SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT *OFFICE OF ENGINEERING AND COMPLIANCE* APPLICATION PROCESSING AND CALCULATIONS	PAGES 28	PAGE 1
	APPL. NO. 547157	DATE 8/13/13
	PROCESSED BY: Bob Sanford	CHECKED BY

PERMIT TO CONSTRUCT / PERMIT TO OPERATE
Modification

COMPANY NAME: Chevron Products Company

MAILING ADDRESS: 324 W. El Segundo Blvd.
El Segundo, CA 90245

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

BACKGROUND/SUMMARY

The Delayed Coking Flare was originally installed in 1968 - 1969 with the construction of the Delayed Coking Unit (DCU or Coker). It is a John Zink elevated flare with a height of 150 ft. The flare was originally equipped with a 48 inch flare tip. The original flare tip was replaced with a Kaldair 54 inch Steadair Tip in 1990. According to Chevron, this flare tip needs to be replaced since it is at the end of its life. Stedair tips are no longer produced. Chevron proposes to replace the current tip with a 48 inch John Zink Model EEF-HSA-QSC-48 Hypersonic Flare Tip. Chevron also proposes to replace the flare molecular seal, steam injection nozzles and pilots.

EQUIPMENT DESCRIPTION:

A permit to construct/permit to operate is proposed for issuance in Section D of the RECLAIM/Title V Facility Permit. The proposed permit pages are contained in this section. In these proposed permit pages, new text is indicated by underline and deleted text is indicated by strikeout.

Section D: Facility Description and Equipment Specific Conditions

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
Process 20: Air Pollution Control					
System 12: Delayed Coking Emergency Relief System (Flare)					S13.2, ~~S18.8~~, S18.24
FLARE, ELEVATED, ~~WITH STEAM INJECTION~~, F-3700, WITH MOLECULAR SEAL AND ~~FLAME FRONT GENERATOR,~~ JOHN ZINK MODEL EEF-HSA-QSC-48 HYPERSONIC STEAM ASSISTED FLARE TIP, HEIGHT: 150 FT; DIAMETER: 9 FT 2 IN **A/ N: ~~498632~~ 547157**	C1785				B61.11, D12.14, D323.2, E193.2, H23.44, H23.46

Description	ID No.	Connected To	RECLAIM Source Type	Emissions and Requirements	Conditions
DRUM, ~~EMERGENCY BLOWDOWN~~ FLARE KO DRUM, V-515, ~~HEIGHT~~ LENGTH: 21 FT; DIAMETER: 10 FT 6 IN **A/ N: ~~498632~~ 547157**	D1786		**Note:** Flare KO Drum more accurately describes the function of this vessel. Also, it is a horizontal vessel so "height" should be "length".		
DRUM, V-3700, WATER SEAL, COKER FLARE, HEIGHT: 23 FT (T/T); DIAMETER: 11 FT **A/ N: ~~498632~~ 547157**	D4214				
FUGITIVE EMISSIONS, MISCELLANEOUS **A/ N: ~~498632~~ 547157**	D3681			HAP: (10) [40CFR 63 Subpart CC, #5A, 6-23-2003]	H23. 3

PROCESS CONDITIONS:

None

SYSTEM CONDITIONS:

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

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1123

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

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

S18.8 All affected devices listed under this process/system shall be used only to receive, recover and/or dispose of vent gases routed from the system(s) or process(es) listed below, in addition to specific devices identified in the "connected to" column:

Crude Distillation (Process: 1, System: 17)

Delayed Coking (Process: 2, System: 1)

Hydrotreating (Process: 4, System: 3 & 5)

Catalytic Reforming (Process: 5, System: 1)

Air Liquide Hydrogen Plant (ID 148236) (Process: N/A, System: N/A)

Hydrocracking (Process: 7, System: 4 & 7)

Oxygenates Production (Process: 9, System: 1)

LPG Production (Process: 10, System: 4)

Treating and Stripping Process (Process: 12, System: 10, 12 & 24)

Storage Tanks (Process: 16, System: 4 & 8)

Air Pollution Control (Process: 20, System: 28, 29, 30 & 37)

Miscellaneous (Process: 21, System: 16)

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

[Systems subject to this condition: **Process 20, System** ~~12~~, 31]

S18.24 All affected devices listed under this process/system shall be used only to receive, recover and/or dispose of vent gases routed from the system(s) or process(es) listed below, in addition to specific devices identified in the "connected to" column:

Delayed Coking (Process: 2, System: 1)

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

[Systems subject to this condition: **Process 20, System 12**]

[Note: As described in the *Process Description*, the Coker Flare no longer backs up the Isomax Flare during shutdown of the flare for repairs/maintenance. Therefore, the flare will only receive relief gases from the Delayed Coking Unit.**]**

DEVICE CONDITIONS:

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

H2S greater than 160 ppm by volume

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

E193.2 The operator shall operate and maintain this equipment according to the following specifications:

The operator shall comply with all applicable requirements specified in Subpart A of the 40CFR60 and 40CFR63.

[**40CFR 60 Subpart A, 5-16-2007; 40CFR 63 Subpart A, 5-16-2007**]

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

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

Contaminant	Rule	Rule/Subpart
VOC	District Rule	1173

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

[Devices subject to this condition : D3576, D3588, D3610, D3631, D3635, D3640, D3642, D3644, D3645, D3646, D3651, D3654, D3655, D3656, D3657, D3659, D3660, D3663, D3678, **D3681**, D3685, D3688, D3691, D3692, D3694, D4086, D4087, D4088, D4310, D4352, D4359, D4368]

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

Contaminant	Rule	Rule/Subpart
H2S	40 CFR 60	Subpart J

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

[Devices subject to this condition: D20, D453, D502, D504, C1746, C1757, **C1785**, C2158, C3012, C3493]

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

Contaminant	Rule	Rule/Subpart
SOx	40 CFR 60	1118

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

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

FEE ANALYSIS

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

Summary of Fee Analysis

A/N	Equipment Description	BCAT/ CCAT	Fee Schedule	Fee Type	Fiscal Year (1)	Fee
547157	Refinery Flare System	92 (CCAT)	F	Alteration/Modification	13-14	$ 10,874.52
547158	RECLAIM/Title V Permit	555009 (BCAT)	na.	Facility Permit Amendment	13-14	$ 1,789.12
				Total		**$ 12,663.64**
				Fees Paid		**$ 12,663.64**
				Outstanding Balance		**$ 0.00**

(1) Based on the date that the application was submitted.

PERMIT HISTORY

The permit history for the Coker Flare is contained in the following table.

Permit History for the Delayed Coking Emergency Relief System (Flare) (P20S12)

Permit to Construct		Permit to Operate		Description of Modification
No.	Issue Date	No.	Issue Date	
A50983	11/15/68	P38588	6/16/70	Original Construction.
C06861		M07336	2/16/79	Installed a spare pump-out pump (P-526A) for the flare Blowdown drum (V-515).
421211	5/11/04	na.	na.	Change of condition S18.8 to allow emergency vent gases from the new SMR Hydrogen Plant to be vented to this flare. The new SMR plant was originally permitted to vent only to the Isomax Flare.
445709	2/03/06	na.	na.	Change of the pilot monitoring condition to allow the use of a thermocouple as a flame detector in addition to the UV/infrared sensor that was already allowed.
448248	8/24/06	na.	na.	Under Chevron's Heavy Crude Project, new PRVs in the Delayed Coking Unit were connected to the flare. .
464818	7/06/07	na.	na.	Installation of a new water seal drum (V-3700; D4214) upstream of the flare to direct routine vent gases (PSV gas leakage) from the Coker to the LSFO Vapor Recovery System (VRS)(P20S10). Larger compressors were installed in the LSFO VRS under this project.
498632	na.	G25382	7/17/13	Chevron accepted applicability of NSPS Subpart J to the Coker Flare under Consent Decree No. C 03-04650 CRB between the US EPA and Chevron. Also processed PC to PO conversion under this application.
547157	na.	na.	na.	Subject application for replacement of the exiting flare tip with a John Zink Model EEF-HAS-QSC-48 Hypersonic Steam Assisted Flare Tip.

COMPLIANCE RECORD REVIEW

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

PROCESS DESCRIPTION:

The Coker Emergency Flare system was originally installed in 1969 – 1970. The flare stack is a freestanding 150 foot stack currently fitted with a Kaldair 54" Stedair tip. The main relief header for the flare was connected into the LSFO Vapor Recovery System (VRS) in 2007 – 2008 under PC A/N 464817. Water Seal Drum V-3700 (D4214) was installed to provide backpressure on the relief header. The capacity of the LSFO VRS was increased from 6 mmscfd to 12 mmscfd by replacement of the three (3) compressors with larger compressors.

The flare was designed and installed at the same time as the Isomax Flare (Process 20, System 31). These flare systems were interconnected and both were designed to handle the maximum load of 1,300,000 lb/hr of 32 molecular weight gas during a power outage in the Isomax Complex. However, Chevron no longer utilizes the Coker flare as a backup for the Isomax Flare and vice versa. The maximum relief case for the Coker is 1,063,000 lbs/hr of gas with a molecular weight of 37 from relief of the main fractionator overhead stream during a total power failure to the plant. The permits for the Coker and Isomax Flares are both tagged with condition S18.8 in the RECLAIM/Title V permit. This condition, which specifies the permit units that are permitted to vent emergency relief gases to the Coker and Isomax Flares, will be split into separate conditions for each flare. New system condition S18.24, which specifies that the flare is only permitted to receive vent gases for the Delayed Coking Unit, will be tagged to the Coker Flare. Condition S18.8 will remain tagged to the Isomax Flare and will be modified as part of the conversion of PC A/N 452976 to a PO.

The new flare tip is a 48 inch John Zink Model EEF-HSA-QSC-48 Hypersonic Steam Assisted Flare Tip. This tip consists of the four parts described below.

1. Shell - The outer shell of the tip which routes the gas flow and provides the structure for the other components.

2. Molecular Seal - The molecular seal which creates a twisted flow path upstream of the flare tip. Together with the natural gas purge, the seal prevents the backflow of air into the flare stack. The design natural gas purge gas flow is 443 scfh. The natural gas purge gas flow to the flare stack is currently around 5200 scfh. The required purge gas flow has increased over time as the condition of the existing molecular seal has degraded

3. Steam Nozzles - Three sets of steam injection nozzles which atomize or disperse the flare gas to improve combustion and induce air into the flare gas. Steam from a nozzle located in the bottom center of the flare tip disperses the flare gas and protects the tip by reducing burn-back into the tip body. Steam from nozzles around the top of the tip disperses the flare gas and draws air into the perimeter of the flame. This steam also protects the tip by helping the flame stay vertical, minimizing flame impingement on the downwind low pressure side of the tip. The third set of nozzles are located around the bottom perimeter of the tip. Steam is injected into pipes that have flared openings to the atmosphere (referred to as bells) at the tip exit. Steam injection draws air into the pipes so that the steam and air mixes with the flare gas just upstream of the pilots, promoting combustion.

4. Pilots - Natural gas pilots ignite the flare gas. The new tip will be equipped with 4 equally spaced pilots with a design natural gas flowrate of 50 scfh each. The combined natural gas flow to the existing pilots is 310 scfh.

As with the current tip, an operator will control steam injection during flaring from the computer console in the control room. There is a video display in the control room showing the flare tip. The operator uses this display to regulate steam injection. According to John Zink, the new flare tip will provide more efficient combustion than the existing tip due to the steam nozzle design that more effectively draws air in and mixes it into the flare gas prior to combustion. The improved steam nozzle design also minimizes energy loss and noise. The estimated maximum smokeless capacity is 260,000 lb/hr of a 37 MW flare gas at a maximum steam flow of 115,000 lb/hr. The minimum continuous steam load to the new flare tip to prevent heat damage will be 2100 lb/hr. It is not desirable to design a flare with smokeless operation up to its maximum relief load due to the additional steam capacity that would have to be added to the refinery to provide the required steam to the flare. Addition of this much boiler capacity would yield a large increase in daily emissions of criteria and toxic air contaminants to produce steam that is vented to the atmosphere during normal operation of the refinery.

The capacity of a flare is limited by the hydraulics of the relief system and the flare tip velocity. As required by 40CFR60 Subpart A, the flare tip velocity should be maintained below 400 ft/sec when the heat value of the relief gas is above 1000 btu/scf. The heat value of the relief gas for all of the major relief scenarios is above 1000 btu/scf. Based on the estimated maximum velocity at the worst case load of 1,063,000 lb/hr and a tip inside diameter of 48 inches, the tip velocity is calculated to be 367 ft/sec., which is under the maximum allowable rate of 400 ft./sec. With internal flare tabs and fitting, the effective area of the tip is 11.04 ft^2.

$$Velocity = \left(\frac{(FlowRate lb/hr)(379 scf/lb-mole)(TemperatureatFlareR)}{(MW)(TipFlowArea ft2)(3600 \sec/hr)(TemperatureStandardR)} \right)$$

$$Velocity = \left(\frac{(1{,}063{,}000 lb/hr)(379 scf/lb-mole)(712R)}{(37)(11.04 ft2)(3600 \sec/hr)(532R)} \right) = 367 \text{ ft/sec}$$

CALCULATIONS

This section contains criteria air pollutant (CO, NOx, PM_{10}, SO2, and VOC) emission estimates for the Coker Flare. The Coker Flare has emissions from combustion as well as fugitive VOC emissions.

Combustion Emissions - The combustion emissions are from combustion of pilot and flare purge gas streams during normal non-emergency operation of the flare. Criteria pollutant emissions from the combustion of gases generated from process upsets or equipment malfunctions are not included in the Regulation XIII emission estimates. Combustion emission estimates utilize District AER/Rule 1118 emission factors for natural gas combustion. As noted in the *Process Description* section, the flare purge gas and flare pilot gas are natural gas. A total pilot/purge gas flow of 3420 scfh (0.082 mmscf/day) was utilized in previous emission calculations.

John Zink estimates the new flare tip and molecular seal will require 200 scfh of pilot gas and 443 scfh of flare purge gas. Since actual flow rates may potentially be higher than these design rates, the estimated maximum pilot/purge gas flow of 3420 scfh for the existing flare tip and molecular seal will be utilized in emission estimates for the new flare tip. Therefore, there is no change in estimated maximum potential criteria pollutant or toxic air contaminant emissions. Combustion emission calculations are summarized in the table below.

Coker Flare: Estimate of Max. Potential Emissions from Combustion of Pilot/Purge Gas

Pollutant	Total Pilot/Purge Gas (MMscf/day)	Emission Factor (lb/MMscf)	Estimated Max. Potential Emissions	
			(lb/day)(1)	(lb/yr)
NOx	0.082	130	10.8	3890
SOx	0.082	0.83	0.07	24
CO	0.082	35	2.91	1047
PM10	0.082	7.5	0.62	224

Pollutant	Total Pilot/Purge Gas (MMscf/day)	Emission Factor (lb/MMscf)	Estimated Max. Potential Emissions	
			(lb/day)(1)	(lb/yr)
VOC	0.082	7	0.58	210

(1) 30-day average = annual emissions divided by 360

Fugitive VOC Emissions - VOC emissions for fugitive components (valves, flanges, connectors, pumps, compressors, PRVs and drains) that handle VOC containing liquids or gases are estimated by multiplying the total number of each fugitive component type by an appropriate emission factor. No new fugtive components are being installed. Total fugitive VOC emissions for the Coker Flare permit unit are estimated to be 9.75 lb/day on a 30-day average basis (3511 lb/yr) using the emission factors based on correlation equations from the *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities* (CARB/CAPCOA - 1999). The detailed fugitive VOC emission estimate is contained in Appendix A of this evaluation.

Total VOC emissions for the permit unit are 10.33 lb/day including the fugitive and combustion VOC emissions [9.75 lb/day + 0.58 lb/day].

RULE COMPLIANCE REVIEW:

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

The California Environmental Quality Act (CEQA), Public Resources Code Section 21000 et seq., requires that the environmental impacts of proposed "projects" be evaluated and that feasible methods to reduce, avoid or eliminate significant adverse impacts of these projects be identified and implemented. According to the District's CEQA Guidelines, the net emission increase thresholds for significant effect are:

ROG: 55 lb/day
PM10: 150 lb/day
CO: 274 lb/day

CEQA analysis is not required for the proposed flare tip replacement since there is no increase in the emissions of any of these criteria air pollutants and there are no other significant environmental impacts. On the 400-CEQA form, Chevron marked "No" to all of the additional criterion that may trigger CEQA. For these reasons, CEQA does not apply.

REGULATION II: PERMITS

RULE 212: STANDARDS FOR APPROVING PERMITS

212(c)(1): Public notice is required for a project if any of the modified permit units are located within 1000 feet of a school. The Coker Flare is more than 1000 feet from the nearest school. Public notice was not required under this clause.

212(c)(2): Public notice is required for any "new or modified facility", which has on-site emission increases exceeding any of the daily maximums specified in subdivision (g) of Rule 212 as shown in the following table.

Air Contaminant	R212(g) Daily Maximum Threshold (lb/day)
VOC	30
NOx	40
PM10	30
SOx	60
CO	220
Lead	3

Public notice is not required under this clause since the replacement of the flare tip does not cause an increase in the emission of any criteria air pollutants.

212(c)(3): Public notice is required for any new or modified permit units that have an increase in toxic air contaminants that results in an increase of maximum individual cancer risk (MICR) of more than one in a million (1×10^{-6}) during a lifetime (70 years). Public notice is not required under this clause since replacement of the flare tip does not cause any increase in MICR.

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

Public notice is not required under this clause since the replacement of the flare tip does not cause an increase in the emission of any criteria air pollutants.

REGULATION IV - PROHIBITIONS

RULE 401: VISIBLE EMISSIONS and RULE 402: NUISANCE

Rule 401 specifies that a person shall not discharge emissions from a source for a period or periods aggregating more than three minutes in any one hour which are as dark or darker in shade as that designated No. 1 on the Ringelmann Chart or emissions of such opacity that it obscures an observers view to an equal or greater level. This is equivalent to opacity of 20%.
Rule 402 requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property.

The function of emergency flares such as the Coker Flare is to reduce the nuisance potential and health impacts from the periodic emergency releases to the atmosphere of waste/process gases that may contain high levels of toxic and odorous air contaminants. In performing this function, flares have the potential to emit dark smoke and other products of incomplete combustion during severe process malfunctions or breakdowns that send large amounts of waste/process gas to the flare. Therefore, all emergency refinery flares do have some potential to emit dark smoke that causes nuisance and exceeds 20 percent opacity for a period of greater than 3 minutes during extreme emergencies during which the process/waste gas load to the flare exceeds the smokeless capacity of the flare.

As discussed in the *Process Description* section of this evaluation, the new flare tip is equipped with an improved steam injection nozzle design to improve combustion efficiency and the smokeless capacity of the flare. This smokeless capacity varies depending on the properties of the waste gas being combusted. For releases up to the smokeless capacity of the flare, smoking will occur only during a short transitory period while the steam injection is adjusted to the load being sent to the flare. An increase of the smokeless capacity beyond that of the proposed tip is not warranted since additional steam would have to be produced around the clock to cover emergency flaring events that are relatively rare. Production of additional steam would cause an increase in the emissions of criteria and toxic pollutants for steam that cannot be utilized during normal operational periods when no flaring occurs.

Emergency situations such as a loss of power are covered by the "Breakdown Provisions" of Regulation 430. If the emergency qualifies as a "Breakdown" and Chevron complies with the requirements of 430(b)(3)(A), the smoking during an emergency will not be a violation of Rule 401.

The LSFO VRS minimizes nuisance and visible emissions through the capture of all normal releases and a portion of the emergency releases to the flare. The Chevron refinery has been relatively effective at minimizing flaring events. The capacity of the LSFO VRS was increased by 6 mmscfd in 2008 through replacement of the three existing vapor recovery compressors with larger compressors. As discussed later in the evaluation of District Rule 1118, SOx emissions from Chevron's flares during 2006 - 2012 were well below Rule 1118 SOx performance targets.

RULE 404: PARTICULATE MATTER - CONCENTRATION

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

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

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

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

$$Coker\ Flare\ Exhaust\ Rate = \left(\frac{5580 scfNG}{hour}\right)\left(\frac{1050 Btu}{scgNG}\right)\left(\frac{8710 scffluegas}{MMBtu}\right)\left(\frac{hour}{60\min}\right)$$

= 851 dscfm

From Table 404(a) in Rule 404, the PM limit for exhaust gas flows below 883 dscfm is 0.196 gr/dscf. The estimated PM concentration of 0.006 gr/dscf is well below the Rule 404 limit of 0.196 gr/dscf. Compliance with this rule is expected.

RULE 405: SOLID PARTICULATE MATTER - WEIGHT
This rule sets solid PM mass emission limits for the processing of solid materials. It is not applicable to combustion sources such as the subject flare.

RULE 407: LIQUID AND GASEOUS AIR CONTAMINANTS
This rule contains the following emission limits:

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

CO Limit

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

Sulfur Compound Limit:

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

RULE 409: COMBUSTION CONTAMINANTS
This rule contains limit on combustion contaminants from the combustion of fuel of 0.23 gram per cubic meter (0.1 grain per cubic foot) of flue gas (15 minute avg. at 12% CO2).

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

REGULATION IX - NEW SOURCE PERFORMANCE STANDARDS (NSPS)

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

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

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

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

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

60.18(c)(3): An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section. Chevron complies with the heat content and maximum tip velocity requirements in paragraphs (c)(3)(ii) and (c)(4), respectively, since the requirements in paragraph (c)(3)(i) apply to non-assisted flares only.

Paragraph (c)(3)(ii) specifies that steam and air-assisted flares shall be used to combust vent gas with a net heating value of 300 Btu/scf or greater. The low heating value (LHV) of the vent gases sent to this flare are expected to be above 300 Btu/scf.

60.18(c)(4)(i): Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in §60.18(f)(4), less than 18.3 m/sec (60 ft/sec), except as provided in §§60.18(c)(4)(ii) and (iii). As discussed below, the flare complies with the alternative velocity requirements specified in §60.18(c)(4)(ii).

60.18(c)(4)(ii): Steam-assisted and non-assisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf). The net heating value of the gases that would be combusted in the Coker Flare is greater than 1000 btu/scf so an exit velocity of less than 400 ft/sec is required. As shown in the *Process Description* section of this evaluation, the exit velocity for the maximum estimated load to the flare is 367 ft/sec.

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

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

40CFR60 SUBPART J- STANDARDS OF PERFORMANCE FOR PETROLEUM REFINERIES

This NSPS is applicable to the following affected facilities in petroleum refineries:

- Fluid Catalytic Cracking Unit Catalyst Regenerators
- Fuel Gas Combustion Devices
- All Claus Sulfur Recovery Plants (SRPs)(except Claus Plants of 20 long tons per day (LTD) or less

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

The Coker Flare became subject to this NSPS under Consent Decree No. C 03-04650 CRB (CD), which was filed in U.S. District Court in San Francisco on October 16, 2003 and approved by a US District Court Judge on June 28, 2005. This Consent Decree is the result of a settlement between Chevron and EPA over alleged violations of the certain Clean Air Act and CERCLA/EPCRA provisions including the New Source Performance Standards. In the RECLAIM/Title V Permit, the flare (C1785) is tagged with condition H23.44, which denotes that the flare is subject to applicable requirements of this regulation.

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

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

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

(B) Relief valve leakage due to malfunction;

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

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

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

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

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

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

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

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

The provisions of this subpart apply to flares which commence construction, modification, or reconstruction after June 24, 2008. *Flare* is defined as a combustion device that uses an uncontrolled volume of air to burn gases. The flare includes the foundation, flare tip, structural support, burner, igniter, flare controls, including air injection or steam injection systems, flame arrestors and the flare gas header system. In the case of an interconnected flare gas header system, the *flare* includes each individual flare serviced by the interconnected flare gas header system and the interconnected flare gas header system.

Flare gas header system means all piping and knockout pots, including those in a subheader system, used to collect and transport gas to a flare either from a process unit or a pressure relief valve from the fuel gas system, regardless of whether or not a flare gas recovery system draws gas from the *flare gas header system*. The *flare gas header system* includes piping inside the battery limit of a process unit if the purpose of the piping is to transport gas to a flare or knockout pot that is part of the flare.

It is specified in §60.100a(c), that a modification to a flare occurs if (1) Any new piping from a refinery process unit, including ancillary equipment, or a fuel gas system is physically connected to the flare, or (2) the flare is physically altered to increase the flow capacity of the flare. However, the following connections are not considered to be modifications of a flare:

(i) Connections made to install monitoring systems to the flare.

(ii) Connections made to install a flare gas recovery system or connections made to upgrade or enhance components of a flare gas recovery system (*e.g.,* addition of compressors or recycle lines).

(iii) Connections made to replace or upgrade existing pressure relief or safety valves, provided the new pressure relief or safety valve has a set point opening pressure no lower and an internal diameter no greater than the existing equipment being replaced or upgraded.

(iv) Connections made for flare gas sulfur removal.

(v) Connections made to install back-up (redundant) equipment associated with the flare (such as a back-up compressor) that does not increase the capacity of the flare.

(vi) Replacing piping or moving an existing connection from a refinery process unit to a new location in the same flare, provided the new pipe diameter is less than or equal to the diameter of the pipe/connection being replaced/moved.

PC A/N 464818, which was issued in July 2007, is the most recent PC issued for the Coker Flare. Therefore, it has not been physically modified in any way since before the June 24, 2008 applicability date of this regulation. Replacement of the existing flare tip with a smaller flare tip does not increase the capacity of the flare and does not include any new connections to the flare. Therefore, the proposed replacement of the flare tip will not cause the Coker Flare to become subject to the requirements of this regulation.

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

The following are affected facilities under these subparts:

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

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

The Coker Flare is not subject to either of these regulations since it is not a process unit as defined in this regulation.

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

40CFR63 SUBPART CC: NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FROM PETROLEUM REFINERIES

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

Applicability for Equipment Leaks: The equipment leak standards for existing sources as specified in 63.648 are applicable to fugitive components that are "in organic hazardous air pollutant service". In "organic hazardous air pollutant service" is defined as a piece of equipment that either contains or contacts a fluid (liquid or gas) that is at least 5% by weight of total organic HAPs as determined according to 63.180(d).

The Coker Flare contains some fugitive components that contact fluids with at least 5% by weight of total organic HAPs are subject to this regulation. These fugitive components are subject to the equipment leak standards for existing sources as specified in 63.648. The "Emissions and Requirements" column for "Fugitive emission, miscellaneous" device D3681 for this permit unit contains "HAP: 40CFR 63 Subpart CC, #5A, 6-23-2003" to denote that some fugitive components in each of these permit units are subject to the equipment leak standards of this regulation.

This regulation refers to the fugitive component monitoring requirements of NSPS Subpart VV and NESHAP Subpart H with exceptions that are specifically noted in the regulation. In general, the equipment leak inspection and monitoring requirements of District Rule 1173 are more stringent than this regulation but pertinent requirements of this regulation have been incorporated into Chevron's Leak Detection and Repair (LDAR) Program for fugitive emissions. It is expected that Chevron will comply with the requirements of this regulation.

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

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

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

All of the streams that vent to the VRS/flare qualify for one of these exemptions. Therefore, none of the streams that vent to the flare are *miscellaneous process vents* as defined in this regulation.

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

RULE 1118: EMISSIONS FROM REFINERY FLARES

<u>Background</u>

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

<u>Current Requirements</u>

Flare Pilot [1118(c)(1)(A)] - Maintain a pilot flame present at all times a flare is operational. The Coker Flare is currently equipped with a thermocouple to monitor the existence of the pilot light. An infrared camera is utilized as a secondary device to monitor the intensity of the pilot flame.

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

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

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

This analysis must be submitted to the District within 30 days of the event unless an extension is granted [1118(i)(3)]. The table below contains a summary of the two Coker flaring events during 2010 – 2013 for which Chevron was required to submit SCAs. Continued compliance with this analysis and reporting requirement is expected.

Summary of Specific Cause Analyses Submitted by Chevron During 2010 - 2013

Date	Gas Combusted (scf)	VOC Emissions (lb)	SO2 Emissions (lb)	Cause
7/2/12	1,804,700	169	469	Failure of a Process Logic Controller (PLC) processor caused the shutdown of wet gas compressor K-501A in the DCU,
7/25/12	930,110	91.3	9651	Shutdown of wet gas compressor K-501A in the DCU due to loss of power to the motor control system during an electrical system upgrade by Southern California Edison. (SCE).

Relative Cause Analysis [1118(c)(1)(E)] - Conduct an analysis and determine the relative cause of any other flare events where more than 5,000 standard cubic feet of vent gas are combusted. When it is not feasible to determine relative cause, state the reason why it was not feasible to make the determination. Reports of these analyses are contained in Chevrons' quarterly reports using a code system developed by the District. For example, flaring due to equipment failure is assigned a District Relative Cause Code of 3. The Coker Flare did not have any events during 2010 - 2013 that required a Relative Cause Analysis. Based on historical compliance with this requirement, compliance is expected.

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

- Create an equipment depressurization schedule that accounts for flare gas recovery capacity and the sources to be depressurized.
- Ensure the flare gas recovery compressors are in reliable condition for full availability prior to the event
- Review the shutdown and startup procedure prior to the event
- Review the shutdown and startup procedures after the event and revise if necessary
- Investigate flaring events causes by planned shutdown, startups and turnarounds to identify and implement corrective actions.

Flare Minimization [1118(c)(4)] - Operate all flares in such a manner that minimizes all flaring and that no vent gas is combusted except during emergencies, shutdowns, startups, turnarounds or essential operational needs. Chevron installed a water seal drum on the Coker Flare header and upgraded the LSFO VRS compressors in 2007 – 2008 to assist in compliance with this requirement. The LSFO VRS currently has excess capacity during normal operation.

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

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

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

If a refinery exceeds the performance targets for any calendar year, the owner or operator must:

- Submit a Flare Minimization Plan, and
- Pay the District mitigation fees. The rule includes a sliding fee schedule based on the relative amount of the exceedance. The rule includes a 60 day public review period for the Flare Minimization plan prior to approval of the plan.

Chevron has a total of six (6) flares that are subject to this rule. As seen in the table below, Chevrons' SO2 emissions from flaring were below the targets for 2006 – 2012.

SO2 Emissions from Flaring

Year	SO2 Target (ton/yr)(1)	SO2 Emissions (ton/yr)
2006	142.7	25.3
2007	142.7	49.3
2008	95.2	43.7
2009	95.2	58.5
2010	66.6	22.8
2011	66.6	9.8
2012	47.6	10.7

(1) Based on crude capacity of 95.16 MMbbl/yr

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

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

Chevron has installed the required monitoring and recording system. A letter of final certification of the flare monitoring system was issued by the District on September 28, 2012. The main components of the certified flare monitoring system are summarized in the table below.

Monitor Type	Make	Model No.	Method of Detection	Range
Flow	Panametrics	GF868	Ultrasonic	0.1 – 250 fps
HHV	Siemens	Maxum II	GC/TCD	0 – 3000 Btu/scf
Total Sulfur	Siemens	Maxum II	GC / Pyrolysis / FPD	10 – 600 ppmv; 450 ppmv – 2%; 1.5 – 25%

Color Video Monitors [1118(g)(7)] - Monitor all flares for visible emissions using color video monitors with date and time stamp, capable of recording a digital image of the flare and flame at a rate of no less than one frame per minute. District inspector Paul Caballero has confirmed that the Coker Flare is equipped with cameras and recorders that comply with this monitoring requirement.

Flare Monitoring and Recording Plan [1118(g)(7)] - By June 30, 2006, submit a revised Flare Monitoring and Recording Plan, which shall include all information specified at 1118(f)(3) [1118(f)(1)(A)]. They must comply with the existing plan until a revised plan is approved. A facility must start monitoring and recording in accordance with the Revised Flare Monitoring and Recording Plan within 6 months after the plan is approved [1118(g)]. Chevron submitted this plan (AN 458606) on June 30, 2006. Chevron has also submitted two addendums to the plan. Chevrons plan is pending issuance by the District.

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

Notification of Unplanned Flare Events [1118(i)(2)] - Notify the Executive Officer by telephone within one hour of any unplanned flare event with emissions exceeding either 100 pounds of

VOC or 500 pounds of sulfur dioxide, or exceeding 500,000 standard cubic feet of flared vent gas. Compliance with this notification requirement is expected.

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

Quarterly Report [1118(i)(5)] - Submit a quarterly report in an electronic format approved by the District within 30 days after the end of each quarter. Chevron has submitted all required quarterly reports. Continued compliance with this requirement is expected.

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

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

Chevron has an existing fugitive emission component leak detection and repair (LDAR) program for compliance with the requirements of this rule. No new fugitive components are being installed. Compliance with the requirements of this regulation is expected.

<u>REGULATION XIII - NEW SOURCE REVIEW</u>

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

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

NSR requirements for these attainment pollutants are specified in the following rules:

- Rule 1303 – PM10 and VOC (all facilities); NOx and SOx (non-RECLAIM facilities)
- Rule 1325 – PM2.5
- Rule 2005 – NOx and SOx (RECLAIM facilities)

Since Chevron is a RECLAIM facility, it is subject to the NSR requirements for NOx and SOx specified in Rule 2005 of the RECLAIM regulation (Regulation XX). However, as discussed in more detail later, emergency flares are exempt from the requirements of regulation XX (RECLAIM). Therefore, emergency flares are subject to the requirements of this regulation.

CO, and Ozone Depleting Compounds (ODCs) are subject to only the BACT requirements of Rule 1303.

RULE 1303: REQUIREMENTS

This rule allows the Executive Officer to deny a Permit to Construct for any new, modified or relocated source which results in an emission increase of CO, PM10, VOC, any ozone depleting compound, or ammonia, unless BACT is used. This rule also requires modeling and offset (among other requirements) if there is a net increase in PM10 or VOC emissions for any new or modified source.

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

BACT is not applicable since replacement of the flare tip does not cause an increase in the emission of any criteria air pollutants.

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

1303(b)(1): Modeling - The applicant must substantiate with modeling that the new facility or modification will not cause a violation, or make significantly worse an existing violation of any state or national ambient air quality standards at any receptor location in the District. According to 1306(b), the new total emissions for modified sources shall be calculated on a pound per day basis for determination of BACT and modeling applicability. The modeling procedures are discussed in Appendix A to the rule. It is specified in Appendix A of this rule that modeling is not required for SOx or VOC. Therefore, under this rule, modeling is required for NOx and PM10 only.

Modeling is not applicable since replacement of the flare tip does not cause an increase in the emission of NOx or PM10.

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

Offsets are not required since replacement of the flare tip does not cause an increase in the emission of any criteria air pollutants.

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

This requirement is not applicable since offsets are not required.

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

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

- an increase of one pound per day or more, of the facility's potential to emit (PTE) for NOx or VOC if the facility is located in the SOCAB , or
- an increase of 40 tons per year or more, of the facility's PTE for SOx, or
- an increase of 15 tons per year or more, of the facility's PTE for PM_{10}; or,
- an increase of 50 tons per year or more, of the facility's PTE for CO.

Replacement of the flare tip does not cause an increase in the emission of any criteria air pollutants. Therefore, replacement of the flare tip is not a “major modification” as defined in this rule.

RULE 1325: FEDERAL PM2.5 NEW SOURCE REVIEW PROGRAM

This NSR rule for PM2.5 and its precursors NOx and SO2 was adopted by the District’s Governing Board on June 3, 2011. Replacement of the flare tip does not impact PM2.5, NOx or SO2 emissions. Therefore, none of the requirements of this rule are applicable.

Regulation XIV - TOXICS AND OTHER NON-CRITERIA POLLUTANTS

RULE 1401: NEW SOURCE REVIEW OF CARCINOGENIC AIR CONTAMINANTS

Requirements – Rule 1401 contains the following requirements:

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

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

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

Analysis **–** Replacement of the flare tip does not cause an increase in the emission of any toxic air contaminants. The combustion efficiency and smokeless capacity of the flare are expected to be equal or better than the current flare tip. Therefore, it is expected that the emission of products of incomplete combustion such as PAHs for the new flare tip will be equivalent or less than the existing flare tip. Compliance with the requirements of this regulation is achieved.

REGULATION XVII - PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

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

RULE 1703 – PSD ANALYSIS (& Associated Rules 1701, 1702, 1704, 1706, 1710 & 1713)

These rules contain the PSD requirements for attainment pollutants and selected unclassified pollutants. As discussed earlier, SOCAB is currently designated as attainment with NAAQSs for CO, NOx, SOx, and lead. Therefore, CO, NOx, SOx and lead compounds must be evaluated under this rule.

Replacement of the flare tip does not cause an increase in the emission of CO, NOx, SOx or lead compounds. Therefore, none of the requirements of this rule are applicable

RULE 1714 – PREVENTION OF SERIOUS DETERIORATION FOR GREENHOUSE GASES

This rule, which was adopted on November 5, 2010, sets preconstruction review requirements for greenhouse gases (GHGs). Replacement of the flare tip does not cause an increase in the emission of any GHGs. Therefore, none of the requirements of this rule are applicable.

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

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

The Coker Flare is exempt from the requirements of this regulation. The gas flare exemption is contained at Rule 2011(i) and 2012(k). The definition of a gas flare, as contained in 2011 Attachment E and 2012 Attachment F is "a combustion equipment used to prevent unsafe operating pressures in process units during shutdowns and startups and to handle miscellaneous hydrocarbon leaks and process upsets". The Coker Flare qualifies for this exemption.

<u>Regulation XXX – TITLE V PERMITS</u>

The initial Title V permit for the refinery was effective on October 12, 2009. The PO for the Coker Flare will be issued as a revision of Chevron's Title V permit. Title V permit revisions are categorized into the following four types: *administrative, minor, de minimis significant and* *significant*. The review and distribution requirements for each revision type are summarized in the following table.

Title V Permit Revisions: Review and Distribution Requirements

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

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

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

This Title V permit revision meets all of the requirements above so it is a minor revision. Chevron has submitted Title V permit revision A/N 547157 for processing of this Title V permit minor revision, which will be sent to EPA for a 45-day review. Public notice is not required.

CONCLUSION / RECOMMENDATION:

Based on the foregoing evaluation, it is expected that the subject applications will comply with all applicable District Rules and Regulations. It is recommended that a permit to construct/permit to operate be issued for the Coker Flare under A/N 547157.

Appendix A: Estimate of Total Fugitive VOC Emissions

Equipment Type	Service	Fugitive Component Count (1)	Emission Factor (lb/yr) (2)	Estimated Fugitive VOC Emissions (1)
Valves - Sealed Bellow	All	30	0	0
Valves - SCAQMD Approved I & M Program	Gas/Vapor	68	4.55	309
	Light Liquid	2	4.55	9
	Heavy Liquid	0	4.55	0
Flanges	Light Liquid/Vapor	256	6.99	1789
	Heavy Liquid	0	6.99	0
Connectors	Light Liquid/Vapor	465	2.86	1330
	Heavy Liquid	0	2.86	0
Pumps	Light Liquid (sealless type)	1	0	0
	Light Liquid (double seal)	0	46.83	0
	Heavy Liquid (single seal)	0	17.21	0
Compressors	Gas/Vapor	0	9.09	0
PRV's	All (To Atmosphere)	0	9.09	0
	All (Closed Vent)	5	0	0
Drains (with p-trap)	All	8	9.09	73
		Total	**lb/yr**	**3511**
			lb/day (3)	**9.75**

(1) Fugitive component count and estimated fugitive VOC emissions (Mr. Pete Allen - 4/16/13 email).
(2) Fugitive emission factors emission factors based on correlation equations from the *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities* (CARB/CAPCOA - 1999)
(3) 30-day average emissions based on annual emissions divided by 360.