



State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of Environmental Quality

Alan Matheson
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQE-AN101240030-16

November 9, 2016

Jerry Lockie
Silver Eagle Refining - Woods Cross Inc.
2355 S 1100 W
PO Box 870298
Woods Cross, UT 84087-0298

Dear Mr. Lockie:

Re: Approval Order: Reduction in Air Contaminants Project for Tank Roster Updates and Instrument
Based Monitoring
Project Number: N10124-0030

The attached document is the Approval Order for the above-referenced project. Future correspondence on this Approval Order should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. The project engineer for this action is John Jenks, who may be reached at (801) 536-4459.

Sincerely,

Bryce C. Bird
Director

BCB:JJ:kw

cc: Davis County Health Department

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

**APPROVAL ORDER: Reduction in Air Contaminants Project for
Tank Roster Updates and Instrument Based Monitoring**

**Prepared By: John Jenks, Engineer
Phone: (801) 536-4459
Email: jjenks@utah.gov**

APPROVAL ORDER NUMBER

DAQE-AN101240030-16

Date: November 9, 2016

**Silver Eagle Refining - Woods Cross Inc.
Petroleum Products Refining**

**Source Contact:
Danielle Knight, Environmental Engineer
Phone: (801) 298-3211
Email: dknight@silvereaglerefining.com**

**Bryce C. Bird
Director**

Abstract

Silver Eagle Refining - Woods Cross Inc. (Silver Eagle) has submitted notification of two projects at its existing facility in Woods Cross. As both projects are exempt under the provisions of R307-401-12, Reduction in Air Pollutants, they have been combined under this single permitting action for convenience.

The first project, submitted May 26, 2016, addresses several changes at existing storage tanks located at the facility. Tank 15 has been retrofitted to store yellow wax crude feedstocks. This retrofit consists of a new internal floating roof and related internal roof support structures. The tank is already subject to NSPS Subpart Kb. Also included in this project was a request to update the listed stored content for several tanks. Silver Eagle estimated the potential VOC emissions from both the prior and new content configurations and showed an emission reduction of 0.4 tons/year.

The second project, submitted July 7, 2016, covers the use of a new instrument-based monitoring methodology. This will more accurately measure crude oil charge rate, by switching to a flow measurement basis, rather than relying on tank level gauges. Also included was the installation of a new diesel additive tank (71 barrels in capacity) which had been left out of the previous tank update (May 26, 2016 submittal). This additional tank is so small in total potential emissions, that it has no impact on the status of the exemption for the May 26, 2016 project. This was verified by supplemental information submitted by Silver Eagle on October 3, 2016 which indicated total VOC emissions of less than 0.002 tons/year and total HAP emissions of less than 0.02 lbs/year from this tank.

Silver Eagle satisfied the requirements of R307-401-12, as: 1) neither project increases the potential to emit of any air pollutant or causes emissions of any new air pollutant, and 2) notified the Director within 60 days of the change having taken place. Thus, both projects qualify as exempt under R307-401-12. This update to Silver Eagle's AO serves as acknowledgement of that fact.

Finally, Silver Eagle has requested a reduction in the NO_x limitation listed in Condition II.B.2.c and a correction to the emission factors listed in Condition II.B.2.d. The limitation in II.B.2.c has been based on outdated AP-42 emission factors carried over from an earlier AO and erroneously maintained in II.B.2.d. By correcting to the updated emission factors in the current version of AP-42, the NO_x limitation will be reduced to 67.5 tons/year.

The Silver Eagle Refinery is located in Davis County, a nonattainment area of the NAAQS for $\text{PM}_{2.5}$, and a maintenance area for ozone. There is no change in emissions resulting from the upgraded monitoring methodology, a decrease in potential VOC emissions (0.4 TPY) from the storage tank changes, and a correction to the potential NO_x emissions (now set at 67.5 TPY) from the use of updated emission factors. The resulting PTE totals, in TPY, are as follows: PM_{10} (which includes $\text{PM}_{2.5}$) = 14.0, $\text{PM}_{2.5}$ = 8.48, NO_x = 67.5, SO_x = 2.03, CO = 85.04, VOC = 65.42, total HAPs = 11.81 and CO_2e = 98,000.

This air quality AO authorizes the project with the following conditions and failure to comply with any of the conditions may constitute a violation of this order. This AO is issued to, and applies to the following:

Name of Permittee:

Silver Eagle Refining - Woods Cross Inc.
2355 S 1100 W
PO Box 870298
Woods Cross, UT 84087-0298

Permitted Location:

Petroleum Products Refining
2355 So. 1100 West
Woods Cross, UT 84087

UTM coordinates: 423,200 m Easting, 4,524,300 m Northing, UTM Zone 12
UTM Datum: NAD27
SIC code: 2911 (Petroleum Refining)

Section I: GENERAL PROVISIONS

- I.1 All definitions, terms, abbreviations, and references used in this AO conform to those used in the UAC R307 and 40 CFR. Unless noted otherwise, references cited in these AO conditions refer to those rules. [R307-101]
- I.2 The limits set forth in this AO shall not be exceeded without prior approval. [R307-401]
- I.3 Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved. [R307-401-1]
- I.4 All records referenced in this AO or in other applicable rules, which are required to be kept by the owner/operator, shall be made available to the Director or Director's representative upon request, and the records shall include the two-year period prior to the date of the request. Unless otherwise specified in this AO or in other applicable state and federal rules, records shall be kept for a minimum of five (5) years. [R307-415-6a]
- I.5 At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this AO including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Director which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded. [R307-401-4]
- I.6 The owner/operator shall comply with UAC R307-107. General Requirements: Breakdowns. [R307-107]
- I.7 The owner/operator shall comply with UAC R307-150 Series. Emission Inventories. [R307-150]

Section II: SPECIAL PROVISIONS

- II.A **The approved installations shall consist of the following equipment:**
- II.A.1 **Refinery**
Source Wide
- II.A.2 **BenSat Furnace**
12 MMBtu/hr furnace, fired on plant gas and/or natural gas
- II.A.3 **F-231: Crude Unit #1 Furnace**
30 MMBtu/hr furnace, fired on plant gas and/or natural gas
- II.A.4 **HT: Hydrotreater Unit**
Fired with two furnaces, controlled with existing flares
- II.A.5 **HT Charge Furnace**
19.55 MMBtu/hr furnace with low-NO_x burners, fired on plant gas

II.A.6	HT Fractionator Furnace 27.6 MMBtu/hr furnace with low-NO _x burners, fired on plant gas
II.A.7	H-104: MDDW Heater 27 MMBtu/hr furnace with low-NO _x burners, fired on natural gas or plant gas
II.A.8	H-103: MDDW Reboiler Heater 10 MMBtu/hr heater, fired on natural gas or plant gas
II.A.9	F-501: Vacuum Furnace 11 MMBtu/hr furnace, fired on plant gas and/or natural gas
II.A.10	B-1: Boiler #1 23,000 lbs/hr steam furnace, fired on plant gas and/or natural gas
II.A.11	B-2: Boiler #2 23,000 lbs/hr steam furnace, fired on plant gas and/or natural gas
II.A.12	Distillate Dewaxing Unit (MDDW)
II.A.13	Vacuum Distillation Unit (VDU)
II.A.14	Cooling Towers Two (2) cooling towers
II.A.15	Sulfur Recovery Unit (NASH Unit)
II.A.16	Two Railcar Loading Terminals North and South Loading Terminals
II.A.17	Finished Products and Intermediates Loading Rack Submerged Loading Normal Service
II.A.18	Vapor Recovery Unit (VRU) Vapor Recovery Unit on Gasoline Loading Rack
II.A.19	North Flare Flare for combusting gases from process relief valves and excess plant gas
II.A.20	South Flare Flare for combusting gases from process relief valves and excess plant gas

- II.A.21 **Isomerization Furnaces**
Two (2) Isomerization Unit Process Furnaces
- II.A.22 **HTR-50401**
Isomerization Unit Hot Oil Heater (1.5 MMBtu/hr)
- II.A.23 **HTR-50402**
Isomerization Unit Stabilizer Heater (10 MMBtu/hr)
- II.A.24 **Emergency Equipment**
Two (2) diesel fired emergency firewater pumps: 460 hp & 300 hp
One (1) diesel fired emergency generator: 369 hp
- II.A.25 **Naphtha Railcar Loading System**
- II.A.26 **Tank Farms Process Drains**
- II.A.27 **Tank 00: Storage vessel - API Separator Wastewater**
9,038 barrel storage vessel with fixed roof
- II.A.28 **Tank 1: yellow wax crude**
61,668 barrel storage vessel with internal floating roof
- II.A.29 **Tank 2: Storage vessel - yellow wax crude**
28,409 barrel storage vessel with floating roof
- II.A.30 **Tank 3: Storage vessel - vacuum tower bottoms**
9,916 barrel storage vessel with fixed roof
- II.A.31 **Tank 9: residual oil #6**
4,979 barrel storage vessel with vertical fixed roof
- II.A.32 **Tank 10: Storage vessel - HT distillate**
4,849 barrel storage vessel with fixed roof
- II.A.33 **Tank 11: Storage vessel - gas oil**
4,874 barrel storage vessel with fixed roof
- II.A.34 **Tank 12: Storage vessel - gas oil**
4,991 barrel storage vessel with fixed roof
- II.A.35 **Tank 15: yellow wax crude**
30,598 barrel storage vessel with internal floating roof

II.A.36	Tank 16: light to heavy distillates 9,918 barrel storage vessel with vertical fixed roof
II.A.37	Tank 17: light to heavy distillates 9,738 barrel storage vessel with vertical fixed roof
II.A.38	Tank 18: Storage vessel - yellow wax crude 33,409 barrel storage vessel with floating roof
II.A.39	Tank 19: refinery stormwater surge 11,207 barrel storage vessel with vertical fixed roof
II.A.40	Tank 20: Storage vessel - heavy vacuum gas oil 11,207 barrel storage vessel with fixed roof
II.A.41	Tank 23: Storage vessel - petroleum liquids 33,391 barrel storage vessel with floating roof
II.A.42	Tank 24: Storage vessel - yellow wax crude 33,391 barrel storage vessel with floating roof
II.A.43	Tank 25: light to heavy distillates 6,658 barrel storage vessel with vertical fixed roof
II.A.44	Tank 26: petroleum liquids 6,463 barrel storage vessel with internal floating roof
II.A.45	Tank 27: distillates 10,979 barrel storage vessel with internal floating roof
II.A.46	Tank 28: distillates 10,990 barrel storage vessel with internal floating roof
II.A.47	Tank 29: distillates 9,800 barrel storage vessel with vertical fixed roof
II.A.48	Tank 31: Storage vessel - diesel additive 200 barrel storage vessel with fixed roof
II.A.49	Tank 41: distillates 4,162 barrel storage vessel with internal floating roof

II.A.50	Tank 42: distillates 5,260 barrel storage vessel with internal floating roof
II.A.51	Tank 43: distillates 1,523 barrel storage vessel with internal floating roof
II.A.52	Tank 47: light distillates 627 barrel storage vessel with internal floating roof
II.A.53	Tank 48: light distillates 627 barrel storage vessel with internal floating roof
II.A.54	Tank 61: petroleum liquids 9,905 barrel storage vessel with fixed roof
II.A.55	Tank 62: recovered slop oil 246 barrel storage vessel with fixed roof
II.A.56	Tank 81: NASH 2,604 barrel storage vessel with fixed roof
II.A.57	Tank 83: caustic 808 barrel storage vessel with fixed roof
II.A.58	Tank 84: caustic 120 barrel storage vessel with fixed roof
II.A.59	Tank 85: caustic 271 barrel storage vessel with fixed roof
II.A.60	Tank 86: caustic 977 barrel storage vessel with fixed roof
II.A.61	Tank 101: petroleum liquids 33,634 barrel storage vessel with floating roof
II.A.62	Tank 102: petroleum liquids 22,157 barrel storage vessel with internal floating roof
II.A.63	Tank 103: petroleum liquids 33,580 barrel storage vessel with floating roof

II.A.64 **Tank 104: petroleum liquids**

33,508 barrel storage vessel with floating roof

II.A.65 **Tank 105: petroleum liquids**

15,887 barrel storage vessel with floating roof

II.A.66 **Tank 106: petroleum liquids**

15,848 barrel storage vessel with internal floating roof

II.B Requirements and Limitations

II.B.1 **The Refinery**

II.B.1.a Visible emissions from the following emission points shall not exceed the following values:

1. Point or fugitive emissions associated with the installation or control facilities from combustion sources shall not exceed 10% opacity.
2. Diesel combustion shall not exceed 20% opacity.
3. Fugitive emissions shall not exceed 15% opacity, except fugitive dust.
4. Fugitive dust emissions shall not exceed 20% opacity and 10% at the property boundary.
5. Flares shall produce no visible emissions except for periods not to exceed five minutes during any two consecutive hours.
6. All other emission points shall not exceed 20% opacity.

Opacity observations of emissions from stationary sources (other than the flares) shall be conducted according to 40 CFR 60, Appendix A, Method 9 or as directed by the Director.

Visible fugitive dust emissions from haul-road traffic and mobile equipment in operational areas shall not exceed 20% opacity at any point. Visible emission determinations shall use procedures similar to Method 9. The normal requirement for observations to be made at 15-second intervals over a six-minute period, however, shall not apply. Visible emissions shall be measured at the densest point of the plume but at a point not less than 1/2 vehicle length behind the vehicle and not less than 1/2 the height of the vehicle.

Opacity observations of emissions from the flares shall be conducted according to 40 CFR 60, Appendix A, Method 22. [R307-401]

II.B.1.b Silver Eagle shall use natural gas, and/or plant fuel gas as a primary fuel in all plant fuel burning equipment except as otherwise specified. Fuel oil may be fired as a backup fuel only during periods of natural gas curtailment or to test oil-burning capability of units. Testing may be done one hour per month. [R307-401]

II.B.1.c Silver Eagle shall use only natural gas, and /or plant fuel gas that has an H₂S content no higher than 0.10 grain/dscf (based on a 3-hour rolling average) as a fuel for any fuel burning devices subject to 40 CFR 60 Subpart J. [R307-401]

- II.B.1.d All fuel oil consumed shall be ultra-low sulfur diesel or better. Sulfur content shall be determined by ASTM Method D-4294-89, or approved equivalent. [R307-401]
- II.B.1.e VOC products shall be stored only in tanks that have the appropriate emissions controls as specified by NSPS and/or R307-327. Silver Eagle shall maintain records to demonstrate the true vapor pressure of the products stored in each tank and the type of emission controls applied to each tank. [R307-401]
- II.B.1.f Silver Eagle shall comply with all applicable provisions of SIP Section IX Part H.11.g. Petroleum Refineries. [SIP Section IX.H.11]
- II.B.2 **Conditions and Limitations**
- II.B.2.a Silver Eagle shall not exceed the following throughput value:
15,000 barrels per day (bpd) of crude on a 30-day rolling average.
Throughput shall be determined through the use of flow meters.
[R307-401-8]
- II.B.2.b Total emissions of greenhouse gases (GHG) shall not exceed 98,000 tons per rolling 12-month period. Compliance with this limitation shall be demonstrated using the monthly GHG emission values recorded for 40 CFR 98 Subpart C, "General Stationary Fuel Combustion Sources", and Subpart Y, "Petroleum Refineries". Each month a new 12-month rolling total will be calculated using the values from the previous 12 months. Compliance shall be determined monthly. [40 CFR 98, R307-401]
- II.B.2.c Total emissions to the atmosphere from all regulated emission points and all regulated fugitive emissions shall not exceed the following rates:
- | Pollutant/Period | Emission Limit | Units |
|----------------------------|----------------|------------------------------|
| PM ₁₀
Annual | 14.47 | tons/rolling 12-month period |
| SO ₂
Annual | 2.03 | tons/rolling 12-month period |
| NO _x
Annual | 67.5 | tons/rolling 12-month period |
- [R307-401]
- II.B.2.d The following combustion emission factors shall be used to calculate emissions:
- | Pollutant/Source | Emission Factors | Units | Reference |
|---|------------------|-----------|------------|
| SO ₂
Natural Gas Combustion | 0.60 | lbs/MMscf | AO limit |
| Plant Fuel Gas Combustion
(Note 2) | (Note 1) | lbs/MMscf | Calculated |

NO _x			
Natural Gas or Plant Fuel Gas Combustion	100	lbs/MMscf	AP-42
Natural Gas or Plant Fuel Gas with Low NO _x burners	50	lbs/MMscf	AP-42
PM ₁₀			
Natural Gas or Plant Fuel Gas Combustion	5	lbs/MMscf	AO limit

Note 1: Emission factor shall be calculated from the H₂S content of the plant fuel gas as shown in Condition II.B.2.e.

Note 2: The term plant fuel gas as used in this permit means either refinery generated fuel gas or a mixture of refinery generated plant fuel gas and natural gas.

[R307-401]

II.B.2.e The SO₂ emission factors for plant fuel gas shall be determined as follows:

The H₂S content of the plant fuel gas shall be measured, in parts per million by volume (ppmv), by a continuous emissions monitor located downstream of the refinery fuel gas drum. Daily plant fuel gas emission factors shall be calculated as follows using average hourly H₂S content data from the CEM:

$(\text{lb SO}_2 / 10^6 \text{ scf gas}) = (24 \text{ hr avg. ppmv H}_2\text{S}) / 10^6 * (64 \text{ lb SO}_2 / \text{lb mole}) / (385.65 \text{ scf} / \text{lb mole measured at } 68^\circ\text{F})$

[R307-401]

II.B.2.f Compliance with the SO₂, NO_x and PM₁₀ emissions limitations in Condition II.B.2.c shall be determined by applying the appropriate emissions factors from Conditions II.B.2.d and II.B.2.e to the relevant quantities of fuel combusted in all furnaces, heaters, and boilers as follows:

For plant fuel gas the following equation shall be used:

Daily Emissions = Emission Factor (lbs/MMscf) * Gas Consumption (MMscf/24 hrs) / (2,000 lb/ton)

The gas stream, providing natural gas/plant fuel gas to all furnaces, heaters and boilers, shall be measured by meters monitoring the flow to each combustion device. Total annual emissions shall be calculated using the sum of all the individual meters.

Fuel gas flow to the individual meters will be normalized to equal the amount of fuel gas consumed as recorded by the supplied natural gas custody transfer meter and the refinery Green House Gas Meter that records the amount of fuel gas generated by the refinery.

SRU turnaround emissions are not to be included in the emissions limitations of Condition II.B.2.c. [R307-401]

II.B.2.g Compliance with annual limitations shall be determined on a rolling 12-month total. Based on the first day of each month, the previous month's daily (24-hour) emissions shall be summed for a monthly total. Annual emissions shall be the summation of the last 12 monthly totals. Results shall be tabulated monthly. [R307-401]

II.B.2.h Silver Eagle shall install, calibrate, maintain, and operate a continuous monitoring system located downstream of the primary fuel mixing drum to determine compliance with the SO₂ emission limits and the H₂S limits of NSPS subpart J. The owner/operator shall record the output of the system, for measuring the H₂S concentration in the plant fuel gas. SO₂ emissions rates shall be calculated assuming 100% of the H₂S in the plant fuel gas is combusted forming SO₂ at a ratio of 34 lbs of H₂S equals 64 lbs of SO₂. The monitoring system shall comply with all applicable sections of R307-170 and 40 CFR 60, Appendix B, Specification 7 - H₂S. Notification about RATA testing shall be submitted 45 days prior to testing. [R307-401]

II.B.2.i Silver Eagle generated plant fuel gas shall be continuously monitored with equipment that will determine the quantity of plant fuel gas consumed. The meters outputs shall be located such that an inspector/operator can safely read the output at any time. An accuracy check of the transmitters and/or transducers for the meter measurement parameters shall be performed at least once every 120 days. The response of each individual transmitter/transducer shall be checked against a standard to verify on overall accuracy of the meter reading to within plus or minus two (2) percent of the full scale of the meter. The accuracy of each transmitter/transducer tested shall be calculated as follows:

$$ACC = 100 \times [(Standard - Reading) / Full Scale]$$

If each transmitter/transducer has an accuracy (ACC) value within plus or minus one (1) percent of transducer full scale, the meter system shall be considered to have passed the two (2) percent overall accuracy criterion. The specification for the measurement standard(s) and/or alternative methods of calculating overall accuracy shall be established by the company and shall be submitted to the Director for approval. [R307-401, 40 CFR 75]

II.B.3 **Vacuum Distillation Unit (VDU)**

II.B.3.a All vacuum ejector exhaust from the vacuum distillation unit shall be incinerated in one of the process heaters. [R307-401]

II.B.4 **Sulfur Recovery Unit (SRU)**

II.B.4.a The SRU shall be at least 95% effective in removing sulfur from the streams fed into the unit. Shutdown for routine maintenance (expected every two to five years for a period of approximately 15 days) for the SRU shall only be scheduled during the period from April through October. The projected periods/forecasts for the SRU (NASH) turnarounds shall be submitted to the Director by the end of the first calendar quarter of each year planned and 30 days prior to the turnaround a notice shall be given to the Director. The emissions increase (above normal operations) experienced during the SRU routine turnarounds shall not be included in the annual compliance demonstration of condition II.B.2.c. Copies of the SRU Operating Instruction/Standard shall be made available to the Director upon request.

In the event the SRU efficiency drops and remains below 95%, the refinery shall isolate the problem within five days from discovery. A permanent repair or modification shall be accomplished within 15 days from the day of discovery. If the repair proves to be satisfactory, i.e., no repeat failure modes of the same type occur for at least 30 days, the efficiency drop shall not be considered a violation. A separate failure within the 30-day period shall constitute a new event.

SRU efficiency shall be estimated and reported to the Director a minimum of once per year via the following method: Over a minimum of three and a maximum of seven operating days or other period of time as approved by the Director, the total H₂S output from the SRU plant fuel gas (prior to mixing with natural gas) and the concentration of sulfur in the inlet and outlet

streams from the low pressure NASH unit shall be measured. From these parameters the SRU efficiency shall be calculated. An alternate method may be used if approved by the Director. [R307-401]

II.B.4.b The SRU throughput rate during SRU testing will be used to determine the maximum monthly operating rate of the unit. The SRU throughput rate during the test plus 10% becomes the monthly maximum allowable operating rate. Additional testing at higher throughput rates will be required to establish a higher monthly maximum allowable operating rate if the existing monthly maximum allowable throughput rate is to be exceeded. The maximum monthly SRU operating rate so determined shall in no way supersede the constraints established in the emissions limitations section of the AO. [R307-401]

II.B.4.c Silver Eagle shall notify the Director of test dates at least 30 days prior to a stack test or SRU compliance test. A pretest conference shall be held if directed by the Director. The conference shall be held at least 30 days prior to the test and shall be attended by the owner/operator, the tester, and the Director or representative. [R307-401]

II.B.5 **Vapor Recovery Unit (VRU)**

II.B.5.a VRU on Loading Rack: The loading device shall not leak and shall be designed and operated to allow no more than an average of 15cc drainage per disconnect for five consecutive disconnects. All loading and vapor lines shall be equipped with fittings which make a vapor tight connection and shall be closed prior to disconnection to prevent release of VOC. In no case shall vapor emissions to the atmosphere exceed 0.64 lb/1000 gallons gasoline/ethanol transferred. An approved inspection program shall be in place prior to the compliance test. Testing procedures shall be consistent with the requirements of R307-328. Necessary repairs to lines, joints, etc., shall be completed as soon as practicable as specified in R307-328. All transport vessels loading gasoline/gasohol shall be equipped with compatible bottom load connections and vapor recovery systems. [R307-401]

II.B.6 **Emergency Equipment**

II.B.6.a All emergency generators shall be used for electricity producing operation only during the periods when electric power from the public utilities is interrupted, or for regular maintenance of the generators. Records documenting generator usage shall be kept in a log and they shall show the date the generator was used, the duration in hours of the generator usage, and the reason for each generator usage. Firewater pumps shall be used only for emergency and maintenance/testing purposes.

Emergency generators and firewater pumps hours of operation for maintenance firing purposes shall not exceed 100 hours per rolling 12-month total for each. To determine compliance with a rolling 12-month total, based on the first day of each month a new 12-month total shall be calculated using data from the previous 12 months. Monthly calculations shall be made no later than 20 days after the end of each calendar month. [R307-401]

Section III: APPLICABLE FEDERAL REQUIREMENTS

In addition to the requirements of this AO, all applicable provisions of the following federal programs have been found to apply to this installation. This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including UAC R307.

NSPS (Part 60), A: General Provisions

NSPS (Part 60), J: Standards of Performance for Petroleum Refineries

NSPS (Part 60), Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

NSPS (Part 60), K: Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978
NSPS (Part 60), Ka: Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984
NSPS (Part 60), Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

NSPS (Part 60), GGG: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006

NSPS (Part 60), QQQ: Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems

NSPS (Part 60), IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

MACT (Part 63), A: General Provisions

MACT (Part 63), ZZZZ: NESHAPs for Stationary Reciprocating Internal Combustion Engines

MACT (Part 63), BBBB: NESHAPs for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities

Title V (Part 70) Area Source

PERMIT HISTORY

This AO is based on the following documents:

Is Derived From	Source Submitted NOI dated May 26, 2016
Is Derived From	Source Submitted NOI dated July 7, 2016
Incorporates	Additional Information Received dated September 14, 2016
Incorporates	Additional Information Received dated October 3, 2016
Supersedes	AO DAQE-AN101240028-15 dated March 9, 2015

ADMINISTRATIVE CODING

The following information is for UDAQ internal classification use only:

Davis County

CDS SM

MACT (Part 63), Nonattainment or Maintenance Area, Title V (Part 70) Area Source, PM₁₀ SIP / Maint Plan, NSPS (Part 60)

ACRONYMS

The following lists commonly used acronyms and associated translations as they apply to this document:

40 CFR	Title 40 of the Code of Federal Regulations
AO	Approval Order
BACT	Best Available Control Technology
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
CDS	Classification Data System (used by EPA to classify sources by size/type)
CEM	Continuous emissions monitor
CEMS	Continuous emissions monitoring system
CFR	Code of Federal Regulations
CMS	Continuous monitoring system
CO	Carbon monoxide
CO ₂	Carbon Dioxide
CO ₂ e	Carbon Dioxide Equivalent - 40 CFR Part 98, Subpart A, Table A-1
COM	Continuous opacity monitor
DAQ/UDAQ	Division of Air Quality
DAQE	This is a document tracking code for internal UDAQ use
EPA	Environmental Protection Agency
FDCP	Fugitive dust control plan
GHG	Greenhouse Gas(es) - 40 CFR 52.21 (b)(49)(i)
GWP	Global Warming Potential - 40 CFR Part 86.1818-12(a)
HAP or HAPs	Hazardous air pollutant(s)
ITA	Intent to Approve
LB/HR	Pounds per hour
MACT	Maximum Achievable Control Technology
MMBTU	Million British Thermal Units
NAA	Nonattainment Area
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOI	Notice of Intent
NO _x	Oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PM ₁₀	Particulate matter less than 10 microns in size
PM _{2.5}	Particulate matter less than 2.5 microns in size
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
R307	Rules Series 307
R307-401	Rules Series 307 - Section 401
SO ₂	Sulfur dioxide
Title IV	Title IV of the Clean Air Act
Title V	Title V of the Clean Air Act
TPY	Tons per year
UAC	Utah Administrative Code
VOC	Volatile organic compounds