DEC 14 2017

Christopher Sherman
Shell Pipeline Company LP
1801 Petrol Rd
Bakersfield, CA 93308

RE: Notice of Final Action - Authority to Construct
Facility Number: C-1235
Project Number: C-1163184

Dear Mr. Sherman:

The Air Pollution Control Officer has issued the Authority to Construct permit to Shell Pipeline Company LP for removal of the 30 billion Btu/yr annual heat input limit from a 20 MMBtu/hr natural gas-fired process heater (Oil Heater #1) at the Panoche Pump Station, at Section 18, Township 14S, Range 12E, Fresno County, CA. Enclosed are the Authority to Construct permit and a copy of the notice of final action to be published approximately three days from the date of this letter.

Notice of the District's preliminary decision to issue the Authority to Construct permit was published on June 9, 2017. The District's analysis of the proposal was also sent to CARB on June 6, 2017. All comments received following the District's preliminary decision on this project were considered.

Comments received by the District during the public notice period resulted in the reduction of the required NOx emission limit from 9 ppmv @ 3% O2 to 7 ppmv @ 3% O2. These changes were minor and did not trigger additional public notification requirements.

Also enclosed is an invoice for the engineering evaluation fees pursuant to District Rule 3010. Please remit the amount owed, along with a copy of the attached invoice, within 60 days.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Errol Villegas at (559) 230-6000.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:rn

Enclosures

cc: Tung Le, CARB (w/enclosure) via email
cc: Elliot Ripley, ALG (w/enclosure) via email: eripley@algcorp.com

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

Facility # C-1235
SHELL PIPELINE COMPANY LP
1801 PETROL RD
BAKERSFIELD, CA 93308

AUTHORITY TO CONSTRUCT (ATC)

QUICK START GUIDE

1. **Pay Invoice**: Please pay enclosed invoice before due date.
2. **Fully Understand ATC**: Make sure you understand ALL conditions in the ATC prior to construction, modification and/or operation.
3. **Follow ATC**: You must construct, modify and/or operate your equipment as specified on the ATC. Any unspecified changes may require a new ATC.
4. **Notify District**: You must notify the District's Compliance Department, at the telephone numbers below, upon start-up and/or operation under the ATC. Please record the date construction or modification commenced and the date the equipment began operation under the ATC. You may NOT operate your equipment until you have notified the District's Compliance Department. A startup inspection may be required prior to receiving your Permit to Operate.
5. **Source Test**: Schedule and perform any required source testing. See http://www.valleyair.org/busind/comply/source_testing.htm for source testing resources.
6. **Maintain Records**: Maintain all records required by ATC. Records are reviewed during every inspection (or upon request) and must be retained for at least 5 years. Sample record keeping forms can be found at http://www.valleyair.org/busind/comply/compliance_forms.htm.

By operating in compliance, you are doing your part to improve air quality for all Valley residents.

For assistance, please contact District Compliance staff at any of the telephone numbers listed below.

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

AUTHORITY TO CONSTRUCT

PERMIT NO: C-1235-1-12 **ISSUANCE DATE:** 12/12/2017

LEGAL OWNER OR OPERATOR: SHELL PIPELINE COMPANY LP
MAILING ADDRESS: 1801 PETROL RD
BAKERSFIELD, CA 93308

LOCATION: PANOCHE PUMP STATION
PANOCHE & I-5
FRESNO COUNTY, CA 93210

SECTION: 18 **TOWNSHIP:** 14S **RANGE:** 12E

EQUIPMENT DESCRIPTION:
MODIFICATION OF 20 MMBTU/HR NATIONAL NATURAL GAS-FIRED OIL HEATER #1 WITH A NORTH AMERICAN MAGNA FLAME LE MODEL 4211-33/X8515, S/N: SD670366-01, ULTRA LOW NOX BURNER WITH INDUCED FLUE GAS RECIRCULATION: REMOVE 30 BILLION BTU/YR ANNUAL HEAT INPUT LIMIT AND REDUCE THE NOX EMISSION LIMIT TO 7 PPMVD NOX @ 3% O2 (0.0085 LB-NOX/MMBTU)

CONDITIONS

1. 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]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. 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]
4. 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. [District Rule 4101]
5. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
6. This unit shall only be fired on PUC or FERC regulated natural gas. [District Rules 2201 and 4320]
7. Permittee shall demonstrate that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081, 2201, and 4320]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 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

for

Arnaud Marjollet, Director of Permit Services
C-1235-1-12 Dec 12 2017 2:29PM -- NORMANR : Joint Inspection NOT Required

8. Emissions from the natural gas-fired heater shall not exceed any of the following limits: 0.00285 lb-SOx/MMBtu, 0.003 lb-PM10/MMBtu, 400 ppmvd CO @ 3% O2 or 0.2956 lb-CO/MMBtu, or 0.0056 lb-VOC/MMBtu. [District Rules 2201 and 4320]

9. Except during start-up and shutdown periods emissions from the natural gas-fired heater shall not exceed 7 ppmvd NOx @ 3% O2 or 0.0085 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

10. During start-up and shutdown periods emissions from the natural gas-fired heater shall not exceed 0.1 lb-NOx/MMBtu. [District Rule 2201]

11. Emissions from the natural gas-fired heater, including start-up and shutdown, shall not exceed 11.4 lb-NOx/day. [District Rule 2201]

12. Duration of start-up or shutdown shall not exceed two hours each per occurrence. During start-up or shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. The operator shall maintain daily records of the number and duration of start-up and shutdown periods. [District Rules 2201, 4305, 4306, and 4320]

13. Start-up is defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. Shutdown is defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 4305, 4306, and 4320]

14. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4320]

15. If either the NOx or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]

16. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

17. The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306, and 4320]

18. 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]

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

CONDITIONS CONTINUE ON NEXT PAGE

20. Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]
21. NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305, 4306, and 4320]
22. CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305, 4306, and 4320]
23. Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306, and 4320]
24. The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]
25. All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4320. [District Rules 4305, 4306, and 4320]
26. 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 Rules 4305, 4306, and 4320]
27. On a monthly basis, the permittee shall calculate and record the VOC emissions in pounds from this unit for the prior calendar month. [District Rule 2201]
28. On a monthly basis, the permittee shall calculate and record the facility-wide VOC emissions in pounds for the prior 12 calendar month period. The facility-wide VOC emissions shall be calculated by summing the VOC emissions from the previous 12 calendar months from every permitted unit at this facility. [District Rule 2201]
29. 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, 4305, 4306, and 4320]

San Joaquin Valley Air Pollution Control District

Authority to Construct Application Review

Remove Annual Fuel Use Limit for 20 MMBtu/hr Natural Gas-Fired Process Heater

Facility Name:	Shell Pipeline Company LP	Date:	November 21, 2017
Mailing Address:	1801 Petrol Rd	Engineer:	Ramon Norman
	Bakersfield, CA 93308	Lead Engineer:	Jerry Sandhu
Contact Person:	Christopher Sherman – Environmental Advisor		
Telephone:	(661) 391-2413	E-Mail:	Christopher.Sherman@shell.com
2nd Contact Person:	Elliot Ripley – Consultant, Ashworth Leininger Group		
Telephone:	(805) 764-6004	E-Mail:	eripley@algcorp.com
Application #:	C-1235-1-12		
Project #:	C-1163184		
Deemed Complete:	February 8, 2017		

I. Proposal

Shell Pipeline Company LP operates a crude oil pipeline station near Panoche, CA. Shell Pipeline Company LP uses a 20 MMBtu/hr natural gas-fired process heater (Oil Heater #1; Permit Unit C-1235-1) to heat the crude oil to reduce its viscosity to transport it via pipeline. Shell Pipeline Company LP has requested an Authority to Construct (ATC) permit to remove the 30 billion Btu/yr annual heat input limit from Permit C-1235-1-9 (See Appendix A for Current Permit to Operate (PTO) C-1235-1-9).

After initial public noticing of the proposed project in June 2017, comments were received from the California Air Resources Board (ARB) regarding the Best Available Control Technology (BACT) determination for the project. As a result of the comments received, the District revised the original BACT determination for modification to the 20 MMBtu/hr natural gas-fired process heater, which reduced the required NO_X emission limit for the unit from 9 ppmvd NO_X @ 3% O_2 (0.011 lb-NO_X/MMBtu) to 7 ppmvd NO_X @ 3% O_2 (0.0085 lb-NO_X/MMBtu). The facility has agreed to comply with this limit to satisfy the BACT requirements for the project.

II. Applicable Rules

Rule 2201	New and Modified Stationary Source Review Rule (2/18/16)
Rule 2410	Prevention of Significant Deterioration (6/16/11)
Rule 2520	Federally Mandated Operating Permits (6/21/01)
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 4304	Equipment Tuning Procedure for Boilers, Steam Generators, and Process Heaters (10/19/95)
Rule 4305	Boilers, Steam Generators and Process Heaters – Phase 2 (8/21/03)
Rule 4306	Boilers, Steam Generators and Process Heaters – Phase 3 (3/17/05)
Rule 4320	Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr (10/16/08)
Rule 4351	Boilers, Steam Generators and Process Heaters – Phase 1 (8/21/03)
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

III. Project Location

This equipment is located at the Panoche Pump Station at Section 18, Township 14S, Range 12E in Fresno County. 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.

IV. Process Description

Shell Pipeline Company operates a crude oil pipeline station near Panoche, CA. Shell Pipeline Company uses the 20 MMBtu/hr natural gas-fired process heater (Oil Heater #1; Permit Unit C-1235-1) to heat the crude oil to reduce its viscosity to transport it via pipeline.

Permit Unit C-1235-1 is permitted to operate 24 hrs/day and 8,760 hours/year. However, the current permit (C-1235-1-9) includes a condition limiting the maximum annual heat input of the unit to no more than 30 billion Btu per calendar year. Under this project, the facility has requested to remove the 30 billion Btu/yr annual heat input limit, which will increase the maximum annual heat input for the unit to 175.2 billion Btu/yr.

V. Equipment Listing

Pre-Project Equipment Description:

C-1235-1-9: 20 MMBTU/HR NATIONAL OIL HEATER #1 NORTH AMERICAN MAGNA FLAME LE, MODEL: 4211-33/X8515, S/N: SD670366-01, ULTRA LOW NOX BURNER WITH INDUCED FLUE GAS RECIRCULATION

Proposed Modification:

Remove the 30 billion Btu/yr annual heat input limit and reduce the required NO_x emission limit for the unit from 9 ppmvd NO_x @ 3% O_2 (0.011 lb-NO_x/MMBtu) to 7 ppmvd NO_x @ 3% O_2 (0.0085 lb-NO_x/MMBtu) except during startups and shutdowns

C-1235-1-12: MODIFICATION OF 20 MMBTU/HR NATIONAL NATURAL GAS-FIRED OIL HEATER #1 WITH A NORTH AMERICAN MAGNA FLAME LE MODEL 4211-33/X8515, S/N: SD670366-01, ULTRA LOW NOX BURNER WITH INDUCED FLUE GAS RECIRCULATION: REMOVE 30 BILLION BTU/YR ANNUAL HEAT INPUT LIMIT AND REDUCE THE NOX EMISSION LIMIT TO 7 PPMVD NOX @ 3% O2 (0.0085 LB-NOX/MMBTU)

Post Project Equipment Description:

C-1235-1-12: 20 MMBTU/HR NATIONAL NATURAL GAS-FIRED OIL HEATER #1 WITH A NORTH AMERICAN MAGNA FLAME LE MODEL 4211-33/X8515, S/N: SD670366-01, ULTRA LOW NOX BURNER WITH INDUCED FLUE GAS RECIRCULATION

VI. Emission Control Technology Evaluation

Emissions from the natural gas-fired process heater include NO_X, CO, VOC, PM_{10}, and SO_X.

NO_X is the major pollutant of concern when burning natural gas. NO_X formation is either due to thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_X) or due to conversion of chemically bound nitrogen in the fuel (fuel NO_X). Due to the low fuel nitrogen content of natural gas, nearly all NO_X emissions are thermal NO_X. Formation of thermal NO_X is affected by four furnace zone factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature.

The unit is equipped with an ultra-low NO_X burner and induced flue gas re-circulation (FGR) and will only be authorized to use PUC or FERC regulated natural gas as fuel.

Ultra-low NO_X burners reduce NO_X formation by producing lower flame temperatures (and longer flames) than conventional burners. Conventional burners thoroughly mix all the fuel and air in a single stage just prior to combustion, whereas low-NO_X burners delay the mixing of fuel and air by introducing the fuel (or sometimes the air) in multiple stages. Generally, in the first combustion stage, the air-fuel mixture is fuel rich. In a fuel rich environment, all the oxygen will be consumed in reactions with the fuel, leaving no excess oxygen available to react with nitrogen to produce thermal NO_X. In the secondary and tertiary stages, the combustion zone is maintained in a fuel-lean environment. The excess air in these stages helps to reduce the flame temperature so that the reaction between the excess oxygen with nitrogen is minimized.

The use of flue gas re-circulation (FGR) reduces nitrogen oxides (NO_X) emissions by recirculating a percentage of the exhaust gas back into the inlet air. As the exhaust gas is composed mainly of nitrogen and the products of combustion, it is much lower in oxygen than the inlet air and contains virtually no combustible hydrocarbons to burn. Thus, the exhaust gas is practically inert. The addition of an inert mass of gas to the combustion reaction serves to absorb heat without producing heat, thereby lowering the flame temperature. Since thermal NO_X is formed by high flame temperatures, the lower flame temperatures produced by FGR serve to reduce thermal NO_X.

The use of PUC or FERC regulated natural gas reduces PM and SO_X emissions from the unit.

VII. General Calculations

A. Assumptions

- The maximum daily operating schedule of the process heater is 24 hours per day
- The unit will only be fired on PUC or FERC regulated natural gas (per applicant)
- Natural Gas Higher Heating Value (HHV): 1,000 Btu/scf (District Policy APR 1720, EPA AP-42 Section 1.4)
- Permit Unit C-1235-1 is allowed a higher NO_X emission limit during startups and shutdowns of 0.1 lb-NO_X/MMBtu.
- The current permit does not limit the number of hours for startups and shutdowns. However, the current permit limits total daily NO_X emissions, including emissions from startups and shutdowns, to 12.4 lb-NO_X/day. This limit was added to the permit under Project C-1112246 based on the assumption that the unit operates for 20 hours in a day during steady conditions and operates four hours in a day for startups and shutdowns.
- Based on the current limit in Permit C-1235-1-9, the daily Pre-Project Potential to Emit (PE1) for NO_X from the unit is 12.4 lb-NO_X/day, including emissions from startups and shutdowns.
- Annual Pre-Project Potential to Emit (PE1) will be calculated based on the maximum heat input of 30 billion Btu per year
- For calculation of the Post-Project Potential to Emit (PE2) for Permit Unit C-1235-1, it will be assumed that there will be no change in the number or duration of startups and shutdowns; therefore, post-project NO_X emissions from the unit will be limited 11.4 lb-NO_X/day, including emissions from startups and shutdowns. This is equivalent to continued operation of the unit for 20 hours in a day during steady conditions and four hours in a day for startups and shutdowns.
- Annual Post-Project Potential to Emit (PE2) will be calculated based on 365 day/yr of operation for NO_X and 8,760 hr/yr for other affected pollutants
- The PE for $PM_{2.5}$ is assumed to be equal to the PE for PM_{10} emissions.
- Oxygen-based F-Factor for Natural Gas, determined at 20 °C (68 °F) and 760 mm Hg (29.92 in Hg): 8,710 dscf/MMBtu (40 CFR 60, Appendix B)
- Oxygen-based F-Factor for Natural Gas, corrected to 60°F (15.6°C) (District standard temperature): 8,578 dscf/MMBtu
- Carbon dioxide-based F-Factor (F_{CO2}) determined at 20 °C (68 °F) and 760 mm Hg (29.92 in Hg): 1,040 dscf/MMBtu (40 CFR 60, Appendix B)

- Carbon dioxide-based F-Factor (F_{CO2}) corrected to 60°F (15.6°C) (District standard temperature): 1,024 dscf/MMBtu

- Permit Unit C-1235-2-7 (Dormant 26 MMBtu/hr Natural Gas & Oil-fired National Oil Heater #2) was designated as a dormant unit in 2001 under Project C-1010734 for compliance with District Rule 4305 Boilers, Steam Generators, and Process Heaters – Phase 2. The unit is now also subject to District Rules 4306 – Boilers, Steam Generators, and Process Heaters – Phase 3 (last amended 10/16/2008) and 4320 – Advanced Emission Reduction Options Greater than 5.0 MMBtu/hr (adopted 10/16/2008). In order to legally recommence operation, the unit must now comply with District Rules 4305, 4306, and 4320. Therefore, for Pre-Project and Post-Project Stationary Source Potential to Emit (SSPE) calculations, the Potential to Emit (PE) for Permit Unit C-1235-2-7 will be recalculated based on the maximum PE for each affected pollutant allowed for compliance with District Rules 4306 and 4320, rather than calculating the PE based on the conditions in the current permit. (See Appendix B for PE Calculations for Permit Unit C-1235-2-7)

- The current permit for Unit C-1235-2-7 includes Condition 8, which designates the unit as a replacement standby unit for compliance with District Rule 4305. This condition prohibits operation of Unit C-1235-2-7 when Unit C-1235-1 is operating except for maintenance, testing, startup, or shutdown. Because to recommence operation, Unit C-1235-2-7 must comply with District Rules 4306 and 4320, the condition designating the unit as a replacement standby unit will no longer be required for compliance with District Rule 4305. Therefore, for more simplified and more conservative SSPE calculations, it will be assumed that this condition will be removed and that Unit C-1235-1 and -2 will be allowed to operate simultaneously.

B. Emission Factors

Pre-Project Emission Factors for PTO C-1235-1-9

For the natural gas-fired process heater (Oil Heater #1), the pre-project emission factors for NO_X, SO_X, CO, and VOC are taken from the current permit. The NO_X emission factor is based on compliance with the standard emission limit from District Rule 4320. The SO_X emission factor is based on the use of PUC-quality natural gas (sulfur content of 1 grain/100 scf).

The PM_{10} emission factor in the current permit of 0.0076 lb-PM_{10}/MMBtu was based on EPA AP-42. Based on source testing data, the District has determined boilers, steam generators and process heaters fired on PUC-quality natural gas will have PM_{10} emissions no greater than 0.003 lb-PM10/MMBtu. Therefore, pursuant to District Policy APR 1110 - *Use of Revised Generally Accepted Emission Factors*, emission factors based on source test have a higher data quality than AP-42. Therefore, the PM_{10} emission factor will be revised to 0.003 lb-PM_{10}/MMBtu and this emission factor will be used to calculate both the pre-project and post-project PE for PM_{10} from the unit.

The pre-project emission factors are shown in the table below.

Pre-Project Emission Factors for PTO C-1235-1-9 (Natural Gas-Fired Process Heater - Oil Heater #1)			
Pollutant	**lb/MMBtu**	**ppmvd @ 3% O_2**	**Source**
NO_X steady	0.011 lb-NO_X/MMBtu	9 ppmvd NO_X @ 3% O_2	Current Permit C-1235-1-9
NO_X startup/shutdown	0.1 lb/MMBtu (startups/shutdowns)	82 ppmvd NO_X @ 3% O_2	Current Permit C-1235-1-9
SO_X	0.00285 lb-SO_X/MMBtu	1.0 grain-S/100 scf	Current Permit C-1235-1-9/ District Policy APR 1720
PM_{10}	0.003 lb-PM10/MMBtu	-	Based on Source Tests from Similar Units fired on PUC-quality natural gas
CO	0.2956 lb-CO/MMBtu	400 ppmvd CO @ 3% O_2	Current Permit C-1235-1-9
VOC	0.0056 lb-VOC/MMBtu	13.2 ppmvd @ 3% O_2 as CH_4	Current Permit C-1235-1-9

Post-Project Emission Factors for ATC C-1235-1-12

As discussed in Section I above, to satisfy the BACT requirements for the project, the steady state emission limit for NO_X will be reduced from 9 ppmvd NO_X @ 3% O_2 (0.011 lb-NO_X/MMBtu) to 7 ppmvd NO_X @ 3% O_2 (0.0085 lb-NO_X/MMBtu). For all other affected pollutants (SO_X, PM_{10}, CO, and VOC), the post-project emission factors will be the same as the pre-project emission factors.

The post-project emission factors are shown in the table below.

Post-Project Emission Factors for ATC C-1235-1-12 (Natural Gas-Fired Process Heater - Oil Heater #1)			
Pollutant	**lb/MMBtu**	**ppmvd @ 3% O_2**	**Source**
NO_X steady	0.0085 lb-NO_X/MMBtu	7 ppmvd NO_X @ 3% O_2	BACT Requirement
NO_X startup/shutdown	0.1 lb/MMBtu (startups/shutdowns)	82 ppmvd NO_X @ 3% O_2	Current Permit C-1235-1-9
SO_X	0.00285 lb-SO_X/MMBtu	1.0 grain-S/100 scf	Current Permit C-1235-1-9/ District Policy APR 1720
PM_{10}	0.003 lb-PM10/MMBtu	-	Based on Source Tests from Similar Units fired on PUC-quality natural gas
CO	0.2956 lb-CO/MMBtu	400 ppmvd CO @ 3% O_2	Current Permit C-1235-1-9
VOC	0.0056 lb-VOC/MMBtu	13.2 ppmvd @ 3% O_2 as CH_4	Current Permit C-1235-1-9

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Daily PE1 for C-1235-1-9

As explained above, C-1235-1-9 is permitted to operate 24 hours per day and the unit is allowed a higher NO_X emission limit during startups and shutdowns. The current permit does not limit to the number of startups and shutdowns, but the total daily NOx emissions are limited to no more than 12.4 lb-NOx/day, equivalent to operation of the unit for 20 hours in a day during steady conditions and four hours in a day for startup and shutdowns.

Daily PE1 for C-1235-1-9 (Natural Gas-Fired Process Heater)							
Pollutant	Emission Factor (lb/MMBtu)	x	Rated Heat Input (MMBtu/hr)	x	Daily Hours of Operation (hr/day)	=	PE1 (lb/day)
$NO_{X\ steady}$	0.011	x	20	x	20	=	4.4
$NO_{X\ startup/shutdown}$	0.1	x	20	x	4	=	8.0
NO_{X} Total Daily	-					=	**12.4**
SO_X	0.00285	x	20	x	24	=	**1.4**
PM_{10}	0.003	x	20	x	24	=	**1.4**
CO	0.2956	x	20	x	24	=	**141.9**
VOC	0.0056	x	20	x	24	=	**2.7**

Annual PE1 for C-1235-1-9

As explained above, Permit C-1235-1-9 limits the annual heat input to no more than 30 billion Btu per year. Because the permit does not limit the number of startups and shutdowns, the annual PE1 for NOx will be conservatively calculated using the higher NOx emission factor allowed during startups and shutdowns. This results in a PE1 for NOx of 3,000 lb/yr. When averaged over 365 days this is equivalent to 8.22 lb-NOx/day, which is less than limit of 12.4 lb-NOx/day contained in the current permit.

Annual PE1 for C-1235-1-9 (Natural Gas-Fired Process Heater)					
Pollutant	Emission Factor (lb/MMBtu)	x	Maximum Annual Heat Input (MMBtu/yr)	=	PE1 (lb/yr)
$NO_{X\ steady}$	0.011	x	30,000	=	330
$NO_{X\ startup/shutdown}$	0.1	x	30,000	=	**3,000**
SO_X	0.00285	x	30,000	=	**86**
PM_{10}	0.003	x	30,000	=	**90**
CO	0.2956	x	30,000	=	**8,868**
VOC	0.0056	x	30,000	=	**168**

2. Post Project Potential to Emit (PE2)

Daily PE2 for ATC C-1235-1-12

As discussed above, the total daily post-project NOx emissions from the unit will be limited to no more than 11.4 lb-NOx/day, equivalent to continued operation of the unit for 20 hours in a day during steady conditions and four hours in a day for startups and shutdowns.

Daily PE2 for ATC C-1235-1-12 (Natural Gas-Fired Process Heater)							
Pollutant	Emission Factor (lb/MMBtu)	x	Rated Heat Input (MMBtu/hr)	x	Daily Hours of Operation (hr/day)	=	PE1 (lb/day)
$NO_{X\ steady}$	0.0085	x	20	x	20	=	3.4
$NO_{X\ startup/shutdown}$	0.1	x	20	x	4	=	8.0
NO_{X} Total Daily	-					=	**11.4**
SO_X	0.00285	x	20	x	24	=	**1.4**
PM_{10}	0.003	x	20	x	24	=	**1.4**
CO	0.2956	x	20	x	24	=	**141.9**
VOC	0.0056	x	20	x	24	=	**2.7**

Annual PE2 for ATC C-1235-1-12

As explained above, this project will remove the annual heat input of 30 billion Btu per year from the permit. The Annual PE2 for NO_X will be calculated based on operation for 365 days per year and the annual PE2 for other affected pollutants will be calculated based on 8,760 hours per year of operation, as shown in the table below.

Annual PE2 for ATC C-1235-1-12 (Natural Gas-Fired Process Heater)							
Pollutant	Daily Emission Limit (lb/day)		x	Annual Operating Schedule (day/yr)		=	PE1 (lb/yr)
NO_X	11.4		x	365		=	**4,161**
Pollutant	Emission Factor (lb/MMBtu)	x	Rated Heat Input (MMBtu/hr)	x	Annual Hours of Operation (hr/yr)	=	PE2 (lb/yr)
SO_X	0.00285	x	20	x	8,760	=	**499**
PM_{10}	0.003	x	20	x	8,760	=	**526**
CO	0.2956	x	20	x	8,760	=	**51,789**
VOC	0.0056	x	20	x	8,760	=	**981**

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

Pursuant to District Rule 2201, the 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 (AER) that have occurred at the source, and which have not been used on-site.

SSPE1 (lb/year)					
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**
C-1235-1-9	3,000	86	90	8,868	168
C-1235-2-7	1,748	3,024	540	9,900	495
C-1235-5-0	0	0	0	0	7,452
C-1235-6-0	0	0	0	0	7,452
SSPE1	**4,748**	**3,110**	**630**	**18,768**	**15,567**

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

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site.

SSPE2 (lb/year)					
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**
C-1235-1-12	4,161	499	526	51,789	981
C-1235-2-7	1,748	3,024	540	9,900	495
C-1235-5-0	0	0	0	0	7,452
C-1235-6-0	0	0	0	0	7,452
SSPE2	**5,909**	**3,523**	**1,066**	**61,689**	**16,380**

5. Major Source Determination

Rule 2201 Major Source Determination:

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

Rule 2201 Major Source Determination (lb/year)						
	NO_X	**SO_X**	**PM_{10}**	**$PM_{2.5}$**	**CO**	**VOC**
SSPE1	4,748	3,110	630	630	18,768	15,567
SSPE2	5,909	3,523	1,066	1,066	61,689	16,380
Major Source Threshold	20,000	140,000	140,000	140,000	200,000	20,000
Major Source?	No	No	No	No	No	No

Note: PM2.5 assumed to be equal to PM10

As seen in the table above, the facility is not an existing Major Source and is not becoming a Major Source as a result of this project.

Rule 2410 Major Source Determination:

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore, the PSD Major Source threshold is 250 tons per year (tpy) for any regulated New and Modified Source (NSR) pollutant.

PSD Major Source Determination (tons/year)						
	NO_2	**VOC**	**SO_2**	**CO**	**PM**	**PM_{10}**
Estimated Facility PE before Project Increase	2.4	7.8	1.6	9.4	0.3	0.3
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source ? (Y/N)	N	N	N	N	N	N

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

6. Baseline Emissions (BE)

The BE calculation (in lb/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 = 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 shown in Section VII.C.5 above, the facility is not a Major Source for any pollutant.

Therefore BE = PE1.

<u>C-1235-1-12:</u>

As calculated in Section VII.C.1 above, PE1 for the unit is summarized in the following table:

BE (lb/year)						
	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC
C-1235-1-12	3,000	86	90	90	8,868	168

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."

Since this facility is not a major source for any of the pollutants addressed in this project, this project does not constitute an SB 288 major modification.

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 any pollutants, this project does not constitute a Federal Major Modification.

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10

I. Project Emissions Increase - New Major Source Determination

The post-project potentials to emit from all new and modified units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). The PSD Major Source threshold is 250 tons per year (tpy) for any regulated NSR pollutant.

PSD Major Source Determination: Potential to Emit (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Total PE from New and Modified Units	2.1	0.5	0.2	25.9	0.3	0.3
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	N	N	N	N	N	N

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore Rule 2410 is not applicable and no further analysis is required.

10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. Detailed QNEC calculations are included in Appendix C.

VIII. Compliance Determination

Rule 2201 New and Modified Stationary Source Review Rule

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. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

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 an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*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 discussed in Section I above, there are no new emissions units associated with this project. Therefore, BACT is not triggered for a new emissions units with PE > 2 lb/day.

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 for relocation of an emissions unit.

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))

C-1235-1-12:

Increasing the annual heat input limit will potentially allow the unit to operate on new days throughout the year that it could not have previously operated. Pursuant to District Policy APR-1350 - Best Available Control Technology (BACT) Requirements for Modifications to Existing Emission Units, "*modifications to existing emission units that result in permitted utilization such that the AIPE increases more than 2.0 lb in any one day, including, but not limited to, increasing daily permitted utilization, increasing the number of days or hours of annual operation, increasing annual throughput limitations, and increasing annual fuel use limitation, are required to satisfy the BACT requirements of Rule 2201 Section 4.1.2..*" Therefore, the proposed modification must be evaluated for BACT.

On any new day on which the unit can operate, PE1 for each affected pollutant would be zero. The PE2 for the emission unit is based on the daily PE2 calculations in Section VII.C.1.

AIPE = PE2 – 0 = PE2

AIPE for C-1235-1-12					
Pollutant	Daily PE2 (lb/day)	AIPE (lb/day)	BACT Threshold (lb/day)	SSPE2 (lb/yr)	BACT Triggered?
NO_X	11.4	11.4	> 2.0	N/A	**Yes**
SO_X	1.4	1.4	> 2.0	N/A	No
PM_{10}	1.4	1.4	> 2.0	N/A	No
CO	141.9	141.9	> 2.0 and SSPE2 ≥ 200,000 lb/yr	61,689	No
VOC	2.7	2.7	> 2.0	N/A	**Yes**

As demonstrated above, the AIPE is greater than 2.0 lb/day for emissions of NO_X and VOC. Therefore, BACT will be triggered for NO_X and VOC emissions from the process heater. However, BACT is not triggered for CO because the SSPE2 for CO is not greater than 200,000 lb/year, as shown above.

d. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 and/or Federal Major Modification. Therefore, BACT is not triggered for any pollutant for an SB 288 or Federal Major Modification.

2. BACT Guideline

Previous District Guideline 1.1.1 – Boiler: < or = 20.0 MMBtu/hr, Natural Gas or Propane Fired has been rescinded and the District does not currently have an approved BACT Guideline for this source category. Therefore, a project-specific BACT analysis is required for the proposed modification of the 20 MMBtu/hr oilfield process heater (ATC C-1235-1-12). The project-specific BACT analysis for the proposed modification will be based on the District's review of information that was available when the application for this project was deemed complete.

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 NSR Rule.

As discussed above, the proposed modification of the process heater under this project triggers BACT for NO_X and VOC emissions from the process heater. Pursuant to the attached Top-Down BACT Analysis (see Appendix D), BACT has been satisfied with the following:

NO_X: 7 ppmvd @ 3% O_2 or 0.0085 lb/MMBtu (Achieved in Practice)
VOC: PUC-quality natural gas fuel (Achieved in Practice)

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
SSPE2	5,909	3,523	1,066	61,689	16,380
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	No	No	No	No	No

2. Quantity of Offsets Required

As seen above, the SSPE2 is not greater than the offset thresholds for all the pollutants; therefore offset calculations are not necessary and 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 SB 288 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,
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant, and/or
e. Any project which results in a Title V significant permit modification.

a. New Major Sources, Federal Major Modifications, and SB 288 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.

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. There are no new emissions units associated with this project. Therefore public noticing is not required for this project for a new emissions unit with PE > 100 lb/day.

c. Offset Threshold

The SSPE1 and SSPE2 are compared to the offset thresholds in the following table.

Offset Thresholds				
Pollutant	**SSPE1 (lb/year)**	**SSPE2 (lb/year)**	**Offset Threshold**	**Public Notice Required?**
NO_X	4,748	5,909	20,000 lb/year	No
SO_X	3,110	3,523	54,750 lb/year	No
PM_{10}	630	1,066	29,200 lb/year	No
CO	18,768	61,689	200,000 lb/year	No
VOC	15,567	16,380	20,000 lb/year	No

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

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1.

The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

SSIPE Public Notice Thresholds					
Pollutant	**SSPE2 (lb/year)**	**SSPE1 (lb/year)**	**SSIPE (lb/year)**	**SSIPE Public Notice Threshold**	**Public Notice Required?**
NO_x	5,909	4,748	1,161	20,000 lb/year	No
SO_x	3,523	3,110	413	20,000 lb/year	No
PM_{10}	1,066	630	436	20,000 lb/year	No
CO	61,689	18,768	42,921	20,000 lb/year	**Yes**
VOC	16,380	15,567	813	20,000 lb/year	No

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

e. Title V Significant Permit Modification

Since this facility does not have a Title V operating permit, this change is not a Title V significant Modification, and therefore public noticing is not required.

2. Public Notice Action

As discussed above, public noticing is required for this project for the SSIPE for CO emissions exceeding 20,000 lb/yr. Therefore, public notice documents will be submitted to the California Air Resources Board (ARB) 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.

For this natural gas-fired process heater, the DELs are stated in the form of the maximum heat input rating of the process heater, the requirement to only use PUC or FERC regulated natural gas as fuel, emission factors (ppmvd or lb/MMBtu), and the maximum operating time of 24 hours per day.

The following conditions will be placed on the ATC permit.

Proposed Rule 2201 (DEL) Conditions:

- This unit shall only be fired on PUC or FERC regulated natural gas. [District Rules 2201 and 4320]

- Emissions from the natural gas-fired heater shall not exceed any of the following limits: 0.00285 lb-SOx/MMBtu, 0.003 lb-PM10/MMBtu, 400 ppmvd CO @ 3% O2 or 0.2956 lb-CO/MMBtu, or 0.0056 lb-VOC/MMBtu. [District Rules 2201 and 4320]

- Except during start-up and shutdown periods emissions from the natural gas-fired heater shall not exceed 7 ppmvd NOx @ 3% O2 or 0.0085 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

- During start-up and shutdown periods emissions from the natural gas-fired heater shall not exceed 0.1 lb-NOx/MMBtu. [District Rule 2201]

- Emissions from the natural gas-fired heater, including start-up and shutdown, shall not exceed 11.4 lb-NOx/day. [District Rule 2201]

E. Compliance Assurance

1. Source Testing

The process heater is subject to District Rule 4305, Boilers, Steam Generators and Process Heaters, Phase 2, District Rule 4306, Boilers, Steam Generators and Process Heaters, Phase 3, and District Rule 4320, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr.

District Rules 4305, 4306, and 4320 require NOx and CO emission testing not less than once every 12 months, unless compliance has been demonstrated for two consecutive source tests, in which case these rules allow the next source test to be deferred for up to thirty-six months. Therefore, source testing for NOx and CO will be required in accordance with District Rules 4305, 4306, and 4320. Source testing for these rules also satisfies any source testing requirements for District Rule 2201. Source testing requirements, in accordance with District Rules 4305, 4306, and 4320 will be discussed in detail in Section VIII of this evaluation.

2. Monitoring

The process heater is subject to District Rule 4305, Boilers, Steam Generators and Process Heaters, Phase 2, District Rule 4306, Boilers, Steam Generators and Process Heaters, Phase 3, and District Rule 4320, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr.

District Rules 4305, 4306, and 4320 require the operators of any unit subject to the emission limits in the rule to install and maintain continuous emissions monitoring equipment for NOx, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install and maintain APCO-approved alternate monitoring plan. Since the process heater is subject to the emission limits of these rules, this requirement applies.

The applicant has proposed to continue utilizing pre-approved alternate monitoring plan "A" (Periodic Monitoring of NOx, CO, and O_2 Concentrations) to meet the requirements of

District Rules 4305, 4306, and 4320. Monitoring for these rules also satisfies the monitoring requirements for District Rule 2201. Monitoring requirements, in accordance with District Rules 4305, 4306, and 4320 will be discussed in detail in Section VIII of this evaluation.

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The following conditions will be listed on the ATC permit:

- Permittee shall demonstrate that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081, 2201, and 4320]

- Duration of start-up or shutdown shall not exceed two hours each per occurrence. During start-up or shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. The operator shall maintain daily records of the number and duration of start-up and shutdown periods. [District Rules 2201, 4305, 4306, and 4320]

- {4318} The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306, and 4320]

- {4911} 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, 4305, 4306, and 4320]

Additionally, the following conditions will be included on the ATC permit to satisfy EPA Practical Enforceability Requirements for Facility SSPE for VOC ≥ 80% of the Federal Major Source Level:

- {4927} On a monthly basis, the permittee shall calculate and record the VOC emissions in pounds from this unit for the prior calendar month. [District Rule 2201]

- {4928} On a monthly basis, the permittee shall calculate and record the facility-wide VOC emissions in pounds for the prior 12 calendar month period. The facility-wide VOC emissions shall be calculated by summing the VOC emissions from the previous 12 calendar months from every permitted unit at this facility. [District Rule 2201]

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 E 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} standard as well as federal and state $PM_{2.5}$ standards. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for PM_{10} and $PM_{2.5}$.

The results of the Criteria Pollutant Modeling conducted for the AAQA are summarized in the following table.

Criteria Pollutant Modeling Results*						
C-1235-1-12	**Background Site**	**1 Hour**	**3 Hours**	**8 Hours.**	**24 Hours**	**Annual**
CO	Fresno (2015)	Pass	X	Pass	X	X
NO_X	Madera (2015)	Pass[1]	X	X	X	Pass
SO_X	Fresno (2015)	Pass	Pass	X	Pass	Pass
PM_{10}	Madera (2015)	X	X	X	Pass[2]	Pass[2]
$PM_{2.5}$	Madera (2015)	X	X	X	Pass[3]	Pass[3]

* Results were taken from the 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.

2 The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

3 The court has vacated EPA's $PM_{2.5}$ SILs. Until such time as new SIL values are approved, the District will use the corresponding PM_{10} SILs for both PM_{10} and $PM_{2.5}$ analyses.

Rule 2410 Prevention of Significant Deterioration

As shown in Section VII.C.9 above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

Rule 2520 Federally Mandated Operating Permits

Since this facility's potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and District Rule 2520 does not apply.

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. 40 CFR Part 60, Subpart Dc applies to Small Industrial-

Commercial-Industrial Steam Generators between 10 MMBtu/hr and 100 MMBtu/hr (post-6/9/89 construction, modification or, reconstruction)

Permit Unit C-1235-1 (20 MMBtu/hr Process Heater (Oil Heater #1)) was installed prior to 6/9/89 (District records for the unit were located dating to the 1970s). Therefore, the unit was not originally subject to 40 CFR Part 60, Subpart Dc. 40 CFR Part 60, Subpart A, section 14, defines the meaning of modification to which the standards are applicable. The unit has not been modified or reconstructed as defined in this subpart. The primary changes to the permit have been to ensure compliance with District rules and regulations. The proposed project will result in increased hours of operation for the unit but will not increase the maximum hourly or daily potential emissions from the unit. 40 CFR Section 60.14, paragraph (e)(3) states that the following will not be considered as a modification: *"An increase in the hours of operation"*.

No newly constructed or reconstructed units are proposed in this project. Since the permittee is only proposing to increase the hours of operation of the process heater under this project, it is not considered a modification as defined by 40 CFR Part 60, Subpart Dc. Therefore, no requirements of this subpart are 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.

The requirements of 40 CFR Part 63, Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters) are applicable to boilers at major hazardous air pollutants (HAP) sources. This facility is not a major source of HAP emissions. Therefore, this subpart does not apply. Additionally, the District has not been delegated the authority to implement this subpart.

The requirements of 40 CFR Part 63, Subpart JJJJJJ (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources) are applicable to boilers at area sources of HAP, except as specified in section §63.11195.

§63.11237 defines provides the following definition of a boiler:

> *Boiler* means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of Boiler.

The unit evaluated under this project is a process heater used to heat crude oil. Process heaters are specifically excluded from the definition of a boiler under this subpart; therefore, the requirements of this regulation do not apply to this unit.

Rule 4101 Visible Emissions

Rule 4101 states that no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity). As the process heater is fired solely on natural gas, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity. Therefore, compliance with District Rule 4101 requirements is expected.

The following condition will be listed on the permit:

- {15} 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. [District Rule 4101]

Rule 4102 Nuisance

Rule 4102 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.

The following condition will be listed on 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.

A Health Risk Assessment (HRA) is not required for a project with a total facility prioritization score less than or equal to one. According to the Technical Services Memo for this project (see Appendix E), the total facility prioritization score including this project was less than or equal to one. Therefore, no future analysis is required to determine the impact from this project and compliance with the District's Risk Management Policy is expected.

To ensure consistency with the Risk Management Review; the following condition will be listed on the ATC permit:

- {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]

Rule 4201 Particulate Matter Concentration

Section 3.1 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.

Natural Gas Combustion:

F-Factor for Natural Gas:	8,578 dscf/MMBtu at 60 °F
PM10 Emission Factor:	0.003 lb-PM10/MMBtu
Percentage of PM as PM_{10} in Exhaust:	100%
Exhaust Oxygen (O_2) Concentration:	3%

$$\text{Excess Air Correction to F Factor} = \frac{20.9}{(20.9 - 3)} = 1.17$$

$$= \left(\frac{0.003\ lb-PM}{MMBtu} \times \frac{7{,}000\ grain}{lb-PM}\right) \div \left(\frac{8{,}578\ ft^3}{MMBtu} \times 1.17\right)$$

$$= 0.0021\ grain/dscf < 0.1\ grain/dscf$$

Therefore, compliance with District Rule 4201 requirements is expected and the following condition will be listed on the ATC permit:

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

Rule 4301 Fuel Burning Equipment

The purpose of this rule is to limit the emission of air contaminants from fuel burning equipment. This rule limits the concentration of combustion contaminants and specifies maximum emission rates for sulfur dioxide, nitrogen oxide and combustion contaminant emissions.

Section 5.1 requires that a person shall not discharge into the atmosphere combustion contaminants exceeding in concentration at the point of discharge, 0.1 grain per cubic foot of gas calculated to 12% of carbon dioxide at dry standard conditions.

Natural Gas Combustion:

Carbon dioxide-based F-Factor (F_{CO2}) for Natural Gas:	1,024 dscf/MMBtu at 60 °F
PM_{10} Emission Factor:	0.003 lb-PM_{10}/MMBtu
Percentage of PM as PM_{10} in Exhaust:	100%
Exhaust Carbon Dioxide (CO_2) Concentration:	12%

$$\text{Excess Air Correction to } F_{CO2} \text{ Factor} = \frac{100}{12} = 8.33$$

$$= \left(\frac{0.003\ lb - PM}{MMBtu} \times \frac{7{,}000\ grain}{lb - PM}\right) \div \left(\frac{1{,}024\ ft^3}{MMBtu} \times 8.33\right)$$

$$= 0.0025\ grain/dscf < 0.1\ grain/dscf$$

As shown above, compliance with the requirements of this section is expected.

Section 5.2 requires that a person shall not build, erect, install or expand any non-mobile fuel burning equipment unit unless the discharge into the atmosphere of contaminants will not and does not exceed any one (1) or more of the following rates:

5.2.1 200 pounds per hour of sulfur compounds, calculated as sulfur dioxide (SO2);
5.2.2 140 pounds per hour of nitrogen oxides, calculated as nitrogen dioxide (NO2);
5.2.3 Ten (10) pounds per hour of combustion contaminants as defined in Rule 1020 (Definitions) and derived from the fuel.

According to AP 42 (Table 1.4-2, footnote c), all PM emissions from natural gas combustion are less than 1 μm in diameter.

District Rule 4301 Limits (lb/hr)			
Pollutant	**NO_2**	**Total PM**	**SO_2**
ATC C-1235-1-12 (lb/hr)	2.0*	0.1	0.1
Rule Limit (lb/hr)	140	10	200

* Maximum NO_X emissions during startup/shutdown

The above table indicates compliance with the maximum lb/hr emissions in this rule; therefore, continued compliance with this section is expected.

As shown above, compliance with District Rule 4301 requirements is expected and no further discussion is required.

Rule 4304 Equipment Tuning Procedure for Boilers, Steam Generators and Process Heaters

Pursuant to District Rules 4305 and 4306, Section 6.3.1, and 4320, Section 6.3.2.1, the process heater is not required to be tuned because it follows a District approved Alternate Monitoring scheme where the applicable emission limits are periodically monitored. Therefore, the process heater is not subject to the requirements of this rule.

Rule 4305 Boilers, Steam Generators and Process Heaters – Phase 2

The unit is a natural gas-fired process heater with a maximum heat input of 20.0 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4305, the unit is subject to District Rule 4305, Boilers, Steam Generators and Process Heaters – Phase 2.

In addition, the unit is also subject to District Rule 4306, Boilers, Steam Generators and Process Heaters – Phase 3 and District Rule 4320, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr.

Since emissions limits of District Rule 4320 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4320 requirements will satisfy requirements of District Rule 4305.

Therefore, compliance with District Rule 4305 requirements is expected and no further discussion is required.

Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3

The unit is a natural gas-fired process heater with a maximum heat input of 20.0 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4306, the units are subject to District Rule 4306, Boilers, Steam Generators and Process Heaters – Phase 3.

In addition, the unit is also subject to District Rule 4320, Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr.

Since emissions limits of District Rule 4320 and all other requirements are equivalent or more stringent than District Rule 4306 requirements, compliance with District Rule 4320 requirements will satisfy requirements of District Rule 4306.

Therefore, compliance with District Rule 4306 requirements is expected and no further discussion is required.

Rule 4320 Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater than 5.0 MMBtu/hr

The permit unit is natural gas-fired process heater with a maximum heat input of 20.0 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4320, the unit is subject to District Rule 4320.

Section 5.2 NO_X and CO Emission Limits

Section 5.2 requires that except for units subject to Sections 5.3, carbon monoxide (CO) emissions shall not exceed 400 ppm and NO_X emissions shall not exceed the limits specified in the following table. All ppmv emission limits specified in this section are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen.

The applicable emission limit category for the 20.0 MMBtu/hr process heater is listed in Section 5.2, Table 1, Category A, from District Rule 4320.

District Rule 4320 Emissions Limits			
Category	NO_x Limit	Authority to Construct	Compliance Deadline
A. Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through G units	a) Standard Schedule 9 ppmv or 0.011 lb/MMBtu; or	July 1, 2011	July 1, 2012
	b) Enhanced Schedule 6 ppmv or 0.007 lb/MMBtu	July 1, 2013	July 1, 2014

The ATC date for submitting an application to meet the NO_x limit for the Standard Schedule is July 1, 2011. The compliance deadline by which units shall not be operated in a manner which exceeds the NO_x emissions limit as shown in the above table is July 1, 2012. Permit Unit C-1235-1-12 is already in compliance with the Standard Schedule emission limit given above.

C-1235-1-12

For Permit Unit C-1235-1 the current NO_x emission factor, except for start-ups and shutdowns is 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu), which will be reduced to 7 ppmvd @ 3% O_2 (0.0085 lb/MMBtu) under this project, and the current CO emission factor is 400 ppmvd CO @ 3% O2 or 0.2956 lb-CO/MMBtu.

Therefore, compliance with Section 5.2 of District Rule 4320 is expected.

A permit condition listing the emissions limits will be listed on the ATC as shown in the DEL section above.

Section 5.3 Annual Fee Calculation

Annual fees are required if the unit will not be meeting the emission limits in Section 5.2 of this rule. Since the process heater complies with the emissions limits of Section 5.2, the annual fee requirements are not applicable.

Section 5.4 Particulate Matter Control Requirements

Section 5.4 of the rule requires one of four options for control of particulate matter: 1) combustion of PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases, 2) limit fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic, 3) install and properly operate an emission control system that reduces SO2 emissions by at least 95% by weight; or limit exhaust SO2 to less than or equal to 9 ppmv corrected to 3.0% O2 or 4) refinery units, which require modification of refinery equipment to reduce sulfur emissions, shall be in compliance with the applicable requirement in Section 5.4.1 no later than July 1, 2013.

The facility has proposed that the process heater will be fired exclusively on PUC or FERC regulated natural gas. Therefore, this requirement has been satisfied.

Section 5.6 Startup and Shutdown Provisions

Section 5.6 states that on and after the full compliance deadline in Section 5.0, the applicable emission limits of Sections 5.2 Table 1 and 5.5.2 shall not apply during start-up or shutdown provided an operator complies with the requirements specified in Sections 5.6.1 through 5.6.5.

Section 5.6.1 specifies that the duration of each start-up or each shutdown shall not exceed two hours, except as provided in Section 5.6.3. The current and proposed permits require that each start-up or shutdown period shall not exceed two hours per occurrence; therefore, continued compliance with this section is expected.

Section 5.6.2 specifies that the emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during start-up or shutdown. The current and proposed permits require that the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible during start-up or shutdown; therefore, continued compliance with this section is expected.

Section 5.6.3 states that notwithstanding the requirement of Section 5.6.1, an operator may submit an application for a Permit to Operate condition to allow more than two hours for each start-up or each shutdown provided the operator meets all of the conditions specified in Sections 5.6.3.1 through 5.6.3.3. The applicant has not requested a start-up or shutdown periods of more than two hours; therefore, this section does not apply.

Section 5.6.4 states that Permit to Operate (PTO) modifications solely to conditions to comply with the provisions of this rule may be exempt from Best Available Control Technology (BACT) and emission offset requirements if the PTO modifications meet the requirements of Rule 2201 (New and Modified Stationary Source Review Rule) Section 4.2 (BACT Exemptions) and Rule 2201 Section 4.6 (Emission Offset Exemptions). The proposed modification is not solely for compliance with District Rule 4320; therefore, this section does not apply.

Section 5.6.5 states that for existing facilities, a replacement unit installed for the sole purpose of complying with the requirements of this rule shall be considered to be an emission control technique and may be exempt from the Best Available Control Technology (BACT) and Offsets requirements of District Rule 2201 (New and Modified Stationary Source Review Rule) provided that all other requirements of Rule 2201 are met. The proposed project does not include a replacement unit installed solely for compliance with District Rule 4320; therefore, this section does not apply.

The following conditions will be included in the permit to ensure compliance with Section 5.6.

- Duration of start-up or shutdown shall not exceed two hours each per occurrence. During start-up or shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. The operator shall maintain daily records of the number and duration of start-up and shutdown periods. [District Rules 2201, 4305, 4306, and 4320]

Section 5.7 Monitoring Provisions

Section 5.7 requires either use of an APCO approved Continuous Emissions Monitoring System (CEMS) for NOx, CO, and oxygen, or implementation of an APCO-approved Alternate Monitoring System.

In order to satisfy the requirements of District Rule 4320, the applicant has proposed to use pre-approved alternate monitoring scheme A (pursuant to District Policy SSP-1105), which requires that monitoring of NO_x, CO, and O_2 exhaust concentrations shall be conducted at least once per month (in which a source test is not performed) using a portable analyzer.

The following conditions will be included on the ATC permit order to ensure compliance with the requirements of the proposed alternate monitoring plan:

- {4315} The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4320]

- {4316} If either the NOx or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]

- {4317} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

- {4318} The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306, and 4320]

5.7.6 Monitoring SOx Emissions

Section 5.7.6.1 requires operators complying with Sections 5.4.1.1 or 5.4.1.2 shall provide an annual fuel analysis to the District unless a more frequent sampling and reporting period is included in the Permit To Operate. Sulfur analysis shall be performed in accordance with the test methods in Section 6.2.

Section 5.7.6.2 requires operators complying with Section 5.4.1.3 by installing and operating a control device with 95% SOx reduction shall propose the key system operating parameters and frequency of the monitoring and recording. The monitoring option proposed shall be submitted for approval by the APCO.

Section 5.7.6.3 requires operators complying with Section 5.4.1.3 shall perform an annual source test unless a more frequent sampling and reporting period is included in the Permit To Operate. Source tests shall be performed in accordance with the test methods in Section 6.2.

The following conditions will be included on the ATC permit:

- This unit shall only be fired on PUC or FERC regulated natural gas. [District Rules 2201 and 4320]
- Permittee shall demonstrate that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081, 2201, and 4320]

Section 5.8 Compliance Determination

Section 5.8.1 requires that the operator of any unit have the option of complying with either the applicable heat input (lb/MMBtu), emission limits or the concentration (ppmv) emission limits specified in Section 5.2. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling).

Therefore, the following condition will be included on the ATC permit:

- {4350} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

Section 5.8.2 requires that all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. Unless otherwise specified in the Permit to Operate, no determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0. Therefore, the following permit condition will be listed on the ATC permit:

- {4351} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4320. [District Rules 4305, 4306, and 4320]

Section 5.8.4 requires that for emissions monitoring pursuant to Sections 5.7.1 and 6.3.1 using a portable NOx analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period. Therefore, the following condition will be on the ATC permit:

- {4317} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

Section 5.8.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. Therefore, the following condition will be listed on the ATC permit:

- {4352} 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 Rules 4305, 4306, and 4320]

Section 6.1 Recordkeeping

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.5 shall be maintained for five calendar years and shall be made available to the APCO and EPA upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule.

Therefore, the following condition will be listed on the ATC permit:

- {4911} 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, 4305, 4306, and 4320]

Section 6.2 Test Methods

Section 6.2 identifies test methods to be used when determining compliance with the rule. The following conditions will be listed on the ATC permit:

- {109} 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]

- {4346} NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305, 4306, and 4320]

- {4347} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305, 4306, and 4320]

- {4348} Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306, and 4320]

Section 6.3 Compliance Testing

Section 6.3.1 requires that this unit be tested to determine compliance with the applicable requirements of section 5.2 not less than once every 12 months (no more than 30 days before or after the required annual source test date). Upon demonstrating compliance on two consecutive compliance source tests, the following source test may be deferred for up to thirty-six months.

Section 6.3.1.1 Units that demonstrate compliance on two consecutive 12-month source tests may defer the following 12-month source test for up to 36 months (no more than 30 days before or after the required 36-month source test date). During the 36-month source testing interval, the operator shall tune the unit in accordance with the provisions of Section 5.5.1, and shall monitor, on a monthly basis, the unit's operational characteristics recommended by the manufacturer to ensure compliance with the applicable emission limits specified in Section 5.2.

Section 6.3.1.2 Tune-ups required by Sections 5.5.1 and 6.3.1 do not need to be performed for units that operate and maintain an APCO approved CEMS or an APCO approved Alternate Monitoring System where the applicable emission limits are periodically monitored.

Section 6.3.1.3 If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits specified in Section 5.2, the source testing frequency shall revert to at least once every 12 months.

The following conditions will be listed on the ATC permit:

- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

- {4345} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]

Sections 6.3.2.1 through 6.3.2.7 address the requirements of group testing which is not proposed in this project. Therefore these sections are not applicable.

Conclusion

Conditions will be incorporated into the permit in order to ensure compliance with each section of this rule. Therefore, compliance with District Rule 4320 requirements is expected.

Rule 4351 Boilers, Steam Generators and Process Heaters – Phase 1

District Rule 4351, Section 1.0 states that the purpose of this rule is to limit emissions of oxides of nitrogen (NOx) from boilers, steam generators, and process heaters to levels consistent with reasonably available control technology (RACT).

Pursuant to Section 2.0, this rule applies to any boiler, steam generator or process heater, with a rated heat input greater than 5 million Btu per hour that is fired with gaseous and/or liquid fuels, and is included in a major NOx source. This rule does not apply to any unit located west of Interstate Highway 5 located in Fresno, Kern, or Kings County.

As shown in Section VII.C.5 above, the Shell Pipeline Company LP Panoche Pump Station (Facility C-1235) is not a major NOx source. Additionally, this facility is located west of Interstate Highway 5 located in Fresno County; therefore, this rule is not applicable.

Rule 4801 Sulfur Compounds

A person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2 % by volume calculated as SO_2, on a dry basis averaged over 15 consecutive minutes.

Using the ideal gas equation and the emission factors presented in Section VII, the sulfur compound emissions are calculated as follows:

$$\text{Volume } SO_2 = \frac{n\,RT}{P}$$

Where:

N = moles SO_2
T (Standard Temperature) = 60°F = 520°R
P (Standard Pressure) = 14.7 psi

R (Universal Gas Constant) = $\dfrac{10.73\,\text{psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot {}^\circ\text{R}}$

F-Factor for Natural Gas: 8,578 dscf/MMBtu at 60 °F

Natural Gas Combustion:

$$\frac{0.00285\,lb - SOx}{MMBtu} \times \frac{1\,MMBtu}{8{,}578\,dscf} \times \frac{1\,lb \cdot mol}{64\,lb - SOx} \times \frac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot {}^\circ R} \times \frac{520\,{}^\circ R}{14.7\,psi} \times \frac{1{,}000{,}000\,parts}{million} = 1.97\frac{parts}{million}$$

$$Sulfur\ Concentration = 1.97\ parts/million < 2{,}000\ ppmv\ (or\ 2\%)$$

Therefore, compliance with District Rule 4801 is expected.

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)

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 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; and
- 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.

<u>District is a Lead Agency & GHG emissions increases are from the combustion of fossil fuel other than jet fuels</u>

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

On December 17, 2009, the District's Governing Board adopted a policy, APR 2005, *Addressing GHG Emission Impacts for Stationary Source Projects Under CEQA When Serving as the Lead Agency,* for addressing GHG emission impacts when the District is Lead Agency under CEQA and approved the District's guidance document for use by other agencies when addressing GHG impacts as lead agencies under CEQA. Under this policy, the District's determination of significance of project-specific GHG emissions is founded on the principal that projects with GHG emission reductions consistent with AB 32 emission reduction targets are considered to have a less than significant impact on global climate change. Consistent with District Policy 2005, projects complying with an approved GHG emission reduction plan or GHG mitigation program, which avoids or substantially reduces GHG emissions within the geographic area in which the project is located, would be determined to have a less than significant individual and cumulative impact for GHG emission.

The California Air Resources Board (ARB) adopted a Cap-and-Trade regulation as part one of the strategies identified for AB 32. This Cap-and-Trade regulation is a statewide plan, supported by a CEQA compliant environmental review document, aimed at reducing or mitigating GHG emissions from targeted industries. Facilities subject to the Cap-and-Trade regulation are subject to an industry-wide cap on overall GHG emissions. Any growth in emissions must be accounted for under that cap such that a corresponding and equivalent reduction in emissions must occur to allow any increase. Further, the cap decreases over time, resulting in an overall decrease in GHG emissions.

Under District policy APR 2025, *CEQA Determinations of Significance for Projects Subject to ARB's GHG Cap-and-Trade Regulation*, the District finds that the Cap-and-Trade is a regulation plan approved by ARB, consistent with AB32 emission reduction targets, and supported by a CEQA compliant environmental review document. As such, consistent with District Policy 2005, projects complying project complying with Cap-and-Trade requirements are determined to have a less than significant individual and cumulative impact for GHG emissions.

The GHG emissions increases associated with this project result from the combustion of fossil fuel(s), other than jet fuel, delivered from suppliers subject to the Cap-and-Trade regulation. Therefore, as discussed above, consistent with District Policies APR 2005 and APR 2025, the District concludes that the GHG emissions increases associated with this project would have a less than significant individual and cumulative 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 § 15301 (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)).

Indemnification Agreement/Letter of Credit Determination

According to District Policy APR 2010 (CEQA Implementation Policy), when the District is the Lead or Responsible Agency for CEQA purposes, an indemnification agreement and/or a letter of credit may be required. The decision to require an indemnity agreement and/or a letter of credit is based on a case-by-case analysis of a particular project's potential for litigation risk, which in turn may be based on a project's potential to generate public concern, its potential for significant impacts, and the project proponent's ability to pay for the costs of litigation without a letter of credit, among other factors.

The criteria pollutant emissions and toxic air contaminant emissions associated with the proposed project are not significant, and there is minimal potential for public concern for this particular type of facility/operation. Therefore, an Indemnification Agreement and/or a Letter of Credit will not be required for this project in the absence of expressed public concern.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATC C-1235-1-12 subject to the permit conditions on the attached draft ATC in Appendix F.

X. Billing Information

Annual Permit Fees			
Permit Number	**Fee Schedule**	**Fee Description**	**Annual Fee**
C-1235-1-12	3020-02-H	20 MMBtu/hr Process Heater (Oil Heater)	$1,128

Appendixes

A: Current Permit to Operate (PTO C-1235-1-9)
B: Potential to Emit (PE) Calculations for Permit Unit C-1235-2-7
C: Quarterly Net Emissions Change (QNEC)
D: BACT Analysis
E: Summary of Risk Management Review (RMR) and Ambient Air Quality Analysis (AAQA)
F: Draft ATC C-1235-1-12
G: ARB Comments and District Responses

APPENDIX A

Current Permit to Operate (PTO C-1235-1-9)

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-1235-1-9 **EXPIRATION DATE:** 04/30/2022

SECTION: 18 **TOWNSHIP:** 14S **RANGE:** 12E

EQUIPMENT DESCRIPTION:
20 MMBTU/HR NATIONAL OIL HEATER #1 NORTH AMERICAN MAGNA FLAME LE, MODEL 4211-33/X8515, S/N SD670366-01, ULTRA LOW NOX BURNER WITH INDUCED FLUE GAS RECIRCULATION

PERMIT UNIT REQUIREMENTS

1. 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]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. 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. [District Rule 4101]
4. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]
6. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of natural gas combusted in the unit shall be installed, utilized and maintained. [District Rules 2201, 4305, and 4306]
7. Maximum annual heat input of the unit shall not exceed 30 billion Btu per calendar year. [District Rules 2201, 4305, 4306, and 4320]
8. Emissions from the natural gas-fired heater shall not exceed any of the following limits: 0.00285 lb-SOx/MMBtu, 0.0076 lb-PM10/MMBtu, 400 ppmvd CO @ 3% O2 or 0.2956 lb-CO/MMBtu, or 0.0056 lb-VOC/MMBtu. [District Rule 2201]
9. Except during start-up and shutdown periods emissions from the natural gas-fired heater shall not exceed 9 ppmvd NOx @ 3% O2 or 0.011 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]
10. During start-up and shutdown periods emissions from the natural gas-fired heater shall not exceed 0.1 lb-NOx/MMBtu. [District Rule 2201]
11. Duration of start-up or shutdown shall not exceed two hours each per occurrence. During start-up or shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. The operator shall maintain daily records of the duration of start-up and shutdown periods. [District Rules 4305, 4306, and 4320]
12. Start-up is defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. Shutdown is defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 4305, 4306, and 4320]
13. Emissions from the natural gas-fired heater shall not exceed 12.4 lb-NOx/day. [District Rule 2201]

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

14. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4320]

15. If either the NOx or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]

16. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

17. The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306, and 4320]

18. All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305, 4306, and 4320]

19. Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]

20. The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]

21. 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]

22. NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305, 4306, and 4320]

23. CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305, 4306, and 4320]

24. Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306, and 4320]

25. 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 Rules 4305, 4306, and 4320]

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

26. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]
27. Records of monthly and annual heat input of the unit shall be maintained. [District Rules 2201, 4305, 4306, and 4320]
28. 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, 4305, 4306, and 4320]

APPENDIX B

Potential to Emit (PE) Calculations for Permit Unit C-1235-2-7

Potential to Emit (PE) Calculations for Permit Unit C-1235-2-7

Permit Unit C-1235-2-7 (Dormant 26 MMBtu/hr Natural Gas & Oil-fired Process Heater (National Oil Heater #2)) was designated as a dormant unit in 2001 under Project C-1010734 for compliance with District Rule 4305 Boilers, Steam Generators, and Process Heaters – Phase 2. The unit is now also subject to District Rules 4306 – Boilers, Steam Generators, and Process Heaters – Phase 3 (last amended 10/16/2008) and 4320 – Advanced Emission Reduction Options Greater than 5.0 MMBtu/hr (adopted 10/16/2008). In order to legally recommence operation, the unit must now comply with District Rules 4305, 4306, and 4320. Therefore, for Stationary Source Potential to Emit (SSPE) calculations, the Potential to Emit (PE) for Permit Unit C-1235-2-7 will be recalculated based on the maximum PE for each affected pollutant allowed for compliance with District Rules 4306 and 4320, rather than calculating the PE based on the conditions in the current permit.

Annual PE Calculations for C-1235-2-7 Based on Conditions in Current Permit

Emission Factors Based on Conditions in Permit C-1235-2-7

Natural Gas Emission Factors for C-1235-2-7			
Pollutant	**lb/MMBtu**	**ppmvd @ 3% O_2**	**Source**
NO_X	0.016	13.2 ppmvd NO_X @ 3% O_2	Current Permit C-1235-2-7
SO_X	0.013	4.8 gr-S/100 scf	Current Permit C-1235-2-7
PM_{10}	0.0048	-	Current Permit C-1235-2-7
CO	0.11	149 ppmvd CO @ 3% O_2	Current Permit C-1235-2-7
VOC*	0.0055	13 ppmvd @ 3% O_2 as CH_4	AP-42, Table 1.4-2 (7/1998)

* The 0.05 lb-VOC/MMBtu emission factor in the current permit appears to be a mistake. Project C-950524 indicates that this emission factor was based on AP-42, Table 1.4-3 (1/1995); however, the VOC emission factor in the permit is approximately 18 times higher than the VOC emission factor based on AP-42, Table 1.4-3 (1/1995) and approximately 9 times higher than the VOC emission factor in the current version of AP-42, Table 1.4-2 (7/1998); Therefore, the VOC emission factor will be based on the current version of AP-42.

Oil Emission Factors for C-1235-2-7				
Pollutant	**lb/1,000 gal**	**MMBtu/1,000 gal** (Conservative Estimate* from AP-42, Table 1.3-2, Note d)	**lb/MMBtu**	**Source**
NO_X	7.28	140	0.052	Current Permit C-1235-2-7
SO_X	235.5	140	1.68	Current Permit C-1235-2-7
PM_{10}	17	140	0.12	Current Permit C-1235-2-7
CO	5	140	0.036	Current Permit C-1235-2-7
VOC	0.28	140	0.002	Current Permit C-1235-2-7

* The District files for this facility include a Crude Oil Analysis performed for this site by Hornkohl Laboratories, Inc. dated September 9, 1971. This Crude Oil Analysis indicates that the heating value of the samples at this site ranged from 145,662 to 149,397 Btu/gallon. Given that over 45 years have passed since this analysis was performed, a value of 140,000 Btu/gallon will be used for more conservative emission calculations.

Maximum Natural Gas or Crude Oil Emission Factors for C-1235-2-7			
Pollutant	**lb/MMBtu**	**Fuel**	**Source**
NO_X	0.052	Crude Oil	Current Permit C-1235-2-7
SO_X	1.68	Crude Oil	Current Permit C-1235-2-7
PM_{10}	0.12	Crude Oil	Current Permit C-1235-2-7
CO	0.11	Natural Gas	Current Permit C-1235-2-7
VOC	0.0055	Natural Gas	Current Permit C-1235-2-7

PE for Unit C-1235-2-7 Based on Conditions in Permit

The PE for Unit C-1235-2-7 will be calculated based on the 90 billion Btu/year heat input limit in the current permit and the maximum emission factors for natural gas or oil.

Annual PE for C-1235-2-7 (26 MMBtu/hr Natural Gas/Oil-Fired Process Heater)					
Pollutant	Emission Factor (lb/MMBtu)	x	Maximum Annual Heat Input (MMBtu/yr)	=	PE (lb/yr)
NO_X	0.052	x	90,000	=	4,680
SO_X	1.68	x	90,000	=	151,200
PM_{10}	0.12	x	90,000	=	10,800
CO	0.11	x	90,000	=	9,900
VOC	0.0055	x	90,000	=	495

Annual PE Calculations for C-1235-2-7 Based on Compliance with District Rule 4320, Section 5.1.1 – Section 5.2 NO_X Emission Limits and Section 5.4 PM/SO_X requirements

Pursuant to Rule 4320, Section 5.2, CO emissions must not exceed 400 ppmv @ 3% O_2 and NO_X emissions must not exceed the applicable emission limit in Table 1 of Rule 4320.

Pursuant to Rule 4320, Section 5.4.1, to limit particulate matter emissions, an operator shall comply with one of the following requirements:

5.4.1.1 On and after the applicable NO_X Compliance Deadline specified in Section 5.2 Table 1, operators shall fire units exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases;

5.4.1.2 On and after the applicable NO_X Compliance Deadline specified in Section 5.2 Table 1, operators shall limit fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet; or

5.4.1.3 On and after the applicable NO_X Compliance Deadline specified in Section 5.2 Table 1, operators shall install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight; or limit exhaust SO_2 to less than or equal to 9 ppmv corrected to 3.0% O_2.

Pursuant to Rule 4320, Section 5.4.2, liquid fuel shall only be used only during PUC quality natural gas curtailment periods, must be limited to no more than 216 hours per year (168 cumulative hours plus 48 hours for equipment testing) pursuant to Section 4.2, and liquid fuel must contain no more than 15 ppm sulfur by weight.

Emission Factors Based on Compliance with District Rule 4320, Section 5.1.1

Natural Gas Emission Factors for C-1235-2-7			
Pollutant	**lb/MMBtu**	**ppmvd @ 3% O_2**	**Source**
NO_X	0.008	7 ppmvd NO_X @ 3% O_2	Rule 4320, Section 5.2, Table 1, Category B, Standard Schedule
SO_X	0.01425	5 grain-S/100 scf	Rule 4320, Section 5.4
PM_{10}	0.0048	--	Current Permit
CO	0.11	149 ppmvd CO @ 3% O_2	Current Permit C-1235-2-7
VOC	0.0055	13 ppmvd @ 3% O_2 as CH_4	AP-42, Table 1.4-2 (7/1998)

Oil Emission Factors for C-1235-2-7				
Pollutant	**lb/1,000 gal**	**MMBtu/1,000 gal** (From U.S. Energy Information Administration)[1]	**lb/MMBtu**	**Source**
NO_X	20	137.381	0.146	AP-42, Table 1.3-1, Distillate oil fired (5/2010)
SO_X	0.216	137.381	0.001572	AP-42, Table 1.3-1, Distillate oil fired, 15 ppm S by weight
PM_{10}	3.3	137.381	0.024	AP-42, Table 1.3-1, Distillate oil fired & Table 1.3-2, No. 2 oil fired (5/2010)
CO	5	137.381	0.0364	Current Permit C-1235-2-7 / AP-42, Table 1.3-1 (5/2010)
VOC	0.2	137.381	0.0015	AP-42, Table 1.3-3, Industrial Boilers, Distillate oil fired (5/2010)

Annual PE for Unit C-1235-2-7 Based on Compliance with District Rule 4320, Section 5.1.1

The PE for Unit C-1235-2-7 will be calculated based on the 90 billion Btu/year heat input limit in the current permit and the maximum emission factors for natural gas or oil with firing on oil limited to 216 hours per year (26 MMBtu/hr x 216 hr/yr = 5,616 MMBtu/yr) pursuant to District Rule 4320, Sections 4.2 and 5.4.2.

[1] U.S. Energy Information Administration (eia) > Energy Explained > Units and Calculators, average heat content for fuels consumed in the United States in 2015, distillate fuel with less than 15 parts per million sulfur content https://www.eia.gov/energyexplained/index.cfm/index.cfm?page=about_energy_units

Annual PE for C-1235-2-7 (Natural Gas/Oil-Fired Process Heater) Based on Compliance with District Rule 4320, Section 5.1.1									
Pollutant	NG EF (lb/MMBtu)	x	Annual NG Heat Input (MMBtu/yr)	+	Oil EF (lb/MMBtu)	x	Annual Oil Heat Input (MMBtu/yr)	=	PE2 (lb/yr)
NO_X	0.008	x	84,384	+	0.146	x	5,616	=	1,495
SO_X	0.01425	x	90,000	+	0.001572	x	0	=	1,283
PM_{10}	0.0048	x	84,384	+	0.024	x	5,616	=	540
CO	0.11	x	90,000	+	0.0364	x	0	=	9,900
VOC	0.0055	x	90,000	+	0.0015	x	0	=	495

Annual PE Calculations for C-1235-2-7 Based on Compliance with District Rule 4306, Section 5.1 Category B NO_X and CO limits (rated heat input > 20.0 MMBtu/hr, except for Categories C, D, E, F, G, H, and I units) and District Rule 4320, Section 5.1.2 – Section 5.3 Annual Emission Fee and Section 5.4 PM/SO_X requirements

Pursuant to Rule 4306, Section 5.1, NO_X and CO emissions must not exceed the applicable emission limit in Table 1 of Rule 4306 (CO limit of 400 ppmvd @ 3% O_2 for all categories).

Pursuant to Rule 4320, Section 5.3, on and after January 1, 2010, an operator, with units that will comply under Section 5.1.2, shall pay a total annual fee to the District based on the total NOx emissions from those units

Pursuant to Rule 4320, Section 5.4.1, to limit particulate matter emissions, an operator shall comply with the requirements of this section for control of SO_X and PM emissions, as explained above.

Pursuant to Rule 4320, Section 5.4.2, liquid fuel shall only be used only during PUC quality natural gas curtailment periods, must be limited to no more than 216 hours per year (168 cumulative hours plus 48 hours for equipment testing) pursuant to Section 4.2, and liquid fuel must contain no more than 15 ppm sulfur by weight.

Emission Factors Based on Compliance with District Rule 4306, Section 5.1.1, Category B Emission Limits and District Rule 4320, Section 5.1.2

Natural Gas Emission Factors for C-1235-2-7			
Pollutant	**lb/MMBtu**	**ppmvd @ 3% O_2**	**Source**
NO_X	0.011	9 ppmvd NO_X @ 3% O_2	Rule 4306, Section 5.1, Table 1, Category B, Standard Option
SO_X	0.01425	5 grain-S/100 scf	Rule 4320, Section 5.4
PM_{10}	0.0048	--	Current Permit
CO	0.11	149 ppmvd CO @ 3% O_2	Current Permit C-1235-2-7
VOC	0.0055	13 ppmvd @ 3% O_2 as CH_4	AP-42, Table 1.4-2 (7/1998)

Oil Emission Factors for C-1235-2-7				
Pollutant	lb/1,000 gal	MMBtu/1,000 gal (From U.S. Energy Information Administration)[2]	lb/MMBtu	Source
NO_X	20	137.381	0.146	AP-42, Table 1.3-1, Distillate oil fired (5/2010)
SO_X	0.216	137.381	0.001572	AP-42, Table 1.3-1, Distillate oil fired, 15 ppm S by weight
PM_{10}	3.3	137.381	0.024	AP-42, Table 1.3-1, Distillate oil fired & Table 1.3-2, No. 2 oil fired (5/2010)
CO	5	137.381	0.0364	Current Permit C-1235-2-7 / AP-42, Table 1.3-1 (5/2010)
VOC	0.2	137.381	0.0015	AP-42, Table 1.3-3, Industrial Boilers, Distillate oil fired (5/2010)

<u>Annual PE for Unit C-1235-2-7 Based on Compliance with District Rule 4306, Section 5.1.1, Category B Emission Limits and District Rule 4320, Section 5.1.2</u>

The PE for Unit C-1235-2-7 will be calculated based on the 90 billion Btu/year heat input limit in the current permit and the maximum emission factors for natural gas or oil with firing on oil limited to 216 hours per year (26 MMBtu/hr x 216 hr/yr = 5,616 MMBtu/yr) pursuant to District Rule 4320, Sections 4.2 and 5.4.2.

Annual PE for C-1235-2-7 (Natural Gas/Oil-Fired Process Heater) Based on Compliance with District Rule 4306, Section 5.1.1, Category B and District Rule 4320, Section 5.1.2								
Pollutant	NG EF (lb/MMBtu)	x	Annual NG Heat Input (MMBtu/yr)	+	Oil EF (lb/MMBtu)	x	Annual Oil Heat Input (MMBtu/yr)	=	PE2 (lb/yr)
NO_X	0.011	x	84,384	+	0.146	x	5,616	=	1,748
SO_X	0.01425	x	90,000	+	0.001572	x	0	=	1,283
PM_{10}	0.0048	x	84,384	+	0.024	x	5,616	=	540
CO	0.11	x	90,000	+	0.0364	x	0	=	9,900
VOC	0.0055	x	90,000	+	0.0015	x	0	=	495

<u>Annual PE Calculations for C-1235-2-7 Based on Compliance with District Rule 4306, Section 5.1 Category H NO_X and CO limits (limited by a Permit to Operate to an annual heat input of 9 to 30 billion Btu/year) and District Rule 4320, Section 5.1.2 – Section 5.3 Annual Emission Fee and Section 5.4 PM/SO_X requirements</u>

Pursuant to Rule 4306, Section 5.1, NO_X and CO emissions must not exceed the applicable emission limit in Table 1 of Rule 4306 (CO limit of 400 ppmvd @ 3% O_2 for all categories).

[2] U.S. Energy Information Administration (eia) > Energy Explained > Units and Calculators, average heat content for fuels consumed in the United States in 2015, distillate fuel with less than 15 parts per million sulfur content https://www.eia.gov/energyexplained/index.cfm/index.cfm?page=about_energy_units

Pursuant to Rule 4320, Section 5.3, on and after January 1, 2010, an operator, with units that will comply under Section 5.1.2, shall pay a total annual fee to the District based on the total NOx emissions from those units

Pursuant to Rule 4320, Section 5.4.1, to limit particulate matter emissions, an operator shall comply with the requirements of this section for control of SOx and PM emissions, as explained above.

Pursuant to Rule 4320, Section 5.4.2, liquid fuel shall only be used only during PUC quality natural gas curtailment periods, must be limited to no more than 216 hours per year (168 cumulative hours plus 48 hours for equipment testing) pursuant to Section 4.2, and liquid fuel must contain no more than 15 ppm sulfur by weight.

<u>Emission Factors Based on Compliance with District Rule 4306, Section 5.1.1, Category H Emission Limits and District Rule 4320, Section 5.1.2</u>

Natural Gas Emission Factors for C-1235-2-7			
Pollutant	**lb/MMBtu**	**ppmvd @ 3% O_2**	**Source**
NO_X	0.016*	13.2 ppmvd NO_X @ 3% O_2	Current Permit C-1235-2-7
SO_X	0.01425	5 grain-S/100 scf	Rule 4320, Section 5.4
PM_{10}	0.0048	--	Current Permit
CO	0.11	149 ppmvd CO @ 3% O_2	Current Permit C-1235-2-7
VOC	0.0055	13 ppmvd @ 3% O_2 as CH_4	AP-42, Table 1.4-2 (7/1998)

* The NO_X emission factor in Permit C-1235-2-7 is lower than the 30 ppmvd @ 3% O2 or 0.036 lb/MMBtu limit given in Rule 4306, Section 5.1.1, Category H

Oil Emission Factors for C-1235-2-7				
Pollutant	**lb/1,000 gal**	**MMBtu/1,000 gal** (From U.S. Energy Information Administration)[3]	**lb/MMBtu**	**Source**
NO_X	20	137.381	0.146	AP-42, Table 1.3-1, Distillate oil fired (5/2010)
SO_X	0.216	137.381	0.001572	AP-42, Table 1.3-1, Distillate oil fired, 15 ppm S by weight
PM_{10}	3.3	137.381	0.024	AP-42, Table 1.3-1, Distillate oil fired & Table 1.3-2, No. 2 oil fired (5/2010)
CO	5	137.381	0.0364	Current Permit C-1235-2-7 / AP-42, Table 1.3-1 (5/2010)
VOC	0.2	137.381	0.0015	AP-42, Table 1.3-3, Industrial Boilers, Distillate oil fired (5/2010)

[3] U.S. Energy Information Administration (eia) > Energy Explained > Units and Calculators, average heat content for fuels consumed in the United States in 2015, distillate fuel with less than 15 parts per million sulfur content https://www.eia.gov/energyexplained/index.cfm/index.cfm?page=about_energy_units

Annual PE for Unit C-1235-2-7 Based on Compliance with District Rule 4306, Section 5.1.1, Category H Emission Limits and District Rule 4320, Section 5.1.2

The PE for Unit C-1235-2-7 will be calculated based on the 30 billion Btu/year heat input limit for Rule 4306 Category H units and the maximum emission factors for natural gas or oil with firing on oil limited to 216 hours per year (26 MMBtu/hr x 216 hr/yr = 5,616 MMBtu/yr) pursuant to District Rule 4320, Sections 4.2 and 5.4.2.

Annual PE for C-1235-2-7 (Natural Gas/Oil-Fired Process Heater) Based on Compliance with District Rule 4306, Section 5.1.1, Category H and District Rule 4320, Section 5.1.2									
Pollutant	NG EF (lb/MMBtu)	x	Annual NG Heat Input (MMBtu/yr)	+	Oil EF (lb/MMBtu)	x	Annual Oil Heat Input (MMBtu/yr)	=	PE (lb/yr)
NO_X	0.016	x	24,384	+	0.146	x	5,616	=	1,210
SO_X	0.01425	x	30,000	+	0.001572	x	0	=	428
PM_{10}	0.0048	x	24,384	+	0.024	x	5,616	=	252
CO	0.11	x	30,000	+	0.0364	x	0	=	3,300
VOC	0.0055	x	30,000	+	0.0015	x	0	=	165

Annual PE Calculations for C-1235-2-7 Based on Compliance with District Rule 4306, Section 5.2 (limited by a Permit to Operate to an annual heat input < 9 billion Btu/year) and District Rule 4320, Section 5.5 (Low-Use Unit Limited to ≤ 1.8 billion Btu/year)

Pursuant to Rule 4306, Section 5.2, for each unit that is limited to less than 9 billion Btu per calendar year heat input pursuant to a Permit to Operate, the operator shall comply with one of the following:

5.2.1 tune the unit at least twice per calendar year, (from four to eight months apart) by a qualified technician in accordance with the procedure described in Rule 4304 (Equipment Tuning Procedure for Boilers, Steam Generators, and Process Heaters). If the unit does not operate throughout a continuous six-month period within a calendar year, only one tune-up is required for that calendar year. No tune-up is required for any unit that is not operated during that calendar year; this unit may be test fired to verify availability of the unit for its intended use, but once the test firing is completed the unit shall be shutdown; or

5.2.2 operate the unit in a manner that maintains exhaust oxygen concentrations at less than or equal to 3.00 percent by volume on a dry basis; or

5.2.3 operate the unit in compliance with the applicable emission limits of Sections 5.1.1 or 5.1.2.

Pursuant to Rule 4320, Section 5.5, for each unit that was installed prior to January 1, 2009 and is limited to less than or equal to 1.8 billion Btu per calendar year heat input pursuant to a District Permit to Operate, the operator shall comply with the requirement of Sections 5.7 and 7.3 and one of the following:

5.5.1 Tune the unit at least twice per calendar year, (from four to eight months apart) by a qualified technician in accordance with the procedure described in Rule 4304 (Equipment

Tuning Procedure for Boilers, Steam Generators, and Process Heaters). If the unit does not operate throughout a continuous six-month period within a calendar year, only one tune-up is required for that calendar year. No tune-up is required for any unit that is not operated during that calendar year; this unit may be test fired to verify availability of the unit for its intended use, but once the test firing is completed the unit shall be shutdown; or

5.5.2 Operate the unit in a manner that maintains exhaust oxygen concentrations at less than or equal to 3.00 percent by volume on a dry basis.

Emission Factors Based on Compliance with District Rule 4306, Section 5.2 (annual heat input < 9 billion Btu/year) and District Rule 4320, Section 5.5 (Low-Use Unit ≤ 1.8 billion Btu/year)

Natural Gas Emission Factors for C-1235-2-7			
Pollutant	**lb/MMBtu**	**ppmvd @ 3% O_2**	**Source**
NO_X	0.016	13.2 ppmvd NO_X @ 3% O_2	Current Permit C-1235-2-7
SO_X	0.01425	5 grain-S/100 scf	Conservative Estimate based on Rule 4320
PM_{10}	0.0048	--	Current Permit
CO	0.11	149 ppmvd CO @ 3% O_2	Current Permit C-1235-2-7
VOC	0.0055	13 ppmvd @ 3% O_2 as CH_4	AP-42, Table 1.4-2 (7/1998)

Oil Emission Factors for C-1235-2-7				
Pollutant	**lb/1,000 gal**	**MMBtu/1,000 gal** (Conservative Estimate* from AP-42, Table 1.3-2, Note d)	**lb/MMBtu**	**Source**
NO_X	7.28	140	0.052	Current Permit C-1235-2-7
SO_X	235.5	140	1.68	Current Permit C-1235-2-7
PM_{10}	17	140	0.12	Current Permit C-1235-2-7
CO	5	140	0.036	Current Permit C-1235-2-7 / AP-42, Table 1.3-1 (5/2010)
VOC	0.28	140	0.002	Current Permit C-1235-2-7

* The District files for this facility include a Crude Oil Analysis performed for this site by Hornkohl Laboratories, Inc. dated September 9, 1971. This Crude Oil Analysis indicates that the heating value of the samples at this site ranged from 145,662 to 149,397 Btu/gallon. Given that over 45 years have passed since this analysis was performed, a value of 140,000 Btu/gallon will be used for more conservative emission calculations.

Maximum Natural Gas or Crude Oil Emission Factors for C-1235-2-7			
Pollutant	**lb/MMBtu**	**Fuel**	**Source**
NO_X	0.052	Crude Oil	Current Permit C-1235-2-7
SO_X	1.68	Crude Oil	Current Permit C-1235-2-7
PM_{10}	0.12	Crude Oil	Current Permit C-1235-2-7
CO	0.11	Natural Gas	Current Permit C-1235-2-7
VOC	0.0055	Natural Gas	Current Permit C-1235-2-7

PE for Unit C-1235-2-7 Based on Compliance with District Rule 4306, Section 5.2 (annual heat input < 9 billion Btu/year) and District Rule 4320, Section 5.5 (Low-Use Unit ≤ 1.8 billion Btu/year)

The PE for Unit C-1235-2-7 will be calculated based on the 1.8 billion Btu/year heat input limit of District Rule 4320, Section 5.5 and the maximum emission factors for natural gas or oil.

Annual PE for C-1235-2-7 (26 MMBtu/hr Natural Gas/Oil-Fired Process Heater)					
Pollutant	Emission Factor (lb/MMBtu)	x	Maximum Annual Heat Input (MMBtu/yr)	=	PE (lb/yr)
NO_X	0.052	x	1,800	=	94
SO_X	1.68	x	1,800	=	3,024
PM_{10}	0.12	x	1,800	=	216
CO	0.11	x	1,800	=	198
VOC	0.0055	x	1,800	=	10

Maximum Annual PE Allowed for Permit Unit C-1235-2-7 for Compliance with District Rules 4306 and 4320

The maximum Annual PE allowed The PE for Permit Unit C-1235-2-7 for compliance with District Rules 4306 and 4320 based on the calculations given above is summarized in the table below.

Max Annual PE for C-1235-2-7 (26 MMBtu/hr Natural Gas/Oil-Fired Process Heater (Oil Heater #2)) for Compliance with District Rules 4306 and 4320		
Pollutant	Max PE (lb/yr)	Basis
NO_X	1,748	90 billion Btu/yr limit in Current Permit C-1235-2-7, District Rule 4306, Section 5.1 Category B NO_X and CO limits (rated heat input > 20.0 MMBtu/hr), District Rule 4320, Section 5.1.2 – Section 5.3 Annual Emission Fee and Section 5.4 PM/SO_X requirements
SO_X	3,024	SO_X Emission Factor for Crude Oil from Current Permit C-1235-2-7 and 1.8 billion Btu heat input limit from District Rule 4320, Section 5.5
PM_{10}	540	90 billion Btu/yr limit in Current Permit C-1235-2-7, Emission Factor for Combustion of Natural Gas from Current Permit C-1235-2-7 and AP-42 PM_{10} Emission Factor for Combustion of Natural Gas and Distillate Oil, and District Rule 4320, Section 5.4 PM/SO_X requirements
CO	9,900	90 billion Btu/yr limit in Current Permit C-1235-2-7 and CO emission factor in Current Permit C-1235-2-7 for combustion of Natural Gas
VOC	495	90 billion Btu/yr limit in Current Permit C-1235-2-7 and AP-42 VOC Emission Factor for Combustion of Natural Gas

APPENDIX C

Quarterly Net Emissions Change (QNEC)

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.

Using the values in Sections VII.C.2 and VII.C.1 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

C-1235-1-12 (Natural Gas-Fired Process Heater (Oil Heater #1))

PE1 (lb/qtr) C-1235-1-9					
	PE1 (lb/year)	÷	4 qtr/year	=	PE1 (lb/qtr)
NO_X	3,000	÷	4 qtr/year	=	750.0
SO_X	86	÷	4 qtr/year	=	21.5
PM_{10}	90	÷	4 qtr/year	=	22.5
CO	8,868	÷	4 qtr/year	=	2,217.0
VOC	168	÷	4 qtr/year	=	42.0

PE2 (lb/qtr) C-1235-1-12					
	PE2 (lb/year)	÷	4 qtr/year	=	PE2 (lb/qtr)
NO_X	4,161	÷	4 qtr/year	=	1,040.3
SO_X	499	÷	4 qtr/year	=	124.8
PM_{10}	526	÷	4 qtr/year	=	131.5
CO	51,789	÷	4 qtr/year	=	12,947.3
VOC	981	÷	4 qtr/year	=	245.3

Quarterly NEC [QNEC] C-1235-1-12					
	PE2 (lb/qtr)	-	PE1 (lb/qtr)	=	NEC (lb/qtr)
NO_X	1,040.3	-	750.0	=	290.3
SO_X	124.8	-	21.5	=	103.3
PM_{10}	131.5	-	22.5	=	109.0
CO	12,947.3	-	2,217.0	=	10,730.3
VOC	245.3	-	42.0	=	203.3

APPENDIX D

BACT Analysis for ATC C-1235-1-12
(20 MMBtu/hr Natural Gas-Fired Process Heater (Oil Heater))

Top-Down BACT Analysis for ATC C-1235-1-12
20 MMBtu/hr Natural Gas-Fired Process Heater (Oil Heater)

The District does not currently have an approved BACT Guideline for this source category. Previous District Guideline 1.1.1 – Boiler: < or = 20.0 MMBtu/hr, Natural Gas or Propane Fired has been rescinded. Therefore, a project-specific BACT analysis is required for the proposed modification of the 20 MMBtu/hr oilfield process heater (ATC C-1235-1-12).

Based on the District's review of the available source test information that was found, the District has determined that at the time the processing of the application for this project began (when the application was deemed complete) the Achieved in Practice BACT limit for NO_X from oilfield process heaters with a rated heat input of 20.0 MMBtu/hr or less was 7 ppmvd NO_X @ 3% O_2 (0.0085 lb-NO_X/MMBtu). A summary of the source tests reviewed by the District for this determination is shown in the table below (note: the table does not include source test results reviewed that exceeded 7 ppmvd NO_X @ 3% O_2).

Summary of Source Test Results for Oilfield Process Heaters Rated ≤ 20 MMBtu/hr with Measured NO_X Emissions ≤ 7 ppmvd @ 3% O_2						
Facility Name		**Facility ID #**		**Location**		
Shell Pipeline Company LP		C-1235		Panoche Pump Station, Fresno County, CA		
Permit Number	Unit Identification	Rated Heat Input (MMBtu/hr)	Permit NO_X Emission Limit (ppmvd @ 3% O_2)	Source Test Date	Source Test Result (ppmvd @ 3% O_2)	Control Equipment
C-1235-1-9	Oil Heater #1	20	9	4/18/2017	5.3	Ultra-Low NO_X Burner & FGR
C-1235-1-9	Oil Heater #1	20	9	4/4/2014	5.3	
C-1235-1-9	Oil Heater #1	20	9	4/18/2013	4.3	
Facility Name		**Facility ID #**		**Location**		
Phillips 66 Pipeline LLC		S-1520		Middlewater Pump Station: Lost Hills, Kern County, CA		
Permit Number	Unit Identification	Rated Heat Input (MMBtu/hr)	Permit NO_X Emission Limit (ppmvd @ 3% O_2)	Source Test Date	Source Test Result (ppmvd @ 3% O_2)	Control Equipment
S-1520-2-5	Heater B-1	14.6	9	1/22/2015	6.08	Ultra-Low NO_X Burner
S-1520-2-5	Heater B-1	14.6	9	1/10/2012	5.34	
Facility Name		**Facility ID #**		**Location**		
Phillips 66 Pipeline LLC		S-1521		McKittrick Pump Station: McKittrick, Kern County, CA		
Permit Number	Unit Identification	Rated Heat Input (MMBtu/hr)	Permit NO_X Emission Limit (ppmvd @ 3% O_2)	Source Test Date	Source Test Result (ppmvd @ 3% O_2)	Control Equipment
S-1521-1-8	Heater B1	14.7	9	12/1/2014	5.83	Ultra-Low NO_X Burner & FGR
S-1521-2-6	Heater B2	14.6	9	3/10/2015	6.43	Ultra-Low NO_X Burner & FGR
Facility Name		**Facility ID #**		**Location**		
Shell Pipeline Co. LP		S-3373		Griffith Station: Bakersfield, Kern County, CA		
Permit Number	Unit Identification	Rated Heat Input (MMBtu/hr)	Permit NO_X Emission Limit (ppmvd @ 3% O_2)	Source Test Date	Source Test Result (ppmvd @ 3% O_2)	Control Equipment
S-3373-1-6	Griffith Heater	12.5	9	8/30/2013	6.52	Ultra-Low NO_X Burner & FGR

As stated above, the District has determined that for this project, the Achieved in Practice BACT limit for NOx from oilfield process heaters with a rated heat input ≤ 20.0 MMBtu/hr is 7 ppmvd NOx @ 3% O_2 (0.0085 lb-NOx/MMBtu).

An ultra-low NOx burner with NOx emissions of 6 ppmvd NOx @ 3% O_2 (0.007 lb-NOx/MMBtu) has been identified as a Technologically Feasible BACT option for the proposed modification of the 20 MMBtu/hr oilfield process heater.

Additionally, greater NOx reductions may be possible by retrofitting the existing 20 MMBtu/hr oilfield process heater with a Selective Catalytic Reduction (SCR) system; therefore, use of an SCR system will also be included as a Technologically Feasible BACT option for NOx emissions from the oilfield process heater. It will be conservatively assumed that an SCR system can reduce emissions from the existing oilfield process heater to 3.5 ppmvd NOx @ 3% O_2 (0.0042 lb-NOx/MMBtu). At this emissions level, steady state (excluding startup and shutdown) NOx emissions from the unit would be no greater than 2.0 lb/day (20 MMBtu/hr x 24 hr/day x 0.0042 lb-NOx/MMBtu = 2.0 lb-NOx/day); 2.0 lb/day is the threshold that typically must be exceeded to trigger BACT requirements for new and modified units.

Top-Down BACT Analyses for the Natural Gas-Fired Process Heater

1. **BACT Analysis for NOx Emissions:**

a. Step 1 - List all control technologies

As stated above, the District BACT Guideline that applies to this source category has been rescinded; therefore, the project-specific BACT analysis for NOx from the process heater will be based on the Achieved in Practice and Technologically Feasible BACT options identified above.

The following control technologies have been identified as BACT options for oilfield process heaters with a maximum heat input rating ≤ 20.0 MMBtu/hr:

1) 3.5 ppmvd NOx @ 3% O_2 or 0.0042 lb-NOx/MMBtu (Selective Catalytic Reduction (SCR) – Technologically Feasible)

2) 6 ppmvd NOx @ 3% O_2 or 0.007 lb-NOx/MMBtu (Ultra-Low NOx Burner/Enhanced Rule 4320 Limit – Technologically Feasible)

3) 7 ppmvd NOx @ 3% O_2 or 0.0085 lb-NOx/MMBtu (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

d. Step 4 - Cost Effectiveness Analysis

Pursuant to Section IX.D of District Policy APR 1305 – BACT Policy, a cost effectiveness analysis is required for the options that have not been determined to be achieved in practice. In accordance with the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), to determine the cost effectiveness of particular technologically feasible control options or alternate equipment options, the amount of emissions resulting from each option will be quantified and compared to the District Standard Emissions allowed by the District Rule that is applicable to the particular unit. The emission reductions will be equal to the difference between the District Standard Emissions and the emissions resulting from the particular option being evaluated.

A cost effective analysis is required for the following Technologically Feasible BACT options that were listed above:

Option 1: 3.5 ppmvd NOx @ 3% O_2 or 0.0042 lb-NOx/MMBtu (SCR)
Option 2: 6 ppmvd NOx @ 3% O_2 or 0.007 lb-NOx/MMBtu (Ultra-Low NO_X Burner)

<u>Option 1: 3.5 ppmvd NOx @ 3% O_2 or 0.0042 lb-NOx/MMBtu (Selective Catalytic Reduction (SCR) – Technologically Feasible)</u>

<u>Capital Cost</u>

This option will require installation of a new SCR system to control emissions from the existing oilfield process heater. The estimated capital cost for retrofitting the existing process heater with a new SCR system is taken from the May 19, 2017 budgetary price quote that R.F. MacDonald Co. provided for an SCR system for an existing 12.6 MMBtu/hr natural gas-fired boiler (ATC- N-164-26-0) that was recently re-permitted under Project N-1171741. It will be conservatively assumed that the cost of an SCR system for the 20 MMBtu/hr oilfield process heater will be the same as the cost for the 12.6 MMBtu/hr boiler.

Cost to Retrofit Process Heater with an SCR system (3.5 ppmvd @ 3% O_2): $250,000

<u>Annualized Capital Cost</u>

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase and installation of the SCR 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)

$$A = [\$250,000 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$$
$$= \mathbf{\$40,686/year}$$

NOx Emission Reductions:

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions will be used to calculate the emission reductions from Technologically Feasible BACT options.

The District Standard Emissions for NOx emissions from the 20 MMBtu/hr process heater is the 9 ppmvd NOx @ 3% O_2 or 0.011 lb-NOx/MMBtu limit given in District Rule 4320, Section 5.2, Table 1, Category A – Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through G units. Therefore, the following NOx emission factors will be used for this cost analysis:

District Standard Emissions: 0.011 lb-NOx/MMBtu (9 ppmvd NOx @ 3% O_2)

Technologically Feasible Option 1 (SCR): 0.0042 lb-NOx/MMBtu (3.5 ppmvd NOx @ 3% O_2)

Emission Reductions:

NOx Emission Reductions (9 ppmvd @ 3% O_2 → 3.5 ppmvd @ 3% O_2)

(0.011 lb-NOx/MMBtu - 0.0042 lb-NOx/MMBtu) x 20.0 MMBtu/hr x 24 hr/day x 365 day/year

= 1,191 lb-NOx/year (0.60 ton-NOx/year)

Cost of NOx Emission Reductions

Cost of reductions = (\$40,686/year)/[(1,191 lb-NOx/year)(1 ton/2000 lb)]
= **\$68,322/ton of NOx reduced**

The analysis above demonstrates that the annualized capital cost for retrofitting the existing 20 MMBtu/hr oilfield process heater alone, not including any annual operating costs, results in costs for this control option that exceed the District's BACT Cost Effectiveness Threshold for NOx of \$24,500/ton. Therefore, this option is not cost-effective and will not be required for the proposed project.

Option 2: 6 ppmvd NOx @ 3% O_2 or 0.007 lb-NOx/MMBtu (Ultra-Low NOx Burner – Technologically Feasible)

Capital Cost

This option will require installation of a new ultra-low NOx burner. The estimated capital cost for retrofitting the existing process heater with a new ultra-low NOx burner capable of achieving 6 ppmvd @ 3% O_2 is taken from the March 15, 2017 budgetary price quote that Esys provided to the facility for retrofitting the burner.

Cost to Retrofit Process Heater with a New 6 ppmvd Ultra-Low NO_x Burner: $146,674

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase and installation of the ultra-low NO_x burner 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)

$$A = [\$146{,}674 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$$

$$= \mathbf{\$23{,}871/year}$$

NO_x Emission Reductions:

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions will be used to calculate the emission reductions from Technologically Feasible BACT options.

The District Standard Emissions for NO_x emissions from the 20 MMBtu/hr process heater is the 9 ppmvd NOx @ 3% O_2 or 0.011 lb-NOx/MMBtu limit given in District Rule 4320, Section 5.2, Table 1, Category A – Units with a total rated heat input > 5.0 MMBtu/hr to ≤ 20.0 MMBtu/hr, except for Categories C through G units. Therefore, the following NO_x emission factors will be used for the cost analysis:

District Standard Emissions: 0.011 lb-NOx/MMBtu (9 ppmvd NOx @ 3% O_2)

Technologically Feasible Option 2 (Ultra-Low NOx Burner): 0.007 lb-NOx/MMBtu (6 ppmvd NOx @ 3% O_2)

Emission Reductions:

NO_x Emission Reductions (9 ppmvd @ 3% O_2 → 6 ppmvd @ 3% O_2)

(0.011 lb-NOx/MMBtu - 0.007 lb-NOx/MMBtu) x 20.0 MMBtu/hr x 24 hr/day x 365 day/year

= 701 lb-NO_x/year (0.35 ton-NO_x/year)

Cost of NO_X Emission Reductions

Cost of reductions = (\$23,871/year)/[(701 lb-NO_X/year)(1 ton/2000 lb)]
= **\$68,106/ton of NO_X reduced**

As shown above, the cost of the NO_X emission reductions for retrofitting the existing process heater with a new ultra-low NO_X burner capable of achieving 6 ppmvd @ 3% O_2 exceeds the \$24,500/ton cost effectiveness threshold of the District BACT policy. Therefore, this option is not cost-effective and will not be required for the proposed project.

Option 3: 7 ppmvd NO_X @ 3% O_2 or 0.0085 lb-NO_X/MMBtu (Achieved in Practice)

This option is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for NO_X from the 20 MMBtu/hr natural gas-fired oilfield process heater (Oil Heater #1) is satisfied with the following: 7 ppmvd NO_X @ 3% O_2 or 0.0085 lb-NO_X/MMBtu

The applicant has agreed to comply with a NO_X emission limit of 7 ppmvd NO_X @ 3% O_2. Therefore, the BACT requirements for NO_X emissions from modification of the existing 20 MMBtu/hr oilfield process heater (Oil Heater #1) will be satisfied.

2. BACT Analysis for VOC Emissions:

a. Step 1 - Identify all control technologies

As stated above, the District BACT Guideline that applies to this source category has been rescinded; therefore, the project-specific BACT analysis for VOC from the natural gas-fired process heater is required.

Previous BACT Guideline 1.1.1 identified Natural Gas with LPG backup or propane fired as Achieved in Practice BACT for VOC emissions from this source category. The applicant has proposed to fire the unit exclusively on PUC-quality natural gas (regulated by the PUC or FERC). District Rule 4320 Section 3.7 indicates that PUC-quality natural gas is a high methane gas with at least 80% methane by volume. Because PUC-quality natural gas is mostly composed of methane, an exempt non-VOC compound, combustion of natural gas generally does not result in significant VOC emissions.

The following has been identified as a potential BACT option for VOC emissions from the process heater:

1) PUC-Quality Natural Gas (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) PUC-Quality Natural Gas (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option listed above has been identified as achieved in practice. Therefore, the option is required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for VOC emissions from the process heater (Oil Heater #1) is the use of PUC-quality natural gas as fuel. The applicant has proposed to use only PUC-quality natural gas (regulated by the PUC or FERC) as fuel. Therefore, the BACT requirements for VOC emissions from modification of the existing 20 MMBtu/hr oilfield process heater (Oil Heater #1) will be satisfied.

APPENDIX E

Summary of Risk Management Review (RMR) and Ambient Air Quality Analysis (AAQA)

San Joaquin Valley Air Pollution Control District
Risk Management Review

To:	Ramon Norman – Permit Services
From:	Anji Amachree – Technical Services
Date:	April 5, 2017
Facility Name:	Shell Pipeline Company LP
Location:	Section 18, Township 14S, Range 12E
Application #(s):	C-1235-1-12
Project #:	C-1163184

A. RMR SUMMARY

RMR Summary						
Units	**Prioritization Score**	**Acute Hazard Index**	**Chronic Hazard Index**	**Maximum Individual Cancer Risk**	**T-BACT Required?**	**Special Permit Requirements?**
Unit 1-12 (NG Heater)	0.43	N/A[1]	N/A[1]	N/A[1]	No	Yes
Project Totals	0.43	N/A[1]	N/A[1]	N/A[1]		
Facility Totals	<1	N/A[1]	N/A[1]	N/A[1]		

[1]The project passed on prioritization with a score less than 1; therefore, no further analysis was required.

<u>Proposed Permit Requirements</u>

To ensure that human health risks will not exceed District allowable levels; the following shall be included as requirements for:

<u>Unit # 1-12</u>

1. 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.

B. RMR REPORT

I. Project Description

Technical Services received a request on April 5th, 2017 to perform an Ambient Air Quality Analysis and a Risk Management Review for a proposed modification to an oil pipeline station. The modification consists of a permit to remove the 30 billion Btu/yr annual heat input limit natural gas-fired from Permit C-1235-1-9 for a 20 MMBtu/hr process heater. The maximum annual heat input will increase from 30 billion Btu/yr (30 million scf of natural gas) to 175.2 billion Btu/yr (175.2 million scf of natural gas).

II. Analysis

Toxic emission factors for this unit were derived from data in the 1992 Radian Corporation report to WSPA, and input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015), risks from the proposed unit's toxic emissions were prioritized using the procedure in the 1990 CAPCOA Facility Prioritization Guidelines. The prioritization score for this proposed unit was less than 1.0 (see RMR Summary Table).Therefore, no further analysis was necessary.

The following parameters were used for the review:

Analysis Parameters Unit 1-12			
NG Combustion (MMscf/hr)	0.02	**NG Combustion (MMscf/yr)**	145.2
Closest Receptor (m)	1300	**Receptor Type**	Business

Technical Services performed modeling for criteria pollutants CO, NO_x, SO_x, and PM10 with the emission rates below:

Unit #	**NO_x (Lbs.)**		**SO_x (Lbs.)**		**CO (Lbs.)**		**PM_{10} (Lbs.)**	
	Hr.	Yr.	Hr.	Yr.	Hr.	Yr.	Hr.	Yr.
1-12	0	1526	0	413	0	42921	0	1104

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

	Background Site	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Fresno (2015)	Pass	X	Pass	X	X
NO_x	Madera (2015)	Pass[1]	X	X	X	Pass
SO_x	Fresno (2015)	Pass	Pass	X	Pass	Pass
PM_{10}	Madera (2015)	X	X	X	Pass[2]	Pass[2]
$PM_{2.5}$	Madera (2015)	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
[2]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).
[3]The court has vacated EPA's $PM_{2.5}$ SILs. Until such time as new SIL values are approved, the District will use the corresponding PM_{10} SILs for both PM_{10} and $PM_{2.5}$ analyses.

III. Conclusion

The prioritization score is less than 1.0. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit requirements 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.

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

IV. Attachments

A. RMR Request
B. Additional information from the applicant/project engineer
C. Prioritization score w/ toxic emissions summary
D. AAQA Summary
E. Facility Summary

APPENDIX F

Draft ATC
(C-1235-1-12)

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: C-1235-1-12 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: SHELL PIPELINE COMPANY LP
MAILING ADDRESS: 1801 PETROL RD
BAKERSFIELD, CA 93308

LOCATION: PANOCHE PUMP STATION
PANOCHE & I-5
FRESNO COUNTY, CA 93210

SECTION: 18 **TOWNSHIP:** 14S **RANGE:** 12E

EQUIPMENT DESCRIPTION:
MODIFICATION OF 20 MMBTU/HR NATIONAL NATURAL GAS-FIRED OIL HEATER #1 WITH A NORTH AMERICAN MAGNA FLAME LE MODEL 4211-33/X8515, S/N: SD670366-01, ULTRA LOW NOX BURNER WITH INDUCED FLUE GAS RECIRCULATION: REMOVE 30 BILLION BTU/YR ANNUAL HEAT INPUT LIMIT AND REDUCE THE NOX EMISSION LIMIT TO 7 PPMVD NOX @ 3% O2 (0.0085 LB-NOX/MMBTU)

CONDITIONS

1. {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]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. {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]
4. {15} 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. [District Rule 4101]
5. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
6. This unit shall only be fired on PUC or FERC regulated natural gas. [District Rules 2201 and 4320]
7. Permittee shall demonstrate that the combusted gas is provided from a PUC or FERC regulated source. [District Rules 1081, 2201, and 4320]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 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

Arnaud Marjollet, Director of Permit Services

C-1235-1-12 Nov 21 2017 3:29PM -- NORMANR : Joint Inspection NOT Required

8. Emissions from the natural gas-fired heater shall not exceed any of the following limits: 0.00285 lb-SOx/MMBtu, 0.003 lb-PM10/MMBtu, 400 ppmvd CO @ 3% O2 or 0.2956 lb-CO/MMBtu, or 0.0056 lb-VOC/MMBtu. [District Rules 2201 and 4320]

9. Except during start-up and shutdown periods emissions from the natural gas-fired heater shall not exceed 7 ppmvd NOx @ 3% O2 or 0.0085 lb-NOx/MMBtu. [District Rules 2201, 4305, 4306, and 4320]

10. During start-up and shutdown periods emissions from the natural gas-fired heater shall not exceed 0.1 lb-NOx/MMBtu. [District Rule 2201]

11. Emissions from the natural gas-fired heater, including start-up and shutdown, shall not exceed 11.4 lb-NOx/day. [District Rule 2201]

12. Duration of start-up or shutdown shall not exceed two hours each per occurrence. During start-up or shutdown, the emissions control system shall be in operation, and emissions shall be minimized insofar as technologically possible. The operator shall maintain daily records of the number and duration of start-up and shutdown periods. [District Rules 2201, 4305, 4306, and 4320]

13. Start-up is defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. Shutdown is defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 4305, 4306, and 4320]

14. {4315} The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every month (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last month. [District Rules 4305, 4306, and 4320]

15. {4316} If either the NOx or CO concentrations corrected to 3% O2, as measured by the portable analyzer, exceed the allowable emissions concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 1 hour of operation after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 1 hour of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 4305, 4306, and 4320]

16. {4317} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rules 4305, 4306, and 4320]

17. {4318} The permittee shall maintain records of: (1) the date and time of NOx, CO, and O2 measurements, (2) the O2 concentration in percent and the measured NOx and CO concentrations corrected to 3% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, and (5) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 4305, 4306, and 4320]

18. {109} 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]

19. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

DRAFT

CONDITIONS CONTINUE ON NEXT PAGE

20. {4345} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305, 4306, and 4320]
21. {4346} NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305, 4306, and 4320]
22. {4347} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305, 4306, and 4320]
23. {4348} Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305, 4306, and 4320]
24. {4350} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305, 4306, and 4320]
25. {4351} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4320. [District Rules 4305, 4306, and 4320]
26. {4352} 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 Rules 4305, 4306, and 4320]
27. {4927} On a monthly basis, the permittee shall calculate and record the VOC emissions in pounds from this unit for the prior calendar month. [District Rule 2201]
28. {4928} On a monthly basis, the permittee shall calculate and record the facility-wide VOC emissions in pounds for the prior 12 calendar month period. The facility-wide VOC emissions shall be calculated by summing the VOC emissions from the previous 12 calendar months from every permitted unit at this facility. [District Rule 2201]
29. {4911} 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, 4305, 4306, and 4320]

DRAFT

APPENDIX G

ARB Comments and District Responses

ARB Comments and District Responses

ARB Comments

The District's Best Available Control Technology (BACT) analysis for the project used a NO_x emission limit of 9 ppmv NO_x @ 3% O_2 as the Achieved in Practice BACT requirement for the proposed modification of the 20 MMBtu/hr oilfield process heater and determined that a lower NO_x emission limit was a Technologically Feasible BACT option that required a cost analysis. The District's BACT analysis for the project determined that retrofitting the unit to achieve a NO_x emission limit less than 9 ppmv NO_x @ 3% O_2 would not be cost effective. However, a NO_x emission limit less than 9 ppmv NO_x @ 3% O_2 should be Achieved in Practice BACT for the unit.

The following are two examples of units with NO_x emission limits less than 9 ppmv @ 3% O_2:

Ventura County Air Pollution Control District (VCAPCD) Authority to Construct No. 00012-320

VCAPCD issued Authority to Construct No. 00012-320 for a 20.0 MMBtu/hr oilfield steam generator on September 3, 2014.

Unit Description: 20.0 MMBtu/hr oilfield steam generator

NO_x emission limits: 5 ppmv NO_x @ 3% O_2 when fueled only with natural gas and 6 ppmv NO_x @ 3% O_2 if produced gas is included in fuel

Source testing of unit performed on November 11, 2015

Permit for unit finalized in January 2016

San Joaquin Valley Air Pollution Control District (SJVAPCD) Permit to Operate (PTO) S-83-7-10 for Shell Pipeline Co. LP

In addition, Shell Pipeline Company is operating pipeline heater in the San Joaquin Valley Air District that is permitted at 7 ppmv NO_x @ 3% O_2

Unit Description: 33.75 MMBtu/hr oilfield process heater

NO_x emission limits: 7 ppmv NO_x @ 3% O_2

District Response to ARB Comments

The District agrees that a NO_x emission limit less than 9 ppmv NO_x @ 3% O_2 is Achieved in Practice BACT for the unit. Based on the District's review of the available information, the District has determined that a NO_x emission limit of 7 ppmv NO_x @ 3% O_2 (0.0085 lb-NO_x/MMBtu) is Achieved in Practice BACT for the unit and has imposed this requirement for this project. The facility has revised their proposal for the project and has agreed to limit NO_x emissions from the unit to 7 ppmv NO_x @ 3% O_2. The District has revised the engineering evaluation and the Authority to Construct (ATC) permit for the project to reflect the revised BACT determination.