S analyzer; or with a total sulfur content greater than 0.50 gr/dscf (797 ppmv), as measured by the Tutweiler test. [40CFR60.104.a.1 and SIP Rule 404.e.1]

2) The AE-457 instrument for continuously monitoring and recording concentrations of hydrogen sulfide in the flare gas shall be installed such that representative measurements of emissions or process parameters are obtained and shall be calibrated and on-line at all times when emissions may be vented to the flare system and maintained in accordance with the provisions of 40CFR60, subpart J. Except for system breakdowns, repairs, calibration checks, and zero or span adjustments, the AE-457 system shall be in continuous operation. [40CFR60.105.a.4, 60.13.e, and 60.13.f]

3) The AE-457 H_2S analyzer shall meet the following specifications.
   i. span, 425 mg/dscfm H_2S [40CFR60.105.a.4.i]
   ii. calibration drift, ≤ 21 ppm [40CFR60.PS-7.6.2]
   iii. relative accuracy - If the average emissions during testing are less than 50% of the emission standard, the applicable emission standard value shall be used in the denominator of the RA equation 2-6 from 40CFR60.PS-2, as it appeared in the federal regulations as published on July 1, 2001, and the RA shall be no greater than 10%. If the average emissions during testing are greater than or equal to 50% of the emission standard, the average reference method value shall be used in the denominator of the equation and the RA shall be no greater than 20%. [40CFR60.PS-2.13.2 & 7.6.3]

4) The AE-457 H_2S analyzer shall be calibrated daily in accordance with 40CFR60.PS-7. [40CFR60.13.d.1]

5) On a weekly basis, the flared gas shall be sampled for hydrogen sulfide by using the drager tube method and total sulfur content using ARB-16A, Tutweiler option. [SIP Rule 205 and SIP Rule 404.E.1]

6) ConocoPhillips shall conduct or cause to be conducted a performance audit at least once during each operational period of the temporary flare system for the AE-457 flared gas monitor. Such testing shall be conducted in compliance with the requirements of 40CFR60 subpart 60.105(a) and the most recent version of the District's source test policy. [40CFR60.13.c and District-only Rule 210.B.1]

7) AE-457 Unusual Operating Condition, Actions, and Reporting
   i. Any instantaneous exceedance of 160 ppmv H_2S in the fuel gas shall be reported immediately to the District, and strip charts for periods of exceedance included in the monthly report under condition III.H.1.b.9.i below. [District-only, Rule 206]
   ii. Any exceedance of 160 ppmv H_2S, averaged over three (3) hours, shall be included with the monthly report under condition III.H.1.b.9.i below and shall include: the magnitude of emissions due to excess H_2S, conversion factors used, and date and time of commencement, and completion of each time period of excess emissions. [40CFR60.105.e.3.ii]
   iii. Specific identification of any exceedance of 160 ppmv H_2S, averaged over three (3) hours, that occurs during start-up, shut-

down, or malfunction of the caustic scrubber shall be included with the monthly report under condition III.H.1.b.9.i below and shall include the nature and cause of any malfunction and corrective action taken. [District-only, Rule 206]

iv. The date and time identifying each period during which AE-457 was inoperative, other than for daily calibration, and the nature of system repairs and adjustments shall be logged and reported to the APCO in accordance with the provisions of District Rules 107 and 113. A summary report of this information shall be included with the monthly report as required under condition III.H.1.b.9.i below. [40CFR60.7.b&c]

8) The following records for the AE-457 H_2S analyzer shall maintained, then retained for a minimum of five (5) years, and be made available to the APCO upon request. [Rule 216.F.1]

i. any measurement made; [40CFR60.105.a.4]

ii. relative accuracy tests performed in accordance with EPA Method 15; [SIP Rule 205]

iii. calibration drift test results as required by 40CFR60.PS-7; [40CFR60.PS-7.6.2]

iv. daily records of the calibration including the date, zero and span values, and calibration drift; [40CFR60.13.d.1]

v. records of all maintenance: [SIP Rule 205]

(a) date, place, and time of maintenance activity;

(b) operating conditions at the time of maintenance activity;

(c) date, place, name of company or entity that performed the maintenance activity and the methods used; and

(d) results of the maintenance; and

vi. all data sufficient to report excess emissions and continuous monitoring system (CMS) downtime as required by 40CFR60.105.e.3.ii and 40CFR60.7.c. [SIP Rule 205]

9) All reporting associated with data gathered from the AN-603 analyzer shall apply to the AE-457 analyzer while the temporary flare is in use. A clear distinction shall be drawn in that reporting as to which instrument any given data applies.

i. On a calendar monthly basis, ConocoPhillips shall submit a report to the APCO. That report shall be submitted no later than ten (10) business days after the end of the month and shall include copies of records, including strip charts as identified under condition III.H.1.b.8 above, and an explanation for any unusual event that causes the flared gas sulfur content to exceed an instantaneous value of 160 ppm H_2S. [District-only, Rule 206]

ii. On a quarterly basis, ConocoPhillips shall submit a report to the APCO, with a copy to the EPA Region IX Administrator. Each report shall be certified to be true, accurate, and complete by a responsible official, and shall include the following data.

(a) Summary information of the hydrogen sulfide concentration in the flared gas based on records maintained under condition III.H.1.b.8. [SIP Rule 205]

(b) Report excess emissions as indicated by, or downtime of, the AE-457 using the summary report form that appears in 40CFR60.7, Figure One (1). If the total duration of excess emissions is less than one percent (1%) and the AE-457 downtime is less than five percent (5%) of the total operating time, only the summary report form, with a statement that no excess emissions and/or no CMS downtime occurred, need be submitted. If the excess emissions or CMS downtime exceeds either of those times, the summary report shall be accompanied by a report that includes: [40CFR60.7.c]

(1) The magnitude of excess emissions, conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

(2) The process operating time during the reporting period.

(3) whether the excess emissions occurred during start-up, shutdown, or malfunction.

(4) The nature and cause of any malfunction, the corrective action taken, or preventive measures adopted.

(5) The date and time of CMS downtime, except for zero and span checks, and the nature of system repairs or adjustments.

10) Action must be taken to comply with the notification, recordkeeping, and reporting requirements as specified in 40CFR60.7. All notifications and reports shall be submitted to the APCO with a copy submitted to the EPA Region IX Administrator. Such action shall include: [40CFR60.7]

i. Written notification, of the anticipated date of any physical or operational change that may increase emissions, no less than 60 days prior to that date.

ii. Written notification, of the date upon which demonstration of the continuous monitoring system performance commences, no less than 30 days prior to that date.

iii. Maintaining records of the occurrence and duration of any startup, shutdown, or malfunction; and any periods when AE-457 is inoperative.

iv. Submitting a summary report on a semiannual basis, if the AE-457 is in operation more than 6 months, and upon the end of the temporary flare's operation in accordance with 40CFR60.7(c) and (d).

IV. Compliance Determination Fees. The following fee schedules shall apply to the indicated process units. [Rule 216.F.1.k]

PROCESS		FEE SCHEDULE (Rule 302.E)		EACH
A-1	Tank Farm, TK-100, 101, 550, & 551	20	fixed roof tank (domed)	4
	TK-800, 801, 900, 901, & 903	21	floating roof tank	5
A-2	Tank Farm Vapor Recovery	45	refining process unit	1
	Temporary Flare (when used)	32	miscellaneous	1
B-1	Coking Unit A	44	refining production line	1
	refinery in general	1	air monitoring oversight	1
	B-201A	4a	small process heater	1
	B-62A	4c	medium process heater	1
	B-2A & B-102A	4c	large process heater	2
	atm distillation, vacuum distillation, & coking sections	45	refining process unit	3
	cooling tower recirc pump, G-51-4	28b	additional engine	1
B-2	Coker Steamout	45	refining process unit	1
	TK-405 & 406	21	open top tank	2
B-3	Gland Oil	32	miscellaneous	1
	TK-500	20	fixed roof tank	1
C	Coking Unit B	44	refining production line	1
	B-201B	4a	small process heater	1
	B-62B	4c	medium process heater	1
	B-2B & B-102B	4c	large process heater	2
	atm distillation, vacuum distillation, & coking sections	45	refining process unit	3
D-1	Main Boiler Plant, B-504, 506 and 507	4c	large boiler	3
	emergency water pump engine, G-515-3	28b	additional engine	1
	emergency water pump engine, G-515-4	28b	additional engine	1
D-2	Electrical Power Generation Plant	4c	large boiler	1
E	Sulfur Units A & B	43	sulfur recovery unit	2
G	Oily Water Treatment	39	oily water treatment	1
	F-408, 409, & 824	20	fixed roof tank	3
	TK-822 & 823	21	floating roof tank	2
H	Gas Oil Loading Rack	42	loading rack	1
	TK-802	20	fixed roof tank	1
I	Hydrogen Sulfide Absorption Unit A	43	sulfur recovery unit	1
J	Hydrogen Sulfide Absorption Unit B	43	sulfur recovery unit	1
K	Tail Gas Unit	43	sulfur recovery unit	1
L	Product Pumps	32	miscellaneous	1
M	Compressor Engine, GB-524S	28a	IC engine – first	1
N	Abrasive Blasting	50	sandblasting	1
O	Hydrocarbon Relief and Recovery	45	refining process unit	1
P	Process Water System	45	refining process unit	1
	process water tank, TK-351	20	fixed roof tank (domed)	1
Q	Green Coke Handling	48c	large screening unit	1
	asphalt emulsion system	32	miscellaneous	1
	portable water pump, GE-522	28b	additional engine	1
A	Petroleum Coke Production	41	coke production	1
	portable air compressor, GB-1015	28b	additional engine	1
S-1	Calcined Coke Storage and Handling	48c	large screening unit	1

PROCESS		FEE SCHEDULE (Rule 302.E)		EACH
S-2	Calcined Coke Loading Control	32	miscellaneous	1
S-3	Calcined Coke Portable Handling	32	miscellaneous	1
U	Sulfur Pelletizing Plant	32	miscellaneous	1
V	Product Elevator Bypass System	32	miscellaneous	1
W	Diesel Engine Systems	28b	additional engine	9
X	Control Devices for Mobile Equipment	32	miscellaneous	1

ConocoPhillips, Santa Maria Facility, 44-49

Appendix A - Approved Alternative Testing Methods

Dated: September 2005
Referenced in Condition: III.D.11

Cal/EPA - Air Resources Board

Approved Alternative Monitoring and Test Methods

This page updated October 2, 2006

This file lists U.S. EPA alternative monitoring methods and California test methods that have been determined by the U.S. EPA, Region IX, to be technically acceptable for inclusion into the State Implementation Plan (SIP) or for use in conjunction with SIP approved rules. However, the U.S. EPA reserves the right to determine the appropriateness of any accepted test method for compliance determinations in new or revised rules submitted for incorporation into the SIP. Initial compliance testing for NSPS must be done with U.S. EPA methods.

The links to the following web sites are provided for information only. Although newer versions of some methods may be available at these web sites, only the versions specially approved by EPA can be used to demonstrate compliance with SIP rules.

http://www.aqmd.gov/tao/methods/labmethtoc.html
http://www.baaqmd.gov/dst/mop/index.htm
http://www.arb.ca.gov/testmeth/testmeth.htm

Equivalent Monitoring Methods

The file lists the method number, the title of the test method, the adoption date of the method version approved by the U.S. EPA, Region IX, and the link to the Federal Register notice. There are comments at the end of this list associated with the test methods identified by an asterisk (*).

METHOD#	TITLE
EPA 1	New Equivalent Method for Monitoring PM10 April 8, 2004 Federal Register Notice

Alternative Test Methods

The file lists the regulatory agency (district or ARB), the method number, the title of the test method, and the adoption date of the method version approved by the U.S. EPA, Region IX. There are comments at the end of this list associated with the test methods identified by an asterisk (*).

For further information, please contact Stanley Tong at (415) 947-4122 of U.S. EPA, Region IX.

METHOD #	TITLE
ARB 1	Sample and Velocity Traverses for Stationary Sources March 28, 1986
ARB 2	Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube) June 29, 1983
ARB 2A	Direct Measurement of Gas Volume Through Pipes and Small Ducts March 28, 1986
ARB 3	Carbon Dioxide, Oxygen, Excess Air, and Molecular Weight March 28, 1986
ARB 4	Determination of Moisture Content in Stack Gases June 29, 1983
ARB 5*	Determination of Particulate Matter Emissions from Stationary Sources July 28, 1997
ARB 7	Determination of Nitrogen Oxide Emissions from Stationary Sources September 26, 1996
ARB 10	Determination of Carbon Monoxide Emissions from Stationary Sources June 29, 1983
ARB 12	Determination of Inorganic Lead Emissions from Stationary Sources March 28, 1986
ARB 13A	Determination of Fluoride Emissions: SPADNS Zirconium Lake Method March 28, 1986
ARB 17	Particulate Emissions (In-Stack Filtration Method) June 29, 1983
ARB 100	Procedures for Continuous Gaseous Emission Stack Sampling June 28, 1997
ARB 310	Determination of Volatile Organic Compounds (VOC) in Consumer Products and Reactive Organic Compounds in Aerosol Coating Products June 22, 2000.
ARB 401*	Determination of the Weight Percent of VOC in Waste Products March 28, 1986
ARB 422	Exempt Halogenated VOCs in Gases September 12, 1990
ARB 425*	Determination of Total and Hexavalent Chromium Emissions July 28, 1997

METHOD #	TITLE
ARB 428*	Determination of Polychlorinated Dibenzo-p-Dioxin, Polychlorinated Dibenzofuran, and Polychlorinated Biphenyl Emissions From Stationary Sources July 3, 2004
ARB 431	Determination of Ethyne Oxide Emissions from Stationary Sources November 13, 1998
ARB 432	Exempt Halogenated VOC in Liquids September 12, 1989
ARB 436	Determination of Multiple Metals September 26, 1996
BAAQMD 4A	Determination of Lead Collected on Particulate Filters February 27, 1996
BAAQMD 9	Determination of Compliance Solvents, Coatings, and Related Products December 12, 1990
BAAQMD 10	Determination of Sulfur in Fuel Oil September 2, 1998
BAAQMD 10A	Determination of Sulfur in Petroleum and Petroleum Products May 18, 2005
BAAQMD 13	Determination of the Reid Vapor Pressure of Petroleum Products September 1989
BAAQMD 15A	Standardization and Analysis of Permanent Gases and Methane September 15, 2000
BAAQMD 17	Standardization of Hydrocarbon Calibration Gases September 15, 2000
BAAQMD 21	Compliance for Air-Dried Arch., Water-Based Coatings June 1989, amended May 18, 2005
BAAQMD 22	Compliance, Air-Dried Solvent-Based Coating December 20, 1995, amended May 18, 2005
ASTM D6133-02	Standard Test method for Acetone, p-Chlorobenzotrifluoride, Methyl Acetate or t-Butyl Acetate Content of Solventborne and Waterborne Paints, Coatings, Resins, and Raw Materials by Direct Injection Into a Gas Chromatograph May 12, 2004
BAAQMD 23	Determination of Volatile Emissions from Polyester Resins April 15, 1992
BAAQMD 26	Determination of Volatile Weight Loss of Gel Coats April 15, 1992
BAAQMD 28	Determination of Vapor Pressure of Organic Liquids from Tanks March 22, 1991
BAAQMD 29	Determination of Ethanol in Bakery Effluents December 21, 1988

METHOD #	TITLE
BAAQMD 31	Determination of Volatile Organic Compounds in Paint Strippers, Solvent Cleaners, and Low Solids Coatings November 1989, amended May 18, 2005
BAAQMD 33	Determination of Dissolved Critical VOCs in Waste Water Separators November 1, 1989, amended May 18, 2005
BAAQMD 35	VOC in Solvent-Based Aerosol Paints January 19, 1994
BAAQMD 36	VOC in Water-Based Aerosol Paints October 3, 1990
BAAQMD 37	Determination of Perchloroethylene in Dry Cleaning Filtration Wastes April 3, 1991
BAAQMD 38	Determination of Petroleum Solvent in Dry Cleaning Filtration Wastes April 3, 1991
BAAQMD 39	Determination of Styrene Monomer Content of Polyester Resins April 15, 1992
BAAQMD 40	Determination of Volatile Organic Compounds in Adhesives Used for Pipes and Fittings June 5, 1996
BAAQMD 41	Determination of Volatile Organic Compounds in Solvent-Based Coatings and Related Materials Containing Parachlorobenzotrifluoride December 20, 1995, amended May 18, 2005
BAAQMD 42	Determination of Ammonia in Coatings, Inks, and Related Materials November 6, 1996
BAAQMD 43	Determination of Volatile Methylsiloxanes in Solvent-Based Coatings, Inks, and Related Materials November 6, 1996, amended May 18, 2005
BAAQMD 45*	Determination of Butanes and Pentanes in Polymeric Materials January 19, 2000, amended May 18, 2005
BAAQMD 46	Determination of the Composite Partial Pressure of Volatile Organic Compounds in Cleaning Products, amended May 18, 2005
BAAQMD ST-1B	Ammonia, Continuous Sampling January 20, 1982
BAAQMD ST-3	Bulk Plants Emission Factor Determination December 21, 1994
BAAQMD ST-7*	Organic Compounds April 15, 1992
BAAQMD ST-27	Gasoline Dispensing Facility - Dynamic Back Pressure December 21, 1994
BAAQMD ST-30	Gasoline Dispensing Facility - Leak Test Procedure December 21, 1994

METHOD #	TITLE
BAAQMD ST-32	Ethanol, Integrated Sampling December 21, 1988
BAAQMD ST-33	Gasoline Cargo Tanks December 21, 1994
BAAQMD ST-34	Bulk Gasoline Distribution Facilities-ER Unit or C Adsorption December 21, 1994
SCAQMD RO	Protocol for Determination of Particulate and Volatile Organic Compound Emissions from Restaurant Operations November 14, 1997
SCAQMD TE*	Procedure for Testing Spray Equipment Transfer Efficiency May 24, 1989
SCAQMD CS*	Solvent Losses from Spray Gun Cleaning Systems October 3, 1989
SCAQMD CE	Protocol for Determination of VOC Capture Efficiency May 1995
SCAQMD 1.1	Sample and Velocity Traverses for Stationary Sources March 1989
SCAQMD 1.2	Sample and Velocity Traverse for Stationary Sources with Small Stacks March 1989
SCAQMD 2.1	Stack Gas Velocity and Volumetric Flow Rate (S-Type Pitot Tube) March 1989
SCAQMD 2.2	Direct Measurement of Gas Volume Through Pipes and Small Ducts March 1989
SCAQMD 2.3	Gas Velocity and Volumetric Flow Rate from Small Stacks or Ducts March 1989
SCAQMD 3.1	Gas Analysis for Dry Molecular Weight and Excess Air March 1989
SCAQMD 4.1	Determination of Moisture Content in Stack Gases March 1989
SCAQMD 5.1	Determination of Particulate Matter Emissions -- Wet Impingement March 1989
SCAQMD 5.2	Determination of Particulate Matter Emissions -- Heated Probe and Filter March 1989
SCAQMD 5.3	Determination of Particulate Matter Emissions from Stationary Sources Using an In-Stack Filter October 2005
SCAQMD 6.1	Determination of Sulfuric Acid and Sulfur Oxides from Stationary Sources March 1989
SCAQMD 7.1	Determination of NOx Emissions from Stationary Sources March 1989

METHOD #	TITLE
SCAQMD 9B	Opacity Methods No. 9B October 2005
SCAQMD 25.1	Total Gaseous Non-Methane Organic Emissions February 1991
SCAQMD 25.3	Determination of Low Concentration Non-Ethane Non-Methane Organic Compound Emissions From Clean-Fueled Combustion Sources March 2000
SCAQMD 100.1	Instrumental Analyzer Procedures for Continuous Gaseous Sampling March 1989
SCAQMD 205.1	Determination of Hexavalent and Total Chromium from Plating August 1991
SCAQMD 300-91	Analysis of Asbestos in Bulk Materials August 1996
SCAQMD 301-91	Identification of Particles by Microscopy August 1996
SCAQMD 302-91	Distillation of Solvents from Paints, Coatings, and Inks February 1993
SCAQMD 303-91	Determination of Exempt Compounds August 1996
SCAQMD 304-91	Determination of VOC in Various Materials February 1996
SCAQMD 305-91	Determination of VOC in Aerosol Applications June 1993
SCAQMD 306-91	Analysis of Pentanes in Expandable Styrene Polymers February 1993
SCAQMD 307-91	Determination of Sulfur in a Gaseous Matrix March 1994
SCAQMD 308-91	Quantitation of Compounds by Gas Chromatography February 1993
SCAQMD 309-91	Determination of Static Volatile Emissions February 1993
SCAQMD 310-91	Determination of Perchloroethylene May 1993
SCAQMD 312-91	Determination of Percent Monomer in Polyester Resins April 1996
SCAQMD 313-91	Determination of VOC by GC / MS June 1993
SCAQMD 314-91	Quantitation of Photochemically Reactive Compounds February 1993
SCAQMD 315-91	Determination of H2S and Mercaptans in Oil and Sludge Samples November 1996
SCAQMD 316B-97	Determination of VOCs in Adhesives Containing Cyanoacrylates August 1997
SCAQMD 316A-92	Determination of VOCs in Materials Used for Pipes And Fittings October 1996

METHOD #	TITLE
SCAQMD 317-93	Determination of Natural Fibers August 1996
SCAQMD 318-95*	Determination of Weight Percent Elemental Metal in Coatings by X-Ray July 1996
SCAQMD 501.1	Total Non-Methane Vapors from Organic Loading and Storage March 1989
SCAQMD 1146*	Protocol for the Measurement of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Sources Subject to South Coast Air Quality Management District Rule 1146, September 2001
SDAPCD	Raoult's Law Calculation for Vapor Pressure of VOC Mixtures
SDAPCD 24D*	Determination of Density, Total Volatile Matter Content and Weight Solids of Surface Coatings Containing Photosensitive Reactive Diluents July 1993
SDAPCD 100*	Test Procedures for the Determination of Nitrogen Oxides, Carbon Monoxide and Diluent Gases by Continuous Emission Monitoring May 1995
SJVUAPCD LBNL-VP*	Vapor Pressure of Reactive Organic Compounds in Heavy Crude Oil Using Gas Chromatography May 2002

* COMMENTS ON ALTERNATIVE CALIFORNIA TEST METHODS

ARB 401	This method cannot be substituted for EPA Method 25D
ARB 425	This method has been approved as an alternative to EPA Method 306 for the purpose o fdemonstrating compliance with the Chrome Plating ATCM / NESHAP
ARB 428	This method has been approved as an alternative to EPA Method 23 for measuring dioxin/furan emissions from the secondary aluminum facilities in California specified as follows: ALRAYCO, LLC, Adelanto CA; Commonwealth Aluminum Corp., Long Beach, CA; Custom Alloy Light Metals, Inc., City of Industry, CA; Custom Alloy Sales, Lynwood, CA; Custom Alloy Scrap Sales, Oakland, CA;Indalex West Inc., City of Industry, CA; Kaiser Aluminum and Chemical Corp., Commerce, CA; Liston Brick of Corona, Corona, CA; Pechiney Cast Plate, Vernon, CA; Timco Standard Tandem, Fontana, CA; Thorock Metals Company, Compton, CA; Tri Alloy Group LLC, Montclair, CA; United State Marine Corp, Twentynine Palms, CA; and Vista Metals Corp., Fontana, CA; *provided they only use high resolution mass spectrometry for sample analysis.*
BAAQMD ST-7	This method cannot be used for combustion processes
BAAQMD 22 - ALT. METHOD	This method is not approved for compliance determination with NSPS or NESHAPs
BAAQMD 45	This method is not approved for compliance determination with NSPS

METHOD #	TITLE
	or NESHAPs
SCAQMD TE	This method cannot be used for generating TE credits
SCAQMD CS	This method cannot be used for actual emission results
SCAQMD 318-95	Use for metals other than Aluminum requires validation
SCAQMD 1146	SCAQMD Rule 1146 must clarify that SCAQMD 1146 Method is an alternative rather than an equivalent method
SDAPCD 24D	This method is only acceptable for NAPP Systems Inc. in the San Diego APCD
SDAPCD 100	This method does not measure SO2
SJVUAPCD LBNL-VP	This method has not been reviewed or approved for use in determining compliance with other programs e.g. the air toxic program. The definition of heavy crude oil in section 3.1.2 should be modified to state it is 26 degrees or less to make this section consistent with Section 1.2.

Title V Activities and Information

Title V Permit to Operate

ConocoPhillips Santa Maria Refinery

Draft Staff Report

Application Numbers 4229, 4255, 4256, 4318, 4369

June 29, 2007

I. Introduction:

The District received two applications for significant Part 70 permit revisions at the COP facility, and three applications for minor revisions. In addition to these five applications some minor administrative amendments are also being made to the permit.

Application 4229 was submitted for the installation of a new 99.9 mmBTU/hr boiler at the Utility Plant. This boiler was intended to replace the steam capacity lost when the calciner waste heat boiler shut down on March 13, 2007. The new boiler is subject to NSPS Subpart Dc and MACT Subpart DDDDD.

Application 4255 was submitted to install an SO2 Continuous Emissions Monitoring System (CEMS) and a stack flow meter on each of the facility's two B602 incinerators. COP installed these CEMS to meet a requirement of the refinery Consent Decree to "either eliminate, control, and/or include and monitor ... all sulfur pit emissions." The Consent Decree also stipulates that the sulfur recovery plants are now subject to the NSPS Subpart J requirements.

Three applications for non-federal minor revisions were also received. Application 4256 was submitted to make minor changes to the temporary flare system listed in the facility's Alternative Operating Scenario. Application 4318 was submitted to replace an abrasive blasting sandpot and remove some associated equipment from the permit. Application 4369 was submitted to update the equipment description at the sulfur pelletizing plant by deleting equipment that has been removed from the facility.

Administrative Changes: 1) The referencing for Permit Condition III.C.5.b was corrected; it addresses control equipment on Tanks 900, 901 and 903. 2) Mutual settlement conditions of Notice of Violation #2146 have been incorporated into Permit Conditions III.B.2.e and III.B.2.h that address the inspections required for Tanks 900, 901 and 903. 3) Requirements of newly adopted District Rule 440, Petroleum Coke Calcining and Storage Operations were added to the permit. 4) Some of the conditions in the future effective condition section were deleted because they were no longer applicable or already implemented. 5) A minor change to Permit Condition III.B.1.a.7 was made to remove the mention of a back-up strip chart which is not required to be maintained.

The significant changes are fully described in Section II of this report. Minor permit revisions are discussed in Section IV, and the administrative changes are described in Section V.

II. Significant Revisions:

(A) Application 4229 – Installation of a new 99.9 mmBTU/hr Boiler

Applicable NSPS Requirements: 40CFR60, Subpart Dc – Standards of Performance for Small Industrial-Commercial Institutional Steam Generating Units, 60.40c – 60.48c: Applicable to 10 mmBTU/hr < units < 100 mmBTU/hr
60.43c Standard for Particulate Matter: (c) 20% opacity limit – **This requirement is listed as Permit Condition III.A.1.a.1**

Section 60.43c (e)(1) was added in 2006 and it specifies a PM limit of 0.03 lb/mmBTU for units with a heat input > 30 mmBTU/hr - **Condition I.A.10**. The preamble to this addition states (9868, FR/Vol71, No. 38, 2/27/06):

C. What are the requirements for small industrial-commercial-institutional steam generating units (40 CFR part 60, subpart Dc)?

The PM emission limit for new and reconstructed small industrial-commercial-institutional steam generating units is 13 ng/J (0.03 lb/ MMBtu) heat input for units that burn coal, oil, gas, wood, or a mixture of these fuels with other fuels. The PM emission limit for modified industrial-commercial-institutional steam generating units is 13 ng/J (0.03 lb/ MMBtu) heat input or 99.8 percent reduction for units that burn coal, oil, gas, wood, or a mixture of these fuels with other fuels with one exception. The standard for modified wood-fired industrial-commercial-institutional steam generating units is 43 ng/J (0.10 lb/MMBtu) heat input. These limits apply to units between 8.7 MW and 29 MW (30 to 100 MMBtu/h) heat input. While not required, PM CEMS may be used as an alternate method to demonstrate continuous compliance and as an alternative to opacity monitoring.

Units burning only oil that contains no more than 0.5 weight percent sulfur or liquid or gaseous fuels that, when combusted without SO2 emission control, have a SO2 emission rate equal to or less than 230 ng/J (0.54 lb/MMBtu) heat input, may demonstrate compliance with the PM standard by maintaining certification of the fuels burned. Such units are not required to conduct PM compliance tests, conduct continuous monitoring, or any other recordkeeping or reporting requirements unless the boiler changes the fuel burned to something other than the certified fuels.

The facility fuel gas is currently limited by permit condition to 50 gr/100 scf which is equivalent to 0.086 lb/mmBTU (assuming 1559 BTU/scf). This facility limit is far below the SO2 emission rate referenced in the paragraph above. Compliance with the PM standard will be assured by use of the refinery fuel gas that is currently regulated and continuously monitored.

(0.5 gr/scf)(1 lb/7000 gr)(1 scf/0.001559 mmBTU) = 0.046 lb/mmBTU, S as H_2S
(64/34)(0.046) = 0.086 lb/mmBTU SO_2

60.45c Compliance and performance test methods and procedures for particulate matter: Section (c) specifies that emissions monitoring is not required for units burning gaseous fuels with potential SO2 emissions rates of 0.54 lb/mmBTU or less. No particulate matter testing is required for this unit.

60.48c Reporting and recordkeeping requirements: (g)… "The owner or operator of an affected facility that only burns very low sulfur fuel oil or other liquid or gaseous fuels with potential sulfur dioxide emissions rate of 140 ng/J (0.32 lb/MMBtu) heat input or less shall record and maintain records of the fuels combusted during each calendar month." **These requirements are listed in permit Condition III.C.6**

40CFR60 Subpart J, Standards of Performance for Petroleum Refineries is applicable
60.100 (a) Applicable to fuel gas combustion devices.
60.104 Standards for sulfur oxides
 (a)(1) Fuel gas can not contain H2S is excess of 0.10 gr/dscf
60.105 Monitoring of emissions and operations
 (a)(4) An H2S fuel gas monitor can be used instead of an exhaust SO2 monitor
 (4)(iii) Performance evaluation specified in 60.13(c) must use Performance Specification 7

The proposed boiler is subject to the 0.10 gr/dscf H2S content and fuel gas monitoring requirements. The refinery fuel gas is already being monitored as required by this regulation. Continued compliance with the monitoring and H2S limit requirements is expected. In addition some of the NSPS general provisions are also applicable to this project. **These are currently listed in the permit in Condition III.C.6**

Applicable MACT Requirements:
40CFR63, Subpart DDDDD MACT for Boilers and Heaters, 63.7480: Carbon monoxide CEMs and a limit of 400 ppm@3%O2 are required on new large (>100 mmBtu/hr) gaseous fueled heaters as a surrogate for good combustion and minimum HAP emissions. This rule is applicable to boilers that are located at a major HAP source, which is defined as a single HAP with PTE > 10 tpy, or a facility total > 25 tpy HAPs. When this boiler began operation almost 100 tons/yr of HCl was being emitted from the calciner stack.

63.7500 Table 1: CO limited to 400 ppmv dry corrected to 3% oxygen, 3 run average
63.7545(d) Submit notification of intent to conduct a performance test at least 30 days before the test. **Compliance with these requirements has been demonstrated. The tested CO emission rate was 11.8 ppmvd @ 3% O2. This limit is listed as new permit condition I.A.9.**

There are also several requirements from the General Provisions: testing, records, notification, and a SSM plan.

63.6(e)(3) Startup, shutdown and malfunction plan required by compliance date of relevant standard (installation). **Required plan has been submitted.**
63.9 Notification requirements: (b)(4)(v) Notify of date of actual startup within 15 calendar days after that date. (e) Notify at least 60 calendar days prior to the required performance test.

Notices supplied.
63.10 Recordkeeping and reporting: Maintain records for 5 years, at least 2 years data on site. (b)(2) – startup, shutdown, malfunction and maintenance records. (d)(2) Results of performance test are required to be submitted prior to the issuance of the Title V permit. (d)(5) Periodic startup, shutdown and malfunction reports. **A new Section III.C.13 Boiler B-507 MACT Standard was added to the permit that lists these requirements.**

The CO limit was established in this MACT regulation as a surrogate for hazardous air pollutant emissions. If the boiler is tuned and combusting properly, the CO and hazardous air pollutant emissions should be low. COP submitted this statement to support their case that CO CEMS should not be required: "CO is a combustion product that is formed when the amount of excess air approaches (or is less than) zero %. This is a condition of incomplete combustion of the fuel gas. The burner management system has an air to gas ratio controller. This is a mechanical device that will increase air in proportion to an increase in gas flow or vise versa. The data sheet that the manufacturer supplied shows that excess air will be controlled around 15 %. The compliance source test will confirm the actual value. As long as the mechanical system is functioning per the manufacturer's design the level of CO will be stable and well below the limit."

40CFR64, Compliance Assurance Monitoring: CAM applies to an emission unit if its facility is a federal major source (PTE>100tpy), and (1) the unit is subject to an emission limitation, (2) uses control equipment, and (3) has a pre-control PTE of >100 tpy. **Not applicable in this case; the PTE for the boiler is far < 100 tpy for all pollutants.**

<u>Applicable SIP Rules:</u>

Rule 113, Particulate Matter: limited to 0.3 gr/scf corrected to 3% oxygen, on a wet basis. **Existing permit condition III.A.1.c.3.i contains this limit. Compliance is indicated by inspection. The boiler will use only low sulfur gaseous fuel that is certified and continuously monitored. No testing is required.**

Rule 114, Gaseous Contaminants: SO2 limited to 0.2% by volume. **This limit is listed as existing permit condition III.A.1.d.1. Use of low sulfur content gaseous fuel will ensure that emissions are far lower than this standard.**

Rule 401, Visible Emissions: limited to Ringlemann 2 or 40% opacity. **This limit is already listed as a Generally Applicable Requirement in III.A.1.a.1. Compliance was verified during the source testing inspection; there were no visible emissions.**

Rule 404, Sulfur Compounds Emission Standards, Limitations and Prohibitions, E. Sulfur Content of Fuels, 1. Sulfur compounds in gaseous fuels are limited to 50 grains per 100 cubic feet. **This facility wide limit is listed in existing permit condition III.A.1.d.2**

Rule 406, Carbon Monoxide Emission Standards and Limitations: CO emissions are limited to 2,000 ppm by volume on a dry basis. **This limit is listed in existing permit condition III.A.1.e. Compliance was demonstrated in the stack testing conducted March 16, 2007 where the tested CO emission rate was 11.8 ppmvd.**

<u>Applicable District-Only Rules:</u>

Rule 113, Continuous Emissions Monitoring: Provisions allow the APCO to specify specific monitoring at identified source types. Section E.4 authorizes the APCO to require CEMS if they are necessary and reasonable. This section specifies that the APCO shall "consider (i) the economic impact on the stationary source, and (ii) the extent to which similar emission information may be obtained through other less costly methods or reporting procedures with comparable accuracy and control."

ConocoPhillips proposed in a September 13, 2006 letter that "If NOx is measured at or above 70% of the standard (i.e. greater than 21 ppm), the facility will perform a feasibility assessment to install a Continuous Emission Monitor for NOx". This agreement has been added to the permit as condition III.E.7: *"If NOx emissions from boiler B-507 exceed 21 ppmv @ 3% O2 dry, then COP shall submit a written evaluation of the feasibility of installing a NOx Continuous Emission Monitor (CEM) within 30 days. [District-only Rule 206]"*

Note that the SIP version of Rule 113 is not applicable because the installed boiler has a heat input rating of less than 250 mmBTU/hr.

Rule 204, Requirements: RACT is required for <25 lb/day, BACT for >=25 lb/day, and offsets for >=25 tpy. Under Section C.2 this installation was exempt from the control technology and offset requirements of this rule because there was no increase in emissions. This new boiler was installed to replace the steam that would be lost from the shutdown of the calciner's waste heat boiler. Emission reductions from the calciner shut down are far greater than the increase from this new boiler as shown below:

New Boiler PTE, ton/yr	1.8	15.9	10.5	27.1	4.4
Criteria Pollutant	ROG	CO	NOx	SO2	PM10
Carbon Plant Actual ton/yr	1.8*	21.9	97.3	2634.9	21.4

*Carbon Plant ROG includes Cold Stack emissions + fugitives from valves/flanges and connectors now removed from gas service. Actual boiler emissions are expected to be significantly lower than the maximum potential shown. Carbon Plant actual from 2005.

Rule 219, Toxics New Source Review: Applies to permitted sources that increase toxic emissions that result in >=1.0E-6 risk or >=0.10 HHI. Modified sources must increase toxic emissions above permitted or normal operating values to be subject.

Section D.2 contains an exemption for modifications where there is no net increase in risk. **This boiler was installed to replace the steam production from the shut down of the carbon plant waste heat boiler. The carbon plant shut down has eliminated over 3,000 tons per year of SO2 emissions. Substantial quantities of HCl and H2SO4 emissions were also eliminated along with other toxic species. This new boiler does have a selective catalytic control system, so a small quantity of ammonia will be emitted. In the March 16, 2007 source testing ammonia emissions were 0.00167 lb/hr or 0.04 lb/day. By inspection the reductions**

far offset the relatively small increase in the facility ammonia emissions. Since there is no net increase in risk, this project is exempt from this rule.

Rule 302, Schedule of Fees: Establishes the fee amounts for application filing, permit issuance, permit renewal, and various other actions. Filing fees are credited toward subsequent permit action fees. **A fee will be charged based on the actual time spent on evaluation and issuance of the permit. Also one new large boiler fee - Permit Category 4.c. - will be added to the facility's annual operating fees. Since this year's renewal was just recently paid this annual fee will be included in the revision billing.**

Rule 401, Visible Emissions: This rule limits visible emissions to 20% opacity. There were no visible emissions noted during the initial source test inspection. **This limit is listed in the permit as condition III.A.1.a.1.**

Rule 404, Sulfur Compounds Emission Standards, Limitations and Prohibitions: The basic limitations are that sulfur compound discharges must not exceed 0.2% (2,000 ppm) calculated as sulfur dioxide and that the sulfur content of gaseous and liquid fuels not exceed 50 gr/100 scf or 0.5% respectfully. **This fuel sulfur limit is currently listed in the permit as Condition I.B.5.b. Fuel sulfur content is continuously monitored and continued compliance is expected.**

Rule 430, Control of NOx from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters: Gas units are limited to 30 ppm or 0.036 lb/mmBtu NOx and CO emissions are limited to 400 ppmvd @3% O2. **The boiler is equipped with an SCR system which can reduce NOx emissions to a very low level. Compliance with the limits of this rule was demonstrated during the March 16, 2007 test – NOx emissions were 8.54 ppmvd @ 3% O2 and CO emissions were 11.8 ppmvd @ 3% O2. This rule's NOx and CO limits are listed in I.A.**

Permit Changes Due to the Addition of Boiler B-507: The following description was added to the table in II.B.7 Specific Equipment Process Unit D-1, Main Boiler Plant:

Steam Boiler, B-507, 99.9 mmBTU/hr, B&W Model FM 103-79, with selective catalytic reduction system, fuel gas only.

A new Section 13 titled Boiler B-507 MACT Standard has been added to the permit in III.C that includes the MACT CO limit and the general provisions. CO, PM and NOx limits are also listed in the Section I Specific Emission and Operation Limits table.

A new condition was added as III.E.7: If NOx emissions from boiler B-507 exceed 21 ppmv @ 3% O2 dry, then COP shall submit a written evaluation of the feasibility of installing a NOx Continuous Emission Monitor (CEM) within 30 days. [District-only Rule 206]

The B-507 has been added to the annual testing requirement in Condition III.D.2. Annual testing will be required for NOx and CO.

Permit Changes Due to the Shut Down of the Petroleum Coke Calciner: ConocoPhillips submitted a letter of their intention to cease calcining operations and to surrender their permits to do the same. A letter of notification was submitted to the District that stated that the calciner was permanently shut down March 13, 2007, and a list of the retired equipment was also submitted. That list is shown below, and it was used to modify the specific equipment descriptions in the permit. Inspections were conducted to verify that the specified equipment is no longer operating.

In addition to the deleted equipment, many permit requirements and operating conditions that were associated with the calciner were also deleted. The calciner cold stack was the main source of emissions from this process. The 2005 criteria air pollutant emissions from the cold stack are shown below.

2005 Cold Stack	ROG	NOx	SO2	PM10
Ton/yr	21.9	97.3	2634.9	13.0

Equipment that was shut down at the Carbon Plant and removed from the permit is shown in red below. The reference is the process units previously listed in Permit 44-47.

21. Process Unit Q, Green Coke Handling System; consisting of:

TITLE		CAPACITY	DESCRIPTION
a.	sizing screen	25 hp - electric	three deck, 70.5" x117", FMC Linkbelt, part# 0827226
b.	conveyors (4)		
c.	stock-piles	five (5) grades	green coke receipts, plus 1/4" kilnfeed, 1/4" x 1", 1/4" x 6 mesh, & minus 6 mesh (fines)
d.	asphalt emulsion system		
1)	tank	13,500 gal	heated with boiler blowdown water
2)	water heater	250 gal	natural gas fired
3)	spray truck	1,175 gal	with spray bar
4)	portable tank	330 gal	with spray
5)	electric pump		for filling truck
e.	portable water pump, GE-522	225 hp	John Deere, model 6081AF001, diesel engine; manufactured in 1999 with turbocharger on the inlet, catalyzed particulate filter on the exhaust, and Claire Longview backpressure monitoring system; located either in the refinery's utility plant or in the carbon plant's green coke pile area
f.	runoff collection pond pump		electrically driven pump

22. Process Unit R-1, Petroleum Coke Calciner

	TITLE	ID	CAP.	DESCRIPTION
a.	coke preheater			
1)	feed conveyor		100 tph	2' W x 400' L, with Ohmart weigh scale
2)	preheater chamber			20' W x 30' L x 30' H
3)	circulating fans (2)		25,000 acfm each	operation as needed
4)	temperature control			
i.	triethylene glycol (TEG) tank		4,500 gal	pressure vessel
(a)	nitrogen blanket		2 psig	
(b)	pressure relief valve		3 psig	discharge to carbon filter
(c)	emergency relief valve		6 psig	discharge to atmosphere
ii.	circulating pumps (2)		140 gpm	Gould model 3196 ST
iii.	shell and tube heat exch			heat exch, no atm vent
iv.	electric heater		0.8 mmBtuh	no atm vent
v.	heater relief valve		150 psig	discharge to TEG tank
vi.	return line relief valve		1 psig	discharge to TEG tank
b.	refractory lined rotary kiln		13 mmBtuh	9'IDx160'L, Kennedy Van Saun
1)	auxiliary diesel engine	GE-4047	78 hp	John Deere, model 4239TF, equipped with a Mine-X DC6 DOC, in infrequent prime mover service, manufactured in 1986 with 940.3 hours as of March 9, 2004
2)	portable air compressor system	GB-1015	375 cfm	Sullair compressor driven by a 115 hp John Deere, model 4045TF275, diesel engine; manufactured in 2004, Tier 2 compliant diesel engine, EPA Family 4JDXL06.8041; with turbocharger on the inlet; Harco catalyzed particulate filter on the exhaust, model SUD-CHEMIE EnviCat; with a Hewitt Industries back-pressure monitor, model 103-718 BP; and **located either at the refinery's utility plant** or in the carbon plant area.
c.	rotary product cooler			
d.	kiln gas exit train			
1)	refractory lined afterburner			9' ID x 30' L
2)	refractory lined pyroscrubber			20' W x 68' L x 35' H

		TITLE	ID	CAP.	DESCRIPTION
	i.	burner (3)		60 mmBtuh each	refinery fuel gas fired, vent to waste heat boiler
	ii.	combustion air blower		42,000 scfm	
	3)	refractory lined hot stack			14' ID x 128' T, four stack cap leaves
e.		coke reclaim			
	1)	hopper	4041	12.5 ton	17' L x 7' W x 9' H
	2)	hopper conveyor	4042		21" W x 33' L
	3)	cooler feed conveyor	4121		18" W x 43' L, vent to kiln burner fan

23. Process Unit R-2, Coke Calcining Kiln, Cold-Side Control System; consisting of:

	TITLE	ID	DESCRIPTION
a.	multiclone	4056	Zurn model MTSA-24-9CYT-STD and differential pressure indicator, DCS tag PDI 122_CP.
b.	wet scrubber		Western Precipitator, Type D-B, size 32, Turbulaire Gas Scrubber and differential pressure indicator, DCS tag PDI 100_CP

24. Process Unit R-3, Coke Calcining Kiln, Hot-Side Control System; consisting of:

	TITLE	CAPACITY	DESCRIPTION
a.	waste heat boiler	100,000 lb-stm/hr @600 psig, 515°F	Zurn Industries
b.	magnesium hydroxide addition system		injection point at pyroscrubber exit bustle
1)	slurry storage tank	5,000 gallons	domed roof with mixer
2)	slurry storage tank radar level meter		Endress+Hauser, Micropilot M, model FRM-240, continuous signal to DCS
3)	injection system coriolis flow meter		Emerson, Micro Motion, model F series, continuous signal to DCS
c.	baghouse		six modules, 13' x 14' 28' H each, 168 eight inch dia. x 286" L fiberglass bags each
1)	induced draft fan	122,000 cfm	electrically driven
2)	broken bag detector		Mfg: SICK AG, model: OMD-41; ConocoPhillips number AI7702_CP located between the ID fan and stack exhaust
d.	cold stack		5.25' dia. x 110' H
e.	baghouse fines system		vent to main baghouse inlet
1)	cyclone		catch discharged to enclosed bin
2)	baghouse		2.5' dia. x 5' H
3)	cartridge		
4)	vacuum blower	565 cfm	
5)	fines bin		enclosed

25. **Process Unit S-1, Calcined Coke Storage and Handling**; consisting of:

TITLE		CAPACITY	DESCRIPTION
a.	enclosed bucket elevator		12" W x 95' H
b.	bypass bin		20' H x 15' dia
c.	covered cross conveyor		18" W x 103' L
d.	triple deck screen		4' W x 12' L, Simplicity model M-120A
e.	single deck screen		60" dia., Sweco
f.	storage silo	1,270 ton total	four compartment
g.	oversized product storage bin		9' W x 9' L x 15' H
h.	steel reclaim hopper		8' W x 16' L x 5' T, discharge to load-out conveyor
i.	covered load-out conveyor		24" W x 231' L
j.	loading chute and shroud		

26. **Process Unit S-2, Calcined Coke Loading Control System**; consisting of:

TITLE	CAPACITY	DESCRIPTION
baghouse	12,200 cfm, 75 hp	Western Precipitation Pulsflo model PF 4595-216, 2315 sq.ft. bag surface area

27. **Process Unit S-3, Calcined Coke Portable Handling Equipment**; consisting of:

Title		ID	CAPACITY	DESCRIPTION
a.	hopper (2)	4005,6	10 ton each	used for stockpiling, blending, or feeding calcined or green coke or elemental sulfur as needed
b.	stacker conveyor (2)	4137,8		used for stockpiling, blending, or feeding calcined or green coke or elemental sulfur as needed
c.	semi-portable hopper and conveyor	4004	10 ton	hopper: 16' L x 9' W x 12' H, conveyor: 24" W x 19' L, used for green coke blending and emergency green coke feed upon failure of normal vibratory feeder

28. **Process Unit U, Sulfur Pelletizing Plant**; consisting of:

TITLE		ID	CAP.	DESCRIPTION
a.	sulfur pump	6000	10 hp	
b.	pelletizing nozzle	6007		
c.	inclined bagging conveyor	6017	1.5 hp	
d.	bagger	6025		
e.	hopper with delumper	6026		
f.	conveyor	6027		between e and g
g.	conveyor	6028		between f and h
h.	rod deck screen	6030	7.5 hp	4' x 8', Symon
i.	screen delumper			

TITLE		ID	CAP.	DESCRIPTION
j.	screened product silo			
k.	portable bagger conveyor and hopper		3 hp	
l.	sulfur storage pit			16' W x 16' L x 13.5' D, below grade

29. Process Unit V, Product Elevator Bypass System; equipment ID 4090, consisting of:

TITLE		DESCRIPTION
a.	elevator bypass flop gate	
b.	uncovered conveyor	48' L
c.	spray hoop	

<u>(B) Application 4255 – Installation of B602 Incinerator SO2 CEMS</u>
SO2 Continuous Emissions Monitoring Systems (CEMS) and stack flow meters were installed on the B602A and the B602B incinerators. Relative accuracy and calibration drift testing was performed March 13-14, 2007. Testing confirmed compliance with the instrument performance specifications.

<u>Applicable NSPS Requirements:</u>
40CFR 60.104(a)(2) has limits of 250 ppmv SO2 dry @ 0% oxygen for oxidation control systems followed by incineration, and 300 ppmv TRS and 10 ppmv H2S for reduction control systems not followed by incineration. **These limits are now applicable to the SRP and are listed as permit conditions I.A.12, I.A.13 and I.A.14.**

60.105 Monitoring of emissions and operations: (a)(5) SO2 monitor specifications for Claus sulfur recovery plants with oxidation control systems followed by incineration - an oxygen monitor is required for correcting for excess air. (i) Monitor span values are 500 ppm SO2 and 25% O2. (iii) Performance Specification 2 is required for the performance evaluation, and Methods 6 or 6C and 3 or 3A for the relative accuracy evaluation. (a)(11) requires that data be recorded during all operations including SSM, except for CEM breakdowns, repairs and calibration. **These requirements are listed as permit operating conditions and compliance is expected.**

<u>Consent Decree requirements:</u> Paragraph 119. NSPS Applicability of SRPs. All of COPC's Sulfur Recovery Plants will be subject to NSPS Subpart J as affected facilities and will comply with the requirements of NSPS Subparts A and J, including all monitoring, recordkeeping, reporting, and operating requirements, by the following dates: Santa Maria SRP SRU A and B = 4/11/05

120. Compliance with NSPS Emission Limits. On and after the date of NSPS applicability for the Covered SRPs, COPC will, for all periods of operation of a Covered SRP, comply with 40 C.F.R. § 60.104(a)(2), except during periods of startup, shutdown or Malfunction of the SRP or Malfunction of the TGU or as provided in Paragraph 134.

The 40CFR 60.104(a)(2) limits from Claus sulfur recovery plants are not applicable during SSM periods of the SRP or the TGU. Subpart J is now applicable to the SMR SRP, but note that paragraph 122 of the CD removes some of the reporting requirements.

121. Compliance with NSPS Operation and Maintenance Requirements. At all times on and after the date of NSPS applicability for the Covered SRPs, including periods of startup, shutdown, and Malfunction, COPC will, to the extent practicable, operate and maintain the SRPs and associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions pursuant to 40 C.F.R. § 60.11(d). **This requirement is currently listed as Condition III.C.6**

122. Compliance with Consent Decree Constitutes Compliance with Certain NSPS Subpart A Requirements. For SRPs that become affected facilities under NSPS Subpart J pursuant to Paragraph 119, entry of this Consent Decree and compliance with the relevant monitoring requirements of this Consent Decree for SRPs will satisfy the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a). 60.7(a) specifies notification of beginning construction, startup, physical or operational changes, and the CEMs demonstration test. 60.8(a) specifies a performance test within 180 days of startup. **COP has complied with all of these notification requirements.**

123. Elimination, Control, and/or Inclusion in Monitoring of Sulfur Pit Emissions. By no later than the following dates for the Covered SRPs, COPC will either eliminate, control, and/or include and monitor as part of a Covered SRP's emissions under 40 C.F.R. § 60.104(a)(2), all sulfur pit emissions. The LAR Wilmington Plant and the Rodeo Refinery will upgrade existing systems to meet this requirement. "Control" for purposes of this Paragraph includes routing sulfur pit emissions into a contactor box of a Beavon Stretford TGU evaporator. For purposes of this Paragraph, the pelletizer at the Santa Maria Refinery and the acid plant at the LAR Wilmington Plant are not "Covered SRPs."

Santa Maria SRP: The earlier of (i) the first SRP turnaround after 12/31/05; or (ii) 12/31/08.
The sulfur pit emissions are vented through the B602s. COP installed flow meters on each B-602 that are now used with the CEMS to calculate the sulfur pit vent SO2 emissions. Compliance with this paragraph has been demonstrated.

124. Monitoring all Emissions Points and Installing CEMS. By no later than the following dates for the Covered SRPs, COPC will monitor all tail gas emission points (stacks) to the atmosphere from the respective SRP and will install and operate a CEMS in accordance with NSPS Subpart J, except where COPC timely submits an AMP:

(SMR SRP Date listed: 4/11/05) COPC must monitor all emissions from the Tail Gas Units associated with these SRPs through the use of an NSPS-compliant CEMS, but COPC may submit an AMP, by no later than March 31, 2005, for any CEMS that, as of the Date of Lodging, has lower span values than NSPS specifications. To the extent that COPC seeks an AMP to monitor any other tail gas emission point to the atmosphere, COPC will submit complete AMPs for all such points by no later than March 31, 2005. If EPA does not approve an AMP, COPC will

install and operate a CEMS at the respective emission point in accordance with NSPS Subpart J by no later than eighteen (18) months after receipt of EPA's disapproval. **COP initially submitted an AMP March 31, 2005, but with this application they have now decided to modify their AMP install a CEMS and conduct the required monitoring.**

COP's current proposed Alternative Monitoring Plan would average the emissions from the B602s with the emissions from B702 to determine the "total molar average SO2 concentration from the SRP". The plan was to then compare that average value with the Subpart J emission limit. If approved the end result of this plan would be two stacks (B602s) with emissions that are higher than the Subpart J limit and one stack with emissions below the limit. Karen Brooks first questioned this plan and the applicable emission limits in a letter to Debora Jordan, EPA Region 9 dated August 26, 2005. Mark Elliott again expressed concern about this plan in a call to Margaret Waldon at Region 9 on March 15, 2007. Mark was told that COP's plan had not yet been approved by EPA and that there was no required timeline for review or approval of the plan.

Applicable SIP Rules:

Rule 401, Visible Emissions: limited to Ringlemann 2 or 40% opacity. **This limit is already listed as a Generally Applicable Requirement in III.A.1.a.1. Compliance was verified during the source testing inspection; there were no visible emissions.**

Rule 113, Particulate Matter: limited to 0.3 gr/scf corrected to 3% oxygen, on a wet basis. **Existing permit condition III.A.1.c.3.i contains this limit. Compliance is indicated for the normal operating condition; only gaseous fuels with relatively low sulfur content are incinerated. No testing is required.**

Rule 114, Gaseous Contaminants: SO2 limited to 0.2% by volume. **This limit is listed as existing permit condition III.A.1.d.1. Initial testing of the incineration of sulfur pit vent vapors demonstrated compliance with this limit – SO2 emissions were 86.4 ppmv @ 18.2% O2, or 669 ppmv @ 0% O2. Section 1.c of this rule allows the APCO to grant a permit for scavenger or recovery plants exceeding this rule's limits where "the total emission of pollutants is substantially less with the plant in operation that when closed..." That would be the case in the event of a sulfur plant breakdown when the incinerators are used to destroy tail gas.**

Rule 404, Sulfur Compounds Emission Standards, Limitations and Prohibitions, E. Sulfur Content of Fuels, 1. Sulfur compounds in gaseous fuels are limited to 50 grains per 100 cubic feet. **This facility wide limit is listed in existing permit condition III.A.1.d.2 Fuel gas is continuously monitored and compliance with this limit has been demonstrated. Section E.1.b exempts waste gases being incinerated from this limit.**

Applicable District-Only Rules:

Rule 113, Continuous Emissions Monitoring: Provisions allow the APCO to specify specific monitoring at identified source types. **Section J.1.c specifies that systems at refineries must be installed, calibrated, maintained and operated in accordance with 40CFR 60.105 – that has been done. This rule also contains standards of performance for monitoring systems, however the applicable sections all state that alternative standards established by the ARB or the EPA may be used. Compliance with this rule is indicated.**

Rule 219, Toxics New Source Review: Applies to permitted sources that increase toxic emissions that result in >=1.0E-6 risk or >=0.10 HHI. Modified sources must increase toxic emissions above permitted or normal operating values to be subject.

Section D.2 contains an exemption for modifications where there is no net increase in risk. **No increase in emissions due to this installation; these monitors just allow the existing emissions to be quantified. Since there is no net increase in risk, this project is exempt from this rule.**

Rule 302, Schedule of Fees: Establishes the fee amounts for application filing, permit issuance, permit renewal, and various other actions. Filing fees are credited toward subsequent permit action fees. **A fee will be charged based on the actual time spent on evaluation and issuance of the permit.**

Rule 401, Visible Emissions: This rule limits visible emissions to 20% opacity. There were no visible emissions noted during the initial source test inspection. **This limit is listed in the permit as condition III.A.1.a.1.**

Rule 404, Sulfur Compounds Emission Standards, Limitations and Prohibitions: The basic limitations are that sulfur compound discharges must not exceed 0.2% (2,000 ppm) calculated as sulfur dioxide and that the sulfur content of gaseous and liquid fuels not exceed 50 gr/100 scf or 0.5% respectfully. **The fuel gas sulfur limit is currently listed in the permit as Condition I.B.5.b. Fuel gas sulfur content is continuously monitored and continued compliance is expected. Section E.1.b exempts waste gases being incinerated from this limit.**

Permit Equipment Additions/Changes: The equipment added under Application 4255 will be added to the permit by modifying the description for Process Unit E-1 as follows: items n. and o. are added as shown below (underlined), and the sulfur pits are changed from item m to item p:

Process Unit E-1, Sulfur Recovery Units A and B; each of a three (3) stage Claus design with 91 long-ton per day capacity and, except as noted, each consisting of:

	TITLE	ID	CAPACITY	DESCRIPTION
a.	acid gas knock-out drum	F-612		3' D x 10'6" T
b.	acid gas preheater	E-600	0.211 mmBtuh	no vent to atmosphere

	TITLE	ID	CAPACITY	DESCRIPTION
c.	process water stripper overhead knock-out drum	F-355		3' D x 8' T
d.	reaction furnace & waste heat boiler	B-600	16.1 mmBtuh	Comprimo burner, no vent to atmosphere
e.	process water stripper knock-out drum cond pump (2)	G-358	30 gpm each	
f.	sulfinol acid gas knock-out drum pump	G-618	30 gpm	
g.	converters (2)	D-603/5		
h.	in-line heaters	B-605		no vent to atmosphere
i.	waste heat condenser	E-611		
j.	air blower (3)	GB-611		driven by: two each steam turbine and one electric
k.	sulfur condensers (4)	E-605/8 & E-610/12		
l.	air demand analyzer (2 total)	AA-601 & AB-601		no vent to atmosphere
m.	sulfur recovery unit incinerator (2 total)	B-602A/B	9 mmBtuh each	normal operation is 750°F
n.	stack flow meters	FI-1600 A/B		EMRC DP-60/75 Mark 2 monitors
o.	incinerator SO2 monitor	AN-1600 A/B		Ametek Model 922 Multi-Gas Analyzer dual span 0-500 ppm and 0-10,000 ppm
p.	sulfur pit (2 total)			vented to B-602A/B

Permit Requirements/Conditions Added or Revised due to Application 4255:

1. There shall be no discharge from the sulfur recovery plant in excess of:
(i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO2) at zero percent excess air. (ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H2S), each calculated as ppm SO2 by volume (dry basis) at zero percent excess air. [40CFR104.a.2] These limits are listed in tabular format in the I.A Emission Limits table

2. Sulfur dioxide emissions from the B602 incinerators shall be continuously monitored and recorded during all operations including startup, shutdown and malfunction, except for periods of CEM system breakdown, repair or calibration. [40CFR60.13.e]

3. The CEMS shall be operated in compliance with 40 CFR 60.13 Monitoring Requirements and 40 CFR 60 Appendix B Performance Specification 2. Data used for determining compliance with emission standards must meet the requirements listed in Appendix F to

Part 60, Procedure 1 – Quality Assurance Requirements for Gas Continuous Emission Monitoring Systems Used for Compliance Determination. [40CFR60.13]

<u>Requirements 2 & 3 above are combined into new permit condition III.E.9/10.a:</u>
<u>The instruments for the continuous monitoring and recording of concentrations of sulfur dioxide in the gases discharged to the atmosphere from the B-602 A/B incinerators, AN-1600 A/B, shall be installed such that representative measurements of emissions or process parameters are obtained; shall be in continuous operation, except for instrument breakdowns, repairs, calibration checks, and zero or span adjustments; and shall be calibrated and on-line whenever gas is being emitted from the incinerators; and shall be operated and maintained in accordance with 40CFR60, subpart J. [40CFR60.105.a.5, 60.13.e, and 60.13.f]</u>

4. Unusual Operating Condition, Actions, and Reporting

   a. Any exceedance of 250 ppmv SO2, averaged over twelve (12) hours, shall be included with the monthly report under Condition 8 below and shall include: the magnitude of emissions due to excess SO2, conversion factors used, and date and time of commencement, and completion of each time period of excess emissions. [40CFR60.105.e.4]

   b. The date and time identifying each period during which the CEMS was inoperative, other than for daily calibration, and the nature of system repairs and adjustments shall be logged and reported to the APCO in accordance with the provisions of District Rules 107 and 113. A summary report of this information shall be included with the monthly report as required under Condition 8 below. [40CFR60.7.b and District-only Rules 107 and 113]

<u>This condition was added as III.B.3.d.1&2</u>

5. The following records for the B602 SO2 CEMS shall maintained, and be made available to the APCO upon request. [40CFR60.7.f]
   a. any measurement made;
   b. relative accuracy tests performed;
   c. calibration drift test results;
   d. daily records of the calibration including the date, zero and span values, and calibration drift;
   e. records of all maintenance:
      1) date, place, and time of maintenance activity;
      2) operating conditions at the time of maintenance activity;
      3) date, place, name of company or entity that performed the maintenance activity and the methods used; and
      4) results of the maintenance; and
   f. all data sufficient to report excess emissions and CEMS downtime.

AN-1600 A/B B-602 sulfur dioxide CMS added to Condition III.B.1.b that already had these exact record keeping requirements for the AN-603 fuel gas CMS.

6. Reporting Requirements:

   a. On a calendar monthly basis, ConocoPhillips shall submit a report to the APCO. That report shall be submitted no later than ten (10) business days after the end of the month and shall include copies of records, including strip charts as identified under Condition 7 above, and an explanation for any unusual event that causes any B602 exhaust to exceed a value of 250 ppm SO2.

This text was added to the monthly required permit reporting as Condtion III.B.4.a.5: The daily average SO2 concentration results from the AN-1600 A/B monitors, and an explanation for any unusual event that either affects the normal operation of the B-602 incinerators or causes the SO2 concentration to exceed 250 ppmv. [40CFR60.7.c]

   b. On a quarterly basis, ConocoPhillips shall submit a report to the APCO, with a copy to the EPA Region IX Administrator. Each report shall be certified to be true, accurate, and complete by a responsible official, and shall include the following data. [40CFR60.7.c]

      1) Summary information of the B602 SO2 exhaust concentration based on records maintained under condition 7.

      2) Report excess emissions as indicated by, or downtime of, the B602 CEMS using the summary report form that appears in 40CFR60.7, Figure One (1). If the total duration of excess emissions is less than one percent (1%) and the CMS downtime is less than five percent (5%) of the total operating time, only the summary report form, with a statement that no excess emissions and/or no CMS downtime occurred, need be submitted. If the excess emissions or CMS downtime exceeds either of those times, the summary report shall be accompanied by a report that includes:

         i. The magnitude of excess emissions, conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.

         ii. The process operating time during the reporting period.

         iii. Whether the excess emissions occurred during start-up, shutdown, or malfunction.

         iv. The nature and cause of any malfunction, the corrective action taken, or preventive measures adopted.

         v. The date and time of CMS downtime, except for zero and span checks, and the nature of system repairs or adjustments.

      3) The daily average SO2 concentration results from the AN-1600 A/B monitors, and an explanation for any unusual event that either affects the normal operation of the B-602 incinerators or causes the SO2 concentration to exceed 250 ppmv. [40CFR60.7.c]

4) Copies of records, including strip charts as identified under condition III.B.3.a.1 above, and an explanation for any unusual event that either affects the normal operation of the B-702 tail gas combustor or causes the fuel gas sulfur content to exceed an instantaneous value of 160 ppm H2S. [District-only, Rule 206]

<u>Quarterly reporting permit Condition III.B.4.b.6 was modified to include these requirements for the AN-1600 A/B monitors.</u>

III. Rule 216 Compliance Evaluation: A section-by-section evaluation of compliance with all the pertinent requirements of this rule follows. Requirements are listed by rule section and are shown in normal text. This evaluation's comments are shown in bold text.

B. Applicability. **COP is subject to the requirement to obtain a Title V permit because their actual emissions exceed the major sources thresholds as follows: 100 tons per year of a criteria air pollutant: oxides of nitrogen (NOx); sulfur dioxide (SO2); and reactive organic gases (ROG). The facility is also subject to the maximum achievable control technology (MACT) standards of 40CFR63 subparts CC, UUU, EEEE, and DDDDD due to EPA's policy of "once in, always in". Emissions of HCl previously exceeded 10 tons/yr, but are now below that threshold since the calciner shut down.**

E. Requirements - Application Contents

1. Required Information for a Part 70 Permit. A complete application for a Part 70 permit shall contain all the information necessary for the APCO to determine compliance with all applicable requirements. The information shall, to the extent possible, be submitted on standard application forms available from the District. **The District's standard forms were used.**

5. Certification by Responsible Official. Any Part 70 permit application shall be certified by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. **James Anderson, Superintendent of HSE, certified the original applications to be true, accurate, and correct.**

F. Requirements - Permit Content

1. Each Part 70 permit shall include the following elements:
   a. Conditions that will assure compliance with all applicable requirements, including conditions establishing emission limitations and standards for all applicable requirements. **All applicable requirements are included in the proposed permit.**
      1) With the exception of acid rain program requirements, where any two or more applicable requirements are mutually exclusive, the more stringent shall be incorporated as a permit condition and the

other(s) shall be referenced. **Several applicable requirements have been streamlined in previous permit actions.**

b. The term of the Part 70 permit. **See condition III.A.8.**

c. Conditions establishing all applicable emissions monitoring and analysis procedures, emissions test methods or continuous monitoring equipment required under all applicable requirements; and related recordkeeping and reporting requirements. **The two significant modifications added equipment that will regularly be tested, and a CEMs for the B602 incinerators.**

3) Records of required monitoring information that include the following: **(see condition III.D.1)**
   - i. The date, place as defined in the permit, and time of sampling or measurements;
   - ii. The date(s) analyses were performed;
   - iii. The company or entity that performed the analyses;
   - iv. The analytical techniques or methods used;
   - v. The results of such analyses; and
   - vi. The operating conditions as existing at the time of sampling or measurement.

4) All applicable records shall be maintained for a period of at least 5 years. **See condition III.B.**

5) All applicable reports shall be submitted every 6 months and shall be certified by a responsible official. **See condition III.B.4.c.**
   - i. All instances of deviations from permit requirements must be clearly identified. **See condition III.B.4.c.3.**

e. A severability clause to ensure the continued validity of the various Part 70 permit requirements in the event of a challenge to any portions of the Part 70 permit. **See condition III.A.6.**

f. A statement that the permittee must comply with all conditions of the Part 70 permit and that any permit noncompliance constitutes a violation of the CAA and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application. **See condition III.A.2.a.**

g. A statement that the need for a permittee to halt or reduce activity shall not be a defense in an enforcement action. **See condition III.A.2.b.**

h. A statement that the Part 70 permit may be modified, revoked, reopened, and reissued, or terminated for cause. **See condition III.A.2.c.**

i. A statement that the Part 70 permit does not convey any property rights of any sort, or any exclusive privilege. **See condition III.A.2.d.**

j. A statement that the permittee shall furnish (information) to the permitting authority.... **See condition III.A.2.e.**

k. A condition requiring the permittee pay fees due to the District consistent with all applicable fee schedules. **See condition III.A.9.**

l. A provision stating that no permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in the permit. **See condition III.A.2.k.**

m. Applicable conditions for all reasonably anticipated operating scenarios identified by the source in its Part 70 permit application. **See section III.H.**

n. Applicable conditions for allowing trading under a voluntary emission cap accepted by the permittee to the extent that the applicable requirements provide for such trading without a case-by-case approval of each emissions trade. **COP has not requested an emission cap.**

o. Prompt reporting of deviations from permit requirements, including those attributable to upset conditions as defined in the permit, the probable cause of such deviations, and the corrective actions or preventive measures taken. **See conditions III.A.3 and III.B.3.g.**

p. For any condition based on a federally-enforceable requirement, references that specify the origin and authority for each condition, and identify any difference in form as compared to such federally-enforceable requirement. **See convention A.1.**

2. Each Part 70 permit shall include the following compliance requirements:

a. Inspection and entry requirements that require that the permittee shall allow the District to perform the following…. **See condition III.A.5.**

b. A schedule of compliance consistent with Subsection L.2. **See condition section III.F.**

d. A requirement that the permittee submit compliance certification pursuant to Subsection L.3. **See condition III.B.4.d.1.**

3. Federally-enforceable requirements. All conditions of the Part 70 permit shall be enforceable by the EPA and citizens under the CAA unless the conditions are specifically designated as not being federally-enforceable and, therefore, a District-only requirement. **See condition III.A.2.h.**

G. Requirements - Operational Flexibility

2. Alternative Operating Scenarios. The owner or operator of any stationary source required to obtain a Part 70 permit may submit a description of all reasonably anticipated operating scenarios for the stationary source as part of the Part 70 permit application. **See section III.H.**

H. Requirements - Timeframes for Applications, Review, and Reissuance

1. Significant Part 70 Permit Actions

b. Completeness Determinations. The APCO shall provide written notice to an applicant regarding whether or not a Part 70 permit application is complete. Unless the APCO requests additional information or otherwise notifies the applicant that the application is incomplete within 60 calendar days after receipt of such application, the application shall be deemed complete. **A notice of incomplete application was sent for the boiler Application 4229 on 8/24/06. Supplemental information was**

submitted by COP and the application was deemed complete 9/28/06. Application 4255 for the SO2 CEMS was complete as submitted.

c. Action on Applications. The APCO shall take final action on each complete Part 70 permit application as follows:

4) Except for applications listed pursuant to Subsections H.1.c.1 through 3, the APCO shall take final action on an application by no later than 18 months after the receipt of such complete application. **Final action on all applications is expected to be taken less than 12 months after receipt, well before this 18 month requirement.**

3. Minor Part 70 Permit Modifications

a. Timely Submission of Applications. For any stationary source that is requesting a minor Part 70 permit modification, an application for a modified Part 70 permit shall be submitted to the District. The APCO must take final action to approve the application before the source may be operated pursuant to the modification.

b. Action on Applications. The APCO shall not issue a final permit modification until after EPA's 45-day review period or until EPA has notified the District that it will not object to the permit modification, whichever is first. The APCO shall take final action on an application for a minor Part 70 permit modification within 90 calendar days of receipt of such application or within 15 calendar days after EPA's 45-day review period, whichever is later. **Three minor permit modifications have been proposed by COP. Application 4256 will make slight changes to the temporary flare listed in the Section III.H Alternative Operating Scenario. Application 4318 will replace an abrasive blasting pot with a similar unit. Application 4369 will delete equipment that has been removed from the sulfur pelletizing Process Unit U.**

Under this final action the APCO shall:

1) Issue the Part 70 permit modification as proposed; **This is the APCO's intent.**
2) Deny the Part 70 permit modification application;
3) Determine the proposed Part 70 permit modification does not meet the minor Part 70 permit modification criteria and should be reviewed under the significant Part 70 permit action procedures; or
4) Revise the proposed Part 70 permit and transmit the revised proposed Part 70 permit to EPA.

I. Requirements - Permit Term and Permit Reissuance

1. All Part 70 permits shall be issued for a fixed term of 5 years from the date of issuance of the permit by the District. **See condition III.A.8.**

J. Requirements - Notification

1. Public Notification
   a. The APCO shall publish a notice, as specified in Subsection J.1.b, of any preliminary decision to grant a Part 70 permit, if such granting would constitute a significant Part 70 permit action. **Public notification of the significant permit actions will be accomplished by putting a notice in the Tribune..**
2. EPA Notification
   b. Minor Part 70 Permit Modifications
      1) The APCO shall, by no later than five (5) working days after receipt of a complete application for a minor Part 70 permit modification, provide to the EPA and affected states a copy of such application. If the proposed Part 70 permit is revised after the proposed Part 70 permit has been provided to EPA, the District shall provide EPA a copy of such revised proposed Part 70 permit and all necessary supporting information pertaining to such revision to the proposed Part 70 permit.
      2) The APCO shall provide, to the EPA and any affected state, written notification of any refusal by the District to accept all recommendations that an affected state submitted for the Part 70 permit. The notice shall include the District's reasons for not accepting such recommendations.
      3) The APCO shall provide written notification of the final decision to grant or deny a minor Part 70 permit modification to EPA. **This is the APCO's intent.**
   c. Significant Part 70 Permit Actions
      1) The APCO shall, by no later than the date of publication specified pursuant to Subsection J.1.b.1, provide to the EPA, affected states, and any person that requests such information a copy of any notification made pursuant to Subsection J.1.a, and the supporting data and analysis relating to any such preliminary decision. If the proposed Part 70 permit is revised after the proposed Part 70 permit has been provided to EPA, the District shall provide EPA a copy of such revised proposed Part 70 permit and all necessary supporting information pertaining to such revision to the proposed Part 70 permit.
      2) The APCO shall provide, to the EPA and any affected state, written notification of any refusal by the District to accept all recommendations that an affected state submitted for the Part 70 permit. The notice shall include the District's reasons for not accepting such recommendations.
      3) The APCO shall provide written notification of the final decision to grant or deny a Part 70 permit to EPA, and any person and/or agency that submitted comments during the comment period. **Required EPA notifications will be made.**

K. Requirements - Reopening of Permits

1. Reopening of Part 70 Permits for Cause. Each issued Part 70 permit shall include provisions specifying the conditions under which the permit will be reopened prior to the expiration of the permit. **(See condition III.A.2.c).** Administrative requirements to reopen and issue a Part 70 permit shall follow the same procedures as apply to initial Part 70 permit issuance and shall affect only those parts of the permit for which cause to reopen exists. **(The proposed permit will undergo a 30-day public notice period, a 45-day EPA review period, and an affected states notification.)**

L. Requirements - Compliance Provisions

2. Compliance Plans. A compliance plan must be submitted with any Part 70 permit application. The compliance plan shall contain all of the following information:
    a. A description of the compliance status of the source with respect to all federally-enforceable requirements.
    b. For federally-enforceable requirements with which the source complies, the plan must state that the source will continue to comply.
    c. For federally-enforceable requirements that will become effective during the Part 70 permit term, the plan must state that the source will comply with such requirements in a timely manner.
        1) A detailed schedule shall be included for compliance with any federally-enforceable requirement that includes a series of actions.
3. Compliance Certification. All permittees and applicants must submit certification of compliance with all applicable requirements and all Part 70 permit conditions. A compliance certification shall be submitted with any Part 70 permit application and annually, on the anniversary date of the Part 70 permit, or on a more frequent schedule if required by an applicable requirement or permit condition. **These applications contained a compliance certification and the annual requirement appears in condition III.b.4.d.1.**
4. Document Certification. Any Part 70 permit application and any document, including reports, schedule of compliance progress reports and compliance certifications, required by a Part 70 permit shall be certified by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. **These applications contained a document certification and the on-going requirements appear in conditions III.B.4.b,c,&d.**
6. Permit Shield
    a. Compliance with all of the conditions of a Part 70 permit shall be deemed compliance with any applicable requirements as of the date of issuance of the Part 70 permit, provided that the Part 70 permit application specifically requests such protection and one of the following conditions is satisfied:
        1) Such applicable requirements are included and specifically identified in the Part 70 permit ... **See condition section III.G.**

IV. Minor Revisions:

Application 4256 – Changes to Temporary Flare, Alternative Operating Scenario
Non-Federal Minor Change. COP had an existing AOS for a temporary flare system with a packed tower caustic scrubber. They previously had some operational problems with that system, and decided to use SulfaTreat since it does not require any pumps. Media consumption will also be reduced with this system because SulfaTreat does not react with carbon dioxide.

In the numbered Sections under III.H.1.a these equipment changes have been made:

1) "packed tower caustic" was deleted and replaced with "SulfaTreat HP" system.
2) "backup scrubber system with activated carbon" was added
4) smokeless flare system was changed from 3" to 4"

These changes were made to reflect the actual equipment that COP would use in an AOS. No changes to the AOS operating conditions were made.

Application 4318 – Replace an Existing Abrasive Blasting Sandpot, Process Unit N
Non-Federal Minor Change. Schmidt 24L-144 sandpot replaced the Kelco 250 lb capacity sandpot under III.B.18.a. COP also reported in this application that the three compressors previously listed as items III.B.18.d, III.B.18.e and III.B.18.f have been removed from the facility. They were removed from the permit by this application. COP indicated that plant air will be used for any small blasting jobs that need to be done. Larger blasting and painting jobs are performed by contractors. No changes were made to the permit conditions due to this application.

Application 4369 – Remove Listed Equipment from the Sulfur Pellitizing Plant, Process Unit U. Non-Federal Minor Change. Several pieces of equipment have been removed from the facility as shown in the application and in underline/strikeout format below. No changes to the operating conditions due to this application.

28. Process Unit U, Sulfur Pelletizing Plant; consisting of:

	TITLE	ID	CAP.	DESCRIPTION
a.	sulfur pump	6000	10 hp	
b.	pelletizing nozzle	6007		
~~c.~~	~~inclined bagging conveyor~~	~~6017~~	~~1.5 hp~~	
~~d.~~	~~bagger~~	~~6025~~		
~~e.~~ <u>c.</u>	hopper with delumper	6026		
~~f.~~ <u>d.</u>	conveyor <u>(short)</u>	6027		between <u>c</u>~~e~~ and <u>e</u>~~g~~
~~g.~~ <u>e.</u>	conveyor <u>(long, inclined)</u>	6028		between <u>d</u>~~f~~ and <u>f</u>~~h~~
~~h.~~	rod deck screen	6030	7.5 hp	4' x 8', Symon

TITLE		ID	CAP.	DESCRIPTION
f.				
~~i.~~g.	screen delumper			
~~j.~~h.	screened product silo (truck loading hopper)			
~~k.~~	~~portable bagger conveyor and hopper~~		~~3 hp~~	
~~l.~~i.	sulfur storage pit			16' W x 16' L x 13.5' D, below grade

V. Administrative Changes:

1. The referencing for one of the standard storage tank conditions was found to be incorrect. Condition III.C.5.b requires that gauging and sampling ports for the storage tanks in process units A-1 (tank farm) and G (waste water treatment) be closed and gas tight. This requirement referred to the SIP for two of the tanks and the District's rule for storage tanks on vapor recovery for all of the rest (Rule 425.E.3.a). Neither was listed as a District-only requirement, yet the evaluation for the original Title V permit proposed that only tanks 550 & 551 would be subject to the condition as a federally-enforceable requirement because of the higher vapor pressure material they stored, which triggered SIP Rule 407.

However, the requirement for tanks 900, 901, & 903 were eventually considered federally enforceable because they had been placed through authorities to construct (ATCs). This was resolved in Oct. 2002 for tanks 900 & 901 by reissuance of the original ATC to strip this and several other requirements off. The gas tight requirement for sampling ports for tank 903 was allowed to continue even though the original streamlining evaluation for that unit felt that the requirement could be considered District-only enforceable. Ultimately, ATC-3285 in Sept. 2002 confirmed the federal enforceablity of this requirement by including it as condition 2.c to that action.

The second reference was a typographical error because seven of the latter tanks are floating roof storage tanks that are not on vapor recovery. Specifically, Tanks 800, 801, 822, 823, 900, 901, and 903 are all double seal, floating roof storage tanks and are not on vapor recovery.

Condition III.C.5.b's reference would be corrected as follows.

Tank	Type	Old Ref. (all federal)	New Ref.	Enforceability
100	vapor recovery	425.E.3.a	425.E.3.a	District-only
101	vapor recovery	425.E.3.a	425.E.3.a	District-only
550	vapor recovery	SIP-407.A.2	SIP-407.A.2	federal

Tank	**Type**	**Old Ref.** (all federal)	**New Ref.**	**Enforceability**
551	vapor recovery	SIP-407.A.2	SIP-407.A.2	federal
800	floating roof	425.E.3.a	425.F.4.b	District-only
801	floating roof	425.E.3.a	425.F.4.b	District-only
822	floating roof	425.E.3.a	206	District-only
823	floating roof	425.E.3.a	206	District-only
900	floating roof	425.E.3.a	425.F.4.b	District-only
901	floating roof	425.E.3.a	425.F.4.b	District-only
903	floating roof	425.E.3.a	425.F.4.b	federal

"III.C.5.b. All gauging and sampling ports shall remain tightly closed and gas-tight except when gauging or sampling is taking place.
[Tanks 100 & 101, District-only, Rule 425.E.3.a;
Tanks 800, 801, 900, & 901, District-only, Rule 425.F.4.b;
Tanks 550 & 551, ~~&~~ SIP Rule 407.A.2; ~~for Tanks 550 & 551,~~
Tanks 822 & 823, District-only, Rule 206, and
Tank 903, Rule 425.F.4.b]"

2. The mutual settlement condition 5.a for Notice of Violation #2146, dated April 23, 2002, needs to be incorporated into the permit. It read as follows:

"Monthly floating roof tank inspections shall be conducted for tanks 900, 901 and 903. These inspections shall include an evaluation of the secondary seals for compliance with all applicable permit conditions."

Accordingly, the following permit conditions would be added or revised as indicated.

"III.B.2.e. On A **Monthly** Basis

Process		**Description**	**Parameter**
8)	A-1	TK-900, 901, & 903	Inspect all openings and fittings for closure and the secondary seal for integrity and gaps. [40CFR60.113b.b.1.ii and Rule 425.I.1 for Tank 903 and District-only, Rule 425.I.1 for Tanks 900 & 901]

"III.B.2.h. On An **Annual** Basis

Process		**Description**	**Parameter**
1)	A-1	TK-900, 901,903	~~i.~~ Inspect the primary seal at four (4) locations to be selected by the APCO. [District-only Rule 425.G.6 for Tanks 900 & 901, federally-enforceable 40CFR60.113b.b.1.i and Rule 425.G.6 for Tank 903]
		~~TK-900,901~~	~~ii. Inspect the secondary seal. [District-only, Rule 425.I.1]~~
		~~TK-903~~	~~iii. Inspect the secondary seal. [40CFR60.113b.b.1.ii and Rule 425.I.1]~~

3. Rule 440 is Petroleum Coke Calcining and Storage Operations: D.2 "Open storage of petroleum coke shall not exceed the volume of coke stored on-site as of January 1, 2006." D.3 "Coke storage volume shall be determined monthly according to an Air Pollution Control Officer (APCO) approved method." F. Compliance Schedule: 1. "By November 30, 2006, obtain APCO approval for the coke storage calculation method under D.2 and D.3 and meet the requirements of D.2." A survey of the coke storage piles conducted by Greenwell at the end of 2005 determined that there was 282,194 tons of green coke at the site. COP reported that this survey did not include piles of calcined or contaminated (with sand) coke. Since the definition of coke in this rule would include all of these materials, COP is now working to determine these totals for the last 18 months. Until those numbers are determined the permit will list the limit in the general terms of "the volume of coke stored on-site as of January 1, 2006."

This condition was added as III.E.21.e: The open storage of petroleum coke at the Santa Maria Facility shall not exceed the volume of coke stored on-site as of January 1, 2006. The on-site open coke storage volume shall be determined monthly using the December 2005 Greenwell survey and the monthly amounts of coke produced and shipped since January 1, 2006.

Added condition to the other monthly reporting requirements as III.B.4.a.8: The amount of open coke storage determined under Condition III.E.21.e

4. Changes to future effective conditions – III.F Deleted F.1.a MACT standard for Boilers and Process Heaters – regulation has a September 13, 2007 implementation date. Facility will not be a major source of HAPs on that date since the calciner has now shut down. The new Boiler B-507 is subject to this regulation.

F.1.b is deleted also. SMF is not a major source of HAPs. Also 40CFR63.2338.c.1 of subpart EEEE excludes from regulation components that are subject to another NESHAP. Subpart CC is already applicable to process vents, storage tanks and equipment leaks.

Deleted F.2 Sulfur Pit Vents – the installation of B602 CEMs satisfied this requirement to "include and monitor". Keep F.3 – these are future effective for diesel ATCMs.

5. COP letter dated 1/23/07 requested the removal of the backup strip recorder listed in Permit Condition III.B.1.a.7. That condition allows "either DCS data or the back-up CEM strip chart from Sulfur Panel Analyzer Recorder #2 as approved alternatives". So the only change would be removing the mention of a back-up strip chart in this condition. There is no change to emissions and the DCS system is providing the required backup.

VI. Conclusions/Recommendations:

1) COP has proposed an Alternative Monitoring Plan that would average the sulfur pit emissions from the B602s with the emissions from the TGU, resulting in an average

sulfur plant emission. Compliance with the proposed limits of that plan is indicated. For all of the other process units and devices listed in this permit compliance with the applicable rules, regulations and permit conditions is indicated.

2) I recommend that the revised permit be issued, subject to EPA and public review.

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