San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 10 2012

Paul Combs
Crimson Resource Management
5001 California Ave, Suite #206
Bakersfield, CA 93309

Re: Notice of Preliminary Decision - Authority to Construct
Project Number: S-1122546

Dear Mr. Combs:

Enclosed for your review and comment is the District's analysis of Crimson Resource Management's application for an Authority to Construct for a flare replacement, increase the fuel flow of flare listed in permit S-2918-1, and lower the vapor pressure of crude oil stored in tank listed in permit S-2918-31, at Panama and Greeley lease, Light Oil Stationary Source, Kern County.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. Please submit your written comments on this project within the 30-day public comment period which begins on the date of publication of the public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Stanley Tom of Permit Services at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:st

Enclosures

Seyed Sadredin
Executive Director/Air Pollution Control Officer

Northern Region
4800 Enterprise Way
Modesto, CA 95356-8718
Tel: (209) 557-6400 FAX: (209) 557-6475

Central Region (Main Office)
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244
Tel: (559) 230-6000 FAX: (559) 230-6061

Southern Region
34946 Flyover Court
Bakersfield, CA 93308-9725
Tel: 661-392-5500 FAX: 661-392-5585

www.valleyair.org www.healthyairliving.com

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 10 2012

Mike Tollstrup, Chief
Project Assessment Branch
Stationary Source Division
California Air Resources Board
PO Box 2815
Sacramento, CA 95812-2815

Re: Notice of Preliminary Decision - Authority to Construct
Project Number: S-1122546

Dear Mr. Tollstrup:

Enclosed for your review and comment is the District's analysis of Crimson Resource Management's application for an Authority to Construct for a flare replacement, increase the fuel flow of flare listed in permit S-2918-1, and lower the vapor pressure of crude oil stored in tank listed in permit S-2918-31, at Panama and Greeley lease, Light Oil Stationary Source, Kern County.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. Please submit your written comments on this project within the 30-day public comment period which begins on the date of publication of the public notice.

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AIR POLLUTION CONTROL DISTRICT

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DEC 1 0 2012

Gerardo C. Rios (AIR 3)
Chief, Permits Office
Air Division
U.S. E.P.A. - Region IX
75 Hawthorne Street
San Francisco, CA 94105

Re: Notice of Preliminary Decision - Authority to Construct
Project Number: S-1122546

Dear Mr. Rios:

Enclosed for your review and comment is the District's analysis of Crimson Resource Management's application for an Authority to Construct for a flare replacement, increase the fuel flow of flare listed in permit S-2918-1, and lower the vapor pressure of crude oil stored in tank listed in permit S-2918-31, at Panama and Greeley lease, Light Oil Stationary Source, Kern County.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. Please submit your written comments on this project within the 30-day public comment period which begins on the date of publication of the public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Stanley Tom of Permit Services at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:st

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Bakersfield Californian
Bakersfield Californian

**NOTICE OF PRELIMINARY DECISION
FOR THE PROPOSED ISSUANCE OF
AN AUTHORITY TO CONSTRUCT**

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District solicits public comment on the proposed issuance of Authority to Construct to Crimson Resource Management for a flare replacement, increase the fuel flow of flare listed in permit S-2918-1, and lower the vapor pressure of crude oil stored in tank listed in permit S-2918-31, at Panama and Greeley lease, Light Oil Stationary Source, Kern County.

The analysis of the regulatory basis for this proposed action, Project #S-1122546, is available for public inspection at http://www.valleyair.org/notices/public_notices_idx.htm and the District office at the address below. Written comments on this project must be submitted within 30 days of the publication date of this notice to **DAVID WARNER, DIRECTOR OF PERMIT SERVICES, SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.**

San Joaquin Valley Air Pollution Control District
Authority to Construct Application Review
Flare Replacement, Increase Flare Fuel Use, Lower Crude Oil Tank RVP

Facility Name:	Crimson Resource Management	Date:	November 14, 2012
Mailing Address:	5001 California Ave, Suite #206 Bakersfield, CA 93309	Engineer:	Stanley Tom
		Lead Engineer:	Joven Refuerzo
Contact Person:	Paul Combs		
Telephone:	(661) 716-5001		
E-Mail:	pcombs@crimsonbak.com		
Application No:	S-2918-1-7, '3-6, '31-4, '62-0		
Project No:	S-1122546		
Deemed Complete:	August 23, 2012		

I. Proposal

Crimson Resource Management has requested an Authority to Construct (ATC) permit to replace the flare listed in permit S-2918-2 with a new 12 MMBtu/hr produced gas-fired air-assisted combustion device (to be listed in permit S-2918-62), to increase the amount of gas allowed to be combusted in flare listed in permit S-2918-1 from 2,045,000 scf/year to 96,000,000 scf/year, and to lower the Reid Vapor Pressure (RVP) limit from 9.5 psia to 6.86 psia of the crude oil stored in storage tank listed in permit S-2918-31.

The new 12 MMBtu/hr produced gas-fired combustion device listed in permit S-2918-62 will serve the vapor controlled tanks listed in permits S-2918-15 and '16. The vapor control system is listed in permit S-2918-3. Permit S-2918-3 will be updated in this project to include the combustion device listed in permit S-2918-62 as an approved incineration device.

The following condition will be listed on ATC S-2918-62-0 to ensure permit S-2918-2 is canceled upon implementation of ATC S-2918-62-0 as part of a Stationary Source Project:

- Within 90 days of startup of the equipment authorized by this Authority to Construct, Permit to Operate S-2918-2-3 shall be surrendered to the District and the associated equipment shall be removed or rendered inoperable. [District Rule 2201]

Crimson Resource Management has received their Title V permit. However, the applicant has submitted a letter indicating the facility is no longer a Title V facility as the actual annual emissions (including greenhouse gases) are below one half of the major source threshold and qualifies as a Rule 2530 source. Conditions will be added to the permit to ensure compliance with Rule 2530. Therefore, Rule 2520 no longer applies and the facility is not subject to Title V requirements.

II. Applicable Rules

Rule 2201 New and Modified Stationary Source Review Rule (4/21/11)
Rule 2520 Federally Mandated Operating Permits (6/21/01)
Rule 2530 Federally Enforceable Potential to Emit (6/10/10)
Rule 4001 New Source Performance Standards (4/14/99)
Rule 4002 National Emissions Standards for Hazardous Air Pollutants (5/20/04)
Rule 4101 Visible Emissions (2/17/05)
Rule 4102 Nuisance (12/17/92)
Rule 4201 Particulate Matter Concentration (12/17/92)
Rule 4301 Fuel Burning Equipment (12/17/92)
Rule 4311 Flares (6/18/09)
Rule 4623 Storage of Organic Liquids (5/19/05)
Rule 4801 Sulfur Compounds (12/17/92)
CH&SC 41700 Health Risk Assessment
CH&SC 42301.6 School Notice

Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

II. Project Location

The facility operates leases in the Light Oil Central Stationary Source within Kern County, CA. The flare and combustion device are authorized to operate at the Panama lease and the Greeley lease and the equipment are authorized to operate at the following locations:

Permit	Section	Township	Range
S-2918-1-7	14	30S	27E
	7	29S	26E
S-2918-3-6	14 and 15	30S	27E
S-2918-31-4	NE 10	30S	26E
S-2918-62-0	14	30S	27E

The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

III. Process Description

Crimson produces light crude oil from their light oil central stationary source. The produced fluids are sent through several vessels to facilitate separation of water, oil and gases.

Light oil is produced from oil wells. Gas produced at the leases is normally sent to the gas plant or sales line. Flaring or gas combustion occurs when the sales line or gas plant compressor is down.

V. Equipment Listing

Pre-Project Equipment Description

Current Permit	Pre-Project Equipment Description
S-2918-1-6	32.5 MMBTU/HR NATIONAL AIR OIL BURNER CO. MODEL NAFV FLARE WITH AUTOMATIC SPARK IGNITED PILOT AND COMBUSTION AIR BLOWER (GREELEY LEASE)
S-2918-3-4	42,000 GALLON PETROLEUM STORAGE TANK (T-1001), SERVED BY VAPOR CONTROL SYSTEM SHARED BETWEEN S-2918-3, -4, -5, -15, & -16 (PANAMA LEASE)
S-2918-31-1	21,000 GALLON FIXED ROOF PETROLEUM STORAGE TANK WITH PRESSURE VACUUM RELIEF HATCH - #20016 (KERN COUNTY LEASE 61)

Proposed Modification

ATC Permit	ATC Equipment Description
S-2918-1-7	MODIFICATION OF 32.5 MMBTU/HR NATIONAL AIR OIL BURNER CO. MODEL NAFV FLARE WITH AUTOMATIC SPARK IGNITED PILOT AND COMBUSTION AIR BLOWER (GREELEY LEASE): INCREASE FLARE FUEL USE LIMIT FROM 2,045,000 SCF/YEAR TO 96,000,000 SCF/YEAR
S-2918-3-6	MODIFICATION OF 42,000 GALLON PETROLEUM STORAGE TANK (T-1001), SERVED BY VAPOR CONTROL SYSTEM SHARED BETWEEN S-2918-3, -4, -5, -15, & -16 (PANAMA LEASE): ALLOW COMBUSTION DEVICE LISTED IN PERMIT UNIT S-2918-62 TO BE AN AUTHORIZED VAPOR CONTROL SYSTEM INCINERATION DEVICE
S-2918-31-4	MODIFICATION OF 21,000 GALLON FIXED ROOF PETROLEUM STORAGE TANK WITH PRESSURE VACUUM RELIEF HATCH - #20016 (KERN COUNTY LEASE 61): LOWER RVP LIMIT FROM 9.5 PSIA TO 6.86 PSIA
S-2918-62-0	12 MMBTU/HR BEKAERT MODEL CEB 350 PRODUCED GAS-FIRED AIR ASSISTED COMBUSTION DEVICE

Post-Project Equipment Description

Proposed Permit	Post-Project Equipment Description
S-2918-1-7	32.5 MMBTU/HR NATIONAL AIR OIL BURNER CO. MODEL NAFV FLARE WITH AUTOMATIC SPARK IGNITED PILOT AND COMBUSTION AIR BLOWER (GREELEY LEASE)
S-2918-3-6	42,000 GALLON PETROLEUM STORAGE TANK (T-1001), SERVED BY VAPOR CONTROL SYSTEM SHARED BETWEEN S-2918-3, -4, -5, -15, & -16 (PANAMA LEASE)
S-2918-31-4	21,000 GALLON FIXED ROOF PETROLEUM STORAGE TANK WITH PRESSURE VACUUM RELIEF HATCH - #20016 (KERN COUNTY LEASE 61)
S-2918-62-0	12 MMBTU/HR BEKAERT MODEL CEB 350 PRODUCED GAS-FIRED AIR ASSIST COMBUSTION DEVICE

VI. Emission Control Technology Evaluation

Flare S-2918-1

The flare is air-assisted, operates in a smokeless manner, and is equipped with an auto electronic igniter with a thermocouple or any other equivalent device to detect the presence of a flame. The sulfur content of the flared gas is permitted to be no greater than 5 ppmv.

Tank S-2918-31

The tank is equipped with a pressure-vacuum (PV) relief vent valve set to within 10% of the maximum allowable working pressure of the tank. The PV-valve will reduce VOC wind induced emissions from the tank vent.

Combustion Device S-2918-62

The applicant is proposing to combust produced gas in a combustion device in the event of an upset plant condition. Produced gas combustion generates NO_x, SO_x, PM_{10}, CO and VOC emissions. Smoke from the combustion device is minimized by the use of an air-assist to improve mixing of the air and produced gas being combusted. The combustion device uses a produced gas-fired automatic ignition pilot.

VII. General Calculations

S-2918-3-6

For ATC S-2918-3-6, this project does not meet the criteria for a Rule 2201 Modification, as defined in Section 3.26, and is not subject to the requirements of Rule 2201. Therefore,

formal calculations for Rule 2201 are not necessary. However, potential to emit calculations will be shown for reference purposes.

A. Assumptions

- Operation schedule = 24 hr/day and 365 days/year (per applicant)
- Produced gas F-factor = 8,600 dscf/MMBtu at 60 degrees F (per gas analysis)
- Produced gas higher heating value = 1200 Btu/scf (per gas analysis)
- Produced gas H2S concentration = 5 ppmv (per current permit S-2918-1-6)

S-2918-1-7

- Daily pre-project maximum flare gas flowrate = 1,000 Mscf/day (per current permit)
- Daily post-project maximum flare gas flowrate = 1,000 Mscf/day (per applicant)
- Annual pre-project maximum flare gas flowrate = 2,045 Mscf/year (per current permit)
- Annual post-project maximum flare gas flowrate = 96,000 Mscf/year (per applicant)

S-2918-2-3

- Daily maximum flare gas flowrate = 46,000 scf/day (per current permit)

S-2918-31-4

- Crude oil throughput = 150 bbl/day (per current permit)
- Pre-project Reid vapor pressure (RVP) = 9.5 psia (Per applicant. Current permit does not have an expressed limit; however, Rule 4623 Table 2 for small producers allows tanks with a capacity of 1,100 to 39,600 gallons and a True Vapor Pressure of 0.5 psia to < 11 psia and a tank crude oil throughput of > 50 bbl/day to < 150 bbl/day to be equipped with a Pressure-vacuum relief valve to meet the VOC control system requirements of the rule. This facility is a small producer. The tank has a capacity of 21,000 gallons, crude oil throughput of < 150 bbl/day, and is equipped with a Pressure-vacuum relief valve. Therefore, a TVP of < 11 psia would be the worst case vapor pressure that would still show compliance with the VOC control system requirements of this rule. RVP = 9.5 psia meets the requirement of TVP < 11 psia as shown in Attachment B.)
- Post-project Reid vapor pressure (RVP) = 6.86 psia (per applicant)

S-2918-62-0

- Daily post-project maximum gas flowrate = 250,000 scf/day (per applicant)
- Annual post-project maximum gas flowrate = 91,250,000 scf/year (per applicant)

B. Emission Factors

S-2918-1-7

Flare Emission Factors		
Pollutant	lb/MMBtu	Source
NO_X	0.068	Current PTO
SO_X	0.0007	Mass balance equation below based on 5 ppmv H_2S in fuel
PM_{10}	0.0202	Current PTO
CO	0.37	Current PTO
VOC	0.063	Project S-1103349

$$SOx = \frac{\left(1{,}000{,}000\frac{ft^3-fuel}{day}\right)\left(\frac{5\,ft^3-H_2S}{10^6\,ft^3-fuel}\right)\left(34\frac{lb-H_2S}{lb-mol}\right)}{\left(379.5\frac{ft^3-H_2S}{lb-mol}\right)\left(\frac{34\,lb-H_2S}{32\,lb-S}\right)\left(\frac{32\,lb-S}{64\,lb-SO_2}\right)}$$

SOx = 0.84 lb/day

SOx = 0.84 lb/day ÷ (1,000,000 scf/day x 1200 Btu/scf) x 1E6/MM
= 0.0007 lb/MMBtu

S-2918-2-3

Flare Emission Factors		
Pollutant	lb/day	Source
NO_X	3.1	Current PTO
SO_X	0.04	Mass balance equation below based on 5 ppmv H_2S in fuel
PM_{10}	0.9	Current PTO
CO	17.0	Current PTO
VOC	4.0	Project S-1103349

$$SOx = \frac{\left(46{,}000\frac{ft^3-fuel}{day}\right)\left(\frac{5\,ft^3-H_2S}{10^6\,ft^3-fuel}\right)\left(34\frac{lb-H_2S}{lb-mol}\right)}{\left(379.5\frac{ft^3-H_2S}{lb-mol}\right)\left(\frac{34\,lb-H_2S}{32\,lb-S}\right)\left(\frac{32\,lb-S}{64\,lb-SO_2}\right)}$$

SOx = 0.04 lb/day

S-2918-31-4

Both the daily and annual potential to emit will be based on the results from the District's Microsoft Excel spreadsheets for Tank Emissions - Fixed Roof Crude Oil 26 API and higher (see Attachment B). The spreadsheet for tanks was developed using the equations for fixed-roof tanks from EPA AP-42, Chapter 7.1.

S-2918-62-0

Combustion Device Emission Factors		
Pollutant	lb/MMBtu	Source
NO_X	0.018	Applicant Proposal
SO_X	0.0007	Mass balance equation below based on 5 ppmv H_2S in fuel
PM_{10}	0.0202	Applicant Proposal
CO	0.01	Applicant Proposal
VOC	0.008	Applicant Proposal

$$SOx = \frac{\left(250{,}000\,\frac{ft^3 - fuel}{day}\right)\left(\frac{5\,ft^3 - H_2S}{10^6\,ft^3 - fuel}\right)\left(34\,\frac{lb - H_2S}{lb - mol}\right)}{\left(379.5\,\frac{ft^3 - H_2S}{lb - mol}\right)\left(\frac{34\,lb - H_2S}{32\,lb - S}\right)\left(\frac{32\,lb - S}{64\,lb - SO_2}\right)}$$

SOx = 0.21 lb/day

SOx = 0.21 lb/day ÷ (250,000 scf/day x 1200 Btu/scf) x 1E6/MM
= 0.0007 lb/MMBtu

C. Calculations

1. Pre-Project Potential to Emit (PE1)

S-2918-1-7

The PE1 for each pollutant is calculated with the following equation:

- PE1 = EF (lb/MMBtu) × Heat Input (MMBtu/day or MMBtu/year) × Heating Value (Btu/scf)

Daily Pre-Project Emissions – Flare												
Pollutant	Emission Factors			Heat input							PE1 Total	
NO_X	0.068	(lb/MMBtu)	x	1,000,000	(scf/day)	x	1200	(Btu/scf)	=	81.6	(lb/day)
SO_X	0.0007	(lb/MMBtu)	x	1,000,000	(scf/day)	x	1200	(Btu/scf)	=	0.8	(lb/day)
PM_{10}	0.0202	(lb/MMBtu)	x	1,000,000	(scf/day)	x	1200	(Btu/scf)	=	24.2	(lb/day)
CO	0.37	(lb/MMBtu)	x	1,000,000	(scf/day)	x	1200	(Btu/scf)	=	444.0	(lb/day)
VOC	0.063	(lb/MMBtu)	x	1,000,000	(scf/day)	x	1200	(Btu/scf)	=	75.6	(lb/day)

Annual Pre-Project Emissions – Flare											
Pollutant	Emission Factors			Heat input						PE1 Total	
NO_X	0.068	(lb/MMBtu)	x	2,045,000	(scf/year)	x	1200	(Btu/scf)	=	167	(lb/year)
SO_X	0.0007	(lb/MMBtu)	x	2,045,000	(scf/year)	x	1200	(Btu/scf)	=	2	(lb/year)
PM_{10}	0.0202	(lb/MMBtu)	x	2,045,000	(scf/year)	x	1200	(Btu/scf)	=	50	(lb/year)
CO	0.37	(lb/MMBtu)	x	2,045,000	(scf/year)	x	1200	(Btu/scf)	=	908	(lb/year)
VOC	0.063	(lb/MMBtu)	x	2,045,000	(scf/year)	x	1200	(Btu/scf)	=	155	(lb/year)

S-2918-2-3

The emissions below were taken from the current permit, sulfur mass balance equation, and project S-1103349.

Daily Pre-Project Emissions – Flare	
Pollutant	PE1 Total (lb/day)
NO_X	3.1
SO_X	0.0
PM_{10}	0.9
CO	17.0
VOC	4.0

Annual Pre-Project Emissions – Flare	
Pollutant	PE1 Total (lb/year)
NO_X	1,132
SO_X	15
PM_{10}	329
CO	621
VOC	1,460

S-2918-3-4

Per Project S-970012,

Daily PE = 0.5 lb-VOC/day
Annual PE = 183 lb-VOC/year

S-2918-31-4

As shown in Attachment B,

Daily Pre-Project Emissions – Storage Tank	
Pollutant	PE1 Total (lb/day)
VOC	38.6

Annual Pre-Project Emissions – Storage Tank	
Pollutant	PE1 Total (lb/year)
VOC	14,105

S-2918-62-0

Since this is a new emission unit, PE1 = 0.

2. Post Project Potential to Emit (PE2)

S-2918-1-7

The PE2 for each pollutant is calculated with the following equation:

- PE2 = EF (lb/MMBtu) × Heat Input (MMBtu/day or MMBtu/year) × Heating Value (Btu/scf)

Daily Post-Project Emissions – Flare												
Pollutant	Emission Factors			Heat input							PE2 Total	
NO_X	0.068	(lb/MMBtu)	x	1,000,000	(scf/day)	x	1200	(Btu/scf)	=		81.6	(lb/day)
SO_X	0.0007	(lb/MMBtu)	x	1,000,000	(scf/day)	x	1200	(Btu/scf)	=		0.8	(lb/day)
PM_{10}	0.0202	(lb/MMBtu)	x	1,000,000	(scf/day)	x	1200	(Btu/scf)	=		24.2	(lb/day)
CO	0.37	(lb/MMBtu)	x	1,000,000	(scf/day)	x	1200	(Btu/scf)	=		444.0	(lb/day)
VOC	0.063	(lb/MMBtu)	x	1,000,000	(scf/day)	x	1200	(Btu/scf)	=		75.6	(lb/day)

Annual Post-Project Emissions – Flare												
Pollutant	Emission Factors		Heat input							PE2 Total	
NO_X	0.068	(lb/MMBtu)	x	96,000,000	(scf/year)	x	1200	(Btu/scf)	=	7,834	(lb/year)
SO_X	0.0007	(lb/MMBtu)	x	96,000,000	(scf/year)	x	1200	(Btu/scf)	=	81	(lb/year)
PM_{10}	0.0202	(lb/MMBtu)	x	96,000,000	(scf/year)	x	1200	(Btu/scf)	=	2,327	(lb/year)
CO	0.37	(lb/MMBtu)	x	96,000,000	(scf/year)	x	1200	(Btu/scf)	=	42,624	(lb/year)
VOC	0.063	(lb/MMBtu)	x	96,000,000	(scf/year)	x	1200	(Btu/scf)	=	7,258	(lb/year)

S-2918-2-3

Since this unit will be replaced with the flare listed in permit S-2918-62-0, PE2 = 0.

S-2918-3-4

Per applicant, the fugitive component count of the vapor control system will not be changed in this project.

Therefore, PE2 = PE1.

S-2918-31-4

As shown in Attachment B,

Daily Post-Project Emissions – Storage Tank	
Pollutant	PE2 Total (lb/day)
VOC	20.7

Annual Post-Project Emissions – Storage Tank	
Pollutant	PE2 Total (lb/year)
VOC	7,573

S-2918-62-0

The PE2 for each pollutant is calculated with the following equation:

- PE2 = EF (lb/MMBtu) × Heat Input (MMBtu/day or MMBtu/year) × Heating Value (Btu/scf)

Daily Post-Project Emissions – Combustion Device												
Pollutant	Emission Factors			Heat input						PE2 Total	
NO_X	0.018	(lb/MMBtu)	x	250,000	(scf/day)	x	1200	(Btu/scf)	=	5.4	(lb/day)
SO_X	0.0007	(lb/MMBtu)	x	250,000	(scf/day)	x	1200	(Btu/scf)	=	0.2	(lb/day)
PM_{10}	0.0202	(lb/MMBtu)	x	250,000	(scf/day)	x	1200	(Btu/scf)	=	6.1	(lb/day)
CO	0.01	(lb/MMBtu)	x	250,000	(scf/day)	x	1200	(Btu/scf)	=	3.0	(lb/day)
VOC	0.008	(lb/MMBtu)	x	250,000	(scf/day)	x	1200	(Btu/scf)	=	2.4	(lb/day)

Annual Post-Project Emissions – Combustion Device											
Pollutant	Emission Factors			Heat input						PE2 Total	
NO_X	0.018	(lb/MMBtu)	x	91,250,000	(scf/year)	x	1200	(Btu/scf)	=	1,971	(lb/year)
SO_X	0.0007	(lb/MMBtu)	x	91,250,000	(scf/year)	x	1200	(Btu/scf)	=	77	(lb/year)
PM_{10}	0.0202	(lb/MMBtu)	x	91,250,000	(scf/year)	x	1200	(Btu/scf)	=	2,212	(lb/year)
CO	0.01	(lb/MMBtu)	x	91,250,000	(scf/year)	x	1200	(Btu/scf)	=	1,095	(lb/year)
VOC	0.008	(lb/MMBtu)	x	91,250,000	(scf/year)	x	1200	(Btu/scf)	=	876	(lb/year)

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the Pre-Project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Pre-Project Stationary Source Potential to Emit [SSPE1] (lb/year)					
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC
S-2918-1-6	167	2	50	908	155
S-2918-2-3	1,132	15	329	621	1,460
S-2918-3-4	0	0	0	0	183
S-2918-4-4	0	0	0	0	183
S-2918-5-4	0	0	0	0	183
S-2918-15-4	0	0	0	0	183
S-2918-16-4	0	0	0	0	475
S-2918-26-4	0	0	0	0	263
S-2918-27-5	0	0	0	0	47
S-2918-28-5	0	0	0	0	47
S-2918-29-6	0	0	0	0	876
S-2918-30-3	0	0	0	0	694
S-2918-31-1	0	0	0	0	14,105
S-2918-45-1	0	0	0	0	N.C.

S-2918-46-4	0	0	0	0	1,852
S-2918-50-3	0	0	0	0	1,314
S-2918-51-0	0	0	0	0	
S-2918-52-0	0	0	0	0	
S-2918-53-0	0	0	0	0	
S-2918-54-0	1,840	6,132	88	350	88
S-2918-55-3	0	0	0	0	3,493
S-2918-56-3	0	0	0	0	4,987
S-2918-58-3	0	0	0	0	4,987
S-2918-59-3	0	0	0	0	4,987
S-2918-60-0	0	0	0	0	110
S-2918-61-0	0	0	0	0	110
Pre-Project SSPE (SSPE1)	3,139	6,149	467	1,879	40,782

N.C. = not calculated (insufficient information to calculate emissions)

4. Post Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Post-Project Stationary Source Potential to Emit [SSPE2] (lb/year)					
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC
S-2918-1-7	7,834	81	2,327	42,624	7,258
S-2918-3-6	0	0	0	0	183
S-2918-4-4	0	0	0	0	183
S-2918-5-4	0	0	0	0	183
S-2918-15-4	0	0	0	0	183
S-2918-16-4	0	0	0	0	475
S-2918-26-4	0	0	0	0	263
S-2918-27-5	0	0	0	0	47
S-2918-28-5	0	0	0	0	47
S-2918-29-6	0	0	0	0	876
S-2918-30-3	0	0	0	0	694
S-2918-31-4	0	0	0	0	7,573
S-2918-45-1	0	0	0	0	N.C.
S-2918-46-4	0	0	0	0	1,852
S-2918-50-3	0	0	0	0	1,314
S-2918-51-0	0	0	0	0	
S-2918-52-0	0	0	0	0	
S-2918-53-0	0	0	0	0	

S-2918-54-0	1,840	6,132	88	350	88
S-2918-55-3	0	0	0	0	3,493
S-2918-56-3	0	0	0	0	4,987
S-2918-58-3	0	0	0	0	4,987
S-2918-59-3	0	0	0	0	4,987
S-2918-60-0	0	0	0	0	110
S-2918-61-0	0	0	0	0	110
S-2918-62-0	1,971	77	2,212	1,095	876
Post-Project SSPE (SSPE2)	11,645	6,290	4,627	44,069	40,769

5. Major Source Determination

Pursuant to District Rule 2201, a Major Source is a stationary source with post-project emissions or a Post Project Stationary Source Potential to Emit (SSPE2), equal to or exceeding one or more of the following threshold values. However, for the purposes of determining major source status, the SSPE2 shall not include the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Major Source Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
Post-Project SSPE (SSPE2)	11,645	6,290	4,627	44,069	40,769
Major Source Threshold	20,000	140,000	140,000	200,000	20,000
Major Source?	No	No	No	No	Yes

6. Baseline Emissions (BE)

The BE calculation (in lbs/year) is performed pollutant-by-pollutant for each unit within the project, to calculate the QNEC and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = Pre-project Potential to Emit for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

a. BE NOx, SOx, PM_{10}, or CO

Unit Located at a Non-Major Source
As shown in Section VII.C.5 above, the facility is not a Major Source for NOx, SOx, PM_{10}, or CO.

Therefore, BE = PE1.

b. BE VOC

Clean Emissions Unit, Located at a Major Source
Pursuant to Rule 2201, a Clean Emissions Unit is defined as an emissions unit that is "equipped with an emissions control technology with a minimum control efficiency of at least 95% or is equipped with emission control technology that meets the requirements for achieved-in-practice BACT as accepted by the APCO during the five years immediately prior to the submission of the complete application.

S-2918-1-7

The flare listed in permit S-2918-1-6 meets the requirements for achieved-in-practice BACT in BACT Guideline 1.4.2 which is Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable. The flare listed in permit S-2918-1-6 is air assisted; therefore, this unit is a clean emissions unit and BE = PE1.

S-2918-2-3

The flare listed in permit S-2918-2-3 meets the requirements for achieved-in-practice BACT in BACT Guideline 1.4.2 which is Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable. The flare listed in permit S-2918-2-3 is air assisted; therefore, this unit is a clean emissions unit and BE = PE1.

S-2918-31-4

The fixed roof storage tank listed in permit S-2918-31-1 meets the requirements for achieved-in-practice BACT in BACT Guideline 7.3.1 which is PV-vent set to within 10% of maximum allowable pressure. The fixed roof storage tank listed in permit S-2918-31-1 is equipped with a PV-vent; therefore, this unit is a clean emissions unit and BE = PE1.

S-2918-62-0

Since this is a new emissions unit, BE = PE1 = 0 for all pollutants.

7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result

in a significant net emissions increase of any pollutant subject to regulation under the Act."

As discussed in Section VII.C.5 above, the facility is not a Major Source for NOx, SOx, PM_{10}, or CO; therefore, the project does not constitute a SB 288 Major Modification for NOx, SOx, PM_{10}, or CO and no further calculations are required.

As discussed in Section VII.C.5 above, the facility is an existing Major Source for VOC; however, the project by itself would need to be a significant increase in order to trigger a SB 288 Major Modification. The emission units within this project do not have a total potential to emit which are greater than SB 288 Major Modification thresholds (see table below). Therefore, the project cannot be a significant increase and the project does not constitute a SB 288 Major Modification.

SB 288 Major Modification Thresholds (Existing Major Source)				
Pollutant	Permit	Project PE (lb/year)	Threshold (lb/year)	SB 288 Major Modification?
VOC	S-2918-1-7	7,258	50,000	No
	S-2918-31-4	7,573		
	S-2918-62-0	876		
	Total	**15,707**		

8. Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

Since this facility is not a Major Source for NOx, SOx, or PM_{10}, this project does not constitute a Federal Major Modification for NOx, SOx, or PM_{10}. Additionally, since the facility is not a major source for PM_{10} (140,000 lb/year), it is not a major source for $PM_{2.5}$ (200,000 lb/year). No further calculations or discussion is required.

<u>VOC</u>

District Rule 2201, Section 3.17 states that Federal Major Modifications are the same as "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA. SB 288 Major Modifications are not federal major modifications if they meet the criteria of the "Less-Than-Significant Emissions Increase" exclusion.

A Less-Than-Significant Emissions Increase exclusion is for an emissions increase for the project, or a Net Emissions Increase for the project (as defined in 40 CFR 51.165 (a)(2)(ii)(B) through (D), and (F)), that is not significant for a given regulated NSR pollutant, and therefore is not a federal major modification for that pollutant.

- To determine the post-project projected actual emissions from existing units, the provisions of 40 CFR 51.165 (a)(1)(xxviii) shall be used.

- To determine the pre-project baseline actual emissions, the provisions of 40 CFR 51.165 (a)(1)(xxxv)(A) through (D) shall be used.
- If the project is determined not to be a federal major modification pursuant to the provisions of 40 CFR 51.165 (a)(2)(ii)(B), but there is a reasonable possibility that the project may result in a significant emissions increase, the owner or operator shall comply with all of the provisions of 40 CFR 51.165 (a)(6) and (a)(7).
- Emissions increases calculated pursuant to this section are significant if they exceed the significance thresholds specified in the table below.

Significant Threshold (lb/year)	
Pollutant	Threshold (lb/year)
VOC	0

The Net Emissions Increases (NEI) for purposes of determination of a "Less-Than-Significant Emissions Increase" exclusion will be calculated below to determine if this project qualifies for such an exclusion.

Since this project consists of both existing and new emissions units, the "hybrid test" specified in 40 CFR(a)(2)(ii)(F) is applicable and requires that the NEI determination be based on the sum of the individual NEI determinations for existing emissions units (NEI_E) and new emissions units (NEI_N) pursuant to 40 CFR(a)(2)(ii)(C) and (D) respectively. In addition, pursuant to 40 CFR (a)(1)(vi)(A)(2), creditable contemporaneous emissions increases (NEI_C) must also be included in the determination of the NEI. Therefore,

$NEI = NEI_E + NEI_N + NEI_C$

<u>Net Emission Increase for Existing Units (NEI_E)</u>

Per 40 CFR 51.165 (a)(1)(xxviii) and 40 CFR 51.165 (a)(2)(ii)(C) for all existing units, if the proposed modification results in an increase in design capacity or potential to emit, or impacts the ability of the emission unit to operate at a higher utilization rate, then the emission increase is calculated as follows:

$NEI_E = PAE - BAE$

where,

PAE = Projected Actual Emissions which are the post-project projected actual emissions of the existing units in this project pursuant to 40 CFR 51.165 (a)(1)(xxviii).

BAE = Baseline Actual Emissions which are the actual emissions created by the project during the baseline period. The BAE are calculated pursuant to 40 CFR 51.165 (a)(1)(xxxv)(A) through (D).

Projected Actual Emissions

If there is no increase in design capacity or potential to emit, the PAE is equal to the annual emission rate at which the unit is projected to emit in any one year, selected by the operator, within 5 years after the unit resumes normal operation (10 years for existing units with an increase in design capacity or potential to emit). If detailed PAE are not provided, the PAE is equal to the PE2 for each permit unit.

For the flare listed in permit S-2918-1-7 and tank listed in permit S-2918-31-4 in this project, the projected actual emissions are assumed to be equal to the post-project potential to emit (PE2).

Projected Actual Emissions (PAE)	
Permit Unit	VOC Emissions (lb/year)
S-2918-1-7	7,258
S-2918-31-4	7,573

Baseline Actual Emissions

The BAE is calculated based on historical emissions and operating records for any 24 month period, selected by the operator, within the previous 10 year period (5 years for electric utility steam generating units). The BAE must be adjusted to exclude any non-compliant operation emissions and emissions that are no longer allowed due to lower applicable emission limits that were in effect when this application was deemed complete.

The baseline period is the two years immediately prior to the submission of a complete application. The following historical fuel use for the flare listed in permit S-2918-1-6 and the historical crude oil production for the storage tank listed in permit S-2918-31-1 were taken from the facility emission inventory submittals.

Baseline Actual Emissions (Permit S-2918-1-7)				
Year	Process Rate (MMscf/year)	Permitted Emission Factor (lb/MMBtu)	Heating Value (from inspection reports) (Btu/scf)	VOC Emissions (lb/year)
2010	2.84	0.068	1301	251
2011	1.44	0.068	921	90
Annual Average				171

Baseline Actual Emissions (Permit S-2918-31-4)					
Year	TVP (from inspection reports, assume @ 89 degrees F maximum ambient temperature in Bakersfield) (psia)	Calculated RVP (psia)	Annual Throughput (from Emission Inventory Submittal) (bbl/year)	Daily Throughput (Annual ÷ 365) (bbl/day)	Annual VOC Emissions (lb/year)
2010	2.66	3.05	4,599	12.6	1,124
2011	2.50	2.90	3,107	8.5	1,086
Annual Average					1,105

Baseline Actual Emissions (BAE)	
Permit Unit	VOC Emissions (lb/year)
S-2918-1-7	171
S-2918-31-4	1,105

Net Emissions Increase for existing units (NEI_E) is calculated as follows:

NEI_E = PAE – BAE

Net Emissions Increase for Existing Units (NEI_E)			
Permit Unit	PAE (lb-VOC/year)	BAE (lb-VOC/year)	NEI_E (lb-VOC/year)
S-2918-1-7	7,258	171	7,087
S-2918-31-4	7,573	1,105	6,468
Total			13,555

Net Emission Increase for New Units (NEI_N)

Per 40 CFR 51.165 (a)(2)(ii)(D) for new emissions units in this project,

$NEI_N = PE2_N$ - BAE

BAE = 0 for the new unit; therefore, $NEI_N = PE2_N$

Net Emissions Increase for New Units (NEI_N)			
Permit Unit	$PE2_N$ (lb-VOC/year)	BAE (lb-VOC/year)	NEI_N (lb-VOC/year)
S-2918-62-0	876	0	876

Creditable Contemporaneous Net Emissions Increase (NEI_C)

This project will cancel and replace the flare listed in permit S-2918-2-3. The resulting emission reduction associated with canceling the permit will be a creditable contemporaneous emission decrease associated with this project.

NEI_C = PAE – BAE

Projected Actual Emissions

As the flare listed in permit S-2918-2-3 is being canceled in this project, PAE = 0.

Baseline Actual Emissions

The baseline period is the two years immediately prior to the submission of a complete application. The following historical fuel use for the flare listed in permit S-2918-2-3 was taken from the facility emission inventory submittals.

Baseline Actual Emissions (Permit S-2918-2-3)				
Year	Process Rate (MMscf/year)	Permitted Emission Factor (lb/MMBtu)	Heating Value (from inspection reports) (Btu/scf)	VOC Emissions (lb/year)
2010	17.93	0.086*	1,224	1,887
2011	21.42	0.086	1,141	2,102
Annual Average				1,995

* 4.0 lb-VOC/day x day/46,000 scf x scf/1000 Btu = 0.086 lb/MMBtu (data taken from project S-980066)

Creditable Contemporaneous Net Emissions Increase (NEI_C) is calculated as follows:

$NEI_C = PAE - BAE$

Creditable Contemporaneous Net Emissions Increase (NEI_C)			
Permit Unit	PAE (lb-VOC/year)	BAE (lb-VOC/year)	NEI_N (lb-VOC/year)
S-2918-2-3	0	1,995	-1,995

Net Emission Increase

The NEI for this project is thus calculated as follows:

$NEI = NEI_E + NEI_N + NEI_C$

Net Emissions Increase (NEI)				
Pollutant	NEI_E (lb/year)	NEI_N (lb/year)	NEI_C (lb/year)	NEI (lb/year)
VOC	13,555	876	-1,995	12,436

The NEI for this project will be greater than the Federal Major Modification threshold for VOC. Therefore, this project does not qualify for a "Less-Than-Significant Emissions Increase" exclusion and is thus determined to be a Federal Major Modification for VOC.

9. Quarterly Net Emissions Change (QNEC)

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Quarterly NEC [QNEC] (Permit S-2918-1-7)			
	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NO_X	1,959	42	1,917
SO_X	20	1	19
PM_{10}	582	13	569
CO	10,656	227	10,429
VOC	1,815	39	1,776

Quarterly NEC [QNEC] (Permit S-2918-31-4)			
	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NO_X	0	0	0
SO_X	0	0	0
PM_{10}	0	0	0
CO	0	0	0
VOC	1,893	3,526	-1,633

Quarterly NEC [QNEC] (Permit S-2918-62-0)			
	PE2 (lb/qtr)	PE1 (lb/qtr)	QNEC (lb/qtr)
NO_X	493	0	493
SO_X	19	0	19
PM_{10}	553	0	553
CO	274	0	274
VOC	219	0	219

VIII. Compliance

Rule 2201 New and Modified Stationary Source Review Rule

S-2918-3-6

As noted in Section VII of this engineering evaluation, the proposed modification does not constitute an NSR modification; Pursuant to section 3.26 of District Rule 2201, a modification is defined as:

3.26.1.1 Any change in hours of operation, production rate, or method of operation of an existing emissions unit, which would necessitate a change in permit conditions.

The proposed modification does not result in a change in the hour of operation, production rate or method of operation which necessitates a change in permit conditions.

3.26.1.2 Any structural change or addition to an existing emissions unit which would necessitate a change in permit conditions. Routine replacement shall not be considered to be a structural change.

The proposed modification does not constitute a structural change or addition to an existing emissions unit which necessitates a change in permit conditions.

3.26.1.3 An increase in emissions from an emissions unit caused by a modification of the Stationary Source when the emissions unit is not subject to a daily emissions limitation.

The proposed modification does not result in an increase in emissions from any emissions unit.

3.26.1.4 Addition of any new emissions unit which is subject to District permitting requirements.

The proposed modification does not result in the addition of any new emissions units.

3.26.1.5 A change in a permit term or condition proposed by an applicant to obtain an exemption from an applicable requirement to which the source would otherwise be subject.

The proposed modification does not change a permit term or condition to obtain an exemption from an applicable requirement to which the source would otherwise be subject.

As discussed above, the modification proposed to unit S-2918-3 does not meet any of the criteria for a modification. Therefore, it is not subject to the requirements of District Rule 2201.

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or

d. Any new or modified emissions unit, in a stationary source project, which results in a Major Modification.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

a. New emissions units – PE > 2 lb/day

As seen in Section VII.C.2 above, the applicant is proposing to install a new combustion device with a PE greater than 2 lb/day for NOx, PM_{10}, CO, and VOC. BACT is triggered for NOx, PM_{10}, and VOC only since the PEs are greater than 2 lb/day. However BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lb/year, as demonstrated in Section VII.C.5 above.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

c. Modification of emissions units – AIPE > 2 lb/day

AIPE = PE2 – HAPE

Where,
AIPE = Adjusted Increase in Permitted Emissions, (lb/day)
PE2 = Post-Project Potential to Emit, (lb/day)
HAPE = Historically Adjusted Potential to Emit, (lb/day)

HAPE = PE1 x (EF2/EF1)

Where,
PE1 = The emissions unit's PE prior to modification or relocation, (lb/day)
EF2 = The emissions unit's permitted emission factor for the pollutant after modification or relocation. If EF2 is greater than EF1 then EF2/EF1 shall be set to 1
EF1 = The emissions unit's permitted emission factor for the pollutant before the modification or relocation

AIPE = PE2 – (PE1 * (EF2 / EF1))

S-2918-1-7

BACT Applicability (Permit S-2918-1-7)						
Pollutant	Daily PE2 (lb/day)	Daily PE1 (lb/day)	EF2 (lb/MMBtu)	EF1 (lb/MMBtu)	AIPE (lb/day)	BACT Triggered?
NO_x	81.6	81.6	0.068	0.068	0.0	No
SO_x	0.8	0.8	0.0007	0.0007	0.0	No
PM_{10}	24.2	24.2	0.0202	0.0202	0.0	No
CO	444.0	444.0	0.37	0.37	0.0	No
VOC	75.6	75.6	0.063	0.063	0.0	No

As demonstrated above, the AIPE is not greater than 2.0 lb/day for any pollutant. Therefore BACT is not triggered for any pollutant.

S-2918-31-4

There are no emission factor changes for this permit unit in this project. Therefore, EF2 / EF1 = 1.

BACT Applicability (Permit S-2918-31-4)				
Pollutant	Daily PE2 (lb/day)	Daily PE1 (lb/day)	AIPE (lb/day)	BACT Triggered?
VOC	20.7	38.6	-17.9 → 0	No

As demonstrated above, the AIPE is not greater than 2.0 lb/day for any pollutant. Therefore BACT is not triggered for any pollutant.

d. SB 288/Federal Major Modification

As discussed in Section VII.C.7 above, this project does constitute a Federal Major Modification for VOC. Therefore BACT is triggered for VOC.

2. BACT Guideline

BACT Guideline 1.4.2, applies to the produced gas flare and combustion device listed in permits S-2918-1-7 and '62-0 in this project. [Waste Gas Flare – Incinerating Produced Gas] (See Attachment C)

BACT Guideline 7.3.1, applies to the fixed roof crude oil storage tank listed in permit S-2918-31-4 in this project. [Petroleum and Petrochemical Production – Fixed Roof Organic Liquid Storage or Processing Tank, < 5,000 bbl Tank capacity] (See Attachment C)

3. Top-Down BACT Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

Pursuant to the attached Top-Down BACT Analysis (see Attachment C), BACT has been satisfied with the following:

S-2918-1-7

VOC: Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable

S-2918-31-4

VOC: PV-vent set to within 10% of maximum allowable pressure

S-2918-62-0

NO_X: Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable
PM_{10}: Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable
Pilot Light fired solely on LPG or natural gas
VOC: Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable

B. Offsets

1. Offset Applicability

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
Post Project SSPE (SSPE2)	11,645	6,290	4,627	44,069	40,769
Offset Threshold	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	No	No	No	No	Yes

2. Quantity of Offsets Required

As seen above, the facility is an existing Major Source for VOC and the SSPE2 is greater than the offset thresholds. Therefore offset calculations will be required for this project.

The quantity of offsets in pounds per year for VOC is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = (Σ[PE2 – BE] + ICCE) x DOR, for all new or modified emissions units in the project,

Where,
PE2 = Post Project Potential to Emit, (lb/year)
BE = Baseline Emissions, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, Located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

As calculated in Section VII.C.6 above, the BE from the units in this project are equal to the PE1 since all of the units in the project are new or Clean Emission Units.

Also, there are no increases in cargo carrier emissions. Therefore offsets can be determined as follows:

Offsets Required (lb/year) = ($[PE2 – BE]_{S\text{-}2918\text{-}1\text{-}7}$ + $[PE2 – BE]_{S\text{-}2918\text{-}2\text{-}3}$ + $[PE2 – BE]_{S\text{-}2918\text{-}31\text{-}4}$ + $[PE2 – BE]_{S\text{-}2918\text{-}62\text{-}0}$ + ICCE) x DOR

Offset Requirement Flare (Permit S-2918-1-7)	
Pollutant	VOC (lb/year)
PE2	7,258
BE	155
PE2 – BE	7,103

Offset Requirement Flare (Permit S-2918-2-3)	
Pollutant	VOC (lb/year)
PE2	0
BE	1,460
PE2 – BE	-1,460

Offset Requirement Tank (Permit S-2918-31-4)	
Pollutant	VOC (lb/year)
PE2	7,573
BE	14,105
PE2 – BE	-6,532

Offset Requirement Combustion Device (Permit S-2918-62-0)	
Pollutant	VOC (lb/year)
PE2	876
BE	0
PE2 – BE	876

Offset Requirement Summary (PE2 – BE)	
Permit	VOC (lb/year)
S-2918-1-7	7,103
S-2918-2-3	-1,460
S-2918-31-4	-6,532
S-2918-62-0	876
Sum	-13 → 0

As demonstrated in the calculation above, the amount of offsets is zero. Therefore, offsets will not be required for this project.

C. Public Notification

1. Applicability

Public noticing is required for:

a. New Major Sources, Federal Major Modifications, and SB288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed, and/or
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.

a. New Major Sources, Federal Major Modifications, and SB288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. Since this is not a new facility, public noticing is not required for this project for New Major Source purposes.

As demonstrated in VII.C.7, this project does constitute a Federal Major Modification for VOC; therefore, public noticing for Federal Major Modification purposes is required.

b. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. As seen in Section VII.C.2 above, this project does not include a new emissions unit which has daily emissions greater than 100 lb/day for any pollutant, therefore public noticing for PE > 100 lb/day purposes is not required.

c. Offset Threshold

The following table compares pollutant will trigger public noticing requirements. As seen the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Threshold				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	3,139	11,645	20,000 lb/year	No
SO_X	6,149	6,290	54,750 lb/year	No
PM_{10}	467	4,627	29,200 lb/year	No
CO	1,879	44,069	200,000 lb/year	No
VOC	40,782	40,769	20,000 lb/year	No

As detailed above, there were no thresholds surpassed with this project; therefore public noticing is not required for offset purposes.

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a Stationary Source Increase in Permitted Emissions (SSIPE) of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE is calculated as the Post Project Stationary Source Potential to Emit (SSPE2) minus the Pre-Project Stationary Source Potential to Emit (SSPE1), i.e. SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table:

Stationary Source Increase in Permitted Emissions [SSIPE] – Public Notice					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO_x	11,645	3,139	8,506	20,000 lb/year	No
SO_x	6,290	6,149	141	20,000 lb/year	No
PM_{10}	4,627	467	4,160	20,000 lb/year	No
CO	44,069	1,879	42,190	20,000 lb/year	Yes
VOC	40,769	40,782	-13 → 0	20,000 lb/year	No

As demonstrated above, the SSIPE for CO is greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

2. Public Notice Action

As discussed above, public noticing is required for this project for Federal Major Modification for VOC and SSIPE greater than 20,000 lb/year for CO. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB), US Environmental Protection Agency (US EPA) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

S-2918-1-7

Daily heat input limit = 1,000,000 scf/day x 1200 Btu/scf x MM/10^6 = 1200.0 MMBtu/day
Annual heat input limit = 96,000,000 scf/day x 1200 Btu/scf x MM/10^6 = 115,200 MMBtu/year

- Sulfur concentration of gas flared shall not exceed 5 ppmv. [District Rule 2201]
- Air contaminant emissions shall not exceed any of the following limits: NOx (as NO2) = 0.068 lb/MMBtu; PM10 = 0.0202 lb/MMBtu; CO = 0.37 lb/MMBtu; VOC = 0.063 lb/MMBtu. [District Rule 2201]
- Non breakdown operation shall not exceed any of the following limits: 1,200.0 MMBtu/day or 115,200 MMBtu/year. [District Rule 2201]

S-2918-31-4

- This tank shall only store, place, or hold organic liquid with a Reid vapor pressure (RVP) of less than 6.86 psia. [District Rules 2201 and 4623]
- Crude oil throughput shall be less than 150 barrels per day. [District Rules 2201 and 4623]

S-2918-62-0

The combustion device heat input will be limited in the permit and calculated as follows:

Daily heat input limit = 250,000 scf/day x 1200 Btu/scf x MM/10^6 = 300.0 MMBtu/day
Annual heat input limit = 91,250,000 scf/day x 1200 Btu/scf x MM/10^6 = 109,500 MMBtu/year

- The combustion device heat input shall not exceed any of the following limits: 300 MMBtu/day or 109,500 MMBtu/year. [District Rule 2201]
- Emissions from the combustion device shall not exceed any of the following limits: 0.018 lb-NOx/MMBtu; 0.0202 lb-PM10/MMBtu; 0.01 lb-CO/MMBtu; or 0.008 lb-VOC/MMBtu. [District Rules 2201 and 4311]
- The sulfur content of the gas being incinerated by the combustion device shall not exceed 5 ppmv (as H2S). [District Rules 2201]

E. Compliance Assurance

1. Source Testing

S-2918-1-7

Pursuant to District Policy APR 1705, source testing is not required to demonstrate compliance with Rule 2201.

S-2918-31-4

The permittee will be required to perform periodic TVP testing by measuring Reid vapor pressure using ASTM Method D323-82 modified by maintaining the hot water bath at storage temperature. Where storage temperature is above 100 degrees F true vapor pressure shall be determined by Reid vapor pressure at 100 degrees F and ARB approved calculations. The testing shall be conducted once every 24 month period or every time when the source of liquid stored is changed.

The following conditions will be placed on the permit to ensure compliance:

- Permittee shall conduct true vapor pressure (TVP) testing of the organic liquid stored in this tank at least once every 24 months during summer (July - September), and/or whenever there is a change in the source or type of organic liquid stored in this tank. [District Rule 2201]
- True vapor pressure shall be measured using Reid vapor pressure ASTM Method D323-82 modified by maintaining the hot water bath at storage temperature. Where storage temperature is above 100 degrees F true vapor pressure shall be determined by Reid vapor pressure at 100 degrees F and ARB approved calculations. [District Rule 4623]
- True vapor pressure of crude oil with an API (American Petroleum Institute) gravity less than 30 deg, as determined by API 2547, may be determined by Headspace Gas Chromatography using the procedures from ARB Evaluation of a Method for Determining Vapor Pressures of Petroleum Mixtures by Headspace Gas Chromatography, October 1990. [District Rule 4623]

S-2918-62-0

Pursuant to District Policy APR 1705, initial source testing is required to demonstrate compliance with Rule 2201 and the BACT requirements.

The following conditions will be placed on the permit to ensure compliance with the assumptions made for Rule 2201. Source testing will be required within 60 days of initial start-up and at least once every 12 months thereafter.

- Source testing to measure NOx, CO and VOC emissions from the combustion device shall be conducted within 60 days of initial start-up. [District Rule 2201]
- For source test purposes, NOx emissions from the combustion device shall be determined using EPA Method 19 on a heat input basis, or EPA Method 3A, EPA Method 7E, or ARB Method 100 on a ppmv basis. [District Rule 2201]
- For source test purposes, CO emissions from the combustion device shall be determined using EPA Method 10 or 10B, ARB Methods 1 through 5 with 10, or ARB Method 100. [District Rule 2201]
- For source test purposes, VOC emissions from the combustion device shall be determined using EPA Method 25 or 25a. [District Rule 2201]
- Stack gas oxygen (O2) shall be determined using EPA Method 3A, EPA Method 7E, or ARB Method 100. [District Rule 2201]
- Operator shall determine gas fuel higher heating value annually by ASTM D 1826 or D 1945 in conjunction with ASTM D 3588 for gaseous fuels. [District Rule 2201]

2. Monitoring

S-2918-1-7 and '62-0

The following conditions will be placed on the permit to ensure compliance with the assumptions made for Rule 2201.

- To show compliance with sulfur emission limits, the gas being flared shall be tested weekly for sulfur content. If compliance with the fuel sulfur content limit and sulfur emission limits has been demonstrated for 8 consecutive weeks for the flared gas, then the compliance testing frequency shall be semi-annually. If the semi-annual sulfur content test fails to show compliance, weekly testing shall resume. [District Rule 2201]
- The sulfur content of the gas being flared shall be determined using ASTM D 1072, D 3031, D 4084, D 3246 or grab sample analysis by GC-FPD/TCD performed in the laboratory. [District Rule 2201]

S-2918-31-4

No monitoring is required to demonstrate compliance with Rule 2201.

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201.

S-2918-1-7

- Permittee shall maintain accurate records of quantity of non-emergency/non-pilot gas combusted in the flare and shall make such records available to District staff upon request. [District Rule 1070]
- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and 4311]

S-2918-31-4

- Permittee shall maintain monthly records of average daily crude oil throughput and shall keep accurate records of each organic liquid stored in the tank, including its storage temperature, TVP, and API gravity. [District Rule 2201]
- All records required to be maintained by this permit shall be maintained for a period of at least five years and shall be made readily available for District inspection upon request. [District Rule 1070]

S-2918-62-0

- Permittee shall maintain daily and annual records of quantity of gas combusted in the combustion device, annual test results of higher heating value of gas, and daily heat input for the combustion device. [District Rules 1070 and 2201]
- All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070]

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

F. Ambient Air Quality Analysis (AAQA)

An AAQA shall be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis. Refer to Appendix X of this document for the AAQA summary sheet.

The proposed location is in an attainment area for NO_X, CO, and SO_X. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X.

The proposed location is in a non-attainment area for the state's PM_{10} as well as federal and state $PM_{2.5}$ thresholds. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for PM_{10} and $PM_{2.5}$.

G. Compliance Certification

Section 4.15.2 of this Rule requires the owner of a new Major Source or federal major modification to demonstrate to the satisfaction of the District that all other major Stationary Sources owned by such person (or by entity controlling, controlled by, or under common control with such person) in California which are subject to emission limitations are in compliance or are on a schedule for compliance with all applicable emission limitations and standards. As discussed in Section VIII above, this project does constitute a federal major modification, therefore this requirement is applicable. Crimson Resource Management's compliance certification is included in Attachment D.

H. Alternate Siting Analysis

The current project occurs at an existing facility. The applicant proposes to replace an existing flare serving various tanks and a gas gathering system.

Since the project will provide produced gas to be used at the same location, the existing site will result in the least possible impact from the project. Alternative sites would involve the relocation and/or construction of various support structures on a much greater scale, and would therefore result in a much greater impact.

Rule 2520 Federally Mandated Operating Permits

Since this facility's emissions exceed the major source thresholds of District Rule 2201, this facility is a major source. However, this facility has elected to comply with Rule 2530, exempts it from the requirements of Rule 2520.

Rule 2530 Federally Enforceable Potential to Emit

The purpose of this rule is to restrict the emissions of a stationary source so that the source may elect to be exempt from the requirements of Rule 2520. Pursuant to Rule 2530, since this facility has elected exemption from the requirements of Rule 2520 by ensuring actual emissions from the stationary source in every 12-month periods to not exceed the following: ½ the major source thresholds for NOx, VOCs, CO, and PM10; 50 tons per year SO2; 5 tons per year of a single HAP; 12.5 tons per year of any combination of HAPs; 50 percent of any lesser threshold for a single HAP as the EPA may establish by rule; and 50 percent of the major source threshold for any other regulated air pollutant not listed in Rule 2530 (including greenhouse gases).

Rule 4001 New Source Performance Standards (NSPS)

This rule incorporates NSPS from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR); and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60.

S-2918-1-7 and '62-0

No subparts of 40 CFR Part 60 apply to flares or combustion devices.

S-2918-31-4

40 CFR Part 60, Subparts, K, Ka and Kb could potentially apply to the storage tanks located at this facility. However, pursuant to 40 CFR 60.110 (b), 60.110(a) (b), and 60.110(b) (b), these subparts do not apply to storage vessels less than 10,000 bbls, used for petroleum or condensate, that is stored, processed, and/or treated at a drilling and production facility prior to custody transfer. Therefore, the requirements of this subpart are not applicable to this project.

Therefore, the requirements of this rule are not applicable to this project.

Rule 4002 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

This rule incorporates NESHAPs from Part 61, Chapter I, Subchapter C, Title 40, CFR and the NESHAPs from Part 63, Chapter I, Subchapter C, Title 40, CFR; and applies to all sources of hazardous air pollution listed in 40 CFR Part 61 or 40 CFR Part 63. However, no subparts of 40 CFR Part 61 or 40 CFR Part 63 apply to flares, combustion devices, or crude oil storage tanks.

Rule 4101 Visible Emissions

Rule 4101 states that no air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity.

The following conditions will be listed on the permit to ensure compliance:

S-2918-1-7

- Flares shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. [40 CFR 60.18(c)(1)]
- Demonstration of compliance with the visible emissions limit of this permit shall be conducted at least annually, using EPA Method 22. The observation period shall be 2 hours. [40 CFR 60.18(f)(1)]

S-2918-31-4

As long as the equipment is properly maintained and operated, compliance with visible emissions limits is expected under normal operating conditions.

S-2918-62-0

- Flares shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. [40 CFR 60.18(c)(1)]
- Demonstration of compliance with the visible emissions limit of this permit shall be conducted at least annually, using EPA Method 22. The observation period shall be 2 hours. [40 CFR 60.18(f)(1)]

Therefore, compliance with the requirements of this rule is expected.

Rule 4102 Nuisance

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations provided the equipment is well maintained. Therefore, compliance with this rule is expected and the following condition will be added to the permit to ensure compliance:

- {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – Risk Management Policy for Permitting New and Modified Sources specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (Attachment E), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.

The cancer risk for this project is shown below:

HRA Summary		
Unit	Cancer Risk	T-BACT Required
S-2918-1-7	0.0 per million	No
S-2918-62-0	1.74 per million	Yes

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is required for this project because the HRA indicates that the risk is above the District's thresholds for triggering T-BACT requirements.

For this project T-BACT is triggered for PM. T-BACT is satisfied with BACT for PM (see Attachment E), which is steam assisted or Air-assisted or Coanda effect burner, when steam unavailable; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 10 in a million). As outlined by the HRA Summary in Attachment E of this report, the emissions increases for this project was determined to be less than significant.

The following condition will be listed on permits S-2918-1-7 and '62-0 to ensure compliance:

- The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

Rule 4201 Particulate Matter Concentration

Section 3.0 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

Particulate matter calculations were performed for each piece of equipment by the following equation:

F-Factor for produced gas:	8,600 dscf/MMBtu
PM_{10} Emission Factor:	0.0202 lb-PM_{10}/MMBtu
Percentage of PM as PM_{10} in Exhaust:	100%

$$GL = \left(\frac{0.0202\ lb - PM}{MMBtu} \times \frac{7{,}000\, grain}{lb - PM} \right) / \left(\frac{8{,}600\ ft^3}{MMBtu} \right)$$

$$GL = 0.016\ grain/dscf < 0.1\, grain/dscf$$

Since the particulate matter concentration is ≤ 0.1 grains per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the permit to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4301 Fuel Burning Equipment

This rule specifies maximum emission rates in lb/hr for SO_2, NO_2, and combustion contaminants (defined as total PM in Rule 1020). This rule also limits combustion contaminants to ≤ 0.1 gr/scf. According to AP 42 (Table 1.4-2, footnote c), all PM emissions from natural gas combustion are less than 1 μm in diameter. As shown below, each unit's maximum hourly emission rates are below the Rule 4301 limits.

District Rule 4301 Limits			
Unit	**NO_2**	**Total PM**	**SO_2**
S-2918-1-7	3.40	1.01	0.03
S-2918-62-0	0.23	0.25	0.008
Rule 4301 Limit	**140 lb/hr**	**10 lb/hr**	**200 lb/hr**

As shown above, compliance with this rule is expected.

Rule 4311 Flares

Rule 4311 limits the emissions of volatile organic compounds (VOCs) and oxides of nitrogen (NOx), and sulfur oxides (SOx) from the operation of flares.

S-2918-62-0

Section 3.11 defines flare as a direct combustion device in which air and all combustible gases react at the burner with the objective of complete and instantaneous oxidation of the combustible gases. Flares are used either continuously or intermittently and are not equipped with devices for fuel-air mix control or for temperature control.

The proposed combustion device utilizes temperature control to control the air-to-fuel ratio of the burner in the premixing process. A given temperature in the stack will correlate to a certain air-to-fuel ratio. By monitoring the temperature and controlling to a temperature set point, the combustion device is controlled to operate at a certain air-to-fuel ratio. The unit is typically controlled to a 15:1 ratio or around 2100 °F. If the temperature starts to increase, the air-to-fuel ratio is reducing so the control system will increase the speed of the fan to add more air. Conversely, if the temperature starts to drop off, the air-to-fuel ratio is increasing and the control system will reduce the speed of the fan to reduce the amount of air entering the system.

Therefore, the combustion device listed in permit S-2918-62-0 does not meet the definition of flare and is not subject to Rule 4311.

S-2918-1-7

Section 5.1

Section 5.1 states flares permitted to operate only during an emergency are not subject to the requirements of Section 5.6 and 5.7. The flare in this project is not an emergency flare; therefore, Sections 5.6 and 5.7 are applicable.

Section 5.2

Section 5.2 requires that the flame be present at all times when combustible gases are vented through the flare.

The following condition will be listed on the permit to ensure compliance:

- A flame shall be present at all times when combustible gases are vented through the flare. [District Rule 4311]

Section 5.3

Section 5.3 requires that the flare outlet be equipped with an automatic ignition system, or operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares.

The following condition will be listed on the permit to ensure compliance:

- Flare outlet shall be equipped with an automatic ignition system, or, shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311]

Section 5.4

Section 5.4 requires that except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an alternative equivalent device, capable of continuously detecting at least one pilot flame or the flare flame is present shall be installed and operated.

The following condition will be listed on the permit to ensure compliance:

- Flare shall be equipped with a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device capable of continuously detecting at least one pilot flame or the flare flame is present. The flame detection device shall be kept operational at all times except during flare maintenance when the flare is isolated from gas flow. During essential planned power outages when the flare is operating, the pilot monitor is allowed to be non-functional if the flare flame is clearly visible to onsite operators. All pilot monitor downtime shall be reported annually pursuant to Rule 4311, Section 6.2.3.6. [District Rule 4311]

Section 5.5

Section 5.5 requires flares that use flow-sensitive automatic ignition systems and which do not use a continuous pilot flame to use purge gas for purging.

The following condition will be listed on the permit to ensure compliance:

- If the flare uses a flow-sensing automatic ignition system and does not use a continuous flame pilot, the flare shall use purge gas for purging. [District Rule 4311]

Section 5.6

Section 5.6 states that open flares (air-assisted, steam-assisted, or non-assisted) in which the flare gas pressure is less than 5 psig shall be operated in such a manner that meets the provisions of 40 CFR 60.18. The requirements of this section shall not apply to Coanda effect flares.

The following condition will be listed on the permit to ensure compliance:

- Open flares in which the flare gas pressure is less than 5 psig shall be operated in such a manner that meets the provisions of 40 CFR 60.18. [District Rule 4311]

Section 5.7

Section 5.7 states that ground-level enclosed flares meet the defined emission standards.

Type of Flare and Heat Release Rate in MMBtu/hr	VOC (lb/MMBtu)	NOx (lb/MMBtu)
Without Steam-assist		
10-100 MMBtu	0.0027	0.1330

This flare is an open flare; therefore, Section 5.7 is not applicable.

Section 5.8

Section 5.8 states that effective on and after July 1, 2011, flaring is prohibited unless it is consistent with an approved flare minimization plan (FMP), pursuant to Section 6.5, and all commitments listed in that plan have been met. This standard does not apply if the APCO determines that the flaring is caused by an emergency as defined by Section 3.7 and is necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere. The facility will submit an updated FMP when the new flare is installed. The current FMP covers the existing permitted equipment.

The following condition will be listed on the permit to ensure compliance:

- Flaring is prohibited unless it is consistent with an approved flare minimization plan (FMP), pursuant to Section 6.5, and all commitments listed in that plan have been met. This standard does not apply if the APCO determines that the flaring is caused by an emergency as defined by Section 3.7 and is necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere. [District Rule 4311]

Section 5.9

Section 5.9 sites Petroleum Refinery SO2 Performance Targets. The flare does not serve a petroleum refinery; therefore, Section 5.9 is not applicable.

Section 5.10

Section 5.10 states the operator of a flare subject to flare minimization requirements pursuant to Section 5.8 shall monitor the vent gas flow to the flare with a flow measuring device or other parameters as specified in the Permit to Operate. The operator shall maintain records pursuant to Section 6.1.7. Flares that the operator can verify, based on permit conditions, are not capable of producing reportable flare events pursuant to Section 6.2.2 shall not be required to monitor vent gas flow to the flare.

The following condition will be listed on the permit to ensure compliance:

- The operator shall monitor and record the vent gas flow to the flare with a flow measuring device or other parameters as specified in the Permit to Operate. [District Rule 4311]

Section 5.11

Section 5.11 states that the operator of a petroleum refinery or a flare with a flaring capacity equal to or greater than 50 MMBtu/hr shall monitor the flare pursuant to Sections 6.6, 6.7, 6.8, 6.9, and 6.10. The flare in this project is not part of petroleum refinery or has a flaring capacity equal to or greater than 50 MMBtu/hr; therefore, Section 5.11 is not applicable.

Section 6.1

Section 6.1 states that the records listed in Sections 6.1.1 through 6.1.7 shall be maintained, retained on-site for a minimum of five years, and made available to the APCO, ARB, and EPA upon request.

The following condition will be placed on the permit to ensure compliance:

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and 4311]

Section 6.1.1

Section 6.1.1 requires the operator of flares that are subject to Section 5.6 to make available to the APCO upon request the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5).

- Flares shall only be used with the net heating value of the gas being combusted being 300 Btu/scf or greater if the flare is air-assisted or steam-assisted. [40 CFR 60.18 (c)(3)]
- Air-assisted flares shall be operated with an exit velocity less than Vmax, as determined by the equation specified in paragraph 40 CFR 60.18 (f)(6). [40 CFR 60.18 (c)(5)]

Section 6.1.2

Section 6.1.2 requires the operator of flares that are subject to Section 5.7 to make available to the APCO upon request a copy of the source testing result conducted pursuant to Section 6.4.2.

The flare is not subject to Section 5.7; therefore, Section 6.1.2 is not applicable.

Section 6.1.3

Section 6.1.3 requires the operator of flares that are used during an emergency, to maintain a record of the duration of flare operation, amount of gas burned, and the nature of the emergency situation.

The following condition will be placed on the permit to ensure compliance:

- Permittee shall maintain records of the following when the flare is used during an emergency: duration of flare operation, amount of gas burned, and the nature of the emergency situation. [District Rule 4311]

Section 6.1.4

Section 6.1.4 applies only to operators claiming an exemption pursuant to Section 4.3. This project is not claiming an exemption pursuant to Section 4.3; therefore, Section 6.1.4 is not applicable.

Section 6.1.5

Sections 6.1.5 applies only to flares operated at petroleum refineries or those with a flaring capacity greater than or equal to 5 MMBtu/hr subject to a flare minimization plan.

The following condition will be listed on the permit to ensure compliance:

- Permittee shall maintain the following records: a copy of the approved flare minimization plan pursuant to Section 6.5; a copy of annual reports submitted to the APCO pursuant to Section 6.2. [District Rule 4311]

Section 6.1.6

Section 6.1.6 applies to flares subject to flare minimization plans pursuant to Section 5.8.

The following condition will be listed on the permit to ensure compliance:

- Permittee shall maintain the following records: a copy of the source testing result conducted pursuant to Section 6.4.2; a copy of the approved flare minimization plan pursuant to Section 6.5; a copy of annual reports submitted to the APCO pursuant to Section 6.2. [District Rule 4311]

Section 6.1.7

Section 6.1.7 applies to flares subject to flare minimization requirements pursuant to Section 5.8 and to flares operated at petroleum refineries or those with a flaring capacity equal to or greater than 50 MMBtu/hr.

The following condition will be listed on the permit to ensure compliance:

- The operator shall monitor and record the vent gas flow to the flare with a flow measuring device or other parameters as specified in the Permit to Operate. [District Rule 4311]

Section 6.2

Section 6.2 applies to flares subject to a flare minimization plan.

Section 6.2.1

Section 6.2.1 states the operator of a flare subject to flare minimization plans pursuant to Section 5.8 of this rule shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, which ever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time.

The following condition will be listed on the permit to ensure compliance:

- The operator of a flare subject to flare minimization plans pursuant to Section 5.8 of this rule shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, which ever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time. [District Rule 4311]

Section 6.2.2

Section 6.2.2 states the operator of a flare subject to flare minimization plans pursuant to Section 5.8 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the twelve month period of the previous year. The report shall include, but is not limited to all of the following:

6.2.2.1 The results of an investigation to determine the primary cause and contributing factors of the flaring event;
6.2.2.2 Any prevention measures considered or implemented to prevent recurrence together with a justification for rejecting any measures that were considered but not implemented;
6.2.2.3 If appropriate, an explanation of why the flaring was an emergency and necessary to prevent accident, hazard or release of vent gas to the atmosphere, or where, due to a regulatory mandate to vent a flare, it cannot be recovered, treated and used as a fuel gas at the facility; and
6.2.2.4 The date, time, and duration of the flaring event.

The following condition will be listed on the permit to ensure compliance:

- The operator of a flare subject to flare minimization plans pursuant to Section 5.8 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the twelve month period of the previous year. The report shall include, but is not limited to all of the following: the results of an investigation to determine the primary cause and contributing factors of the flaring event; any prevention measures considered or implemented to prevent recurrence together with a justification for rejecting any measures that were considered but not implemented; if appropriate, an explanation of why the flaring was an emergency and necessary to prevent accident, hazard or release of vent gas to the atmosphere, or where, due to a regulatory mandate to vent a flare, it cannot be recovered, treated and used as a fuel gas at the facility; and the date, time, and duration of the flaring event. [District Rule 4311]

Section 6.2.3

Section 6.2.3 states the operator of a flare subject to flare monitoring requirements pursuant to Sections 5.10, 6.6, 6.7, 6.8, 6.9, and 6.10, as appropriate, shall submit an annual report to the APCO within 30 days following the end of each 12 month period. The report shall include the following:

6.2.3.1 The total volumetric flow of vent gas in standard cubic feet for each day.
6.2.3.2 Hydrogen sulfide content, methane content, and hydrocarbon content of vent gas composition pursuant to Section 6.6.
6.2.3.3 If vent gas composition is monitored by a continuous analyzer or analyzers pursuant to Section 5.11, average total hydrocarbon content by volume, average methane content by volume, and depending upon the analytical method used pursuant to Section 6.3.4, total reduced sulfur content by volume or hydrogen sulfide content by volume of vent gas flared for each hour of the month.
6.2.3.4 If the flow monitor used pursuant to Section 5.10 measures molecular weight, the average molecular weight for each hour of each month.
6.2.3.5 For any pilot and purge gas used, the type of gas used, the volumetric flow for each day and for each month, and the means used to determine flow.
6.2.3.6 Flare monitoring system downtime periods, including dates and times.
6.2.3.7 For each day and for each month provide calculated sulfur dioxide emissions.
6.2.3.8 A flow verification report for each flare subject to this rule. The flow verification report shall include flow verification testing pursuant to Section 6.3.5.

The flare in this project is not subject to Sections 6.6, 6.7, 6.8, 6.9, and 6.10.

The following condition will be listed on the permit to ensure compliance:

- The operator of a flare subject to flare monitoring requirements pursuant to Section 5.10 shall submit an annual report to the APCO within 30 days following the end of each 12 month period. The report shall include the following: the total volumetric flow of vent gas in standard cubic feet for each day; if the flow monitor used pursuant to Section 5.10 measures molecular weight, the average molecular weight for each hour of each month; a flow verification report which shall include flow verification testing pursuant to Section 6.3.5. [District Rule 4311]

Section 6.3

Section 6.3 lists test methods to be used to demonstrate compliance with this rule. Alternate equivalent test methods may be used provided the test methods have been approved by the APCO and EPA.

The flare in this project is not subject to the source test methods listed in Section 6.3.

Section 6.3.4

Section 6.3.4 applies to flares subject to vent gas composition monitoring requirements pursuant to Section 6.6. The flare in this project is not subject to Section 6.6.

Section 6.3.5

Section 6.3.5 applies to flares subject to vent gas flow verification requirements pursuant to Section 6.2.3.8. For purposes of the flow verification report required by Section 6.2.3.8, vent gas flow shall be determined using one or more of the following methods, or by any alternative method approved by the APCO, ARB, and EPA:

6.3.5.1 EPA Methods 1 and 2;
6.3.5.2 A verification method recommended by the manufacturer of the flow monitoring equipment installed pursuant to Section 5.10.
6.3.5.3 Tracer gas dilution or velocity.
6.3.5.4 Other flow monitors or process monitors that can provide comparison data on a vent stream that is being directed past the ultrasonic flow meter.

The following condition will be listed on the permit to ensure compliance:

- For purposes of the flow verification report required by Section 6.2.3.8, vent gas flow shall be determined using one or more of the following methods, or by any alternative method approved by the APCO, ARB, and EPA: EPA Methods 1 and 2; a verification method recommended by the manufacturer of the flow monitoring equipment installed pursuant to Section 5.10; tracer gas dilution or velocity; other flow monitors or process monitors that can provide comparison data on a vent stream that is being directed past the ultrasonic flow meter. [District Rule 4311]

Section 6.4

Section 6.4 applies only to flares subject to Section 5.6 and 5.7.

Section 6.4.1

Section 6.4.1 states upon request, the operator of flares that are subject to Section 5.6 shall make available, to the APCO, the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5).

The following condition will be listed on the permit to ensure compliance:

- The operator of flares that are subject to Section 5.6 shall make available, to the APCO, the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). [District Rule 4311]

Section 6.4.2

Section 6.4.2 states the operator of ground-level enclosed flares shall conduct source testing at least once every 12 months to demonstrate compliance with Section 5.7. The operator shall submit a copy of the testing protocol to the APCO at least 30 days in advance of the scheduled testing. The operator shall submit the source test results not later than 45 days after completion of the source testing.

The flare in this project is not a ground-level enclosed flare. Therefore, Section 6.4.2 is not applicable.

Section 6.5

Section 6.5 applies to flares operated at a petroleum refinery or any flare that has a flaring capacity of greater than or equal to 5.0 MMBtu/hr subject to a flare minimization plan.

Section 6.5.1

Section 6.5.1 states by July 1, 2010, the operator of a petroleum refinery flare or any flare that has a flaring capacity of greater than or equal to 5.0 MMBtu per hour shall submit a flare minimization plan (FMP) to the APCO for approval. The FMP shall include, but not be limited to:

6.5.1.1 A description and technical specifications for each flare and associated knock-out pots, surge drums, water seals and flare gas recovery systems.
6.5.1.2 Detailed process flow diagrams of all upstream equipment and process units venting to each flare, identifying the type and location of all control equipment.
6.5.1.3 A description of equipment, processes, or procedures the operator plans to install or implement to eliminate or minimize flaring and planned date of installation or implementation.

6.5.1.4 An evaluation of prevention measures to reduce flaring that has occurred or may be expected to occur during planned major maintenance activities, including startup and shutdown.

6.5.1.5 An evaluation of preventative measures to reduce flaring that may be expected to occur due to issues of gas quantity and quality. The evaluation shall include an audit of the vent gas recovery capacity of each flare system, the storage capacity available for excess vent gases, and the scrubbing capacity available for vent gases including any limitations associated with scrubbing vent gases for use as a fuel; and shall determine the feasibility of reducing flaring though the recovery, treatment and use of the gas or other means.

6.5.1.6 An evaluation of preventative measures to reduce flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. The evaluation shall determine the adequacy of existing maintenance schedules and protocols for such equipment. For purposes of this section, a failure is recurrent if it occurs more than twice during any five year period as a result of the same cause as identified in accordance with Section 6.2.2.

6.5.1.7 Any other information requested by the APCO as necessary for determination of compliance with applicable provisions of this rule.

The facility has submitted a FMP in July 2010. Therefore, the requirements of this section have been satisfied.

Section 6.5.2

Section 6.5.2 states every five years after the initial FMP submittal, the operator shall submit an updated FMP for each flare to the APCO for approval. The current FMP shall remain in effect until the updated FMP is approved by the APCO. If the operator fails to submit an updated FMP as required by this section, the existing FMP shall no longer be considered an approved plan.

The following condition will be listed on the permit to ensure compliance:

- Every five years after the initial FMP submittal, the operator shall submit an updated FMP for each flare to the APCO for approval. The current FMP shall remain in effect until the updated FMP is approved by the APCO. If the operator fails to submit an updated FMP as required by this section, the existing FMP shall no longer be considered an approved plan. [District Rule 4311]

Section 6.5.3

Section 6.5.3 states an updated FMP shall be submitted by the operator pursuant to Section 6.5 addressing new or modified equipment, prior to installing the equipment. Updated FMP submittals are only required if:

6.5.3.1 The equipment change would require an authority to construct (ATC) and would impact the emissions from the flare, and

6.5.3.2 The ATC is deemed complete after June 18, 2009, and

6.5.3.3 The modification is not solely the removal or decommissioning of equipment that is listed in the FMP, and has no associated increase in flare emissions.

The following condition will be listed on the permit to ensure compliance:

- An updated FMP shall be submitted by the operator pursuant to Section 6.5 addressing new or modified equipment, prior to installing the equipment. Updated FMP submittals are only required if: (1) The equipment change would require an authority to construct (ATC) and would impact the emissions from the flare, and (2) The ATC is deemed complete after June 18, 2009, and (3) The modification is not solely the removal or decommissioning of equipment that is listed in the FMP, and has no associated increase in flare emissions. [District Rule 4311]

Section 6.5.4

Section 6.5.4 states when submitting the initial FMP, or updated FMP, the operator shall designate as confidential any information claimed to be exempt from public disclosure under the California Public Records Act, Government Code Section 6250 et seq. If a document is submitted that contains information designated confidential, the operator shall provide a justification for this designation and shall submit a separate copy of the document with the information designated confidential redacted.

The facility has not requested confidentiality for any submitted FMPs.

Sections 6.6 through 6.9

Sections 6.6 through 6.9 applies to flares operated at a petroleum refinery or any flare that has a flaring capacity of greater than or equal to 50 MMBtu/hr. The flare does not fall under either category; therefore, Sections 6.6 through 6.9 are not applicable.

Section 6.10

Section 6.10 applies to flares operated at a petroleum refinery. The flare is not operated at a petroleum refinery; therefore, Section 6.10 is not applicable.

Therefore, compliance with the requirements of this section is expected.

Rule 4623 Storage of Organic Liquids

<u>S-2918-3-6 and '31-4</u>

This rule applies to any tank with a capacity of 1,100 gallons or greater in which any organic liquid is placed, held, or stored.

Section 5.1

Section 5.1.2 provides the Small Producer VOC control system requirements. A small producer shall not place, hold, or store crude oil in any tank unless such tank is equipped with a VOC control system identified in Table 2. The specifications for the VOC control system are described in Sections 5.2, 5.3, 5.4, 5.5, and 5.6. The requirements from Section 5.1.1 Table 2 are listed in the table below,

Tank Capacity (Gallons)	TVP and Crude Oil Throughput		
	0.5 psia to <11 psia and a tank throughput of >50 to <150 barrels of crude oil per day	0.5 psia to <11 psia and a tank throughput ≥150 barrels of crude oil per day	≥11.0 psia and regardless of crude oil tank throughput
(Group A) 1,100 to 39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system
(Group B) >39,600	Pressure-vacuum relief valve, or internal floating roof, or external floating roof, or vapor recovery system	Internal floating roof, or external floating roof, or vapor recovery system	Pressure vessel or vapor recovery system

The tank emissions for permit S-2918-3 will be controlled with a vapor recovery system that will be listed on permit S-2918-3 in the equipment description. The tank emissions for permit S-2918-31 will be controlled with pressure-vacuum relief valve that will be listed on permit S-2918-31 in the equipment description.

The following condition will be listed on permit S-2918-3 to ensure compliance with the requirements of the rule:

- Tank vapor control system shall be capable of collecting all VOC emissions and preventing their emissions to the atmosphere at an efficiency of at least 99% by weight [District Rules 2201 and 4623]

The following condition will be listed on permit S-2918-31 to ensure compliance with the requirements of the rule:

- This tank shall be equipped with a pressure-vacuum (PV) relief valve set to within 10% of the maximum allowable working pressure of the tank, permanently labeled with the operating pressure settings, properly maintained in good operating order in accordance with the manufacturer's instructions, and shall remain in leak-free condition except when the operating pressure exceeds the valve's set pressure. [District Rules 2201 and 4623]

Section 5.1.3 requires all tanks subject to the control requirements of this rule to be maintained in a leak-free condition, except for components in Sections 5.1.3.1 through 5.1.3.4 and as allowed by Section 5.2 and applicable provisions of Table 3 through Table 5, and Section 5.7.5.4:

The following condition will be listed on the permits to ensure compliance with this section.

- This tank shall be in a leak-free condition. A leak-free condition is defined as a condition without a gas leak. A gas leak is defined as a reading in excess of 10,000 ppmv, above background, as measured by a portable hydrocarbon detection instrument in accordance with the procedures specified in EPA Test Method 21. A reading in excess of 10,000 ppmv above background is a violation of this permit and Rule 4623. [District Rule 4623]

Section 5.2

Section 5.2 provides specifications for Pressure-Vacuum relief valves. This section is not applicable to permit S-2918-3 for tanks connected to a vapor control system.

The pressure-vacuum relief valve shall be set to within ten (10) percent of the maximum allowable working pressure of the tank. The pressure-vacuum relief valve shall be permanently labeled with the operating pressure settings. The pressure-vacuum relief valve shall be properly installed and maintained in good operating order in accordance with the manufacturer's instructions, and shall remain in leak-free condition except when the operating pressure exceeds the valve set pressure.

The following condition will be listed on permit S-2918-31 to ensure compliance with the requirements of the rule:

- This tank shall be equipped with a pressure-vacuum (PV) relief valve set to within 10% of the maximum allowable working pressure of the tank, permanently labeled with the operating pressure settings, properly maintained in good operating order in accordance with the manufacturer's instructions, and shall remain in leak-free condition except when the operating pressure exceeds the valve's set pressure. [District Rules 2201 and 4623]

Section 5.3

Section 5.3 provides specifications for external floating roof tanks. The tanks in this project are fixed roof tanks; therefore, this section is not applicable.

Section 5.4

Section 5.4 provides specifications for internal floating roof tanks. The tanks in this project are fixed roof tanks; therefore, this section is not applicable.

Section 5.5

Section 5.5 provides specifications for floating roof deck fitting requirements. The tanks in this project are fixed roof tanks; therefore, this section is not applicable.

Section 5.6

Section 5.6.1 requires that fixed roof tanks shall be fully enclosed and shall be maintained in a leak-free condition. An APCO-approved vapor recovery system shall consist of a closed vent system that collects all VOCs from the storage tank and a VOC control device. The vapor recovery system shall be maintained in a leak-free condition. The VOC control device shall be one of the following: A condensation or vapor return system that connects to one of the following; a gas processing plant, a field gas pipeline, a pipeline distributing Public Utility Commission quality gas for sale, an injection well for disposal of vapors as approved by the California Department of Conservation, Division of Oil Gas, and Geothermal Resources; or a VOC destruction device that reduces the inlet VOC emissions by at least 95% by weight as determined by the test method specified in Section 6.4.6.

The tank listed in permit S-2918-3 is served by a vapor control system that has a control efficiency of at least 99%. This rule also requires the tank and tank vapor control system to be maintained in a leak-free condition. Leak-free is defined in the rule as no readings on a portable VOC detection device greater than 10,000 ppmv above background and no dripping of organic liquid at a rate of more than 3 drops per minute.

Therefore, the following conditions will be listed on the permit S-2918-3-6 to ensure compliance:

- Tank vapor control system shall be capable of collecting all VOC emissions and preventing their emissions to the atmosphere at an efficiency of at least 99% by weight. [District Rules 2201 and 4623]
- All piping, valves, and fittings shall be constructed and maintained in leak-free condition. [District Rule 4623]
- A leak-free condition is defined as a condition without a gas leak. A gas leak is defined as a reading in excess of 10,000 ppmv, above background, as measured by a portable hydrocarbon detection instrument in accordance with the procedures specified in EPA Test Method 21. A reading in excess of 10,000 ppmv above background is a violation of this permit and Rule 4623 and shall be reported as a deviation. [District Rule 4623]

The following conditions will be listed on the permit S-2918-31-4 to ensure compliance:

- All piping, valves, and fittings shall be constructed and maintained in leak-free condition. [District Rule 4623]
- A leak-free condition is defined as a condition without a gas leak. A gas leak is defined as a reading in excess of 10,000 ppmv, above background, as measured by a portable hydrocarbon detection instrument in accordance with the procedures specified in EPA

Test Method 21. A reading in excess of 10,000 ppmv above background is a violation of this permit and Rule 4623 and shall be reported as a deviation. [District Rule 4623]

Section 5.6.2 requires that any tank gauging or sampling device on a tank vented to the vapor recovery system shall be equipped with a leak-free cover which shall be closed at all times except during gauging or sampling. Therefore, the following condition will be listed on permit S-2918-3-6 to ensure compliance:

- Any tank gauging or sampling device on a tank vented to the vapor recovery system shall be equipped with a leak-free cover which shall be closed at all times except during gauging or sampling. [District Rule 4623]

Section 5.6.3 requires that all piping, valves, and fittings shall be constructed and maintained in a leak-free condition. Therefore, the following condition will be listed on the permits to ensure compliance:

- All piping, valves, and fittings shall be constructed and maintained in leak-free condition. [District Rule 4623]

Section 5.7

Inspection and Maintenance

The facility has proposed to continue to follow the voluntary Inspection and Maintenance program outlined in the rule. The following conditions, taken from draft District Policy SSP 2215, Organic Liquid Storage Tanks – Voluntary Inspection and Maintenance Program will appear on permit S-2918-3:

- Operator shall visually inspect tank shell, hatches, seals, seams, cable seals, valves, flanges, connectors, and any other piping components directly affixed to the tank and within five feet of the tank at least once per year for liquid leaks, and with a portable hydrocarbon detection instrument conducted in accordance with EPA Method 21 for gas leaks. Operator shall also visually or ultrasonically inspect as appropriate, the external shells and roofs of uninsulated tanks for structural integrity annually. [District Rule 4623, Table 3]
- Upon detection of a liquid leak, defined as a leak rate of greater than or equal to 30 drops per minute, operator shall repair the leak within 8 hours. For leaks with a liquid leak rate of between 3 and 30 drops per minute, the leaking component shall be repaired within 24 hours after detection. [District Rule 4623, Table 3]
- Upon detection of a gas leak, defined as a VOC concentration of greater than 10,000 ppmv measured in accordance with EPA Method 21, operator shall take one of the following actions: 1) eliminate the leak within 8 hours after detection; or 2) if the leak cannot be eliminated, then minimize the leak to the lowest possible level within 8 hours after detection by using best maintenance practices, and eliminate the leak within 48 hours after minimization. In no event shall the total time to minimize and eliminate a leak exceed 56 hours after detection. [District Rule 4623, Table 3]

- Components found to be leaking either liquids or gases shall be immediately affixed with a tag showing the component to be leaking. Operator shall maintain records of the liquid or gas leak detection readings, date/time the leak was discovered, and date/time the component was repaired to a leak-free condition. [District Rule 4623, Table 3]
- Leaking components that have been discovered by the operator that have been immediately tagged and repaired within the timeframes specified in District Rule 4623, Table 3 shall not constitute a violation of this rule. Leaking components as defined by District Rule 4623 discovered by District staff that were not previously identified and/or tagged by the operator, and/or any leaks that were not repaired within the timeframes specified in District Rule 4623, Table 3 shall constitute a violation of this rule. [District Rule 4623, Table 3]
- If a component type for a given tank is found to leak during an annual inspection, operator shall conduct quarterly inspections of that component type on the tank or tank system for four consecutive quarters. If no components are found to leak after four consecutive quarters, the operator may revert to annual inspections. [District Rule 4623, Table 3]
- Any component found to be leaking on two consecutive annual inspections is in violation of this rule, even if covered under the voluntary inspection and maintenance program. [District Rule 4623, Table 3]

Since Rule 4623, Table 3 does not explicitly state what records are required from the I&M conducted, nor is a recordkeeping condition specified in draft District Policy SSP 2215, Organic Liquid Storage Tanks – Voluntary Inspection and Maintenance Program, the following standard I&M recordkeeping condition found on most oil production tank permits will be listed on permit S-2918-3.

- Operator shall maintain an inspection log containing the following 1) Type of component leaking; 2) Date and time of leak detection, and method of detection; 3) Date and time of leak repair, and emission level of recheck after leak is repaired; 4) Method used to minimize the leak to lowest possible level within 8 hours after detection. [District Rule 1070]

Section 6.1

Section 6.0 provides administrative requirements. Section 6.1 contains inspection requirements for floating roof tanks. Since, the tanks in this project are fixed roof tanks, Section 6.1 does not apply to these tanks.

Section 6.2

Section 6.2 concerns TVP and API gravity testing of stored organic liquids in uncontrolled fixed roof tanks. This section requires initial and periodic testing of the TVP and API gravity of the oil stored. The API gravity determines which TVP test method is appropriate. This section also allows for representative testing of the organic liquid in a tank battery provided the enumerated criteria are met.

Section 6.2.3 exempts tanks subject to the control requirements in Table 1 (Group A) or Table 2 (Group A and B) of this rule from the initial and periodic testing requirements. The tanks in this project meet these control requirements; therefore, the tanks are not subject to the testing requirements of this section.

Section 6.3

This section requires an operator to retain accurate records required by this rule for a period of five years. Records must be made available to the APCO upon request, except for certain records that need to be submitted as specified in the respective sections (e.g. 6.3.6) below.

Compliance with the record retention requirements of this section is ensured by the following standard permit condition which will appear on the permits in this project:

- All records required to be maintained by this permit shall be maintained for a period of at least five years and shall be made readily available for District inspection upon request. [District Rules 1070 and 4623]

Section 6.3.6 requires an operator to submit the records of TVP and API gravity testing conducted in accordance with the requirements of Section 6.2 to the APCO within 45 days after the date of testing. The record should include the tank identification number, PTO number, type of stored organic liquid, TVP and API gravity of the stored organic liquid, test methods used, and a copy of the test results.

The tanks in this project are not subject to the TVP or API gravity testing requirements; therefore, Section 6.3.6 is not applicable.

Section 6.4

The tanks in this project are not subject to periodic API gravity or TVP testing requirements. Therefore, the approved test methods for API gravity and TVP will not be listed on the permits.

Section 7.2

Any tank that is exempted under Section 4.0 that becomes subject to the VOC control system requirements of this rule through the loss of exemption status shall be in full compliance with this rule on the date the exemption status is lost.

The tanks in this project will be in full compliance with the requirements of this rule.

Therefore, continued compliance with the requirements of this rule is expected.

Rule 4801 Sulfur Compounds

Rule 4801 requires that sulfur compound emissions (as SO_2) shall not exceed 0.2% by volume. Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

F-Factor for Produced gas: 8,600 dscf/MMBtu

$$\frac{0.0007\,lb-SOx}{MMBtu}\times\frac{MMBtu}{8{,}600\,dscf}\times\frac{1\,lb\cdot mol}{64\,lb}\times\frac{10.73\,psi\cdot ft^3}{lb\cdot mol\cdot{}^\circ R}\times\frac{520^\circ R}{14.7\,psi}\times\frac{1{,}000{,}000\cdot parts}{million}=0.5\frac{parts}{million}$$

Since the SOx concentration is ≤ 2,000 ppmv, the flare is expected to comply with Rule 4801.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Environmental Quality Act (CEQA)

The California Environmental Quality Act (CEQA) requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The San Joaquin Valley Unified Air Pollution Control District (District) adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities.
- Identify the ways that environmental damage can be avoided or significantly reduced.
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible.
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

Greenhouse Gas (GHG) Significance Determination

It is determined that no other agency has or will prepare an environmental review document for the project. Thus the District is the Lead Agency for this project.

Project specific impacts on global climate change were evaluated consistent with the adopted District policy – Addressing GHG Emission Impacts for Stationary Source Projects Under CEQA When Serving as the Lead Agency. The District's engineering evaluation (this document – Attachment F and G) demonstrates that the project includes Best Performance Standards (BPS) for each class and category of greenhouse gas emissions unit. The District therefore concludes that the project would have a less than cumulatively significant impact on global climate change.

District CEQA Findings

The District is the Lead Agency for this project because there is no other agency with broader statutory authority over this project. The District performed an Engineering Evaluation (this document) for the proposed project and determined that the activity will occur at an existing facility and the project involves negligible expansion of the existing use. Furthermore, the District determined that the activity will not have a significant effect on the environment. The District finds that the activity is categorically exempt from the provisions of CEQA pursuant to CEQA Guideline § 15031 (Existing Facilities), and finds that the project is exempt per the general rule that CEQA applies only to projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061(b)(3)).

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue Authorities to Construct S-2918-1-7, '3-6, '31-4, '62-0 subject to the permit conditions on the attached draft Authorities to Construct in Attachment H.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-2918-1-7	3020-02-H	32.5 MMBtu/hr flare	$1030.00
S-2918-3-6	3020-05S-C	42,000 Gallons	$63.00
S-2918-31-4	3020-05S-C	21,000 Gallons	$63.00
S-2918-62-0	3020-02-G	12 MMBtu/hr flare	$815.00

Attachments

A: Current Permits to Operate
B: Tank Emission Calculations
C: BACT Guidelines and Top Down BACT Analyses
D: Compliance Certification
E: Health Risk Assessment and Ambient Air Quality Analysis
F: Greenhouse Gas Calculations
G: Best Performance Standard
H: Draft Authority to Construct Permits

Attachment A

Current Permit to Operate

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: S-2918-1-6 **EXPIRATION DATE:** 06/30/2017

SECTION: 15 **TOWNSHIP:** 30S **RANGE:** 27E

EQUIPMENT DESCRIPTION:
32.5 MMBTU/HR NATIONAL AIR OIL BURNER CO. MODEL NAFV FLARE WITH AUTOMATIC SPARK IGNITED PILOT AND COMBUSTION AIR BLOWER (GREELEY LEASE)

PERMIT UNIT REQUIREMENTS

1. The flare is approved to operate at the following locations; Sec. 14, T30S, R27E and Sec. 7, T29S, R26E. [District NSR Rule]
2. Flare shall be equipped with recording operational flow meter. [District NSR Rule]
3. Natural gas shall be used as pilot fuel. [District NSR Rule]
4. Sulfur concentration of gas flared shall not exceed 5 ppmv. [District NSR Rule]
5. Air contaminant emissions shall not exceed the following limits: PM10: 0.0202 lb/MMBtu, ; NOx (as NO2): 0.068 lb/MMBtu, CO: 0.37 lb/MMBtu. [District NSR Rule]
6. Non breakdown operation shall not exceed 1000 Mscf per day and 2045 Mscf per year. [District NSR Rule]
7. The permittee shall notify the District Compliance Division of each location at which the operation is located in excess of 24 hours. Such notification shall be made no later than 48 hours after starting operation at the location. [District Rule 1070]
8. Permittee shall maintain accurate records of quantity of non-emergency/non-pilot gas combusted in the flare and shall make such records available to District staff upon request. Records shall be maintained for a period of no less than five years. [District Rule 1070 and District Rule 2520, 9.5.2]
9. Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting the presence of at least one pilot flame or the flare flame, shall be installed and operated. [District Rule 4311]
10. A flame shall be present at all times when combustible gases are vented through the flare. [District Rule 4311]
11. Flare outlet shall be equipped with an automatic ignition system, or, shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311]
12. If the flare uses a flow-sensing automatic ignition system and does not use a continuous flame pilot, the flare shall use purge gas for purging. [District Rule 4311]
13. Open flares in which the flare gas pressure is less than 5 psig shall be operated in such a manner that meets the provisions of 40 CFR 60.18. [District Rule 4311]
14. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. [40 CFR 60.18(c)(1)]
15. Demonstration of compliance with the visible emissions limit of this permit shall be conducted at least annually, using EPA Method 22. The observation period shall be 2 hours. [40 CFR 60.18(f)(1)]

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

16. A trained observer, as defined in EPA Method 22, shall check visible emissions at least once every two weeks for a period of 15 minutes. If visible emissions are detected at any time during this period, the observation period shall be extended to two hours. A record containing the results of these observations shall be maintained, which also includes company name, process unit, observer's name and affiliation, date, estimated wind speed and direction, sky condition, and the observer's location relative to the source and sun. [District Rule 2520, 9.4.2]
17. The operator shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rule 2520, 9.5.2]
18. The flare shall be operated according to the manufacturer's specifications, a copy of which shall be maintained on site. [District Rule 2520, 9.4.2]
19. Actual flare emissions shall not exceed 20 tons VOC/year. Process information, including fuel usage data for the flare and process rates for operations controlled by the flare, shall be submitted to the District annually to demonstrate compliance with this requirement. [District Rule 2520, 9.4.2]
20. Flares shall only be used with the net heating value of the gas being combusted being 300 Btu/scf or greater if the flare is air-assisted or steam-assisted. [40 CFR 60.18 (c)(3)]
21. The net heating value of the gas being combusted in a flare shall be calculated annually, pursuant to 40 CFR 60.18(f)(3) and using EPA Method 18, ASTM D1946, and ASTM D2382. [40 CFR 60.18 (f)(3-6)]
22. Air-assisted flares shall be operated with an exit velocity less than Vmax, as determined by the equation specified in paragraph 40 CFR 60.18 (f)(6). [40 CFR 60.18 (c)(5)]
23. The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip. [40 CFR 60.18 (f)(4)]
24. Flares shall be operated with a flame present at all times, and kept in operation when emissions may be vented to them. 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. [40 CFR 60.18 (c)(2), 60.18 (e), and 60.18 (f)(2)]
25. To show compliance with sulfur emission limits, the gas being flared shall be tested weekly for sulfur content. If compliance with the fuel sulfur content limit and sulfur emission limits has been demonstrated for 8 consecutive weeks for the flared gas, then the compliance testing frequency shall be semi-annually. If the semi-annual sulfur content test fails to show compliance, weekly testing shall resume. [District Rule 2520, 9.4.2]
26. The sulfur content of the gas being flared shall be determined using ASTM D 1072, D 3031, D 4084, D 3246 or grab sample analysis by GC-FPD/TCD performed in the laboratory. [District Rule 2520, 9.4.2]

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: S-2918-3-4 **EXPIRATION DATE:** 06/30/2017

SECTION: 15 **TOWNSHIP:** 30S **RANGE:** 27E

EQUIPMENT DESCRIPTION:
42,000 GALLON PETROLEUM STORAGE TANK (T-1001), SERVED BY VAPOR CONTROL SYSTEM SHARED BETWEEN S-2918-3, -4, -5, -15, & -16 (PANAMA LEASE)

PERMIT UNIT REQUIREMENTS

1. Operation shall include 36" diameter by 10' high vertical liquid/gas separator; 48" diameter by 10' long horizontal gas/liquid separator, and 42,000 gallon 40' diameter by 16' high produced water tank (WW-15). [District NSR Rule]
2. Operation shall include Varec Model 2010-51 pressure relief valve with flame arrestor and vapor compressor. [District Rule 4623]
3. VOC vapors shall be incinerated in a permit exempt 1.5 MMBTU/hr heater treater. [District NSR Rules & 4623]
4. True vapor pressure of liquids stored shall not exceed 6 psia. [District NSR Rule & 4623]
5. Tank throughput shall not exceed 667 bbl/day. [District NSR Rule & 4623]
6. Tank vapor control system shall be capable of collecting all VOC emissions and preventing their emissions to the atmosphere at an efficiency of at least 99% by weight. [District NSR Rule & 4623, 5.3.1]
7. The permittee shall keep accurate records of True vapor pressure, Reid vapor pressure, storage temperature, types of liquids stored in each container and daily throughput for a period of five years, and shall make such records available for District inspection upon request. [District Rules 4623, 6.1, 2520, 9.4.2, 2520, 9.5.2, and District NSR Rule]
8. VOC emissions (including fugitive emissions) from this permit unit shall not exceed 0.5 lb/day. [District NSR Rule]
9. Any tank gauging or sampling device on a tank vented to the vapor recovery system shall be equipped with a gas-tight cover which shall be closed at all times except during gauging or sampling. Gas-tight shall be defined as emitting no more than 10,000 ppm of methane measured at a distance of one centimeter from the potential source with an instrument calibrated with methane in accordance with EPA Method 21. Emissions in excess of this limit shall be considered a leak. [District Rule 4623, 5.3.2]
10. All piping, valves and fittings shall be constructed and maintained in a gas-tight condition. Gas-tight shall be defined as emitting no more than 10,000 ppm of methane measured at a distance of one centimeter from the potential source with an instrument calibrated with methane in accordance with EPA Method 21. Emissions in excess of this limit shall be considered a leak. [District Rule 4623, 5.3.3]
11. All piping, fittings, and valves on this tank shall be inspected annually by the facility operator in accordance with EPA Method 21, with the instrument calibrated with methane, to ensure compliance with the leaking provisions of this permit. [District Rule 4623, 5.7 (Table 3)]
12. If any of the tank components are found to be leaking, operator shall immediately affix a tag and maintain records of gas leak detection readings, date/time leak was discovered, and date/time the component was repaired to a leak-free condition. [District Rule 4623, 5.7 (Table 3)]

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

13. Upon detection of any leaking components (having a gas leak >10,000 ppmv, measured in accordance with EPA Method 21 by a portable hydrocarbon detection instrument that is calibrated with methane) operator shall: (a) Eliminate or minimize the leak within 8 hours after detection. (b) If the leak can not be eliminated, then minimize the leak to the lowest possible level within 8 hours after detection by using best maintenance practices; and eliminate the leak within 48 hours after detection. (c) In no event that the total time to minimize and eliminate the leak shall exceed 56 hours after detection. [District Rule 4623, 5.7 (Table 3)]

14. Leaking tank components affixed to the tank or within five feet of the tank that have been discovered by the operator and that have been immediately tagged and repaired within the specified deadlines, shall not constitute a violation of the District Rule 4623. However, leaking components discovered during inspections by District staff that were not previously identified and/or tagged by the operator, and/or any leaks that were not repaired within specified deadlines, shall constitute a violation of the District Rule 4623. [District Rule 4623, 5.7 (Table 3)]

15. If a component type for a given tank is found to leak during an annual inspection, then conduct quarterly inspections of that component type on the tank or tank system for four consecutive quarters. If a component type is found to have no leak after four consecutive quarterly inspections, then revert to annual inspections. [District Rule 4623, 5.7 (Table 3)]

16. Any component found to be leaking on two consecutive annual inspections is in violation of the District Rule 4623, even if it is under the voluntary inspection and maintenance program. [District Rule 4623, 5.7 (Table 3)]

17. Operator shall maintain an inspection log containing the following 1) Type of component leaking; 2) Date and time of leak detection, and method of detection; 3) Date and time of leak repair, and emission level of recheck after leak is repaired; 4) Method used to minimize the leak to lowest possible level within 8 hours after detection. [District Rule 2520, 9.3.2]

18. True vapor pressure shall be measured using Reid vapor pressure ASTM Method D323-82 modified by maintaining the hot water bath at storage temperature. Where storage temperature is above 100 degrees F true vapor pressure shall be determined by Reid vapor pressure at 100 degrees F and ARB approved calculations. [District Rule 4623, 6.2.2]

19. True vapor pressure of crude oil with an API (American Petroleum Institute) gravity less than 30 deg, as determined by API 2547, may be determined by Headspace Gas Chromatography using the procedures from ARB Evaluation of a Method for Determining Vapor Pressures of Petroleum Mixtures by Headspace Gas Chromatography, October 1990. [District Rule 4623, 6.2.3]

20. Control efficiency shall be determined by a comparison of controlled emissions to those emissions which would occur from a fixed or cone roof tank in the same product service without a vapor recovery system. Emissions shall be determined based on tank emission factors in EPA Publication AP-42, component counts for fugitive emissions sources, recognized emission factors for fugitive emission sources and the efficiency of any VOC destruction device. [District Rule 4623, 6.2.4]

21. The efficiency of any VOC destruction device shall be measured by EPA Method 25, 25a, or 25b. [District Rule 4623, 6.2.5]

22. The operator shall ensure that the vapor recovery system is functional and is operating as designed at all times. [District Rule 2520, 9.3.2]

23. The operator of a fixed roof tank shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rule 2520, 9.4.2]

24. The operator shall determine the true vapor pressure of the petroleum liquid stored in the tank at least once per year in accordance with methods described in 40 CFR 60.113 and section 6.2 of District Rule 4623 (amended 12/17/92). Determinations shall be made annually during the summer and whenever there is a change in the source or type of petroleum entering the tank. [District Rule 2520, 9.3.2]

25. As used in this permit, the term "source or type of petroleum" shall mean petroleum liquids with similar characteristics. The operator shall maintain records of the API gravity of petroleum liquids stored in this unit to determine which oils are from a common source. [District Rule 2520, 9.3.2]

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: S-2918-31-1 **EXPIRATION DATE:** 06/30/2017

SECTION: NE10 **TOWNSHIP:** 30S **RANGE:** 26E

EQUIPMENT DESCRIPTION:
21,000 GALLON FIXED ROOF PETROLEUM STORAGE TANK WITH PRESSURE VACUUM RELIEF HATCH - #20016 (KERN COUNTY LEASE 61)

PERMIT UNIT REQUIREMENTS

1. The tank shall be equipped with a pressure relief device set to within 10 percent of the maximum working pressure of the tank. [District Rule 4623, 5.4]
2. Crude Oil throughput shall be less than 150 barrels per day. [District Rule 4623, 4.2.2]
3. Permittee shall maintain monthly records of average daily throughput and shall submit such information to the APCO 30 days prior to annual permit renewal. [District Rule 4623, 6.1.3]
4. Operator shall keep a record of liquids stored in each container, storage temperature, and the Reid vapor pressure of such liquids. [District Rule 4623, 6.1]
5. True vapor pressure shall be measured using Reid vapor pressure ASTM Method D323-82 modified by maintaining the hot water bath at storage temperature. Where storage temperature is above 100 degrees F true vapor pressure shall be determined by Reid vapor pressure at 100 degrees F and ARB approved calculations. [District Rule 4623, 6.2.2]
6. True vapor pressure of crude oil with an API (American Petroleum Institute) gravity less than 30 deg, as determined by API 2547, may be determined by Headspace Gas Chromatography using the procedures from ARB Evaluation of a Method for Determining Vapor Pressures of Petroleum Mixtures by Headspace Gas Chromatography, October 1990. [District Rule 4623, 6.2.3]
7. The operator of a fixed roof tank shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rule 2520, 9.4.2]

Attachment B

Tank Emission Calculations

FOR REFERENCE PAINT TABLE

PAINT COLOR	SHADE/ TYPE	PAINT FACTORS PAINT CONDITION GOOD	POOR
ALUMINUM	SPECULAR	0.39	0.49
ALUMINUM	DIFFUSE	0.60	0.68
GRAY	LIGHT	0.54	0.63
GRAY	MEDIUM	0.68	0.74
RED	PRIMER	0.89	0.91
WHITE	--NONE--	0.17	0.34

LIQUID TYPE	CODE	
CRUDE OIL	0	CRUDE
MOTOR GASOLINE	1	MOTOR GAS
AVIATION GASOLINE	2	AV GAS
LIGHT NAPHTHA (RVP 9-14 PSIA)	3	LT NAPTHA
NAPHTHA (RVP 2-8 PSIA)	4	NAPTHA

METEOROLOGICAL DATA CODES	
AREA	CODE
BAKERSFIELD	0
FRESNO	1
STOCKTON	2

PRESS [TAB] TO SKIP TO NEXT MODIFIABLE CELL

GIVEN AND ASSUMED DATA	
USING THE CODES ABOVE, WHAT REGION PERMIT	----
NUMBERS DO YOU WANT TO USE? (0, 1, OR 2)	0
USING THE CODES ABOVE, WHAT AREA METEOROLOGICAL	----
DATA DO YOU WANT TO USE? (0, 1, 2, ...)	0
REID VAPOR PRESSURE (psia)	9.50
VAPOR MOLECULAR WEIGHT (Mv)	50.00
USING THE CODES ABOVE, WHAT	----
TYPE OF ORGANIC LIQUID (0, 1, 2, ...)	0
VOC CONTROL EFFICIENCY	0.00
TANK SHELL DIAMETER (FEET)	15.00
TANK SHELL HEIGHT, Hs (FEET)	16.00
VENT VACUUM (ENTER "-" FOLLOWED BY A VALUE IN PSIG)	-0.03
VENT PRESSURE (POSITIVE psig)	0.03
TANK ID	S-2918-31-1
TANK USE	Stock
SJVUAPCD PERMIT#	S-2918-31-1
CONE OR DOME ROOF (C/D)	C
MAXIMUM TOTAL DAILY THROUGHPUT (BBL/DAY)	150.00
MIN LIQUID HEIGHT (USE 0.0 FT FOR DEFAULT)	2.00
TANK ROOF PAINT CONDITION, GOOD OR POOR (G/P)	G
TANK ROOF PAINT COLOR, SEE ABOVE (A/G/R/W)	G
TANK ROOF PAINT SHADE, SEE ABOVE (S/D/L/M/P/N)	M
TANK SHELL PAINT CONDITION, GOOD OR POOR (G/P)	G
TANK SHELL PAINT COLOR, SEE ABOVE (A/G/R/W)	G
TANK SHELL PAINT SHADE, SEE ABOVE (S/D/L/M/P/N)	M

MODIFIABLE DATA	
----	----
-----	----

-----	--N/R--

CONE ROOF	----
GIVEN ROOF HEIGHT OR SLOPE (H/S)	S
-----	0.94
TANK CONE ROOF SLOPE, Sr (DEFAULT=0.0625) (ft/ft)	0.0625
----	----

DO YOU WANT TO ENTER A MAX LIQUID HEIGHT? (Y/N)	N

DEFAULT MAX LIQUID HEIGHT (SHELL HT - 2.0 FT)	14.00
DO YOU WANT TO ENTER AN AVERAGE LIQUID HEIGHT? (Y/N)	Y
-----	----
ENTER AVERAGE LIQUID HEIGHT (ft)	9.0
IS TANK CONSTANT LEVEL? (Y/N)	N

ARE THE CONTENTS OF THE TANK HEATED? (Y/N)	N

TANK ID	TANK USE	SJVUAPCD PERMIT #	TANK TYPE H OR V	SHELL DIMENSIONS D (FT)	SHELL DIMENSIONS Hs (FT)	CAPACITY (BBL)	ROOF TYPE (C/D)	VENT PSIG VAC.	VENT PSIG PRESS.
3	Stock	S-2918-31-1	VERTICAL	15.0	16.0	503.6	CONE	-0.03	0.03

TANK ROOF COND.	TANK ROOF COLOR	PAINT FACTOR	LIQUID DATA TYPE	LIQUID DATA Ht=H(lx)	LIQUID DATA Kp	LIQUID DATA RVP	CONSTANT LEVEL?	VAPOR MOL. WT.	VOC CNTRL %EFF (w/w)
GOOD	GRAY	0.68	CRUDE	14.0	0.75	9.50	NO	50.00	0.0

UNCONTROLLED EMISSIONS

CALENDAR QUARTER	CALENDAR MONTH	SURFACE T(la) F	CALC TVP @ T(la)	RATE (BBL/MON)	TURNOVER PER MON.	FAC-(Kn)	VOC (LBM/MONTH) Ls	VOC (LBM/MONTH) Lw	VOC (LBM/MONTH) TOTAL (Lt)	TOTAL (LBM/QTR)
FIRST	JANUARY	63.30	7.34	4650	12.31	0.374	185.28	478.04	663.33	
	FEBRUARY	67.50	7.86	4200	11.12	0.374	248.61	462.57	711.18	
	MARCH	71.54	8.39	4650	12.31	0.374	393.45	546.70	940.16	2314.67
SECOND	APRIL	76.59	9.09	4500	11.91	0.374	563.53	573.23	1136.76	
	MAY	82.17	9.92	4650	12.31	0.374	833.62	646.12	1479.74	
	JUNE	86.51	10.60	4500	11.91	0.374	1059.51	668.15	1727.66	4344.16
THIRD	JULY	88.94	10.99	4650	12.31	0.374	1242.02	716.27	1958.29	
	AUGUST	87.00	10.68	4650	12.31	0.374	1034.70	695.52	1730.22	
	SEPTEMBER	82.28	9.93	4500	11.91	0.374	692.27	626.37	1318.64	5007.15
FOURTH	OCTOBER	75.71	8.97	4650	12.31	0.374	457.21	584.22	1041.44	
	NOVEMBER	67.78	7.90	4500	11.91	0.374	250.77	497.95	748.71	
	DECEMBER	62.82	7.28	4650	12.31	0.374	174.32	474.25	648.57	2438.72

CONTROLLED EMISSIONS (BASED ON MONTHLY CALCULATIONS)

CALENDAR QUARTER	CALENDAR MONTH	SURFACE T(la) F	CALC TVP @ T(la)	RATE (BBL/QTR)	TURNOVER PER QTR.	FAC-(Kn)	VOC (LBM/QTR) Ls	VOC (LBM/QTR) Lw	VOC (LBM/QTR) TOTAL (Lt)
FIRST	JAN-MAR	67.44	7.86	13500	36	0.374	827	1487	2315
SECOND	APR-JUN	81.76	9.87	13650	36	0.374	2457	1887	4344
THIRD	JUL-SEP	86.07	10.53	13800	37	0.374	2969	2038	5007
FOURTH	OCT-DEC	68.77	8.05	13800	37	0.374	882	1556	2439
QUARTERLY AVERAGE		76.01	9.08	13688			1784	1742	3526
DAILY AVERAGE (LB/DAY, BASED ON MONTHLY CALCULATIONS)							19.5	19.1	38.6
ANNUAL EMISSIONS (LB/YEAR, BASED ON MONTHLY CALCULATIONS)							7135	6969	14105

Tank Emission Calculation Spreadsheet, version 01/23/03

FOR REFERENCE PAINT TABLE

PAINT COLOR	SHADE/ TYPE	PAINT FACTORS PAINT CONDITION GOOD	POOR
ALUMINUM	SPECULAR	0.39	0.49
ALUMINUM	DIFFUSE	0.60	0.68
GRAY	LIGHT	0.54	0.63
GRAY	MEDIUM	0.68	0.74
RED	PRIMER	0.89	0.91
WHITE	--NONE--	0.17	0.34

LIQUID TYPE	CODE	
CRUDE OIL	0	CRUDE
MOTOR GASOLINE	1	MOTOR GAS
AVIATION GASOLINE	2	AV GAS
LIGHT NAPHTHA (RVP 9-14 PSIA)	3	LT NAPTHA
NAPHTHA (RVP 2-8 PSIA)	4	NAPTHA

METEOROLOGICAL DATA CODES	
AREA	CODE
BAKERSFIELD	0
FRESNO	1
STOCKTON	2

PRESS [TAB] TO SKIP TO NEXT MODIFIABLE CELL

GIVEN AND ASSUMED DATA	
USING THE CODES ABOVE, WHAT REGION PERMIT	----
NUMBERS DO YOU WANT TO USE? (0, 1, OR 2)	0
USING THE CODES ABOVE, WHAT AREA METEOROLOGICAL	----
DATA DO YOU WANT TO USE? (0, 1, 2, ...)	0
REID VAPOR PRESSURE (psia)	6.86
VAPOR MOLECULAR WEIGHT (Mv)	50.00
USING THE CODES ABOVE, WHAT	----
TYPE OF ORGANIC LIQUID (0, 1, 2, ...)	0
VOC CONTROL EFFICIENCY	0.00
TANK SHELL DIAMETER (FEET)	15.00
TANK SHELL HEIGHT, Hs (FEET)	16.00
VENT VACUUM (ENTER "-" FOLLOWED BY A VALUE IN PSIG)	-0.03
VENT PRESSURE (POSITIVE psig)	0.03
TANK ID	S-2918-31-1
TANK USE	Stock
SJVUAPCD PERMIT#	S-2918-31-1
CONE OR DOME ROOF (C/D)	C
MAXIMUM TOTAL DAILY THROUGHPUT (BBL/DAY)	150.00
MIN LIQUID HEIGHT (USE 0.0 FT FOR DEFAULT)	2.00
TANK ROOF PAINT CONDITION, GOOD OR POOR (G/P)	G
TANK ROOF PAINT COLOR, SEE ABOVE (A/G/R/W)	G
TANK ROOF PAINT SHADE, SEE ABOVE (S/D/L/M/P/N)	M
TANK SHELL PAINT CONDITION, GOOD OR POOR (G/P)	G
TANK SHELL PAINT COLOR, SEE ABOVE (A/G/R/W)	G
TANK SHELL PAINT SHADE, SEE ABOVE (S/D/L/M/P/N)	M

MODIFIABLE DATA	
-----	----
-----	----

-----	--N/R--

CONE ROOF	----
GIVEN ROOF HEIGHT OR SLOPE (H/S)	S
-----	0.94
TANK CONE ROOF SLOPE, Sr (DEFAULT=0.0625) (ft/ft)	0.0625
-----	----
-----	1.00
DO YOU WANT TO ENTER A MAX LIQUID HEIGHT? (Y/N)	N

DEFAULT MAX LIQUID HEIGHT (SHELL HT - 2.0 FT)	14.00
DO YOU WANT TO ENTER AN AVERAGE LIQUID HEIGHT? (Y/N)	Y
-----	---
ENTER AVERAGE LIQUID HEIGHT (ft)	9.0
IS TANK CONSTANT LEVEL? (Y/N)	N

ARE THE CONTENTS OF THE TANK HEATED? (Y/N)	N

TANK ID	TANK USE	SJVUAPCD PERMIT #	TANK TYPE H OR V	SHELL DIMENSIONS D (FT)	SHELL DIMENSIONS Hs (FT)	CAPACITY (BBL)	ROOF TYPE (C/D)	VENT PSIG VAC.	VENT PSIG PRESS.
3	Stock	S-2918-31-1	VERTICAL	15.0	16.0	503.6	CONE	-0.03	0.03

TANK ROOF COND.	TANK ROOF COLOR	PAINT FACTOR	LIQUID DATA TYPE	LIQUID DATA Ht=H(lx)	LIQUID DATA Kp	LIQUID DATA RVP	CONSTANT LEVEL?	VAPOR MOL. WT.	VOC CNTRL %EFF (w/w)
GOOD	GRAY	0.68	CRUDE	14.0	0.75	6.86	NO	50.00	0.0

UNCONTROLLED EMISSIONS

CALENDAR QUARTER	CALENDAR MONTH	SURFACE T(la) F	CALC TVP @ T(la)	RATE (BBL/MON)	TURNOVER PER MON.	FAC-(Kn)	VOC (LBM/MONTH) Ls	VOC (LBM/MONTH) Lw	VOC (LBM/MONTH) TOTAL (Lt)	TOTAL (LBM/QTR)
FIRST	JANUARY	63.30	4.72	4650	12.31	0.374	96.41	307.22	403.63	
	FEBRUARY	67.50	5.08	4200	11.12	0.374	125.69	299.07	424.77	
	MARCH	71.54	5.46	4650	12.31	0.374	192.09	355.50	547.58	1375.98
SECOND	APRIL	76.59	5.95	4500	11.91	0.374	260.02	375.37	635.39	
	MAY	82.17	6.54	4650	12.31	0.374	353.16	426.33	779.49	
	JUNE	86.51	7.03	4500	11.91	0.374	409.76	443.44	853.19	2268.07
THIRD	JULY	88.94	7.32	4650	12.31	0.374	450.07	476.90	926.97	
	AUGUST	87.00	7.09	4650	12.31	0.374	395.27	461.89	857.16	
	SEPTEMBER	82.28	6.56	4500	11.91	0.374	292.50	413.36	705.86	2489.99
FOURTH	OCTOBER	75.71	5.87	4650	12.31	0.374	213.15	382.11	595.25	
	NOVEMBER	67.78	5.11	4500	11.91	0.374	126.44	322.08	448.52	
	DECEMBER	62.82	4.67	4650	12.31	0.374	90.95	304.57	395.52	1439.29

CONTROLLED EMISSIONS (BASED ON MONTHLY CALCULATIONS)

CALENDAR QUARTER	CALENDAR MONTH	SURFACE T(la) F	CALC TVP @ T(la)	RATE (BBL/QTR)	TURNOVER PER QTR.	FAC-(Kn)	VOC (LBM/QTR) Ls	VOC (LBM/QTR) Lw	VOC (LBM/QTR) TOTAL (Lt)
FIRST	JAN-MAR	67.44	5.08	13500	36	0.374	414	962	1376
SECOND	APR-JUN	81.76	6.51	13650	36	0.374	1023	1245	2268
THIRD	JUL-SEP	86.07	6.99	13800	37	0.374	1138	1352	2490
FOURTH	OCT-DEC	68.77	5.22	13800	37	0.374	431	1009	1439
QUARTERLY AVERAGE		76.01	5.95	13688			751	1142	1893
DAILY AVERAGE (LB/DAY, BASED ON MONTHLY CALCULATIONS)							8.2	12.5	20.7
ANNUAL EMISSIONS (LB/YEAR, BASED ON MONTHLY CALCULATIONS)							3006	4568	7573

Tank Emission Calculation Spreadsheet, version 01/23/03

Attachment C

BACT Guidelines and Top Down BACT Analyses

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 1.4.2*

Last Update 12/31/1998

Waste Gas Flare - Incinerating Produced Gas

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable		
NOx	Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable		
PM10	Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable Pilot Light fired solely on LPG or natural gas.		
SOx	Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable Pilot Light fired solely on LPG or natural gas.	Precombustion SOx scrubbing system (non-emergency flares only.)	
VOC	Steam assisted or Air-assisted or Coanda effect burner, when steam unavailable		

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source**

NOx Top-Down BACT Analysis for Permit Units S-2918-62-0

Step 1 - Identify All Control Technologies

The SJVUAPCD BACT Clearinghouse Guideline 1.4.2, Waste Gas Flare - Incinerating Produced Gas, (4th quarter, 2012), identifies BACT for NOx as:

1) Steam assisted or Air assisted or Coanda effect burner, when steam unavailable. (Achieved in Practice)

The combustion unit listed in permit S-2918-62-0 in this project is not a flare as defined in Rule 4311 as the rule has a very specific definition. However, for BACT purposes the combustion unit is considered a waste gas flare and BACT Guideline 1.4.2 is applicable.

Step 2 - Eliminate Technologically Infeasible Options

This light oil operation is not a thermally enhanced oil recovery operation; therefore, there are no existing steam generating units at the lease that could be used as a source of steam. Any steam generating units would have to be new, which would result in additional combustion emissions. Therefore, since steam is unavailable, Achieved-in-Practice BACT is an Air-assisted or a Coanda effect burner.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	Air assisted or Coanda effect burner	Y

Step 4 - Cost Effectiveness Analysis

There are no Technologically Feasible or Alternate Basic Equipment options listed in the guideline; therefore, no cost effective analysis is necessary.

Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the waste gas flare must be satisfied with the following:

NOx: Air assisted or Coanda effect burner (Achieved in Practice)

The applicant has proposed an air assisted flare. Therefore, the BACT requirements are satisfied.

PM10 Top-Down BACT Analysis for Permit Unit S-2918-62-0

Step 1 - Identify All Control Technologies

The SJVUAPCD BACT Clearinghouse Guideline 1.4.2, Waste Gas Flare - Incinerating Produced Gas, (4th quarter, 2012), identifies BACT for PM10 as:

1) Steam assisted or Air assisted or Coanda effect burner, when steam unavailable and Pilot Light fired solely on LPG or natural gas. (Achieved in Practice)

The combustion unit listed in permit S-2918-62-0 in this project is not a flare as defined in Rule 4311 as the rule has a very specific definition. However, for BACT purposes the combustion unit is considered a waste gas flare and BACT Guideline 1.4.2 is applicable.

Step 2 - Eliminate Technologically Infeasible Options

This light oil operation is not a thermally enhanced oil recovery operation; therefore, there are no existing steam generating units at the lease that could be used as a source of steam. Any steam generating units would have to be new, which would result in additional combustion emissions. Therefore, since steam is unavailable, Achieved-in-Practice BACT is an Air-assisted or a Coanda effect burner.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	Air assisted or Coanda effect burner and Pilot Light fired solely on LPG or natural gas	Y

Step 4 - Cost Effectiveness Analysis

There are no Technologically Feasible or Alternate Basic Equipment options listed in the guideline; therefore, no cost effective analysis is necessary.

Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the waste gas flare must be satisfied with the following:

PM10: Air assisted or Coanda effect burner and Pilot Light fired solely on LPG or natural gas (Achieved in Practice)

The applicant has proposed an air assisted flare and a pilot light fired on produced gas. The produced gas proposed in this project has a higher heating value of 1,200 Btu/scf which is greater than the typical natural gas higher heating value of 1,000 Btu/scf. The pilot light fired on produced gas is deemed equivalent to a pilot light fired on natural gas. Therefore, the BACT requirements are satisfied.

VOC Top-Down BACT Analysis for Permit Units S-2918-1-7 and '62-0

Step 1 - Identify All Control Technologies

The SJVUAPCD BACT Clearinghouse Guideline 1.4.2, Waste Gas Flare - Incinerating Produced Gas, (4th quarter, 2012), identifies BACT for VOC as:

1) Steam assisted or Air assisted or Coanda effect burner, when steam unavailable. (Achieved in Practice)

The combustion unit listed in permit S-2918-62-0 in this project is not a flare as defined in Rule 4311 as the rule has a very specific definition. However, for BACT purposes the combustion unit is considered a waste gas flare and BACT Guideline 1.4.2 is applicable.

Step 2 - Eliminate Technologically Infeasible Options

This light oil operation is not a thermally enhanced oil recovery operation; therefore, there are no existing steam generating units at the lease that could be used as a source of steam. Any steam generating units would have to be new, which would result in additional combustion emissions. Therefore, since steam is unavailable, Achieved-in-Practice BACT is an Air-assisted or a Coanda effect burner.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	Air assisted or Coanda effect burner	Y

Step 4 - Cost Effectiveness Analysis

There are no Technologically Feasible or Alternate Basic Equipment options listed in the guideline; therefore, no cost effective analysis is necessary.

Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the waste gas flare must be satisfied with the following:

VOC: Air assisted or Coanda effect burner (Achieved in Practice)

The applicant has proposed an air assisted flare. Therefore, the BACT requirements are satisfied.

VOC Top-Down BACT Analysis for Permit Unit S-2918-31-4

Step 1 - Identify All Control Technologies

The SJVUAPCD BACT Clearinghouse Guideline 7.3.1, Petroleum and Petrochemical Production – Fixed Roof Organic Liquid Storage or Processing Tank, < 5,000 bbl Tank capacity, (4th quarter, 2012), identifies BACT for VOC as:

1) 99% control (Waste gas incinerated in steam generator, heater treater, or other fired equipment and inspection and maintenance program; transfer of noncondensable vapors to gas pipeline; reinjection to formation (if appropriate wells are available); or equal. (Technologically Feasible)
2) PV-vent set to within 10% of maximum allowable pressure (Achieved in Practice)

Step 2 - Eliminate Technologically Infeasible Options

All options listed above are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Rank	Control Technology	Achieved in Practice
1	99% control (Waste gas incinerated in steam generator, heater treater, or other fired equipment and inspection and maintenance program; transfer of noncondensable vapors to gas pipeline; reinjection to formation (if appropriate wells are available); or equal.	N
2	PV-vent set to within 10% of maximum allowable pressure	Y

Step 4 - Cost Effectiveness Analysis

<u>Option 1: 99% control (Waste gas incinerated in steam generator, heater treater, or other fired equipment and inspection and maintenance program; transfer of noncondensable vapors to gas pipeline; reinjection to formation (if appropriate wells are available); or equal. (Technologically Feasible)</u>

The following cost information for a vapor control system to address the technologically feasible control option was taken from projects S-1120238 and S-1114894. The cost information was submitted to the District in January and February 2012.

<u>Capital Cost</u>

Vapor Recovery Unit = $48,654
Piping = $392,660 x 6 miles / 2.5 miles = $942,384

The following cost data is taken from EPA Control Cost Manual, Sixth Edition (EPA/452/B-02-001).

Vapor Control System – Cost Estimate	
Cost Description	Cost ($)
Direct Costs (DC)	
Base Equipment Costs (Carbon Material)	48,654
Instrumentation	0.10 x 48,654 = 4,865
Sales Tax	0.03 x 48,654 = 1,460
Freight	0.05 x 48,654 = 2,433
Purchased equipment cost	**57,412**
Foundations & supports	0.08 x 57,412 = 4,593
Handling & erection	0.14 x 57,412 = 8,038
Electrical	0.04 x 57,412 = 2,296
Piping	0.02 x 57,412 = 1,148
Painting	0.01 x 57,412 = 574
Insulation	0.01 x 57,412 = 574
Direct installation costs	**17,223**
Total Direct Costs	**74,635**
Indirect Costs (IC)	
Engineering	0.10 x 57,412 = 5,741
Construction and field expenses	0.05 x 57,412 = 2,871
Contractor fees	0.10 x 57,412 = 5,741
Start-up	0.02 x 57,412 = 1,148
Performance test	0.01 x 57,412 = 574
Contingencies	0.03 x 57,412 = 1,722
Total Indirect Costs	**17,797**
Total Capital Cost (DC + IC)	**92,432**

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

$A = [P \times i(I+1)^n]/[(I+1)^n-1]$

Where:
A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

$A = \$(92{,}432 + 942{,}384) \times [0.1(1.1)^{10}]/[(1.1)^{10}-1]$
= **$168,412/year**

Maintenance and Operation Annual Costs

Maintenance = $12,000 ($1000/mo per contract)
Electricity = $4,800 (Vapor Recovery Unit)
Total = $12,000 + $4,800 = $16,800

Total Annual Costs

Total Annual Costs = Annualized Capital Cost + Maintenance and Operation Annual Costs
Total Annual Costs = $(168,412 + 16,800)/year
Total Annual Costs = $185,212/year

Emission Reductions

Annual Emission Reduction = Uncontrolled Emissions x 0.99
= 7,573 lb-VOC/year x 0.99
= 7,497 lb-VOC/year
= 3.75 tons-VOC/year

Cost Effectiveness

Cost Effectiveness = Total Annual Costs ÷ Annual Emission Reduction

Cost Effectiveness = $185,212/year ÷ 3.75 tons-VOC/year
= $49,390/ton-VOC

The analysis demonstrates that the annualized capital cost of the required vapor recovery unit and piping and maintenance and operation costs results in a cost effectiveness which exceeds the District's Guideline of $17,500/ton-VOC. Therefore, this option is not cost effective and is being removed from consideration.

Option 2: PV-vent set to within 10% of maximum allowable pressure (Achieved in Practice)

The applicant has proposed this option; therefore a cost analysis is not required.

Step 5 - Select BACT

Pursuant to the above Top-Down BACT Analysis, BACT for the crude oil storage tank must be satisfied with the following:

VOC: PV-vent set to within 10% of maximum allowable pressure (Achieved in Practice)

The applicant has proposed a tank equipped with a PV-vent set to within 10% of maximum allowable pressure. Therefore, the BACT requirements are satisfied.

Attachment D

Compliance Certification

CRIMSON RESOURCE MANAGEMENT
5001 California Ave., Suite 206
Bakersfield, CA 93309
Phone 661-716-5001 Fax 661-716-5008

RECEIVED
AUG 17 2012
SJVAPCD
Southern Region

August 16, 2012

Mr. Steve Roeder
Permit Services
San Joaquin Valley Unified APCD
34946 Flyover Court
Bakersfield, CA 93308

Subject: Project Number S-1122546 – (S-2918) - Compliance Certification

Dear Mr. Roeder:

I hereby certify that all major Stationary Sources owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in California, which are subject to emission limitations, are in compliance or on a schedule for compliance with all applicable emission limitations and standards.

Alternative siting analysis is required for any project, which constitutes a New Major Source or a Federal Major Modification.

The current project occurs at existing facilities. Since the project will provide additional capacity for an existing source, utilizing the existing site will result in the least possible impact from the project. Alternative sites would involve the relocation and/or construction of various support structures on a much greater scale, and would therefore result in a much greater impact.

Paul Q Combs
Signature

EHS MANAGER
Title

Attachment E

Health Risk Assessment and Ambient Air Quality Analysis

San Joaquin Valley Air Pollution Control District
Risk Management Review

To:	Steve Roeder, AQE – Permit Services
From:	Trevor Joy, AQS – Technical Services
Date:	September 19, 2012
Facility Name:	Crimson Resource Management
Location:	S14, T30S, R27E
Application #(s):	S-2918-1-7, 31-4, and 62-0
Project #:	1122546

A. RMR SUMMARY

Categories	Unit 1-7 NG Flare	Unit 62-0 NG Flare	Project Totals	Facility Totals
Prioritization Score	5.0	4.8	9.9	>1
Acute Hazard Index	0.00	0.00	0.00	0.01
Chronic Hazard Index	0.00	0.00	0.00	0.00
Maximum Individual Cancer Risk (10^{-6})	0.0	1.74	1.74	6.45
T-BACT Required?	No	Yes		
Special Permit Conditions?	Yes	Yes		

Proposed Permit Conditions

To ensure that human health risks will not exceed District allowable levels; the following permit conditions must be included for:

Units 1 and 62

{1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102] N

B. RMR REPORT

I. Project Description

Technical Services received a request on August 21, 2012 to perform an Ambient Air Quality Analysis and a Risk Management Review for the proposed increase in yearly emissions (no increase in hourly emissions) for unit 1, a NG Flare; and the addition of unit 62, a NG Flare. As part of this project, unit 2, a NG Flare, will be deleted. Also, as part of this project, unit 31 will be have the RVP decreased, which will not cause an increase in emissions nor will the modification change emission parameters.

II. Analysis

Technical Services performed a prioritization using the District's HEARTs database. Emissions were calculated using "NG Flare External Combustion" emission factors. In accordance with the District's *Risk Management Policy for Permitting New and Modified Sources* (APR 1905, March 2, 2001), risks from the proposed unit's toxic emissions were prioritized using the procedure in the 1990 CAPCOA Facility Prioritization Guidelines and incorporated in the District's HEARTs database. The prioritization score for the facility was greater than 1.0 (see RMR Summary Table). Therefore, a refined analysis was required and performed. AERMOD was used, with the parameters outlined below and concatenated meteorological data for Bakersfield 2005 to 2009 to determine the maximum dispersion factor at the nearest residential and business receptors. These dispersion factors were input into the HARP model to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameter Units 1-7			
Closest Receptor - Business (m)	22	Closest Receptor – Resident (m)	265
Increase in NG Usage (MMScf/hr)	0.0	Increase in NG Gas Usage (MMScf/yr)	93.96
Effective Release Height (m)	7.0	Gas Exit Temperature (K)	1273
Calculated Stack Inside Diameter (m)	1.0	Gas Exit Velocity (m/s)	20

Analysis Parameter Units 62-0			
Closest Receptor - Business (m)	22	Closest Receptor – Resident (m)	265
NG Usage (MMScf/hr)	0.01	NG Usage (MMScf/yr)	91.25
Effective Release Height (m)	6.5	Gas Exit Temperature (K)	1273
Calculated Stack Inside Diameter (m)	0.6	Gas Exit Velocity (m/s)	20

Technical Services also performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR. The emission rates used for criteria pollutant modeling were

Unit 1	NOx	Sox	CO	PM10	PM2.5
Lbs/hr	0	0	0	0	0
Lbs/yr	6,389	268	34,763	2,443	2,443

Unit 62	NOx	Sox	CO	PM10	PM2.5
Lbs/hr	0.19	0.03	0.1	0.21	0.21
Lbs/yr	1,643	260	913	1,843	1,843

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*
Values are in $\mu g/m^3$

Steam Generator	1 Hour	3 Hours	8 Hours.	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass[1]	X	X	X	Pass
SO_x	Pass[2]	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[3]	Pass[3]
PM2.5	X	X	X	Pass[3]	Pass[3]

*Results were taken from the attached PSD spreadsheet.
[1]The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures. The criteria pollutant 1-hour value passed using TIER I NO_2 NAAQS modeling
[2]The project was compared to the 1-hour SO2 National Ambient Air Quality Standard that became effective on August 23, 2010 using the District's approved procedures.
[3]The maximum predicted concentration for emissions of these criteria pollutants from the proposed unit are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

III. Conclusion

Unit 1

The acute and chronic indices are below 1.0. The cancer risk is less then 1 in a million. In accordance with the District's Risk Management Policy, the unit is approved without Toxic Best Available Control Technology (T-BACT).

Unit 62

The acute and chronic indices are below 1.0. The cancer risk is greater then 1 in a million, but less then 10 in a million -- **In accordance with the District's Risk Management Policy, the unit is approved with Toxic Best Available Control Technology (T-BACT) for PM.**

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for this proposed unit.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

Attachments:

A. RMR request from the project engineer
B. Prioritization score with toxic emissions summary
C. HEARTS – Facility Summary
D. AAQA spreadsheet

AAQA for Crimson Resource (S2918)
All Values are in ug/m^3

	NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
FLARE1	0.000E+00	1.503E-01	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	4.401E-05	0.000E+00	4.012E-04
FLARE2	2.349E+00	3.830E-04	1.236E+00	8.601E-01	3.709E+00	2.721E+00	1.256E+00	9.077E-03	8.791E-01	6.435E-02
Background	6.370E+01	1.339E+01	4.078E+03	2.563E+03	1.598E+02	1.332E+02	7.193E+01	2.664E+01	2.560E+02	6.500E+01
Facility Totals	6.605E+01	1.354E+01	4.079E+03	2.564E+03	1.635E+02	1.359E+02	7.319E+01	2.665E+01	2.569E+02	6.506E+01
AAQS	188.68	56	23000	10000	195	1300	105	80	50	30
	Pass	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Pass**	**Fail**	**Fail**

EPA's Significance Level (ug/m^3)

NOx 1 Hour	NOx Annual	CO 1 Hour	CO 8 Hour	SOx 1 Hour	SOx 3 Hour	SOx 24 Hour	SOx Annual	PM 24 Hour	PM Annual
0.0	1.0	2000.0	500.0	0.0	25.0	5.0	1.0	5.0	1.0

1.75 * 0.2
= 0.3
13.4 + 0.3 = 13.7
13.7 < 56
PASS

0 * 1.75 = 0
0 + 26.6 = 26.6
26.6 < 80
PASS

0.9 < 5
PASS

0.06 * 1.75 = 0.1
0.1 < 1
PASS

PM 2.5

	24	Annual
Limit	1.2	0.3
new standard		
	0.9 < 1.2	0.1 < 3
	PASS	PASS

Attachment F

Greenhouse Gas Calculations

Greenhouse Gas Calculations

Basis and Assumptions

- Annual pre-project maximum flare gas flowrate for flare S-2918-1-7 = 2,045 Mscf/year (per current permit)
- Annual post-project maximum flare gas flowrate for flare S-2918-1-7 = 96,000 Mscf/year (per applicant)
- Daily pre-project maximum flare gas flowrate for flare S-2918-2-3 = 46,000 scf/day (per current permit)
- Annual pre-project potential to emit for tank S-2918-31-4 = 14,105 lb/year
- Annual post-project potential to emit for tank S-2918-31-4 = 7,573 lb/year
- Annual post-project maximum gas flowrate for combustion device S-2918-62-0 = 91,250,000 scf/year (per applicant)
- Emission factors and global warming potentials (GWP) are taken from EPA 40 CFR Part 98, Subpart A, Tables C-1 and C-2:

  CO_2 53.02 kg/MMBtu (116.89 lb/MMBtu)
  CH_4 1×10^{-3} kg/MMBtu (0.002 lb/MMBtu)
  N_2O 1×10^{-4} kg/MMBtu (0.0002 lb/MMBtu)

  GWP for CH_4 = 21 lb-CO_2(eq) per lb-CH_4
  GWP for N_2O = 310 lb-CO_2(eq) per lb-N_2O

Calculations

S-2918-1-7

Annual Emissions

CO_2 Emissions = (96,000,000 – 2,045,000) scf/year x 1200 Btu/scf x 116.89 lb/MMBtu
= 13,178,879.94 lb-CO_2(eq)/year
CH_4 Emissions = (96,000,000 – 2,045,000) scf/year x 1200 Btu/scf x 0.002 lb/MMBtu x 21 lb-CO_2(eq) per lb-CH_4
= 4,735.332 lb-CO_2(eq)/year
N_2O Emissions = (96,000,000 – 2,045,000) scf/year x 1200 Btu/scf x 0.0002 lb/MMBtu x 310 lb-CO_2(eq) per lb-N_2O
= 6,990.252 lb-CO_2(eq)/year

Total = 13,178,879.94 + 4,735.332 + 6,990.252 = 13,190,605.52 lb-CO_2(eq)/year

Total = 13,190,605.52 lb-CO_2(eq)/year ÷ 2,000 lb/ton = **6,595.3 short tons-CO_2(eq)/year**
Total = 6,595.3 short tons-CO_2e/year x 0.9072 metric tons/short ton = **5,983 metric tons-CO_2(eq)/year**

S-2918-2-3

Annual Emissions

CO2 Emissions = (0 – 46,000) scf/day x 365 days/year x 1200 Btu/scf x 116.89 lb/MMBtu
= -23,550,099.72 lb-CO2(eq)/year
CH4 Emissions = (0 – 46,000) scf/day x 365 days/year x 1200 Btu/scf x 0.002 lb/MMBtu x 21 lb-CO2(eq) per lb-CH4
= -846.216 lb-CO2(eq)/year
N2O Emissions = (0 – 46,000) scf/day x 365 days/year x 1200 Btu/scf x 0.0002 lb/MMBtu x 310 lb-CO2(eq) per lb-N2O
= -1,249.176 lb-CO2(eq)/year

Total = -23,550,099.72 + -846.216 + -1249.176 = -23,552,195.11 lb-CO2(eq)/year

Total = -23,552,195.11 lb-CO2(eq)/year ÷ 2,000 lb/ton = **-11,776 short tons-CO2(eq)/year**
Total = 11,776 short tons-CO2e/year x 0.9072 metric tons/short ton = **-10,683 metric tons-CO2(eq)/year**

S-2918-31-4

For crude oil, VOC is assumed to be 85% by weight of total organic carbon (TOC) (EPA, AP-42 Section 5.2, 2008). Also, assume 15% by weight of TOC is CH4 (methane) if site specific data is not available (2009 API Compendium of Greenhouse Gas Emissions for the Oil and Gas Industry, Appendix E, page E-6)

Annual Emissions

CH4 Emissions = (VOC Emissions ÷ 0.85) x 0.15

CH4 Emissions = [(7,573 – 14,105) ÷ 0.85 x 0.15] lb/year x 21 lb-CO2(eq) per lb-CH4
= -24,206.8 lb-CO2(eq)/year

Total = -24,206.8 lb-CO2(eq)/year ÷ 2,000 lb/ton = **-12.1 short tons-CO2(eq)/year**
Total = -12.1 short tons-CO2e/year x 0.9072 metric tons/short ton = **-10.9 metric tons-CO2(eq)/year**

S-2918-62-0

Annual Emissions

CO2 Emissions = 91,250,000 scf/year x 1200 Btu/scf x 116.89 lb/MMBtu
= 12,799,455 lb-CO2(eq)/year
CH4 Emissions = 91,250,000 scf/year x 1200 Btu/scf x 0.002 lb/MMBtu x 21 lb-CO2(eq) per lb-CH4
= 4,599 lb-CO2(eq)/year

N2O Emissions = 91,250,000 scf/year x 1200 Btu/scf x 0.0002 lb/MMBtu x 310 lb-CO2(eq) per lb-N2O
= 6,789 lb-CO2(eq)/year

Total = 12,799,455 + 4,599 + 6,789 = 12,810,843 lb-CO2(eq)/year

Total = 12,810,843 lb-CO2(eq)/year ÷ 2,000 lb/ton = **6,405.4 short tons-CO2(eq)/year**
Total = 6,405.4 short tons-CO2e/year x 0.9072 metric tons/short ton = **5,810 metric tons-CO2(eq)/year**

Total GHG Annual Emissions

Total = Permits S-2918-1-7 + '2-3 + '31-4 + '62-0
Total = (5,983 + -10,683 + -10.9 + 5,810) metric tons-CO2(eq)/year
Total = **1,099.1 metric tons-CO2(eq)/year**

This exceeds the District's threshold of 230 metric tons of CO_2 equivalent. To address the potential increase in GHG emissions, the applicant is proposing to comply with the best performance standard (BPS) developed by the District for VOC Control/Gas Disposal devices as the flare and combustion unit are the result of the GHG emission increase in this project.

Attachment G

Best Performance Standard

Best Performance Standard Project Analysis

Step 1 - Identify Best Performance Standard

Best Performance Standard that applies to this project has been established for Class and Category VOC Control/Gas Disposal and Oil and Gas Production, Processing, and Refining on August 2, 2011.

Class	**VOC Control/Gas Disposal**
Category	**Oil and Gas Production, Processing, and Refining**
Best Performance Standard (in order of recommendation)	1) –Incineration in existing engine, boiler, etc that crates useful work – provided that equipment is available and practically capable of incinerating vapors (see equipment specific BPS for standards and requirements for new fired equipment) and currently burning fossil fuel, or; –Transfer to Sales Gas Line – provided that access to sales gas line infrastructure is available; or, –Reinjection to Formation – provided that access to a disposal well is available.
	The following options supersede the BPS requirements above if: a) equipment listed above is not available; or, b) gas cannot safely be transferred to equipment listed above; or, c) used to control emergency gas releases. 2) –Incineration in new Thermal oxidizer – see equipment specific Thermal Oxidizer BPS for standards and requirements for new equipment; or, –Incineration in New Flare with >98% TOC destruction efficiency, steam assist, air assist when steam is not available, or Coanda effect and equipped with non-continuous automatic electronic or ballistic ignition; or, –Incineration in Existing Thermal Oxidizer or Flare

Step 2 - Select Best Performance Standard

The purpose of the flare and combustion device in this project is to incinerate produced gas when the sales gas line is not available. There are no incineration devices that produce useful work and no disposal wells in the area. Therefore, the options in item #1 above are not applicable.

The produced gas in this project will be incinerated in existing flare listed in permit S-2918-1 or in new combustion device listed in permit S-2918-62. The new combustion device will achieve >98% TOC destruction efficiency and will be air assisted as steam is not available at the site with a non-continuous automatic electronic ignition.

Therefore, the requirements of Best Performance Standard are satisfied in this project.

Step 3 – Best Performance Standard Conditions

The following condition will be listed on permit S-2918-3-6 to ensure compliance as the vapor control system conditions are listed on permit S-2918-3-6:

- Tank vapor control system shall be capable of collecting all VOC emissions and preventing their emissions to the atmosphere at an efficiency of at least 99% by weight. [District Rules 2201 and 4623 and Public Resources Code 21000-21177: California Environmental Quality Act]

The following condition will be listed on permit S-2918-62-0 to ensure compliance:

- Combustion device outlet shall be equipped with an automatic ignition system, or, shall operate with a pilot flame present at all times when combustible gases are vented through the combustion device, except during purge periods for automatic-ignition equipped combustion devices. [Public Resources Code 21000-21177: California Environmental Quality Act]

Attachment H

Draft Authority to Construct Permits

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-2918-1-7

ISSUANCE DATE: DRAFT

DRAFT

LEGAL OWNER OR OPERATOR: CRIMSON RESOURCE MANAGEMENT
MAILING ADDRESS: ATTN: ENVIR H & S ENGINEER
5001 CALIFORNIA AVE, SUITE #206
BAKERSFIELD, CA 93309

LOCATION: LIGHT OIL CENTRAL STATIONARY SOURCE
KERN COUNTY, CA

SECTION: 7 **TOWNSHIP:** 29S **RANGE:** 26E

EQUIPMENT DESCRIPTION:
MODIFICATION OF 32.5 MMBTU/HR NATIONAL AIR OIL BURNER CO. MODEL NAFV FLARE WITH AUTOMATIC SPARK IGNITED PILOT AND COMBUSTION AIR BLOWER (GREELEY LEASE): INCREASE FLARE FUEL USE LIMIT FROM 2,045,000 SCF/YEAR TO 96,000,000 SCF/YEAR

CONDITIONS

1. The permittee shall not emit more than one half of the major source threshold based on a rolling 12-month summary of actual emissions. [District Rule 2530]
2. The permittee shall maintain a record of the rolling 12-month summary of actual emissions from permitted operations. This record shall be kept on site and made available to the District upon request. [District Rule 2530]
3. The flare is approved to operate at the following locations; Sec. 14, T30S, R27E and Sec. 7, T29S, R26E. [District Rule 2201]
4. Flare shall be equipped with recording operational flow meter. [District Rule 2201]
5. Natural gas shall be used as pilot fuel. [District Rule 2201]
6. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]
7. Sulfur concentration of gas flared shall not exceed 5 ppmv. [District Rule 2201]
8. Air contaminant emissions shall not exceed any of the following limits: 0.068 lb-NOx/MMBtu; 0.0202 lb-PM10/MMBtu; 0.37 lb-CO/MMBtu; 0.063 lb-VOC/MMBtu. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director/APCO

DRAFT

DAVID WARNER, Director of Permit Services

Southern Regional Office • 34946 Flyover Court • Bakersfield, CA 93308 • (661) 392-5500 • Fax (661) 392-5585

9. Non breakdown operation shall not exceed any of the following limits: 1,200.0 MMBtu/day or 115,200 MMBtu/year. [District Rule 2201]

10. The permittee shall notify the District Compliance Division of each location at which the operation is located in excess of 24 hours. Such notification shall be made no later than 48 hours after starting operation at the location. [District Rule 1070]

11. Except for flares equipped with a flow-sensing ignition system, a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device, capable of continuously detecting the presence of at least one pilot flame or the flare flame, shall be installed and operated. [District Rule 4311]

12. A flame shall be present at all times when combustible gases are vented through the flare. [District Rule 4311]

13. Flare outlet shall be equipped with an automatic ignition system, or, shall operate with a pilot flame present at all times when combustible gases are vented through the flare, except during purge periods for automatic-ignition equipped flares. [District Rule 4311]

14. Flare shall be equipped with a heat sensing device such as a thermocouple, ultraviolet beam sensor, infrared sensor, or an equivalent device capable of continuously detecting at least one pilot flame or the flare flame is present. The flame detection device shall be kept operational at all times except during flare maintenance when the flare is isolated from gas flow. During essential planned power outages when the flare is operating, the pilot monitor is allowed to be non-functional if the flare flame is clearly visible to onsite operators. All pilot monitor downtime shall be reported annually pursuant to Rule 4311, Section 6.2.3.6. [District Rule 4311]

15. If the flare uses a flow-sensing automatic ignition system and does not use a continuous flame pilot, the flare shall use purge gas for purging. [District Rule 4311]

16. Open flares in which the flare gas pressure is less than 5 psig shall be operated in such a manner that meets the provisions of 40 CFR 60.18. [District Rule 4311]

17. Flaring is prohibited unless it is consistent with an approved flare minimization plan (FMP), pursuant to Section 6.5, and all commitments listed in that plan have been met. This standard does not apply if the APCO determines that the flaring is caused by an emergency as defined by Section 3.7 and is necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere. [District Rule 4311]

18. The operator shall monitor and record the vent gas flow to the flare with a flow measuring device or other parameters as specified in the Permit to Operate. [District Rule 4311]

19. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. [40 CFR 60.18(c)(1)]

20. Demonstration of compliance with the visible emissions limit of this permit shall be conducted at least annually, using EPA Method 22. The observation period shall be 2 hours. [40 CFR 60.18(f)(1)]

21. The operator shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rule 1070]

22. The flare shall be operated according to the manufacturer's specifications, a copy of which shall be maintained on site. [District Rule 1070]

23. Actual flare emissions shall not exceed 20 tons VOC/year. Process information, including fuel usage data for the flare and process rates for operations controlled by the flare, shall be submitted to the District annually to demonstrate compliance with this requirement. [District Rule 2201]

24. Flares shall only be used with the net heating value of the gas being combusted being 300 Btu/scf or greater if the flare is air-assisted or steam-assisted. [40 CFR 60.18 (c)(3)]

25. The net heating value of the gas being combusted in a flare shall be calculated annually, pursuant to 40 CFR 60.18(f)(3) and using EPA Method 18, ASTM D1946, and ASTM D2382. [40 CFR 60.18 (f)(3-6)]

26. Air-assisted flares shall be operated with an exit velocity less than Vmax, as determined by the equation specified in paragraph 40 CFR 60.18 (f)(6). [40 CFR 60.18 (c)(5)]

CONDITIONS CONTINUE ON NEXT PAGE

27. The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip. [40 CFR 60.18 (f)(4)]

28. Flares shall be operated with a flame present at all times, and kept in operation when emissions may be vented to them. 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. [40 CFR 60.18 (c)(2), 60.18 (e), and 60.18 (f)(2)]

29. The operator of flares that are subject to Section 5.6 shall make available, to the APCO, the compliance determination records that demonstrate compliance with the provisions of 40 CFR 60.18, (c)(3) through (c)(5). [District Rule 4311]

30. To show compliance with sulfur emission limits, the gas being flared shall be tested weekly for sulfur content. If compliance with the fuel sulfur content limit and sulfur emission limits has been demonstrated for 8 consecutive weeks for the flared gas, then the compliance testing frequency shall be semi-annually. If the semi-annual sulfur content test fails to show compliance, weekly testing shall resume. [District Rule 2201]

31. The sulfur content of the gas being flared shall be determined using ASTM D 1072, D 3031, D 4084, D 3246 or grab sample analysis by GC-FPD/TCD performed in the laboratory. [District Rule 2201]

32. Permittee shall maintain accurate records of quantity of non-emergency/non-pilot gas combusted in the flare and shall make such records available to District staff upon request. [District Rule 1070]

33. Permittee shall maintain records of the following when the flare is used during an emergency: duration of flare operation, amount of gas burned, and the nature of the emergency situation. [District Rule 4311]

34. Permittee shall maintain the following records: a copy of the approved flare minimization plan pursuant to Section 6.5; a copy of annual reports submitted to the APCO pursuant to Section 6.2. [District Rule 4311]

35. The operator of a flare subject to flare minimization plans pursuant to Section 5.8 of this rule shall notify the APCO of an unplanned flaring event within 24 hours after the start of the next business day or within 24 hours of their discovery, which ever occurs first. The notification shall include the flare source identification, the start date and time, and the end date and time. [District Rule 4311]

36. The operator of a flare subject to flare minimization plans pursuant to Section 5.8 shall submit an annual report to the APCO that summarizes all Reportable Flaring Events as defined in Section 3.0 that occurred during the previous 12 month period. The report shall be submitted within 30 days following the end of the twelve month period of the previous year. The report shall include, but is not limited to all of the following: the results of an investigation to determine the primary cause and contributing factors of the flaring event; any prevention measures considered or implemented to prevent recurrence together with a justification for rejecting any measures that were considered but not implemented; if appropriate, an explanation of why the flaring was an emergency and necessary to prevent accident, hazard or release of vent gas to the atmosphere, or where, due to a regulatory mandate to vent a flare, it cannot be recovered, treated and used as a fuel gas at the facility; and the date, time, and duration of the flaring event. [District Rule 4311]

37. The operator of a flare subject to flare monitoring requirements pursuant to Section 5.10 shall submit an annual report to the APCO within 30 days following the end of each 12 month period. The report shall include the following: the total volumetric flow of vent gas in standard cubic feet for each day; if the flow monitor used pursuant to Section 5.10 measures molecular weight, the average molecular weight for each hour of each month; a flow verification report which shall include flow verification testing pursuant to Section 6.3.5. [District Rule 4311]

38. For purposes of the flow verification report required by Section 6.2.3.8, vent gas flow shall be determined using one or more of the following methods, or by any alternative method approved by the APCO, ARB, and EPA: EPA Methods 1 and 2; a verification method recommended by the manufacturer of the flow monitoring equipment installed pursuant to Section 5.10; tracer gas dilution or velocity; other flow monitors or process monitors that can provide comparison data on a vent stream that is being directed past the ultrasonic flow meter. [District Rule 4311]

39. Every five years after the initial FMP submittal, the operator shall submit an updated FMP for each flare to the APCO for approval. The current FMP shall remain in effect until the updated FMP is approved by the APCO. If the operator fails to submit an updated FMP as required by this section, the existing FMP shall no longer be considered an approved plan. [District Rule 4311]

CONDITIONS CONTINUE ON NEXT PAGE

40. An updated FMP shall be submitted by the operator pursuant to Section 6.5 addressing new or modified equipment, prior to installing the equipment. Updated FMP submittals are only required if: (1) The equipment change would require an authority to construct (ATC) and would impact the emissions from the flare, and (2) The ATC is deemed complete after June 18, 2009, and (3) The modification is not solely the removal or decommissioning of equipment that is listed in the FMP, and has no associated increase in flare emissions. [District Rule 4311]

41. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rules 1070 and 4311]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

DRAFT

PERMIT NO: S-2918-3-6 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: CRIMSON RESOURCE MANAGEMENT
MAILING ADDRESS: ATTN: ENVIR H & S ENGINEER
5001 CALIFORNIA AVE, SUITE #206
BAKERSFIELD, CA 93309

LOCATION: LIGHT OIL CENTRAL STATIONARY SOURCE
KERN COUNTY, CA

SECTION: 14&15 **TOWNSHIP:** 30S **RANGE:** 27E

EQUIPMENT DESCRIPTION:
MODIFICATION OF 42,000 GALLON PETROLEUM STORAGE TANK (T-1001), SERVED BY VAPOR CONTROL SYSTEM SHARED BETWEEN S-2918-3, -4, -5, -15, & -16 (PANAMA LEASE): ALLOW COMBUSTION DEVICE LISTED IN PERMIT UNIT S-2918-62 TO BE AN AUTHORIZED VAPOR CONTROL SYSTEM INCINERATION DEVICE

CONDITIONS

1. The permittee shall not emit more than one half of the major source threshold based on a rolling 12-month summary of actual emissions. [District Rule 2530]
2. The permittee shall maintain a record of the rolling 12-month summary of actual emissions from permitted operations. This record shall be kept on site and made available to the District upon request. [District Rule 2530]
3. VOC vapors shall be incinerated in any of the following units: a permit exempt 1.5 MMBTU/hr heater treater or combustion device listed in permit S-2918-62. [District Rules 2201 and 4623]
4. True vapor pressure of liquids stored shall not exceed 6 psia. [District Rules 2201 and 4623]
5. Tank vapor control system shall be capable of collecting all VOC emissions and preventing their emissions to the atmosphere at an efficiency of at least 99% by weight. [District Rules 2201 and 4623 and Public Resources Code 21000-21177: California Environmental Quality Act]
6. The permittee shall keep accurate records of True vapor pressure, Reid vapor pressure, storage temperature, and types of liquids stored in each container. [District Rules 2201 and 4623]
7. VOC emissions (including fugitive emissions) from this permit unit shall not exceed 0.5 lb/day. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DRAFT

DAVID WARNER, Director of Permit Services
S-2918-3-6 : Nov 14 2012 3:39PM – TOMS : Joint Inspection NOT Required

8. A leak-free condition is defined as a condition without a gas leak. A gas leak is defined as a reading in excess of 10,000 ppmv, above background, as measured by a portable hydrocarbon detection instrument in accordance with the procedures specified in EPA Test Method 21. A reading in excess of 10,000 ppmv above background is a violation of this permit and Rule 4623 and shall be reported as a deviation. [District Rule 4623]

9. All piping, valves, and fittings shall be constructed and maintained in leak-free condition. [District Rule 4623]

10. Any tank gauging or sampling device on a tank vented to the vapor recovery system shall be equipped with a leak-free cover which shall be closed at all times except during gauging or sampling. [District Rule 4623]

11. All piping, fittings, and valves on this tank shall be inspected annually by the facility operator in accordance with EPA Method 21, with the instrument calibrated with methane, to ensure compliance with the leaking provisions of this permit. [District Rule 4623, 5.7 (Table 3)]

12. If any of the tank components are found to be leaking, operator shall immediately affix a tag and maintain records of gas leak detection readings, date/time leak was discovered, and date/time the component was repaired to a leak-free condition. [District Rule 4623, 5.7 (Table 3)]

13. Upon detection of any leaking components (having a gas leak >10,000 ppmv, measured in accordance with EPA Method 21 by a portable hydrocarbon detection instrument that is calibrated with methane) operator shall: (a) Eliminate or minimize the leak within 8 hours after detection. (b) If the leak can not be eliminated, then minimize the leak to the lowest possible level within 8 hours after detection by using best maintenance practices; and eliminate the leak within 48 hours after detection. (c) In no event that the total time to minimize and eliminate the leak shall exceed 56 hours after detection. [District Rule 4623, 5.7 (Table 3)]

14. Leaking tank components affixed to the tank or within five feet of the tank that have been discovered by the operator and that have been immediately tagged and repaired within the specified deadlines, shall not constitute a violation of the District Rule 4623. However, leaking components discovered during inspections by District staff that were not previously identified and/or tagged by the operator, and/or any leaks that were not repaired within specified deadlines, shall constitute a violation of the District Rule 4623. [District Rule 4623, 5.7 (Table 3)]

15. If a component type for a given tank is found to leak during an annual inspection, then conduct quarterly inspections of that component type on the tank or tank system for four consecutive quarters. If a component type is found to have no leak after four consecutive quarterly inspections, then revert to annual inspections. [District Rule 4623, 5.7 (Table 3)]

16. Any component found to be leaking on two consecutive annual inspections is in violation of the District Rule 4623, even if it is under the voluntary inspection and maintenance program. [District Rule 4623, 5.7 (Table 3)]

17. Operator shall maintain an inspection log containing the following 1) Type of component leaking; 2) Date and time of leak detection, and method of detection; 3) Date and time of leak repair, and emission level of recheck after leak is repaired; 4) Method used to minimize the leak to lowest possible level within 8 hours after detection. [District Rule 4623]

18. Permittee shall conduct true vapor pressure (TVP) testing of the organic liquid stored in this tank at least once every 24 months during summer (July - September), and/or whenever there is a change in the source or type of organic liquid stored in this tank in order to maintain exemption from the rule. [District Rule 4623]

19. True vapor pressure shall be measured using Reid vapor pressure ASTM Method D323-82 modified by maintaining the hot water bath at storage temperature. Where storage temperature is above 100 degrees F true vapor pressure shall be determined by Reid vapor pressure at 100 degrees F and ARB approved calculations. [District Rule 4623]

20. True vapor pressure of crude oil with an API (American Petroleum Institute) gravity less than 30 deg, as determined by API 2547, may be determined by Headspace Gas Chromatography using the procedures from ARB Evaluation of a Method for Determining Vapor Pressures of Petroleum Mixtures by Headspace Gas Chromatography, October 1990. [District Rule 4623]

21. Control efficiency shall be determined by a comparison of controlled emissions to those emissions which would occur from a fixed or cone roof tank in the same product service without a vapor recovery system. Emissions shall be determined based on tank emission factors in EPA Publication AP-42, component counts for fugitive emissions sources, recognized emission factors for fugitive emission sources and the efficiency of any VOC destruction device. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

22. The efficiency of any VOC destruction device shall be measured by EPA Method 25, 25a, or 25b. [District Rule 4623]
23. The operator shall ensure that the vapor recovery system is functional and is operating as designed at all times. [District Rule 2201]
24. All records required to be maintained by this permit shall be maintained for a period of at least five years and shall be made readily available for District inspection upon request. [District Rules 1070 and 4623]
25. The operator shall determine the true vapor pressure of the petroleum liquid stored in the tank at least once per year in accordance with methods described in 40 CFR 60.113 and section 6.2 of District Rule 4623 (amended 12/17/92). Determinations shall be made annually during the summer and whenever there is a change in the source or type of petroleum entering the tank. [District Rule 4623]
26. As used in this permit, the term "source or type of petroleum" shall mean petroleum liquids with similar characteristics. The operator shall maintain records of the API gravity of petroleum liquids stored in this unit to determine which oils are from a common source. [District Rule 4623]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

DRAFT

PERMIT NO: S-2918-31-4 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: CRIMSON RESOURCE MANAGEMENT
MAILING ADDRESS: ATTN: ENVIR H & S ENGINEER
5001 CALIFORNIA AVE, SUITE #206
BAKERSFIELD, CA 93309

LOCATION: LIGHT OIL CENTRAL STATIONARY SOURCE
KERN COUNTY, CA

SECTION: NE10 **TOWNSHIP:** 30S **RANGE:** 26E

EQUIPMENT DESCRIPTION:
MODIFICATION OF 21,000 GALLON FIXED ROOF PETROLEUM STORAGE TANK WITH PRESSURE VACUUM RELIEF HATCH - #20016 (KERN COUNTY LEASE 61): LOWER RVP LIMIT FROM 9.5 PSIA TO 6.86 PSIA

CONDITIONS

1. The permittee shall not emit more than one half of the major source threshold based on a rolling 12-month summary of actual emissions. [District Rule 2530]
2. The permittee shall maintain a record of the rolling 12-month summary of actual emissions from permitted operations. This record shall be kept on site and made available to the District upon request. [District Rule 2530]
3. This tank shall be equipped with a pressure-vacuum (PV) relief valve set to within 10% of the maximum allowable working pressure of the tank, permanently labeled with the operating pressure settings, properly maintained in good operating order in accordance with the manufacturer's instructions, and shall remain in leak-free condition except when the operating pressure exceeds the valve's set pressure. [District Rules 2201 and 4623]
4. This tank shall only store, place, or hold organic liquid with a Reid vapor pressure (RVP) of less than 6.86 psia. [District Rules 2201 and 4623]
5. Crude Oil throughput shall be less than 150 barrels per day. [District Rules 2201 and 4623]
6. This tank shall be in a leak-free condition. A leak-free condition is defined as a condition without a gas leak. A gas leak is defined as a reading in excess of 10,000 ppmv, above background, as measured by a portable hydrocarbon detection instrument in accordance with the procedures specified in EPA Test Method 21. A reading in excess of 10,000 ppmv above background is a violation of this permit and Rule 4623. [District Rule 4623]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director APCO

DRAFT

DAVID WARNER, Director of Permit Services
S-2918-31-4 : Nov 14 2012 1:30PM -- TOMS : Joint Inspection NOT Required

7. All piping, valves, and fittings shall be constructed and maintained in leak-free condition. [District Rule 4623]
8. A leak-free condition is defined as a condition without a gas leak. A gas leak is defined as a reading in excess of 10,000 ppmv, above background, as measured by a portable hydrocarbon detection instrument in accordance with the procedures specified in EPA Test Method 21. A reading in excess of 10,000 ppmv above background is a violation of this permit and Rule 4623 and shall be reported as a deviation. [District Rule 4623]
9. Permittee shall maintain monthly records of average daily throughput and shall submit such information to the APCO 30 days prior to annual permit renewal. [District Rules 2201 and 4623]
10. Operator shall keep a record of liquids stored in each container, storage temperature, and the Reid vapor pressure of such liquids. [District Rule 4623]
11. Permittee shall conduct true vapor pressure (TVP) testing of the organic liquid stored in this tank at least once every 24 months during summer (July - September), and/or whenever there is a change in the source or type of organic liquid stored in this tank. [District Rule 2201]
12. True vapor pressure shall be measured using Reid vapor pressure ASTM Method D323-82 modified by maintaining the hot water bath at storage temperature. Where storage temperature is above 100 degrees F true vapor pressure shall be determined by Reid vapor pressure at 100 degrees F and ARB approved calculations. [District Rule 2201]
13. True vapor pressure of crude oil with an API (American Petroleum Institute) gravity less than 30 deg, as determined by API 2547, may be determined by Headspace Gas Chromatography using the procedures from ARB Evaluation of a Method for Determining Vapor Pressures of Petroleum Mixtures by Headspace Gas Chromatography, October 1990. [District Rule 2201]
14. The API gravity of crude oil or petroleum distillate shall be determined by using ASTM Method D 287 e1 "Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method). Sampling for API gravity shall be performed in accordance with ASTM Method D 4057 "Standard Practices for Manual Sampling of Petroleum and Petroleum Products. [District Rule 2201]
15. Permittee shall maintain monthly records of average daily crude oil throughput and shall keep accurate records of each organic liquid stored in the tank, including its storage temperature, TVP, and API gravity. [District Rule 2201]
16. All records required to be maintained by this permit shall be maintained for a period of at least five years and shall be made readily available for District inspection upon request. [District Rule 1070 and 4623]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

DRAFT

PERMIT NO: S-2918-62-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: CRIMSON RESOURCE MANAGEMENT
MAILING ADDRESS: ATTN: ENVIR H & S ENGINEER
5001 CALIFORNIA AVE, SUITE #206
BAKERSFIELD, CA 93309

LOCATION: LIGHT OIL CENTRAL STATIONARY SOURCE
KERN COUNTY, CA

SECTION: 14 **TOWNSHIP:** 30S **RANGE:** 27E

EQUIPMENT DESCRIPTION:
12 MMBTU/HR BEKAERT MODEL CEB 350 PRODUCED GAS-FIRED AIR ASSISTED COMBUSTION DEVICE

CONDITIONS

1. The permittee shall not emit more than one half of the major source threshold based on a rolling 12-month summary of actual emissions. [District Rule 2530]
2. The permittee shall maintain a record of the rolling 12-month summary of actual emissions from permitted operations. This record shall be kept on site and made available to the District upon request. [District Rule 2530]
3. Within 90 days of startup of the equipment authorized by this Authority to Construct, Permit to Operate S-2918-2-3 shall be surrendered to the District and the associated equipment shall be removed or rendered inoperable. [District Rule 2201]
4. {1407} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
5. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
6. Flares shall be designed for and operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. [40 CFR 60.18(c)(1)]
7. Demonstration of compliance with the visible emissions limit of this permit shall be conducted at least annually, using EPA Method 22. The observation period shall be 2 hours. [40 CFR 60.18(f)(1)]
8. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DRAFT

DAVID WARNER, Director of Permit Services
S-2918-62-0 : Nov 14 2012 1:30PM – TOMS : Joint Inspection NOT Required

9. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

10. Combustion device outlet shall be equipped with an automatic ignition system, or, shall operate with a pilot flame present at all times when combustible gases are vented through the combustion device, except during purge periods for automatic-ignition equipped combustion devices. [Public Resources Code 21000-21177: California Environmental Quality Act]

11. The combustion device heat input shall not exceed any of the following limits: 300 MMBtu/day or 109,500 MMBtu/year. [District Rule 2201]

12. The unit shall be equipped with an operational, non-resettable, totalizing mass or volumetric fuel flow meter or other District-approved alternative method to measure the amount of gas combusted in the unit. [District Rule 2201]

13. The sulfur content of the gas being incinerated by the combustion device shall not exceed 5 ppmv (as H2S). [District Rule 2201]

14. Emissions from the unit shall not exceed any of the following limits: 0.018 lb-NOx/MMBtu; 0.0202 lb-PM10/MMBtu; 0.01 lb-CO/MMBtu; or 0.008 lb-VOC/MMBtu. [District Rule 2201]

15. Source testing to measure NOx, CO and VOC emissions from the produced gas-fired flare shall be conducted within 60 days of initial start-up. [District Rule 2201]

16. To show compliance with sulfur emission limits, the gas being combusted shall be tested weekly for sulfur content. If compliance with the fuel sulfur content limit and sulfur emission limits has been demonstrated for 8 consecutive weeks for the combusted gas, then the compliance testing frequency shall be semi-annually. If the semi-annual sulfur content test fails to show compliance, weekly testing shall resume. [District Rule 2201]

17. The sulfur content of the gas being combusted shall be determined using ASTM D 1072, D 3031, D 4084, D 3246 or grab sample analysis by GC-FPD/TCD performed in the laboratory. [District Rule 2201]

18. For source test purposes, NOx emissions from the unit shall be determined using EPA Method 19 on a heat input basis, or EPA Method 3A, EPA Method 7E, or ARB Method 100 on a ppmv basis. [District Rule 2201]

19. For source test purposes, CO emissions from the unit shall be determined using EPA Method 10 or 10B, ARB Methods 1 through 5 with 10, or ARB Method 100. [District Rule 2201]

20. For source test purposes, VOC emissions from the unit shall be determined using EPA Method 25 or 25a. [District Rule 2201]

21. Stack gas oxygen (O2) shall be determined using EPA Method 3A, EPA Method 7E, or ARB Method 100. [District Rule 2201]

22. Operator shall determine produced gas fuel higher heating value annually by ASTM D 1826 or D 1945 in conjunction with ASTM D 3588 for gaseous fuels. [District Rule 2201]

23. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

24. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rule 1081]

25. The results of each source test shall be submitted to the District within 60 days of completion of the source test. [District Rule 1081]

26. Permittee shall maintain daily and annual records of quantity of produced gas combusted in the unit and annual test results of higher heating value of produced gas. [District Rules 1070 and 2201]

27. All records shall be maintained and retained on-site for a period of at least 5 years and shall be made available for District inspection upon request. [District Rule 1070]