



State of Utah

GARY R. HERBERT
Governor

GREG BELL
Lieutenant Governor

Department of
Environmental Quality

Amanda Smith
Executive Director

DIVISION OF AIR QUALITY
Cheryl Heying
Director

DAQE-AN0101230027-09

November 3, 2009

Mike Astin
Holly Refining & Marketing Company
393 S 800 W
Woods Cross, UT 84087-1435

Dear Mr. Astin:

Re: Approval Order: Modifications to DAQE-AN0101230023-07 to Incorporate Consent Decree Requirements, Davis County; CDS A; MACT (Part 63), NESHAP (Part 61), NSPS (Part 60), NSR, Nonattainment or Maintenance Area, Title V (Part 70)
Project Number: N010123-0027

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,

M. Cheryl Heying, Executive Secretary
Utah Air Quality Board

MCH:JJ:kw

cc: Mike Owens
Davis County Health Department

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

**APPROVAL ORDER: Modifications to DAQE-AN0101230023-07
to Incorporate Consent Decree Requirements.**

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

APPROVAL ORDER NUMBER

DAQE-AN0101230027-09

Date: November 3, 2009

**Holly Refining & Marketing Company
Woods Cross Refinery
Source Contact:
Mr. Bo Bothwell
Phone: (801) 299-6619**

**M. Cheryl Heying
Executive Secretary
Utah Air Quality Board**

Abstract

Holly Refining and Marketing (Holly) entered into a consent decree (CD) on July 2, 2008. In compliance with paragraph 137 of that CD, Holly submitted a NOI on September 19, 2008. This NOI was to incorporate the limitations and standards imposed by the CD into Holly's AO. On December 23, 2008, Holly submitted an addendum to the NOI to incorporate the requirements of paragraph 46. These various requirements are summarized as follows:

- Incorporate new permit limits on heaters 8H1 and 12H1 based on performance tests conducted in October 2008
- Inclusion of a small portable electric generator for use as an emergency power supply with an associated hours of operation limitation
- Make several changes to the Indicators section of Holly's AO relating to SRU efficiency and monitoring
- Impose a restriction on the burning of fuel oil except during periods of natural gas curtailment. Limit the throughput of the catalytic cracking unit to 3,250,000 barrels per year

The new diesel generator and the new heater permit limits will result in an increase in allowable emissions from the refinery. Particulate matter, SO₂ and CO emissions will all increase by less than 1 ton per year. Emissions of NO_x will increase by 39.9 tons per year, primarily as a result of the more accurate values provided by performance testing on heaters 8H1 and 12H1. While this is an increase over the values from Holly's existing AO, the new totals are less than the existing limitations from section IX.H.2.f of the PM₁₀ SIP. Holly is located in Davis County, which is a maintenance area for ozone. Holly is also defined as a contributing source for the Salt Lake County PM₁₀ nonattainment area.

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:

Holly Refining & Marketing Company
393 S 800 W
Woods Cross, UT 84087-1435

Permitted Location:

Woods Cross Refinery
393 South 800 West
Woods Cross, UT 84087-1435

UTM coordinates: 424,000 m Easting, 4,526,227 m Northing

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 Executive Secretary or Executive Secretary'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]. [R307-415-6b]
- 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 Executive Secretary 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 R307-150 Series. Inventories, Testing and Monitoring. [R307-150]
- I.7 The owner/operator shall comply with UAC R307-107. General Requirements: Unavoidable Breakdowns. [R307-107]
- I.8 Holly shall continue to install the new gas oil hydrocracking unit, vacuum tower, associated heaters, two new SRUs with tail gas treatment, upgrade the FCCU and solvent deasphalting unit, make the required changes in storage tanks, and operate its facility in accordance with the terms and conditions of this AO that were written pursuant to Holly's notice of intent submitted to the Division of Air Quality on October 5, 2006.
- Holly shall notify the Executive Secretary in writing when the installation of the equipment has been completed and the equipment is operational, as an initial compliance inspection is required. To insure proper credit when notifying the Executive Secretary, send your correspondence to the Executive Secretary, attn: Compliance Section.
- If construction and/or installation have not been completed within eighteen months from the date of this AO, the Executive Secretary shall be notified in writing on the status of the construction and/or installation. At that time, the Executive Secretary shall require documentation of the continuous construction and/or installation of the operation and may revoke the AO in accordance with R307-401-18. [R307-401]

Section II: SPECIAL PROVISIONS

II.A The approved installations shall consist of the following equipment:

- II.A.1 **Holly Refinery**
Permitted Source

- II.A.2 **(4-1) 4H1: FCC feed heater**
68.4 MMBtu/hr process furnace, fired on plant gas, restricted to 39.9 MMBtu/hr, equipped with low-NO_x burners

- II.A.3 **(4-4a) 4K1A: KVG compressor west**
660 hp internal combustion engine, fired on natural gas

- II.A.4 **(4-4b) 4K1B: KVG compressor east**
660 hp internal combustion engine, fired on natural gas

- II.A.5 **(6-1) 6H1: Reformer charge and reheater furnace**
54.7 MMBtu/hr process furnace, fired on plant gas

- II.A.6 **(6-2) 6H3: Reformer reheat furnace**
37.7 MMBtu/hr process furnace, fired on plant gas

- II.A.7 **(6-3) 6H2: Prefractionator reboiler heater**
12.0 MMBtu/hr process furnace, fired on plant gas

- II.A.8 **(6-4a) 6K1 SVG compressor east**
325 hp internal combustion engine, fired on natural gas

- II.A.9 **(6-4b) 6K2: SVG compressor west**
325 hp internal combustion engine, fired on natural gas

- II.A.10 **(7-1) 7H3: HF alkylation depropanizer reboiler**
33.3 MMBtu/hr process furnace, fired on plant gas

- II.A.11 **(7-2) 7H1: HF alkylation regeneration furnace**
4.4 MMBtu/hr process furnace, fired on plant gas

- II.A.12 **(8-1) 8H1: Crude furnace**
99.0 MMBtu/hr process furnace, fired on plant gas, equipped with NGULNB

- II.A.13 **(9-1) 9H1: DHT reactor charge heater**
8.1 MMBtu/hr process furnace, fired on plant gas

- II.A.14 **(9-2) 9H2: DHT stripper reboiler**
4.1 MMBtu/hr process furnace, fired on plant gas

- II.A.15 **(10-2) 10H1: Asphalt mix heater**
13.2 MMBtu/hr process furnace, fired on plant gas

- II.A.16 **(11-1) 11H1: SRGP depentanizer reboiler**
24.2 MMBtu/hr process furnace, fired on plant gas

- II.A.17 **(11-2) 11K1: Clark compressor**
600 hp internal combustion engine, fired on natural gas

- II.A.18 **(12-1) 12H1: NHDS reactor charge furnace**
50.2 MMBtu/hr process furnace, fired on plant gas, equipped with NGULNB
- II.A.19 **(13-1) 13H1: Isomerization reactor feed furnace**
6.5 MMBtu/hr process furnace, fired on plant gas
- II.A.20 **(17-1) SRU - tailgas incinerator**
For SRU under 20 LTPD
- II.A.21 **(19-1) DHT reactor charge heater**
18.1 MMBtu/hr Process Furnace, fired on plant gas, equipped with low-NO_x burners
- II.A.22 **(45-1) 45H1: Asphalt mix and storage furnace**
15.3 MMBtu/hr process furnace, fired on plant gas, equipped with low-NO_x burners
- II.A.23 **(68-2) 68H2: North in-tank asphalt heater**
0.8 MMBtu/hr tank heater, fired with natural gas
- II.A.24 **(68-3) 68H3: South in-tank asphalt heater**
0.8 MMBtu/hr tank heater, fired with natural gas
- II.A.25 **(51-4) Boiler #4**
35.6 MMBtu/hr boiler, fired on plant gas
- II.A.26 **(51-5) Boiler #5**
70.0 MMBtu/hr boiler, fired on plant gas
- II.A.27 **(51-6) CO boiler/FCC scrubber**
60.0 MMBtu/hr boiler, fired on plant gas
- II.A.28 **(51-7) FCC 34" CO boiler bypass**
34" Stack
- II.A.29 **(51-8) #8 Boiler**
92.7 MMBtu/hr boiler, fired on plant gas, equipped with low-NO_x burner
- II.A.30 **(66-1) Process flare south**
Flare
- II.A.31 **(66-2) Process flare north**
Flare
- II.A.32 **(68-1) Propane pit flare**
Flare
- II.A.33 **Emergency equipment**
1. Diesel powered water well No. 3
2. Caterpillar diesel fire pump No. 1
3. Caterpillar diesel fire pump No. 2

4. Detroit Diesel fire pump
5. Diesel powered plant air backup compressors (3)
6. Diesel powered standby generator, Boiler House
7. Diesel powered standby generator, Central Control Room

- II.A.34 **Three amine units**
Two new units
- II.A.35 **Fluid catalytic cracking unit**
FCC includes 02 skid, item #4-97-0010
- II.A.36 **DHT**
Distillate hydro-desulfurization treatment unit
- II.A.37 **Cooling tower #7**
- II.A.38 **Gas oil hydrocracking unit**
Includes reactor charge heater and fractionator charge heater
- II.A.39 **20H1: Reactor charge heater**
14.9 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB
- II.A.40 **20H2: Fractionator charge heater**
47.1 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB
- II.A.41 **Vacuum tower and vacuum furnace heater**
15.2 MMBtu/hr using ultra low-NO_x burners
- II.A.42 **Hot oil heater**
99 MMBtu/hr using ultra low-NO_x burners
- II.A.43 **Asphalt tank heaters**
Two new in-tank heaters sized at 0.8 MMBtu/hr each
- II.A.44 **Tank 167**
1,300,000 gallon sour water storage tank
- II.A.45 **SRU/TGI (2)**
Two new Claus sulfur recovery units with tail gas recovery, each sized at 50 long tons of sulfur per day
- II.A.46 **Sour water strippers (2)**
One existing unit (#18), and one new unit (#22) with ammonia stripper
- II.A.47 **NaSH sour gas treatment unit**
Sized at 50 long tons of sulfur per day

- II.A.48 **Hydrogen plant**
Two hydrogen reformer feed furnaces, each sized at 123.1 MMBtu/hr using ultra low-NO_x burners
- II.A.49 **Storage tanks**
Three 14,000 Bbl NaSH tanks (two currently installed)
Two 7,100 Bbl caustic tanks (one currently installed)
One 80,000 Bbl fuel oil tank (not yet installed)
One 50,000 Bbl cutter tank (not yet installed)
- II.A.50 **Crude heater**
35 MMBtu/hr using ultra low-NO_x burners
- II.A.51 **Tank 23: Storage vessel - petroleum liquids**
14,600 Bbl capacity storage tank with a fixed roof
- II.A.52 **Tank 35: Storage vessel - petroleum liquids**
105,000 Bbl capacity storage tank with a fixed roof
- II.A.53 **Tank 71: Storage vessel - petroleum liquids**
67,155 Bbl capacity storage tank with internal floating roof, primary and secondary seals
- II.A.54 **Tank 72: Storage vessel - petroleum liquids**
124,388 bbl storage vessel with floating roof, primary and secondary seals
- II.A.55 **Tank 79**
10,000 Bbl capacity storage tank with a fixed roof
- II.A.56 **Tank 323: Storage vessel - petroleum liquids**
14,686 bbl capacity storage tank with internal floating roof, and primary seal
- II.A.57 **ETF portable diesel generator**
135 kW diesel-fired generator
- II.A.58 **SO₂ Emissions Cap Sources**
SO₂ Emissions Cap Sources: includes (4-4b) 4K1B: KVG compressor east, (8-1) 8H1: Crude furnace, (10-2) 10H1: Asphalt mix heater, 20H2: Fractionator charge heater, ETF portable diesel generator, (4-4a) 4K1A: KVG compressor west, Hydrogen plant, (6-1) 6H1: Reformer charge and reheater furnace, (7-2) 7H1: HF alkylation regeneration furnace, (51-4) Boiler #4, (68-2) 68H2: North in-tank asphalt heater, (6-4a) 6K1 SVG compressor east, (7-1) 7H3: HF alkylation depropanizer reboiler, (9-1) 9H1: DHT reactor charge heater, 20H1: Reactor charge heater, (6-2) 6H3: Reformer reheat furnace, (45-1) 45H1: Asphalt mix and storage furnace, (51-8) #8 Boiler, (19-1) DHT reactor charge heater, (4-1) 4H1: FCC feed heater, (6-3) 6H2: Prefractionator reboiler heater, (13-1) 13H1: Isomerization reactor feed furnace, Vacuum tower and vacuum furnace heater, Asphalt tank heaters, (12-1) 12H1: NHDS reactor charge furnace, (51-5) Boiler #5, Hot oil heater, (9-2) 9H2: DHT stripper reboiler, (11-1) 11H1: SRGP depentanizer reboiler, (68-3) 68H3: South in-tank asphalt heater, (6-4b) 6K2: SVG compressor west

II.A.59 NO_x Emissions Cap Sources

NO_x Emissions Cap Sources: includes (4-4b) 4K1B: KVG compressor east, (8-1) 8H1: Crude furnace, (10-2) 10H1: Asphalt mix heater, 20H2: Fractionator charge heater, ETF portable diesel generator, (4-4a) 4K1A: KVG compressor west, Hydrogen plant, (6-1) 6H1: Reformer charge and reheater furnace, (7-2) 7H1: HF alkylation regeneration furnace, (51-4) Boiler #4, (68-2) 68H2: North in-tank asphalt heater, (6-4a) 6K1 SVG compressor east, (7-1) 7H3: HF alkylation depropanizer reboiler, (9-1) 9H1: DHT reactor charge heater, (17-1) SRU - tailgas incinerator, 20H1: Reactor charge heater, SO₂ Emissions Cap Sources, (6-2) 6H3: Reformer reheat furnace, (45-1) 45H1: Asphalt mix and storage furnace, (51-8) #8 Boiler, (19-1) DHT reactor charge heater, SRU/TGI (2), (4-1) 4H1: FCC feed heater, (6-3) 6H2: Prefractionator reboiler heater, (13-1) 13H1: Isomerization reactor feed furnace, (51-7) FCC 34" CO boiler bypass, Vacuum tower and vacuum furnace heater, Asphalt tank heaters, (12-1) 12H1: NHDS reactor charge furnace, (51-5) Boiler #5, Hot oil heater, (9-2) 9H2: DHT stripper reboiler, (11-1) 11H1: SRGP depentanizer reboiler, (51-6) CO boiler/FCC scrubber, (68-3) 68H3: South in-tank asphalt heater, (6-4b) 6K2: SVG compressor west

II.A.60 PM₁₀ Emissions Cap Sources

PM₁₀ Emissions Cap Sources: includes (8-1) 8H1: Crude furnace, (10-2) 10H1: Asphalt mix heater, 20H2: Fractionator charge heater, ETF portable diesel generator, Hydrogen plant, (6-1) 6H1: Reformer charge and reheater furnace, (7-2) 7H1: HF alkylation regeneration furnace, (51-4) Boiler #4, (68-2) 68H2: North in-tank asphalt heater, (7-1) 7H3: HF alkylation depropanizer reboiler, (9-1) 9H1: DHT reactor charge heater, (17-1) SRU - tailgas incinerator, 20H1: Reactor charge heater, (6-2) 6H3: Reformer reheat furnace, (45-1) 45H1: Asphalt mix and storage furnace, (51-8) #8 Boiler, (19-1) DHT reactor charge heater, SRU/TGI (2), (4-1) 4H1: FCC feed heater, (6-3) 6H2: Prefractionator reboiler heater, (13-1) 13H1: Isomerization reactor feed furnace, Vacuum tower and vacuum furnace heater, Asphalt tank heaters, (12-1) 12H1: NHDS reactor charge furnace, (51-5) Boiler #5, Hot oil heater, (9-2) 9H2: DHT stripper reboiler, (11-1) 11H1: SRGP depentanizer reboiler, (51-6) CO boiler/FCC scrubber, (68-3) 68H3: South in-tank asphalt heater

II.B Requirements and Limitations

II.B.1 Conditions on Permitted Source

II.B.1.a Stack testing to determine compliance shall be performed in accordance with the requirements of Section IX.H.1.a of the PM₁₀ SIP. The owner/operator shall test SO₂ emissions from the (51-6) CO Boiler/FCC Scrubber. The source shall be tested if directed by the Executive Secretary.

The CO Boiler/FCC Scrubber shall be tested at least once every five years.

SO₂ emissions shall be tested using 40 CFR 60, Appendix A, Method 6, 6A, 6B, 6C, or other testing methods approved by the Executive Secretary. [R307-150]

II.B.1.b The emissions of NO_x from heaters 8H1 and 12H1 shall not exceed 0.10 lb/mmBtu on a 3-hour average basis each. Compliance shall be determined by stack test to be performed every five (5) years.

Except as specified below, emissions of NO_x shall be determined through use of 40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, 7E, or other testing methods approved by the Executive Secretary.

Emissions of NO_x from the FCCU shall be determined through use of a CEM. The monitoring system shall comply with all applicable sections of R307-170-1, and 40 CFR 60, Appendix B, Specifications 2 (NO_x) and 3 (O₂). [R307-401, R307-170]

II.B.1.c The applicant shall provide a notification of the test date at least 30 days prior to the test. A pretest conference shall be held if directed by the Executive Secretary. It shall be held at least 30 days prior to the test between the owner/operator, the tester, and the Executive Secretary. The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, and of the Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA).

A sample location shall be chosen as outlined in 40 CFR 60 Appendix A, Method 1. The volumetric flow rate shall be determined by 40 CFR 60 Appendix A, Method 2.

To determine mass emission rates, the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary to give the results in the specified units of the emission limitation.

For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum production achieved in the previous three years. [R307-165]

II.B.1.d Visible emissions shall not exceed the following specifications:

All scrubbers: 15% opacity
All baghouses: 10% opacity
All combustion sources without controls: 10% opacity
FCC Unit/(51-6): 20% opacity
(8-1) 8H1 Crude Furnace: 20% opacity
Flares - 20% opacity
All fugitive emission points - 20% opacity

Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9. [R307-401]

II.B.1.e The amine plants shall reduce the H₂S content of the refinery fuel gas to 0.10 grain/dscf (160 ppm) or less. The owner/operator has installed and maintains a continuous monitoring system for monitoring the H₂S content of the refinery fuel gas and a continuous recorder to record the H₂S in the refinery fuel gas. The monitoring system shall comply with all applicable sections of R307-170-1, and 40 CFR 60, Appendix B, Specification 7. [R307-401]

II.B.1.f Except as outlined in conditions II.B.1.g and II.B.1.h, the total hours of operation for testing and maintenance purposes for all emergency diesel-powered equipment shall not exceed 300 hours per 12-month period, without prior approval in accordance with R307-401. Compliance

with the annual limitation shall be determined on a rolling 12-month total. By the last day of each month a new 12-month total shall be calculated using the previous 12 months. Records of the hours of operation shall be kept for all periods when the plant is in operation. Records of the hours of operation shall be made available to the Executive Secretary or the Executive Secretary's representative upon request, and shall include a period of two years ending with the date of the request. The total hours of operation may be determined by an engine hour totalizer installed on each engine, but a separate record of non-emergency hours shall be kept on a weekly basis. Emissions from this equipment shall not be included under the emissions cap. [R307-401]

II.B.1.g Except for use in emergency generators, fuel oil shall not be burned in any existing combustion device at the refinery except during periods of natural gas curtailment.

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.

Torch oil may be burned in the FCCU regenerator to assist in starting, restarting, maintaining hot standby, or maintaining regenerator heat balance.

Small (<100 HP) portable fuel oil-powered equipment is exempt from the requirements of this AO and related emissions are not to be used for purposes of determining compliance. [R307-401]

II.B.1.h The ETF portable diesel generator shall not be operated more than 1,300 hours per rolling 12-month period without prior approval in accordance with R307-401. The total hours of operation shall be determined by an engine hour totalizer or by supervisor monitoring and maintaining of an operations log. [R307-401]

II.B.1.i The throughput of the catalytic cracking unit shall not exceed 3,250,000 barrels per rolling 12-month period. [R307-401]

II.B.1.j Compliance with the annual limitations shall be determined on a rolling 12-month total except where specifically exempted or otherwise provided for. By the last day of each month, a new 12-month total shall be calculated using the previous 12 months. Records of tank throughput shall be kept for all periods when the plant is in operation. Records of tank throughput, including calendar year totals shall be made available to the Executive Secretary's representative upon request. Records shall be kept for a period of five years. Records of tank throughput shall be maintained on blend sheets. Records of end-of-month tank volumes shall be maintained on the month-end gauge sheets. [R307-401]

II.B.2 **Conditions on the SRU/Tail gas incinerators (3 units)**

II.B.2.a Copies of the SRU Operating Instruction/Standard shall be made available to the Executive Secretary upon request. [R307-401]

- II.B.2.b Holly shall utilize monitors to measure volumetric flow rates from the Unit 17 SRU stack. The flow measurement shall be in accordance with the requirements of 40 CFR 52, Appendix E; 40 CFR 60 Appendix B; or 40 CFR 75, Appendix A. [R307-401]
- II.B.2.c The three SRUs shall each achieve 95% recovery efficiency for all periods of operation except during periods of startup, shutdown or malfunction of the SRU. [R307-401]
- II.B.2.d The Unit 17 SRU/Tail gas incinerator shall be equipped with a CEMS to measure SO₂ emissions. The 95% recovery efficiency shall be determined on a daily basis; however compliance shall be determined on a 30-day rolling average basis by measuring the flow rate and concentration of hydrogen sulfide (H₂S) in the feed streams going to the Unit 17 SRU and by measuring the SO₂ emissions with the CEMS at the SRU incinerator. The flow rate shall be determined continuously; the H₂S concentration shall be determined quarterly for the first four quarters and at least semiannually thereafter. The flow rate and the H₂S concentration values shall be used to determine the daily feed rate.
- The 95% recovery efficiency for the new SRUs shall be determined on a daily basis; however compliance shall be determined as outlined in Section IX.H.1.i of the PM₁₀ SIP. [R307-401]
- II.B.2.e All sulfur pit emissions shall be routed to an SRU incinerator. [R307-401]
- II.B.2.f If sulfur input to the Unit 17 SRU exceeds 20 long tons per day, NSPS Subparts A and J shall apply. [40 CFR 60 Subpart J]
- II.B.2.g The refinery may exercise an option to trade allowed annual SRU SO₂ emissions for cap sources' SO₂ emissions in the event the Unit 17 SRU is operating at better than 95% efficiency. This option shall not be made available until at least one year of data (12 efficiency determinations), as described below, has been collected and a trade-off request is submitted to and approved by the Executive Secretary. The (Unit 17 SRU) 24-hour minimum operating efficiency shall have been demonstrated to be no less than 95%. When the SRU efficiency, as determined below, is greater than 95%, adjustments to the annual SO₂ emission limit for cap sources (see the AO conditions for definition of cap sources) may be made by the following procedure:
- An adjusted annual cap emission limit is the annual cap sources' emission limit adjusted upward. This adjustment is derived from SO₂ emission decreases resulting from a better than 95% efficient SRU operation.
- The adjusted annual cap emission limit shall only be used for compliance demonstration purposes. The combined annual total cap sources' and SRU SO₂ limit used for attainment and maintenance demonstration shall not be increased.
- Daily compliance limits shall not be adjusted. [R307-401]
- II.B.3 **Conditions on SO₂ emissions sources**
- II.B.3.a The emission of SO₂ into the atmosphere [excluding those from flares and during SRU down times] shall not exceed 1639 tons/year.

Emissions of SO₂ shall be limited as follows:

Emission Points	Emissions (TPD)	Total Emissions (tons/yr)
(17-1) SRU Tail Gas Incinerator	1.60	582
(new) SRU Tail Gas Incinerator #1	0.25	90
(new) SRU Tail Gas Incinerator #2	0.25	90
(51-6) CO Boiler/FCC Scrubber	1.93	706
Emission Cap sources	0.47	171

Tons Per Day = Daily 24-hour total. Daily means an interval of time between two consecutive midnights.

For all emission points except (51-6) a CEM shall be used to determine compliance. For emission point (51-6) stack testing shall be performed as outlined in condition II.B.1.a. [R307-401]

II.B.3.b The following sources shall not be regulated for SO₂ emissions, nor shall they be included in the emission limitation totals herein:

- (66-1) Process Flare South
- (66-2) Process Flare North
- (68-1) Propane Pit Flare
- Emergency Equipment

[R307-401]

II.B.3.c SO₂ emissions for the emissions cap sources shall be determined by applying the following emission factors to the relevant quantities of fuel burned. SO₂ Emission factors for the various fuels shall be as follows:

Natural gas - 0.60 lb SO₂/MMscf (Compressors Only)

Plant gas - The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a continuous emissions monitor which will measure the H₂S content of the fuel gas in parts per million by volume (ppmv). Daily emission factors shall be calculated using average daily H₂S content data from the CEM. The emission factor shall be calculated as follows:

$$(\text{lb SO}_2/\text{MMscf gas}) = (24 \text{ hr avg. ppmv H}_2\text{S})/10^6 * (64 \text{ lb SO}_2/\text{lb mole}) * (10^6 \text{ scf/MMscf})/(379 \text{ scf / lb mole})$$

Fuel oil - The emission factor to be used in conjunction with fuel oil combustion (during natural gas curtailments) shall be calculated based on the weight percent of sulfur, as determined by ASTM Method 0-4294-89 or approved equivalent, and the density of the fuel oil, as follows:

$$(\text{lb of SO}_2/\text{kgal}) = (\text{density lb/gal}) * (1000 \text{ gal/kgal}) * (\text{wt. \%S})/100 * (64 \text{ g SO}_2/32 \text{ g S})$$

The weight percent sulfur and the fuel oil density shall be recorded for each day any fuel oil is combusted. Fuel oil may be combusted only during periods of natural gas curtailment. The sulfur content of the fuel oil shall be tested if directed by the Executive Secretary.

Fuel Consumption shall be measured as follows:

Natural gas consumption shall be determined by the meter totalizer on the natural gas supplied to the plant.

Plant gas consumption shall be determined through the use of flow meters.

Fuel oil consumption shall be measured each day by means of leveling gauges on all tanks that supply oil to combustion sources.

The equations used to determine emissions for the emission cap sources shall be as follows:

Emissions (tons/day) = Emission Factor (lb/MMscf) * Natural Gas Consumption (MMscf/day) / (2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/MMscf) * Plant Gas Consumption (MMscf/day) / (2,000 lb/ton)

Emissions (tons/day) = Emission Factor (lb/kgal) * Fuel Oil Consumption (kgal/24 hrs) / (2,000 lb/ton)

Total daily SO₂ emissions for the sources included in the emissions cap shall be calculated by adding the daily results of the above SO₂ emissions equations for natural gas, plant gas, and fuel oil combustion. Results shall be tabulated for every day, and records shall be kept which include the CEM readings for H₂S (averaged for each one-hour period), all meter readings (in the appropriate units), fuel oil parameters (density and wt. %S, recorded for each day any fuel oil is burned), and the calculated emissions. [R307-401]

II.B.4 **Conditions on NO_x emissions sources**

II.B.4.a Maximum NO_x emissions to the atmosphere shall not exceed 2.09 tons per day. The emissions of NO_x from all sources shall not exceed 653 tons/year. [R307-401]

II.B.4.b The following sources shall not be regulated for NO_x emissions, nor shall they be included in the emission limitation totals herein:

- (66-1) Process Flare South
- (66-2) Process Flare North
- (68-1) Propane Pit Flare
- Emergency Equipment

[R307-401]

II.B.4.c NO_x emissions for the Emissions Cap Sources shall be determined by applying the following emission factors to the relevant quantities of fuel combusted.

Boilers and Furnaces:

Natural gas/refinery fuel gas combusted using Low NO_x burners: 81 lbs/MMscf

Natural gas/refinery fuel gas combusted using Ultra-Low NO_x burners: 41 lbs/MMscf

Natural gas/refinery fuel gas combusted using all other burners: 140 lbs/MMscf

All fuel oil combustion: 120 lbs/Kgal

Where "Natural gas/refinery fuel gas" shall represent any combustion of natural gas, refinery fuel gas, or combination of the two in the associated burner.

Daily natural gas consumption shall be determined by the meter totalizer on the natural gas supplied to the plant.

Daily plant gas consumption shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Natural Gas Consumption (MMscf/day)} / (2,000 \text{ lb/ton})$$

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Plant Gas Consumption (MMscf/day)} / (2,000 \text{ lb/ton})$$

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/kgal)} * \text{Fuel Oil Consumption (kgal/day)} / (2,000 \text{ lb/ton})$$

Compressors:

The NO_x Emission Factor for natural gas (firm supply) combustion in the compressor drivers shall be 3400 lb/MMscf.

Daily natural gas (firm supply) consumption for the compressor drivers shall be quantified by meters, which shall be installed if necessary, that will differentiate the flow of natural gas to the compressors from the flow to the of boilers and furnaces.

The emissions shall then be determined using the following equation:

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Natural Gas Consumption (MMscf/day)} / (2,000 \text{ lb/ton})$$

Total 24-hour NO_x emissions for sources included in the emissions cap shall be calculated by adding the results of the above NOX equations for plant gas, fuel oil, and natural gas combustion. Results shall be tabulated for every day, and records shall be kept which include the meter readings (in the appropriate units), emission factors, and the calculated emissions.

See Section IX.H.1.i(2) of the PM₁₀ SIP for details of compliance determination. [R307-401]

II.B.5 **Conditions on PM₁₀ emissions sources**

II.B.5.a The emissions of PM₁₀ shall not exceed the following:

Emission Points	Emissions (TPD)	Total Emissions (tons/yr)
(51-6) CO Boiler/FCC Scrubber	0.09	32
Emission Cap	0.13	47
Total	0.22	79

[R307-401]

II.B.5.b The following sources shall not be regulated for PM₁₀ emissions, nor shall they be included in the emission limitation totals herein:

- (4-4a) 4K1A KVG Compressor West
- (4-4b) 4K1B KVG Compressor East
- (6-4a) 6K1 SVG Compressor East
- (6-4b) 6K2 SVG Compressor West
- (66-1) Process Flare South
- (66-2) Process Flare North
- (68-1) Propane Pit Flare
- Emergency Equipment

[R307-401]

II.B.5.c PM₁₀ emissions for the Emissions Cap Sources shall be determined by applying the following emission factors to the relevant quantities of fuel combusted in each unit. PM₁₀ Emission Factors for the combustion sources will be as follows:

- Natural gas: 5 lb PM₁₀/MMscf
- Plant gas: 5 lb PM₁₀/MMscf

The PM₁₀ emission factor for fuel oil combustion shall be determined based on the H₂S content of the fuel oil as follows:

$$PM_{10} \text{ (lb/kgal)} = (10 * \text{wt.\%S}) + 3$$

Daily natural gas consumption for each cap source shall be determined by the meter totalizer on the natural gas supplied to the plant.

Daily plant gas consumption for each cap source shall be determined through the use of flow meters.

Daily fuel oil consumption shall be monitored by means of leveling gages on all tanks that supply fuel oil to combustion sources. Fuel oil consumption shall be allowed only during periods of natural gas curtailment.

The equations used to determine emissions for the boilers and furnaces shall be as follows:

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Natural Gas Consumption (MMscf/day)} / (2,000 \text{ lb/ton})$$

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/MMscf)} * \text{Plant Gas Consumption (MMscf/day)} / (2,000 \text{ lb/ton})$$

$$\text{Emissions (tons/day)} = \text{Emission Factor (lb/kgal)} * \text{Fuel Oil Consumption (kgal/day)} / (2,000 \text{ lb/ton})$$

Total 24-hour PM₁₀ emissions for the sources included in the emissions cap shall be calculated by adding the daily results of the above PM₁₀ emissions equations for natural gas, plant gas, and fuel oil combustion. Results shall be tabulated for every day, and records shall be kept which include all meter readings (in the appropriate units), fuel oil parameters (wt. %S), and the calculated emissions. For the details of compliance demonstration, refer to Section IX.H.1.i(2) of the PM₁₀ SIP. [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.

MACT (Part 63), CC: Petroleum Refineries
 NSPS (Part 60), Kb: VolatLiq/PetroStorageVessel 7/23/84
 MACT (Part 63), UUU: Petro Refineries Cat Crkg,Ref,SPU
 NESHAP (Part 61), FF: Benzene Waste Operations
 NSPS (Part 60), A: General Provisions
 NSPS (Part 60), J: Petroleum Refineries
 NSPS (Part 60), GGG: VOC Equip Leaks Petro Refineries
 NSPS (Part 60), QQQ: VOC Emis Petro Ref Wastewtr Sys

PERMIT HISTORY

This AO is based on the following documents:

Supersedes

DAQE-AN0101230023-07 dated June 8, 2007

ACRONYMS

The following lists commonly used acronyms and their 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
CO	Carbon monoxide
COM	Continuous opacity monitor
DAQ	Division of Air Quality (typically interchangeable with UDAQ)
DAQE	This is a document tracking code for internal UDAQ use
EPA	Environmental Protection Agency
HAP or HAPs	Hazardous air pollutant(s)
ITA	Intent to Approve
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
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
UAC	Utah Administrative Code
UDAQ	Utah Division of Air Quality (typically interchangeable with DAQ)
VOC	Volatile organic compounds