

UTAH DIVISION OF AIR QUALITY
SOURCE PLAN REVIEW

Mike Astin
Holly Refining & Marketing Company - Woods
Cross LLC
1070 W 500 S
Woods Cross, UT 840871442

Project Number: N101230041

RE: Heavy Crude Processing Project
Davis County; CDS A; NSR, Nonattainment or
Maintenance Area, Title V (Part 70) major source, PM₁₀
SIP / Maint Plan, NESHAP (Part 61), Major HAP source,
NSPS (Part 60), MACT (Part 63), PSD

Review Engineer: Camron Harry
Date: June 10, 2013

Notice of Intent Submitted: May 23, 2012

Plant Contact: Eric Benson
Phone Number: (801) 299-6623
Fax Number: (801) 299-6609

Source Location: 393 South 800 West, Woods Cross, UT
Davis County
4,526,227 m Northing, 424,000 m Easting, UTM Zone 12
UTM Datum: NAD27

DAQ requests that a company/corporation official read the attached draft/proposed Plan Review with Recommended Approval Order Conditions. If this person does not understand or does not agree with the conditions, the review engineer should be contacted within five days after receipt of the Plan Review. If this person agrees with the Plan Review and Recommended Approval Order Conditions, this person should sign below and return (FAX # 801-536-4099) within 10 days after receipt of the conditions. If the review engineer is not contacted within 10 days, the review engineer shall assume that the company/corporation official agrees with this Plan Review and will process the Plan Review towards final approval. A public comment period will be required before the Approval Order can be issued.

Applicant Contact _____
(Signature & Date)

OPTIONAL: In order for this Source Plan Review and associated Approval Order conditions to be administratively included in your Operating Permit (Application), the Responsible Official as defined in R307-415-3, must sign the statement below and the signature above is not necessary. **THIS IS STRICTLY OPTIONAL!**

If you do not desire this Plan Review to be administratively included in your Operating Permit (Application), only the Applicant Contact signature above is required. Failure to have the Responsible Official sign below will not delay the Approval Order, but will require a separate update to your Operating Permit Application or a request for modification of your Operating Permit, signed by the Responsible Official, in accordance with R307--415-5a through 5e or R307-415-7a through 7i.

“Based on reasonable inquiry, I certify that the information provided for this Approval Order has been true, accurate and complete and request that this Approval Order be administratively amended to the Operating Permit (Application).”

Responsible Official _____
(Signature & Date)

Print Name of Responsible Official _____

ABSTRACT

Holly Refining & Marketing Company - Woods Cross LLC (Holly Refinery) is requesting a modification to their existing AO DAQE-AN0101230039-11 to accommodate processing black and yellow wax crudes. This modification includes increasing crude processing from 40,000 barrels per day to 60,000 barrels per day. Changes to the Holly Refinery include installation of new equipment and replacement and/or modifications to existing equipment as needed.

The heavy crude processing project involves changes to existing refinery operations and addition of new process units at the facility including:

- 1) Expansion of existing crude unit (Unit 8) through addition of a preflash tower;
- 2) Installation of second crude unit (Unit 24);
- 3) Installation of second fluid catalytic cracking unit (FCC Unit 25);
- 4) Installation of Poly Gasoline Unit (Unit 26);
- 5) Installation of Hydrocracker Unit (Unit 27);
- 6) Installation of a new cooling tower (#10) and expansion of an existing cooling tower (#11);
- 7) Installation of emergency generators;
- 8) Installation of several process heaters and furnaces; and
- 9) Installation of a steam boiler (Boiler #11).

Other existing facility process units will be modified and/or removed in this modification:

- 1) Installation of new or modification to existing tanks;
- 2) Installation of additional truck bays for crude unloading;
- 3) Changes to rail loading and unloading locations;
- 4) Removal of frozen earth propane storage; and
- 5) Removal of gas driven compressor engines.

The Holly Refinery is located in West Bountiful, Davis County. Davis County is nonattainment for $PM_{2.5}$ and is a maintenance area for Ozone. Holly Refinery is located four miles north of Salt Lake County and is defined as a contributing source for the Salt Lake County PM_{10} nonattainment area. The Holly Refinery is a major source of HAPs, a SIP source, and a PSD source. This modification is major for GHG and CO emissions. Title V of the Clean Air Act of 1990 applies to this source as a major source.

The projected emissions increase/decrease for this modification, in tons per year, are as follows: PM_{10} + 8.31, $PM_{2.5}$ (subset of PM_{10}) + 6.82, NO_x - 21.53, SO_2 - 150.69, CO + 146.76, VOC - 17.42, total HAPs + 13.08, and CO_2e + 279,610.

Previous exclusions from the AO emission caps will be removed therefore the AO emission caps will be source wide caps. In addition, the AO emission caps will be reduced as follows, in tons per year: PM_{10} - 0.05, NO_x - 322.9, and SO_2 - 725.7.

The source wide potential to emit totals, in tons per year, are as follows: PM_{10} = 147.8, $PM_{2.5}$ (a subset of PM_{10}) = 47.6, NO_x = 341.1, SO_2 = 110.3, CO = 967.3, VOC = 102.60, and CO_2e = 1,003,300.

This project previously went out to public comment on December 4, 2012 with a hearing held on January 3, 2013. This project has been modified since then as follows:

- 1) The originally proposed 2008 EPA Consent Decree emission reductions have been removed from the PSD and Major NSR applicability netting analysis
- 2) Unit 26H1 (poly gasoline unit heater) will now be an electric heater
- 3) Four (4) existing gas driven compressor engines (4K1A KVG Compressor West, 4K1B KVG Compressor East, 6K1 SVG Compressor East, and 6K2 Compressor West) will be replaced with four (4) electric compressor engines.
- 4) EPA published AP-42 PM emission factors have been replaced with EPA published PM National Emissions Inventory (NEI) emission factors. Verification stack testing requirements have been included.
- 5) Change of baseline actual emission 24-month periods for criteria pollutants
- 6) As a result of the changes stated above, the PSD, Major NSR, and offsetting applicability and netting analysis calculations have been adjusted. However, the project remains PSD for only CO and GHGs with no offset requirements triggered.
- 7) The permit caps for NO_x, SO_x, and PM₁₀ have been reduced.
- 8) BACT determinations have remained the same.

SOURCE SPECIFIC DESIGNATIONS

Applicable Programs:

- NSPS (Part 60), Subpart A: General Provisions applies to Holly Refinery
- NSPS (Part 60), Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units applies to Boiler #10
- NSPS (Part 60), Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units applies to Boiler #11
- NSPS (Part 60), Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units applies to Boiler #8
- NSPS (Part 60), Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units applies to Boiler #9
- NSPS (Part 60), Subpart J: Standards of Performance for Petroleum Refineries applies to 13H1: Isomerization Reactor Feed Furnace
- NSPS (Part 60), Subpart J: Standards of Performance for Petroleum Refineries applies to 19H1: DHT Reactor Charge Heater
- NSPS (Part 60), Subpart J: Standards of Performance for Petroleum Refineries applies to 24H1: Crude Unit Furnace
- NSPS (Part 60), Subpart J: Standards of Performance for Petroleum Refineries applies to 27H1: Reactor Charger Heater
- NSPS (Part 60), Subpart J: Standards of Performance for Petroleum Refineries applies to 68H2: North In-tank Asphalt Heater
- NSPS (Part 60), Subpart J: Standards of Performance for Petroleum Refineries applies to 68H3: South In-Tank Asphalt Heater
- NSPS (Part 60), Subpart J: Standards of Performance for Petroleum Refineries applies to Boiler #8
- NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to 10H2: Hot Oil Furnace
- NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to 23H1: Reformate Splitter Reboiler Heater
- NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which

Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to 25H1: FCC Feed Heater

NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to 30H1 Hydrogen Reformer Feed Furnace

NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to 30H2 Hydrogen Reformer Feed Furnace

NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to 68H10: North In-Tank Asphalt Heater

NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to 68H11: South In-Tank Asphalt Heater

NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to 68H12: North In-Tank Asphalt Heater

NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to 68H4: North West In-Tank Asphalt Heater

NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to 68H5: North East In-Tank Asphalt Heater

NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to 68H6: South East In-Tank Asphalt Heater

NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to 68H7: South West In-Tank Asphalt Heater

NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to Boiler #10

NSPS (Part 60), Subpart Ja: Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to Boiler #9

NSPS (Part 60), Subpart 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 applies to Tank 145: Petroleum Liquids (1974)

NSPS (Part 60), Subpart 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 applies to Tank 146: Petroleum Liquids (1974)

NSPS (Part 60), Subpart 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 applies to Tank 159: Petroleum liquids (1987)

NSPS (Part 60), Subpart 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 applies to Tank 170: Petroleum Liquids

NSPS (Part 60), Subpart 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 applies to Tank 171: Petroleum Liquids

NSPS (Part 60), Subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels

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Commenced After July 23, 1984 applies to Tank 97: Petroleum Liquids
NSPS (Part 60), Subpart 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 applies to Tank 98: Petroleum Liquids
NSPS (Part 60), Subpart 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 applies to Tank 99: Petroleum Liquids
NSPS (Part 60), Subpart UU: Standards of Performance for Asphalt Processing and Asphalt Roofing
Manufacture applies to Holly Refinery
NSPS (Part 60), Subpart 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 applies to 19H1: DHT Reactor Charge Heater
NSPS (Part 60), Subpart 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 applies to 68H2: North In-tank Asphalt Heater
NSPS (Part 60), Subpart 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 applies to 68H3: South In-Tank Asphalt Heater
NSPS (Part 60), Subpart 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 applies to Boiler #8
NSPS (Part 60), Subpart 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 applies to SRU - Tailgas Incinerator
NSPS (Part 60), Subpart 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 applies to Unit 16: Amine Treatment Unit
NSPS (Part 60), Subpart 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 applies to Unit 17: Sulfur Recovery (SRU)
NSPS (Part 60), Subpart 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 applies to Unit 19: Distillate Hydrodesulfurization Treatment
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum
Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7,
2006 applies to 20H1: Reactor Charge Heater
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum
Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7,
2006 applies to 20H2: Fractionator Charge Heater
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum
Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7,
2006 applies to 20H3: Fractionator Charge Heater
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum
Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7,
2006 applies to 30H1 Hydrogen Reformer Feed Furnace
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum
Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7,
2006 applies to 30H2 Hydrogen Reformer Feed Furnace
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum
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Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to 33H1: Vacuum Furnace Heater
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to 68H10: North In-Tank Asphalt Heater
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to 68H11: South In-Tank Asphalt Heater
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to 68H12: North In-Tank Asphalt Heater
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to 68H4: North West In-Tank Asphalt Heater
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to 68H5: North East In-Tank Asphalt Heater
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to 68H6: South East In-Tank Asphalt Heater
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to 68H7: South West In-Tank Asphalt Heater
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to Boiler #10
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to Boiler #9
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to Unit 20: Gas Oil Hydrocracking (GHC) Unit
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to Unit 21: NaSH Sour Gas Treatment Unit
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to Unit 30: Hydrogen plant
NSPS (Part 60), Subpart GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to Unit 33: Vacuum Unit
NSPS (Part 60), Subpart QQQ: Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems applies to Holly Refinery
NSPS (Part 60), Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines applies to Emergency Equipment (Diesel)
NSPS (Part 60), Subpart JJJJ: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines applies to Emergency Equipment (Natural Gas)
NESHAP (Part 61), Subpart A: General Provisions applies to Holly Refinery
NESHAP (Part 61), Subpart FF: National Emission Standard for Benzene Waste Operations applies to Engineering Review N101230041: Holly Refining & Marketing Company - Woods Cross LLC - Heavy Crude Processing

Holly Refinery

MACT (Part 63), Subpart A: General Provisions applies to Holly Refinery

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Cooling Tower #10

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Cooling Tower #11

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Cooling Tower #4

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Cooling Tower #6

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Cooling Tower #7

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Cooling Tower #8

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Tank 100: Petroleum Liquids (1952)

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Tank 104: Petroleum Liquids (1952)

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Tank 106: Petroleum Liquids (1952)

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Tank 107: Petroleum Liquids (1952)

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Tank 108: Petroleum Liquids (1952)

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Tank 109: Petroleum Liquids (1952)

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Tank 121: Petroleum Liquids (1954)

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Tank 126: Petroleum Liquids (1955)

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Tank 145: Petroleum Liquids (1974)

MACT (Part 63), Subpart CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries applies to Tank 146: Petroleum Liquids (1974)

MACT (Part 63), Subpart UUU: National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units applies to FCC 34" Flue Gas Bypass

MACT (Part 63), Subpart UUU: National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units applies to Unit 17: Sulfur Recovery (SRU)

MACT (Part 63), Subpart UUU: National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units applies to Unit 4: Fluid Catalytic Cracking Unit (FCCU)

MACT (Part 63), Subpart UUU: National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units applies to Unit 6: Catalytic Reforming Unit (Reformer)

MACT (Part 63), Subpart ZZZZ: National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines applies to Emergency Equipment (Diesel)

MACT (Part 63), Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Engineering Review N101230041: Holly Refining & Marketing Company - Woods Cross LLC - Heavy Crude Processing

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Industrial, Commercial, and Institutional Boilers and Process Heaters applies to 10H2: Hot Oil Furnace
 MACT (Part 63), Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for
 Industrial, Commercial, and Institutional Boilers and Process Heaters applies to 19H1: DHT Reactor
 Charge Heater
 MACT (Part 63), Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for
 Industrial, Commercial, and Institutional Boilers and Process Heaters applies to 20H1: Reactor Charge
 Heater
 MACT (Part 63), Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for
 Industrial, Commercial, and Institutional Boilers and Process Heaters applies to 20H2: Fractionator
 Charge Heater
 MACT (Part 63), Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for
 Industrial, Commercial, and Institutional Boilers and Process Heaters applies to 20H3: Fractionator
 Charge Heater
 MACT (Part 63), Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for
 Industrial, Commercial, and Institutional Boilers and Process Heaters applies to 30H1 Hydrogen
 Reformer Feed Furnace
 MACT (Part 63), Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for
 Industrial, Commercial, and Institutional Boilers and Process Heaters applies to 30H2 Hydrogen
 Reformer Feed Furnace
 MACT (Part 63), Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for
 Industrial, Commercial, and Institutional Boilers and Process Heaters applies to 33H1: Vacuum
 Furnace Heater
 MACT (Part 63), Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for
 Industrial, Commercial, and Institutional Boilers and Process Heaters applies to Boiler #10
 MACT (Part 63), Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for
 Industrial, Commercial, and Institutional Boilers and Process Heaters applies to Boiler #9
 Major HAP source applies to Holly Refinery
 NSR applies to Holly Refinery
 PM₁₀ SIP / Maint Plan applies to Holly Refinery
 PSD applies to Holly Refinery
 Title V (Part 70) major source applies to Holly Refinery
 Davis County O3 Maintenance Area applies to Holly Refinery
 Davis County PM_{2.5} NAA applies to Holly Refinery
 Salt Lake County PM₁₀ NAA applies to Holly Refinery
 Salt Lake County SO₂ NAA applies to Holly Refinery

Permit History:

When issued, the approval order shall supersede or will be based on the following documents:

Supersedes	DAQE-AN101230040 dated December 16, 2011
Incorporates	Notice of Intent dated May 23, 2012
Incorporates	Additional Information (Unit Designations) dated May 31, 2012
Incorporates	Additional Information (Equip Spec Sheets) dated June 18, 2012
Incorporates	Additional Information (NO ₂ to NO _x stack ratio) dated June 28, 2012
Incorporates	Additional Information (from NOI Completeness Cklist) dated July 5, 2012
Incorporates	Additional Information (Updated NOI) dated July 12, 2012
Incorporates	Additional Information (In Stack Ratio info) dated July 19, 2012
Incorporates	Additional Information (Modeling Analysis Update) dated July 30, 2012

Incorporates	Additional Information (Updated Emissions) dated August 28, 2012
Incorporates	Additional Information (BACT) dated October 17, 2012
Incorporates	Additional Information (GHG & BACT) dated October 18, 2012
Incorporates	Additional Information (emergency generators) dated October 23, 2012
Incorporates	Additional Information (NEI EF and flare info) dated March 21, 2013
Incorporates	Additional Information (Netting Analysis) dated April 1, 2013
Incorporates	Additional Information (Calculations) dated April 10, 2013
Incorporates	Additional Information (Corrected Netting Analysis) dated April 22, 2013
Incorporates	Additional Information (Boiler #8 CD) dated April 30, 2013

Nonattainment or Maintenance Areas Impacted:

- Davis County O3 Maintenance Area
- Davis County PM_{2.5} NAA
- Salt Lake County PM₁₀ NAA
- Salt Lake County SO₂ NAA

SUMMARY OF NOTICE OF INTENT INFORMATION

Description of Proposal:

In 2007 Holly Refinery permitted a number of changes to modernize the refinery and expand processing capacity. Although many of those changes have been implemented or are in the process of being implemented. Holly Refinery is seeking to modify certain previously permitted changes. Central to these changes is a revision in the planned nature of the crude oil feed to the refinery. The 2007 modernization included a significant increase in processing of heavier crude oil with higher sulfur content. This proposed revision replaces that heavier crude with local production primarily from eastern Utah (black wax and yellow wax). This local production is highly-paraffinic crude oil with lower sulfur content.

The Uinta Basin in Eastern Utah contains resources of black-wax and yellow-wax crude, which have low sulfur content and are suitable for the creation of various refined petroleum products. Because of the paraffinic nature and high pour point of these crudes, they become solid wax at ambient temperatures and must be transported to Salt Lake City refineries via insulated tanker trucks and trailers. To be able to accommodate additional crude, Holly Refinery is expanding and modifying its refining capabilities.

The heavy crude processing project involves changes to existing refinery operations and addition of new process units at the facility including:

- 1) Expansion of existing crude unit (Unit 8) through addition of a preflash tower;
- 2) Installation of second crude unit (Unit 24);
- 3) Installation of second fluid catalytic cracking unit (FCCU Unit 25);
- 4) Installation of Poly Gasoline Unit (Unit 26);
- 5) Installation of Hydrocracker Unit (Unit 27);
- 6) Installation of a new cooling tower (#10) and expansion of an existing cooling tower (#11);
- 7) Installation of emergency generators;
- 8) Installation of several process heaters and furnaces; and
- 9) Installation of a steam boiler (Boiler #11).

Other existing facility process units will be modified and/or removed in this modification:

- 1) Installation of new or modification to existing tanks;
- 2) Installation of additional truck bays for crude unloading;
- 3) Changes to rail loading and unloading locations;
- 4) Removal of frozen earth propane storage; and
- 5) Removal of gas driven compressor engines.

For the current request for modification, the following changes are being proposed:

The existing crude unit's (Unit 8) capacity will be expanded from 26,000 barrels per day (bpd) to 45,000 bpd with the addition of a preflash tower. A previously permitted 35 MMBtu/hr crude feed heater (8H2) will not be constructed.

A proposed second crude unit (Unit 24) with a capacity of 15,000 barrels per day of crude will be installed along with a 60 MMBtu/hr crude ultra-low NO_x burner (ULNB) heater (24H1).

SRU (Unit 17) emissions will be routed to the FCCU scrubber (25FCC Scrubber) prior to being released into the atmosphere.

The existing charge heater on the Gas Oil Hydrocracking Unit (GHC) will be replaced with a 42.1 MMBtu/hr reactor charge ULNB heater (20H3).

The Distillate Hydrotreater (DHT) will be expanded to handle the additional distillate by utilizing the GHC charge heater (20H1).

To process the additional bottom cut from the new crude unit (Unit 24), an additional Fluid Catalytic Cracking Unit (FCCU Unit 25) with a capacity of processing 8500 barrels per day will be constructed along with a 45 MMBtu/hr ULNB feed heater (25H1). Emissions from the FCCU will be controlled by a wet gas scrubber (25FCC Scrubber).

A poly gasoline unit (Unit 26) will be constructed to convert olefin to a high octane gasoline blend stock.

A Hydrocracker/Hydroisom unit (Unit 27) which will produce high-quality lubricants and ultralow sulfur diesel will be constructed. This unit will be equipped with a 99 MMBtu/hr reactor charge low NO_x burner (LNB) heater (27H1). Emissions from this heater will be controlled using Selective Catalytic Reduction (SCR).

A sour water stripper with a capacity of handling 100 gallons per minute will be constructed (Unit 28). Emissions from this unit will be controlled through the existing sour water stripper/ammonia stripping unit (Unit 22) prior to treatment in the existing sulfur recovery unit (Unit 17) under normal operations.

To improve recovery of gas oil from the crude distillation bottoms, a vacuum tower and vacuum furnace, with a rating of 130 MMBtu/hr will be installed (33H1). A previously permitted 15.2 MMBtu/hr vacuum furnace heater will not be constructed. Emissions from the new heater will be controlled using SCR.

A previously permitted 15.3 MMBtu/hr asphalt mix heater (45H1) was determined to not be required for processing and will not be included in the permit.

Six additional (stab-in) asphalt tank heaters (68H6, 68H7, 68H10, 68H11, 68H12, and 68H13) will be added, each at 0.8 MMBtu/hr.

One (1) new cooling tower (Cooling tower #10) will be constructed and one existing cooling tower (Cooling tower #11) will be expanded by adding a cell. These cooling towers will be equipped with high efficiency drift eliminators.

The 60 MMBtu/hr CO boiler (Boiler #6) will be decommissioned as the FCC Unit 4 wet scrubber (4V82 FCC Scrubber) is replacing it.

An 89.3 MMBtu/hr steam boiler (Boiler #11) will be installed. Emissions from this boiler will be equipped with LNB technology and controlled through SCR.

A new 540 hp diesel fired emergency generator will be installed.

Two (2) natural gas fired emergency generators, 142 kW each, will be located at the new Administration Building.

40 previously permitted rail spots for loading fuel oil will be revised to 16 for fuel oil and 24 for lube oil (Unit 87).

Two (2) existing biodiesel loading spots will be moved to the East Tank Farm. The existing biodiesel spots will be converted to fuel oil/asphalt loading.

At the west track, one (1) existing LPG rail loading spot will be converted to load propane and one additional rail spot for loading propane will be constructed.

The crude truck unloading facilities will be expanded for twelve more truck bays.

The south flare will be reconstructed and reconfigured at its current location.

Several storage tanks will be modified, reconstructed or removed as part of this project. Ten (10) new tanks for oil lubes feed/product, two (2) for gas oil, one (1) for poly gasoline, one (1) for gasoline, two (2) for diesel, four (4) for propane, one (1) for wastewater, and one (1) for sour water feed will be constructed.

The frozen earth propane storage will be removed (Tank 137).

Replace four (4) existing gas-driven compressor engines with four (4) electric motors: 4K1A KVG Compressor West, 4K1B KVG Compressor East, 6K1 SVG Compressor East, and 6K2 Compressor West.

Units 10H2, 30H1, 30H2, and Boiler #8 will be equipped with LNB and controlled with SCR add-on control technology.

Because of the lower sulfur content of the black and yellow wax crude, the following previously permitted equipment will no longer be required to control SO₂:

Two amine units (Units 32 & 35) will not be constructed.

Two Claus sulfur recovery units (Units 31 & 34) and tail gas treatment units will not be constructed.

Summary of Emission Totals:

The emissions listed below are an estimate of the total potential emissions from the source. Some rounding of emissions is possible.

Estimated Criteria Pollutant Potential Emissions

CO ₂ Equivalent	1,003,300	tons/yr
Carbon Monoxide	967.30	tons/yr
Nitrogen Oxides	341.10	tons/yr
Particulate Matter - PM ₁₀	147.80	tons/yr
Particulate Matter - PM _{2.5}	47.60	tons/yr
Sulfur Dioxide	110.30	tons/yr
Volatile Organic Compounds (non fugitive)	102.60	tons/yr

Estimated Hazardous Air Pollutant Potential Emissions

2,2,4-Trimethylpentane (CAS #540841)	1352	lbs/yr
Acetaldehyde (CAS #75070)	8	lbs/yr
Acrolein (CAS #107028)	2	lbs/yr
Arsenic (TSP) (CAS #7440382)	1	lbs/yr
Benzene (Including Benzene From Gasoline) (CAS #71432)	1.46	tons/yr
Cadmium (CAS #7440439)	4	lbs/yr
Chlorine (CAS #7782505)	2.38	tons/yr
Chromium Compounds (CAS #CMJ500)	6	lbs/yr
Cobalt (TSP) (CAS #7440484)	0	lbs/yr
Ethyl Benzene (CAS #100414)	320	lbs/yr
Formaldehyde (CAS #50000)	478	lbs/yr
Generic HAPs (CAS #GHAPS)	1461	lbs/yr
Hexane (CAS #110543)	5.41	tons/yr
Lead (CAS #7439921)	2	lbs/yr
Manganese (TSP) (CAS #7439965)	2	lbs/yr
Mercury (Organic) (CAS #22967926)	1	lbs/yr
Naphthalene (CAS #91203)	1	lbs/yr
Toluene (CAS #108883)	1.21	tons/yr
Xylenes (Isomers And Mixture) (CAS #1330207)	1598	lbs/yr
Total hazardous air pollutants	13.08	tons/yr

Review of Best Available Control Technology:

1. BACT review regarding BACT Analysis
Holly Refinery's NOI included a BACT analysis which generally followed the "top-down" method for making BACT determinations as set forth in EPA's New Source Review Workshop Manual (EPA, 1990). A "top-down" BACT analysis takes into account energy, environmental, economic, and other costs associated with each alternative technology.

DAQ NSR based the following BACT recommendations on review and verification (by means Engineering Review N101230041: Holly Refining & Marketing Company - Woods Cross LLC - Heavy Crude Processing

of internet searches, DAQ staff's knowledge of technologies and processes, and technical documentation when available) of the latest Holly Refinery July 13, 2012 NOI BACT analysis and information received on March 21, 2013, April 1, 2013 April 10, 2013, and April 22, 2013.

The emissions from natural gas and/or refinery fuel gas combustion (process heaters, boilers, and flares) include NO_x, CO, CO₂ trace amounts of PM, SO₂, VOCs, methane (CH₄), and nitrous oxide (N₂O).

Emissions from the burning of coke off the catalyst in the FCCU regenerator vessel are released out the regenerator stack. The emissions include: NO_x, CO, PM, and SO₂.

Fugitive VOC emissions from tanks result from vapor expansion and contraction due to internal temperature and pressure variations, vapor losses at roof tank seals, and vapor losses due to filling and emptying tanks. The amount of VOC loss is dependent on the tanks' roof design and vapor pressure of the stored liquid.

Emissions from emergency equipment include NO_x, CO, CO₂, trace amounts of PM, SO₂, VOCs, methane (CH₄), and nitrous oxide (N₂O).

Included with the proposed changes at the refinery, piping, valves, connectors, pumps, compressors and other components will be installed for the movement of gas and liquid raw materials. Leakage from this equipment is a potential source of fugitive VOC emissions.

Cooling towers are final heat exchangers that are used to dissipate large heat loads to the atmosphere. PM₁₀ and PM_{2.5} emissions result from the presence of dissolved or suspended solids in water droplets from cooling tower drift. VOC emissions result from VOCs that are present in the cooling water due to equipment or upstream heat exchanger leaks. Small amounts of hydrocarbons may be present in the cooling water.

General BACT Considerations:

While PM emissions from this source are primarily from combustion, most of the emissions will be PM_{2.5}. By addressing PM_{2.5} controls as the primary pollutant, this will address PM₁₀ by default. However, PM stack testing requirements in this permit will be based on PM₁₀ limitations. The basis for this is that any PM₁₀ collected would by default also be PM_{2.5}.

With regards to a relocation analysis; Holly Refinery's Salt Lake City refinery site began operations in 1932 as Wasatch Oil Refining Company. Holly Refinery purchased the refinery in 2003. This classifies the refinery as an existing source under air quality rules. Therefore UDAQ has analyzed Holly Refinery's submission as a modification following the requirements outlined in R307-401. Those rules do not require that the source submit an analysis of relocating an existing source nor is DAQ aware of regulations under NSR to require a source to do so.

With regards to inclusion of a cost vs. health benefit in the BACT analysis; DAQ evaluates and reviews permit applications against current air pollution standards. These standards, established by the EPA, are health-based standards (see <http://www.epa.gov/apti/bces/module7/title1/title1.htm> - an EPA webpage that addresses the history and bases for the establishment of NAAQS). Concerns about the adequacy of those standards are not addressed in DAQ's review. [Last updated June 4, 2013]

2. BACT review regarding Process Heaters CO Emissions

The proposed process heaters include the following (each will be fired on natural gas or refinery fuel gas):

24H1 - 60 MMBtu/hr Crude Heater:

20H3 - 42.1 MMBtu/hr Reactor Charge Heater;

25H1 - 45 MMBtu/hr FCCU #2 Feed Heater;

27H1 - 99 MMBtu/hr Reactor Charge Furnace;

68H6, 68H7, 68H10, 68H11, 68H12, & 68H13 - 0.8 MMBtu/hr Tank Asphalt Heaters (6 heaters); and 33H1 - 130 MMBtu/hr Vacuum Furnace Heater.

CO is a product of the chemical reaction between carbonaceous fuels and oxygen. The EPA's RACT/BACT/LEAR (RBLC) and California Air Resources Board BACT Clearinghouses as well as other data sources show Good Combustion Practices (GCP), oxidation catalyst, and thermal oxidation as technically feasible for reducing CO emissions from refinery process heaters. The NOI identified EMx as a control alternative.

Oxidation catalyst is similar to a Selective Catalytic Reduction (SCR) system in that a catalyst bed facilitates the conversion of CO to CO₂. Unlike SCR, CO does not use additional chemicals such as ammonia to facilitate the conversion. Oxidation catalysts allow complete oxidation to take place at a faster rate and a lower temperature than is possible with thermal oxidation. Oxidation catalyst typically operates at a narrow temperature range of approximately 600 to 1100 degrees F. At lower temperatures, the CO conversion efficiency falls off rapidly. In flue gas containing more than trace levels of SO₂, poisoning and deactivation of the catalyst occurs. In addition, SO₂ would be converted to SO₃ which will form sulfuric acid. Oxidation catalyst is not a technically feasible option for control of CO from process heaters because the plant gas contains sulfur.

Thermal oxidation requires operating temperatures in the 1200 to 2000 degrees F range to ensure conversion of CO to CO₂. CO removal efficiencies of 90% removal can be achieved with thermal oxidation. The combustion process occurs in two (2) separate stages; (1) the combustion of fuels, and (2) the combustion of pollutants. The combustion in the first stage is extremely rapid and is an irreversible chemical reaction. In the second stage, the heated gases from the burners pass through residence chambers where the CO is oxidized. Residence time, heating value of the gas stream, and operating temperatures determine the efficiency of the process. Raising the exit gas to the appropriate temperature range would require a significant amount of energy and generate increased combustion emissions. Heaters can be considered thermal oxidation themselves and adding another thermal oxidation downstream of a heater to control CO is impractical.

EMx is a developing add-on technology with the potential to reduce NO_x and CO emissions from combustion sources. EMx utilizes a catalytic technique that simultaneously oxidizes NO to NO₂ and CO to CO₂, and then absorbs the NO₂ into the surface of a catalyst through the use of a potassium carbonate coating. The CO₂ passes through the catalyst unchanged. Currently, EMx is not being used in any commercial refinery situation with equipment using a sulfur-bearing fuel gas stream because SO_x will contaminate the catalyst and reduce efficiency over time. EMx is not a technically feasible option for control of CO from process heaters because of the catalyst's sensitivity to sulfur compounds.

GCP includes adequate fuel residence times, proper fuel-air mixing, and temperature control.

A review of EPA's RBLC indicates a CO limit of 0.08 lb/MMBtu based on a one-hour average and a 0.04 lb/MMBtu based on a three-hour average.

Based on review of the above BACT analysis, DAQ NSR recommends proper equipment design and operation, GCP, and gaseous fuels as well as a 0.08 lb/MMBtu CO limit based on a one-hour average as BACT for control of CO emissions for proposed process heaters. [Last updated June 4, 2013]

3. BACT review regarding Process Heaters PM Emissions

For gaseous fuel combustion, nearly all particle emissions fall in the PM_{2.5} range; therefore focusing on control of PM_{2.5} emissions will control all particulate emissions equally. PM_{2.5} emissions can be controlled by the following technologies: GCP, use of low sulfur gaseous fuels, proper design and operation, wet gas scrubber, electrostatic precipitator (ESP), cyclone, and baghouse/fabric filter.

A wet gas scrubber is a air pollution device that removes PM and acid gases from waste streams from stationary point sources. PM and acid gases are primarily removed through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. Wet scrubbers have an advantage over ESPs and baghouses in that they are particularly useful in removing PM from sticky and/or hygroscopic materials; combustible, corrosive or explosive materials; particles that are difficult to remove in dry form; PM in the presence of soluble gases; and PM in gas streams with high moisture content.

An ESP is a particle control device that uses electrical forces to move the particles out of the gas stream onto collector plates. ESPs are used to capture coarse particles at high concentrations.

A cyclone operates on the principle of centrifugal separation. The exhaust enters the top and spirals around towards the bottom. As the particles proceed downward, the heavier materials hit the outside wall and drop to the bottom where they are collected. Cyclones are generally used to reduce dust loading and collecting large particles.

A baghouse/fabric filter consists of one or more compartments containing rows of fabric bags. Particle-laden gases pass along the surface of the bags then go through the fabric. Particles are retained on the upstream face of the bags and the cleaned gas stream is vented to the atmosphere. Fabric filters are used for medium to low gas flow streams with high particulate concentrations.

None of the add on PM control devices have been found to be suitable for process heaters burning gaseous fuels due to extremely low concentration of small particulates expected in gas fired heaters.

Proper design and operation of combustion sources to minimize PM emissions include adequate fuel residence time, proper fuel-air mixing, and temperature control to ensure the maximum amount of fuel is combusted. Optimizing these factors for PM control can result in an increase in the NO_x emissions. Heater designers strive to balance these factors to achieve the lowest possible emissions of all pollutants.

Based on review of the above BACT analysis, DAQ NSR recommends GCP as BACT. In addition, based on current DAQ established BACT for natural gas combustion, a 10% opacity limit for PM emission for the proposed process heaters is also recommended as BACT. [Last updated June 4, 2013]

4. BACT review regarding Process Heaters SO_x Emissions

SO₂ emissions come from the sulfur in the fuel gas. Refinery gas contains sulfur, mostly in the form of hydrogen sulfide (H₂S). When burned in a boiler or heater, essentially all the sulfur in the fuel is oxidized to SO₂.

The following is a list of control technologies for controlling SO₂ emissions: fuel specification - low sulfur fuels, wet flue gas desulfurization (wet FGD), advanced flue gas desulfurization (AFGD), and dry absorption (dry FGD).

Nearly all of the sulfur combusted in the fuel will be converted to SO₂. By limiting the sulfur content of the fuel, emissions of SO₂ will be reduced. NSPS 40 CFR 60 Subpart Ja specification for low sulfur fuels is 60 ppmv or less.

The simplest method for flue gas desulfurization is with the use of a wet scrubber. In a wet caustic scrubbing system, the flue gas and a caustic solution flow counter-current to each other. The sulfur reacts with the caustic solution and is stripped out of the flue gas. Approximately 90-99% reduction can be achieved.

The AFGD process accomplishes SO₂ removal by utilizing a single absorber which performs three functions which are prequenching the flue gas, absorption of SO₂, and oxidation of the resulting calcium sulfite to wallboard-grade gypsum. Incoming flue gas is cooled and humidified with process water sprays before passing to the absorber. Approximately 95-99.5% reduction can be achieved.

In the absorber, two tiers of fountain-like sprays distribute reagent slurry over polymer grid packing that provides a large surface area for gas/liquid contact. The gas then enters a large gas/liquid disengagement zone above the slurry reservoir in the bottom of the absorber and exits through a horizontal mist eliminator. As the flue gas contacts the slurry, the SO₂ is absorbed, neutralized, and partially oxidized to form calcium sulfite and calcium sulfate.

Dry FGD systems spray lime slurry into an absorption tower where the SO₂ is absorbed by the slurry forming calcium sulfite and calcium sulfate. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are carried out with the gas and collected with a fabric filter or an ESP. Approximately 90-95% reduction can be achieved.

Recent permits and the RBLC database did not result in AFGD, wet FGD or dry FGD as BACT. Limestone slurry scrubbing systems are usually applied to power plants for flue gas desulfurization. With wet caustic scrubbing, water contamination issues arise with the disposal of large volumes of sodium sulfite and sodium sulfate solution. In addition, based on available literature which included cost information, these control options were not cost effective in terms of dollars per ton removal. Hence, these three options were eliminated from consideration.

The only control strategy identified for the fuel gas-fired process heaters is adherence to fuel

specifications - low sulfur fuel. This control strategy is technically feasible.

Based on review of the above BACT analysis, DAQ NSR recommends an annual fuel sulfur content limit of 60 ppmv or less as BACT for SO₂ emissions for proposed process heaters. [Last updated June 4, 2013]

5. BACT review regarding Process Heaters NO_x Emissions

NO_x is formed during fuel combustion by oxidation of chemically-bound nitrogen in the fuel and by thermal fixation of nitrogen in the combustion air. There are three different formation mechanisms: thermal, fuel, and prompt NO_x. Thermal NO_x is primarily temperature dependent (above 2000°F); fuel NO_x is primarily dependent on the presence of fuel-bound nitrogen and the local oxygen concentration. Prompt NO_x is formed in relatively small amounts from the reaction of molecular nitrogen in the combustion air with hydrocarbon radicals in the flame front.

Available control technologies for NO_x emissions include: low NO_x burners (LNB), next or current generation ultra-low NO_x burners (ULNB), flue gas recirculation (FGR), selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), and combinations of the above technologies. All of the individual controls or combinations of controls are technically feasible. All controls except the combination of SNCR and LNB or ULNB have been demonstrated on process heaters.

SCR is a process that involves the post combustion removal of NO_x from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the exhaust gas reacts with nitrogen oxides and oxygen to form nitrogen and water. The reactions take place on the surface of the catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging, and the ammonia slip emissions.

The applicability of SCR is limited to heaters that have both a flue gas temperature appropriate for the catalytic reaction and space for a catalyst bed large enough to provide sufficient residence time for the reaction to occur. Optimum NO_x reduction occurs at catalyst bed temperatures of 600°F to 750°F for vanadium or titanium based catalysts and 470°F to 510°F for platinum catalysts.

EMx is a post combustion control system produced by EmeraChem LLC. The EMx system uses a coated oxidation catalyst in the flue gas to remove both NO_x and other pollutants with a reagent such as ammonia. The emissions of NO_x are oxidized to NO₂ and then absorbed onto the catalyst. A dilute hydrogen gas is passed through the catalyst periodically to regenerate the catalyst. This gas absorbs the NO₂ from the catalyst and reduces N₂ before it exits the stack.

The EMx system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. The EMx system is typically used to control emissions from natural gas-fired combustion turbines, reciprocating engines, and industrial boilers in which the sulfur concentration in the exhaust stream is low. The higher concentration of sulfur in the refinery gas will poison the EMx catalyst. EMx has not been demonstrated for refinery fuel gas-fired process heaters. This technology has not been demonstrated to function efficiently on combustion sources burning fuels other than natural gas. In addition, there are significant technical differences between the proposed refinery's combustion sources and those few sources

where EMx has been demonstrated in practice. [Last updated June 4, 2013]

6. BACT review regarding Process Heaters NO_x Emissions (continued)

Selective non-catalytic reduction (SNCR) is a post-combustion NO_x control technology based on the reactions of ammonia and NO_x. SNCR involves injecting urea/ammonia into the combustion gas to reduce the NO_x to nitrogen and water. There are two advantages of an SNCR system over a SCR system. These include lower capital costs and there are no liquid or solid wastes generated with a SNCR system.

The optimum exhaust gas temperature range for implementation of SNCR is 1600 F to 2100 F. Operating temperatures below this range results in ammonia slip which form additional NO_x. In addition, the ammonia/urea must have sufficient residence time, approximately 3 to 5 seconds, at the optimum operating temperatures for efficient NO_x reduction. The exhaust temperatures of the proposed process heaters are estimated to be 900° F or less. Therefore, SNCR was eliminated as BACT for use as a post-combustion control for NO_x emissions from the proposed process heaters.

LNB technology uses advanced burner design to reduce NO_x formation through the restriction of oxygen, flame temperature, and/or residence time. There are two general types of LNB: staged fuel and staged air burners. In a staged fuel LNB, the combustion zone is separated into two regions. The first region is a lean combustion region where a fraction of the fuel is supplied with the total quantity of combustion air. Combustion in this zone takes place at substantially lower temperatures than a standard burner. In the second combustion region, the remaining fuel is injected and combusted with left over oxygen from the first region. This technique reduces the formation of thermal NO_x.

Current ULNB installations combine the benefits of flue gas recirculation and low-NO_x burner control technologies. The ULNB is designed to recirculate hot, oxygen depleted flue gas from the flame or firebox back into the combustion zone. By doing this, the average oxygen concentration is reduced in the flame without reducing the flame temperatures below that which is necessary for optimal combustion efficiency. Reducing oxygen concentrations in the flame impacts the amount of fuel NO_x generated. ULNB designs have a control efficiency of up to 85% and coupling them with SCR, the control efficiency can range from 85-97%.

Flue gas recirculation is another combustion control used to reduce NO_x. FGR involves the recycling of fuel gas into the air-fuel mixture at the burner to help cool the burner flame. Internal FGR, used primarily in ULNB, involves recirculation of the hot O₂-depleted flue gas from the heater into the combustion zone using burner design features. External FGR, usually used with LNB, requires the use of hot-side fans and ductwork to route a portion of the flue gas in the stack back to the burner windbox. [Last updated June 4, 2013]

7. BACT review regarding Process Heaters NO_x Emissions (continued)

Flue gas recirculation has not been demonstrated to function efficiently on process heaters that are subject to highly variable loads and that burn fuels with variable heat value. There are significant technical differences between the proposed process heaters and those combustion sources where flue gas recirculation has been demonstrated in practice. Thus, FGR has been eliminated as BACT for NO_x reduction for the process heaters proposed by Holly Refinery.

A review of EPA's RBLC indicates a NO_x limit of 0.04 lb/hr based on a three-hour average for
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ULNB. Holly Refinery has obtained a performance guarantee of 0.02 lb/hr for LNB and SCR. And has obtained a performance guarantee of 0.098 lb/MMBtu for the 0.8 MMBtu/hr tank heaters.

Based on review of the above BACT analysis, DAQ NSR recommends the following as BACT for NO_x emissions for process heaters:

For the process heaters 24H1, 20H3, and 25H1: ULNB technology with a NO_x emission rate of 0.04 lb/MMBtu.

Although as stated above, DAQ NSR has determined 0.04 lb/MMBtu as BACT, Holly Refinery is proposing a lower NO_x emission rate limit of 0.02 lb/MMBtu for the reactor charge heater (27H1) and the vacuum furnace heater (33H1) which will be installed with LNB and SCR technology.

Because the 0.8 MMBtu/hr stab-in tank heaters (68H6, 68H7, 68H10, 68H11, 68H12, & 68H13) are relatively small heaters, DAQ NSR recommends a NO_x emission rate of 0.098 lb/MMBtu limit be BACT for these heaters. [Last updated May 14, 2013]

8. BACT review regarding Process Heaters VOC Emissions

Emissions of VOCs results from the incomplete combustion of carbon and organic compounds and are a function of oxygen availability, temperature, residence time, and turbulence. Two (2) control technologies for controlling VOC emissions are GCP and catalytic oxidation.

GCP includes operational and design elements to control the amount and distribution of excess air in the flue gas. This ensures that there is enough oxygen present for complete combustion. If sufficient combustion air supply, temperature, residence time, and mixing are incorporated in the combustion design and operation, VOC emissions are minimized.

The formation of VOC in combustion units depends on the efficiency of combustion. Catalytic oxidation decreases VOC emissions by allowing the complete oxidation to take place at a faster rate and a lower temperature than is possible with thermal oxidation. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 to 30 feet per second. The optimal range for oxidation catalysts is approximately 850 to 1,100 °F.

With the use of oxidation catalysts, emissions of acid gases increase as does the need for additional heat input and power. Plant gas generally contains higher levels of sulfur (in the form of H₂S) than ultra-low sulfur diesel fuel. When plant gas is combusted, unlike ultra-low sulfur fuel, H₂S converts to more than trace levels of SO₂ which poisons and deactivates an oxidation catalyst. Furthermore, a review of the RBLC did not indicate that this technology has been used as a VOC control for process heaters. Therefore, the use of oxidation catalysts for control of VOC emissions from process heaters at the Holly Refinery is not technically feasible.

Based on review of the above BACT analysis, DAQ NSR recommends GCP as BACT for control of VOC emissions for all proposed process heaters. [Last updated June 4, 2013]

9. BACT review regarding Boiler #11 CO and VOC Emissions

CO and VOCs are products of the chemical reaction between carbonaceous fuels and oxygen.

The primary factors influencing generation of CO and VOC are temperature and residence time in the combustion zone. Higher combustion zone temperatures and residence times lead to more complete combustion and lower CO emissions.

Two control options, GCP and catalytic oxidation, are available for the control of CO and VOC emissions from the proposed boiler. The first control technology identified to reduce CO and VOC emissions is through good engineering design of the equipment utilizing GCP. GCP for CO and VOC include adequate fuel residence times, proper fuel-air mixing, and temperature control. For the proposed boiler, there will be adequate turbulence in the flue gas which will ensure good mixing, a high temperature zone (greater than 1800°F) that will ensure complete burnout along with a sufficient residence time (one to two seconds) at high temperature which will lead to minimized CO and VOC emissions. Higher combustion zone temperatures favor the complete oxidation of carbon-containing compounds to CO₂ and water. Therefore, emissions of CO and VOC would be expected to decrease at higher temperatures.

Catalytic oxidation allows complete oxidation to take place at a faster rate and a lower temperature than is possible with thermal oxidation. In a typical catalytic oxidizer, the gas stream is passed through a flame area and then through a catalyst bed at a velocity in the range of 10 to 30 feet per second (fps). Catalytic oxidizers typically operate at a narrow temperature range of approximately 600°F to 1100°F. At lower temperatures, the CO conversion efficiency decreases rapidly.

Catalytic oxidizers are similar to a SCR system in that a catalyst bed facilitates the conversion of a CO to CO₂. Unlike SCR, catalytic oxidizers do not use additional chemicals such as ammonia to facilitate the conversion.

The Holly Refinery plant gas contains sulfur. Plant gas generally contains higher levels of sulfur (in the form of H₂S) than ultra-low sulfur diesel fuel. When plant gas is combusted, unlike ultra-low sulfur fuel, H₂S converts to more than trace levels of SO₂ which poisons and deactivates an oxidation catalyst. In addition, SO₂ would be converted to SO₃ which will form sulfuric acid increasing the emissions of this acid gas and will increase both condensable particulate emissions and flue gas system corrosion rates. Oxidation catalyst is not a technically feasible option for control of CO and VOC emissions from the proposed boiler.

The EPA's RBLC and recent issued permits were reviewed and catalytic oxidation was not identified as a CO and VOC technically feasible control option for refinery-fuel gas-fired boilers.

CO and VOC emissions can be controlled by using GCP, including providing adequate fuel residence time, excess oxygen and high temperature combustion zone to ensure complete combustion. Thus, the only identified control technology, GCP, is considered technically feasible for refinery or natural gas fired boilers. With the use of GCP, no adverse economic, energy, or collateral environmental impacts are identified that preclude the use of this control option.

Holly Refinery is proposing to utilize GCP to reduce CO emissions from the proposed boiler. Holly Refinery has obtained performance guarantee of 50 ppm or approximately 0.037 lb/MMBtu for CO and 10 ppm for VOC or approximately 0.004 lb/MMBtu.

Based on review of the above BACT analysis, DAQ NSR recommends a CO emission limit of 0.037 lb/MMBtu and a VOC limit of 0.004 lb/MMbtu as BACT for Boiler #11. [Last updated June 4, 2013]

10. BACT review regarding Boiler #11 PM and SO₂ Emissions
Boiler #11 PM Emissions

For gaseous fuel combustion, nearly all particle emissions fall in the PM_{2.5} range; therefore focusing on control of PM_{2.5} emissions will control all particulate emissions equally. PM_{2.5} emissions can be controlled by the following technologies:

GCP,
wet gas scrubber,
ESP,
cyclone, and
baghouse/fabric filters.

None of the add-on control devices are technically feasible for the proposed boiler burning gaseous fuels due to the extremely low concentration of small particulates expected in gas streams from this type of equipment. PM concentrations in the refinery fuel and natural gas-fired boilers are even less than the concentrations guaranteed by the cyclones, ESP's, fabric filters, and wet gas scrubbers. Therefore, wet gas scrubbers, ESP's, cyclones, and fabric filtration (baghouses) were rejected as BACT for PM emissions from the proposed boiler.

The remaining control option is the utilization of GCP.

The manufacturer's data indicates a guaranteed emission factor of 0.01 lb/MMBtu (equivalent to 0.52 lb/MMScf); however, Holly Refinery is proposing to utilize a NEI emission factor of 0.00051 lb/MMbtu, therefore this is the emission limit that Holly Refinery will be held to comply with.

The proposed PM emission limit for the proposed Boiler #11 is based on EPA published NEI emission factors of 0.00051 lb/MMbtu utilizing proper equipment design and operation, GCP, and the use of gaseous fuels. Based on review of the above BACT analysis, DAQ NSR recommends a PM₁₀ emission limit of 0.00051 lb/MMBtu as BACT for the proposed Boiler #11.

Boiler #11 SO₂ Emissions

The quantity of SO₂ emissions from the proposed boiler depends on the sulfur content of the fuels combusted. For refinery fuel gas, when burned in a boiler, the result is essentially all the sulfur in the fuel is oxidized to SO₂.

The following is a list of control technologies are available technologies for controlling SO₂ emissions:

fuel specification - low sulfur fuels;
wet FGD;
advanced flue gas desulfurization; and
dry FGD.

All listed control options are technically feasible. Research, including recent permits and the RBLC database, did not result in AFGD, wet FGD, or dry FGD as BACT for large boilers therefore these options were eliminated from further consideration. The only control strategy identified for the fuel gas-fired boiler is adherence to fuel specifications. This control strategy is technically feasible and will not cause adverse energy, environmental, or economic impacts.

Holly Refinery has a fuel gas sulfur content limit of 60 ppmv or less which is proposed as the BACT emission limit for the boiler. In addition to the fuel gas sulfur content limit, equipment design and work practice requirements will be implemented to minimize, to the greatest extent possible, emissions that would occur due to upsets.

Based on review of the above BACT analysis, DAQ NSR recommends a fuel gas sulfur content limit of 60 ppmv or less as BACT for SO₂ emissions from proposed Boiler #11. [Last updated June 4, 2013]

11. BACT review regarding Boiler #11 NO_x Emissions

Oxides of nitrogen are formed during the combustion of fuels by oxidation of chemically bound nitrogen in the fuel and by thermal fixation of nitrogen in the combustion air.

There are a variety of options available for control of NO_x emissions from combustion sources. These include modifications that reduce NO_x formation, add-on control devices, or combinations of both. The same control technologies and techniques for NO_x emissions that were identified for the process heaters are applicable to the boiler. They include:

LNB,
ULNB,
FGR,
SNCR,
SCR,
LNB +FGR,
ULNB + FGR,
LNB + SNCR,
ULNB + SNCR,
LNB + SCR,
ULNB + SCR,
EMx (formerly SCONO_x),
LNB and EMx,
ULNB and EMx, and
GCP.

All of the individual controls or combinations of controls are technically feasible.

As discussed with the process heaters, with SCR, ammonia is injected as the flue gas passes through a catalyst bed. SNCR consists of injecting ammonia or urea into the combustion unit flue gases in a specific temperature zone between 1600°F to 2100°F. The exhaust temperature of the proposed boiler is estimated to be 900° F or less. This would require additional energy input and therefore, additional exhaust emissions to raise the temperature of the power boiler exhaust to the operating temperature of the SNCR. Therefore, SNCR was eliminated as BACT for use as a post combustion control for NO_x emissions from the proposed boiler. SNCR+LNB and

SNCR+ULNB were also eliminated.

ULNB and LNB are burner designs that reduce NO_x formation. The ULNB is designed to recirculate hot, oxygen depleted flue gas from the flame or firebox back into the combustion zone. By doing this, the average oxygen concentration is reduced in the flame without reducing the flame temperatures below that which is necessary for optimal combustion efficiency. Low-NO_x burner technology uses advanced burner design to reduce NO_x formation through the restriction of oxygen, flame temperature, and/or residence time.

FGR is another combustion control used to reduce NO_x. FGR involves the recycling of fuel gas into the air-fuel mixture at the burner to help cool the burner flame. Internal FGR, used primarily in ULNB, involves recirculation of the hot O₂-depleted flue gas from the heater into the combustion zone using burner design features. External FGR, usually used with LNB, requires the use of hot-side fans and ductwork to route a portion of the flue gas in the stack back to the burner windbox.

EMx is an add-on technology that utilizes a catalyst to absorb the SO₂ in the flue gas. The catalyst is periodically regenerated using hydrogen. This technology has only been used on a small number of natural gas combustion turbines for NO_x control and not on power boilers. Thus, it was eliminated from further BACT consideration.

In summary, based on the above discussion, SNCR, ULNB+SNCR, LNB + SNCR, EMx, EMx+LNB and EMx+ULNB were eliminated due to technical, economic, energy and environmental impacts. ULNB, LNB, and ULNB or LNB+SCR are all viable options to control NO_x emissions.

With the use of an SCR, adverse energy impacts occur. The adverse energy impact is due to the electrical requirements of the SCR system operation and to the reduction in energy efficiency attributable to the pressure drop across the catalyst. [Last updated June 4, 2013]

12. BACT review regarding Boiler #11 NO_x Emissions (continued)

The adverse environmental impacts attributable to the use of an SCR system includes the use of ammonia reagent, the handling and disposal of a spent catalyst as a solid waste stream, and ammonia emissions. The ammonia needed for the SCR will be available from other on-site operations and will not be trucked to the facility. Industry experience with SCR systems indicates that the removal and disposal of the spent catalyst can be conducted safely with insignificant risk to the environment.

With the use of addition energy and the SCR system, additional costs are incurred. The average cost effectiveness of this control option was justified by the air quality benefit gained through the use of an SCR system. Thus, although the use of an SCR has adverse energy, environmental and economic impacts, the beneficial environmental impacts outweigh the adverse impacts.

The combination of LNB and a SCR with combustion control for controlling NO_x emissions is the option with the highest ranking control (approximately 99.9% efficient) and has been chosen by Holly Refinery for the proposed boiler #11 at Holly Refinery. Holly Refinery has obtained a performance guarantee of 0.02 lb/MMBtu based on a three-hour average for NO_x.

Based on review of the above BACT analysis, DAQ NSR recommends a NO_x emission limit of

0.02 lb/MMBtu for Boiler #11 as BACT. [Last updated May 14, 2013]

13. BACT review regarding FCCU (Unit 25) CO Emissions

This BACT review was based on data summarized by EPA's RBLC, review of state databases and review of recent consent decrees. While the emission limits imposed by the consent decrees do not necessarily represent BACT, they do represent the most stringent emissions limitations placed upon FCCUs.

CO will be present in the FCCU regenerator flue gas. The FCCU will be run in 'full burn' operation. In full burn, the FCCU regenerator, when properly designed and operated, will convert nearly all of the coke to CO₂, thereby limiting CO emissions.

Three CO control technology options from a full burn FCCU regenerator include: catalytic oxidation, CO combustion promoters, and GCP.

Catalytic oxidizers, a post-emission control technology, are designed so that the waste gases pass through a flame area and then through a catalyst bed where CO is oxidized to CO₂ at temperatures of 650 to 1100°F. The regenerator flue gas will exit the wet gas scrubber at approximately 150°F. The process of reheating the flue gas would result in increased CO. In addition, catalytic oxidation cannot be used on waste gas streams that contain particulate due to the potential for fouling the catalyst which prohibits oxidation. Thus, catalytic oxidizers are technically infeasible and are eliminated from further consideration.

CO combustion promoters and GCP are technically feasible and will be considered further.

CO combustion promoters are an additive to the coke combustion process in the regenerator that hampers the formation of NO_x while enhancing the combustion of coke on the catalyst. The CO combustion promoters are readily fluidized, mixing with the catalyst. They are added to the circulating fluid bed (CFB) regenerator unit to improve the efficiency of CO burning, reduce emissions of CO and improve the efficiency of the unit. The CO combustion promoter accumulates in, or just above, in the fast fluidized bed combustion zone of the regenerator. There are several CO promoters that are available for use including Engelhard Corporations OxyClean, Intercat, and Grace Davison's XNO_x all of which are effective in reducing CO emissions while controlling NO_x emissions.

A second control technology for reducing CO emissions is GCP. Full burn regenerators operate with excess oxygen in the flue gas, typically 1-3 volume percent on a dry basis. The minimum excess oxygen required to promote complete CO oxidation is a function of bed temperature, gas residence time in the bed, and how efficiently the regenerator design utilizes the available oxygen. If the full burn unit is properly designed and operated, with sufficient oxygen present, the oxidation of CO to CO₂ should be complete. Therefore, GCP design and operation will effectively control CO emissions present in the FCCU regenerator exhaust gas.

Holly Refinery is proposing that GCP and a CO promoter will minimize CO emissions from the new FCCU. Using these control options, there are no anticipated additional environmental or energy impacts associated with this unit. Holly Refinery has obtained a performance guarantee of 500 ppmvd based on a one-hour average at 0% O₂ for CO.

Based on review of the above BACT analysis, DAQ NSR recommends a CO emission limit of

500 ppmvd based on a one-hour average at 0% O₂ be BACT for the FCCU (Unit 25). This is in line with the existing FCCU Unit 4's current CO limitation. [Last updated June 4, 2013]

14. BACT review regarding FCCU (Unit 25) PM Emissions

The main source of PM is catalyst fines and products of incomplete combustion that are released in the regenerator exhaust stack.

The following is a list of PM control technologies for the FCCU regenerator stack:

Wet Gas Scrubber;
ESPs; and
Third Stage Separator (TSS)/Cyclone.

A TSS is a specially designed cyclone or set of cyclones, for the flue gas from an FCCU regenerator. The TSS is in a separate vessel, outside the regenerator, that houses a number of small diameters, high efficiency cyclones arranged in parallel in the vessel. There is a flow distributor at the inlet to evenly distribute the regenerator flue gas to each small cyclone to create better efficiencies in particulate removal. The TSS is able to remove a significant amount of particulate that would normally go out the regenerator stack.

Each of the technologies is technically feasible. The following lists the ranking of the remaining control options:

ESP - Up to 95% reduction

Wet Gas Scrubber - 85 to 95 % reduction

TSS - No efficiency percentages were found but the literature suggests that the TSS is able to reduce the amount of particulate to approximately 0.6 lbs per 1000 lbs of coke burned.

ESP is a proven technology. The collected particulate is disposed of as a dry solid. The discharge doesn't have a vapor plume. There is a small pressure drop across the ESP. The particle collection process begins when the particle absorbs a charge sufficient amount to be attracted to the collection plates. However, the particle charging and collection process can be affected by several factors including particle size, particle resistivity, electric field and the temperature and composition of the flue gas stream.

There are reliability issues with electrostatic precipitators, so in many cases, multiple units are installed for redundancy which adds cost. Temperature and humidity affect the resistivity of PM. An ESP has a limited ability to handle high temperature excursions or FCCU upsets. In addition, any VOCs that might be in the stream because of an upset are dangerous to the unit. ESPs are also susceptible to changes in catalysts.

Wet gas scrubbers are also a proven technology. They have been demonstrated on a long-term basis to remove particles to very low levels. They have an excellent reliability so there is no need for multiple units. Wet scrubbers have a much broader operating range and are more able to handle upsets from the FCCU. A wet gas scrubber also has a lower operating temperature than an ESP which provides for improved removal of condensable PM. The waste from a wet gas scrubber can be disposed of as a wet solid.

The TSS removes a significant amount of catalyst fines from the flue gas stream. However, a

TSS by itself will not reduce particulate to meet the NSPS standard of 0.5lb/1000lb coke burned.

According to EPA's RBLC, wet scrubbers are used extensively as one method to reduce particulate from FCCUs and a wet gas scrubber is proposed by Holly Refinery to reduce PM emissions from the new FCCU. Holly Refinery has received a performance guarantee of 0.3 lb/1000 lbs of coke burned for PM₁₀ emissions.

Based on review of the above BACT analysis, DAQ NSR recommends a PM₁₀ emission limit of 0.3 lbs/1000 lbs of coke burned-off for the FCCU (Unit 25). Annual testing requirements will follow the 2008 Holly Refinery Consent Decree requirements. [Last updated June 4, 2013]

15. BACT review regarding FCCU (Unit 25) SO₂ Emissions

Depending on the feed sulfur content and FCCU design, sulfur emissions in the form of SO₂ and SO₃ from the regenerator can vary significantly. Black wax crude is inherently low in sulfur. In the FCCU reactor, 70 to 95 percent of the incoming feed sulfur is transferred to the acid gas and product side in the form of H₂S. The remaining of the incoming feed sulfur is attached to the coke where it is oxidized into sulfur oxides and emitted in the FCCU regenerator flue gas.

The following is a list of technologies for controlling SO₂ emissions from the FCCU:

Control of sulfur in the FCCU feed

Feed hydrotreatment

Wet Gas Scrubbers

Wellman-Lord Flue Gas Desulfurization Process

DeSO_x Additives

In the feedstock hydrotreatment process, the FCCU feedstock is treated over a metal catalyst in a hydrogen environment before the cracking process. Depending on initial sulfur levels, flue gas emissions of SO₂ can be reduced by up to 90 percent with the additional benefit of reductions in nitrogen compound and trace metal emissions.

The water used in a wet gas scrubber is mixed with an alkaline reagent to react with the SO₂ to form sulfate and sulfite salts. These compounds are captured as a wet solid in the filtering section of the wet gas scrubber. The SO₂ removal efficiencies typically range from 95 to 99.9%.

In the Wellmann-Lord flue gas desulfurization process, flue gas enters the absorber and gas is scrubber using an aqueous sodium sulfate solution. The scrubbed flue gas exits the absorber, passes through a set of demisters and is discharged to the atmosphere. The SO₂ removal efficiency using this process is between 85 to 98%.

DeSO_x additives are typically metal oxide catalysts that are added to the regenerator to convert SO₂ to SO₃. The metal oxide catalyst is introduced to the feed in the riser with the regenerated catalyst. The SO₃ is adsorbed to a sulfate and then recycled back to the reactor with the FCCU catalyst where it is reduced in the riser/reactor to H₂S which is controlled by a refineries sulfur plant.

All options are technically feasible with the exception of feedstock hydrotreatment. The feedstock hydrotreatment requires a large number of process units to take the sulfur out of the

feed to the FCCU. This equipment includes a hydrogen plant, a high pressure hydrotreater, approximately three additional heaters, a fractionation tower, and a gas plant. This sulfur removal technique is larger than the FCCU process itself. The three additional process heaters would operate full time and each heater would have additional emissions. In addition, there are additional environmental concerns with catalyst removal and disposal from the hydrotreater.

The catalyst beds in the hydrotreater are layers of catalyst inside high pressure vessels. The feedstock flows through these beds where the reactions take place. The Black Wax crude has a heavy residual bottoms fraction. This fraction is too heavy for the catalyst beds to efficiently crack into lighter fractions. It would plug up the catalyst beds in the hydrotreater. This issue makes it technically infeasible to hydrotreat the Black Wax feedstock to the FCCU without removing the bottoms fraction first. Thus, this option has been determined to be technically infeasible. [Last updated June 4, 2013]

16. BACT review regarding FCCU (Unit 25) SO₂ Emissions (continued)

According to EPA's RBLC, wet scrubbers have been successfully applied to several refinery FCCUs to control emissions of SO₂ and PM. Recent consent decrees will require several refineries to install wet gas scrubbers to reduce SO₂ emissions. Several designs of wet scrubbers are available (plate or tray towers, spray chambers, and venturi) and emission control levels for SO₂ between 95-99.9% have been achieved.

The Wellman-Lord Flue Gas Desulfurization process has been used successfully in Japan, Germany, and the United States but no new units were identified that have been built in recent years.

DeSO_x additives are added to a regenerator to reduce the SO_x from the flue gas of the regenerator. This catalyst converts SO₂ in the regenerator to SO₃ and stabilizes it as a metal sulfate. This metal sulfate is then introduced to the feed in the riser with the regenerated catalyst. The riser has a reducing atmosphere as opposed to the oxidizing atmosphere in the regenerator. The metal sulfate is converted to H₂S in the riser/reactor and released with the products to the fractionator.

Although more than 70 refiners have successfully used DeSO_x additives worldwide, there are a number of operating variables that have been identified as having significant effects on the performance of SO_x reduction additives. Some of these include the presence of combustion promoters, the ratio of catalyst circulation rate to unit catalyst inventory, temperature, availability of oxygen in the regenerator, feed sulfur content, and SO_x concentration. Various scientific studies have shown that the fraction of sulfur in the feed has a direct impact on the coke sulfur content deposited on spent catalyst and, thus, on SO_x emissions. Since the sulfur content of the proposed feed is extremely low and the amount of SO₂ control that can be achieved by using DeSO_x additives is significantly less than the top ranking option, DeSO_x additives are eliminated from further consideration.

The top control option, a wet gas scrubber with a control efficiency of up to 99% is proposed by Holly Refining to reduce SO₂ emissions from the proposed FCCU. SO₂ emissions from the wet gas scrubber are estimated to be 25 ppmvd at 0% O₂ based on a 365-day average and 50 ppmvd at 0% O₂ per 7-day average.

Based on review of the above BACT analysis, DAQ NSR recommends a wet gas scrubber with

a SO₂ limit of 25 ppmvd at 0% O₂ based on a 365-day average as BACT. This is in line with the existing 4V82 FCC Wet Scrubber's current SO₂ limit. [Last updated May 13, 2013]

17. BACT review regarding FCCU (Unit 25) NO_x Emissions

The FCCU regenerator is proposed as a full-burn unit which is recognized by EPA as an inherently low NO_x design. The predominant NO_x species inside an FCCU regenerator is NO that is further oxidized to NO₂ upon release to the atmosphere. NO_x in the regenerator can be formed by two mechanisms, thermal NO_x produced from the reaction of molecular nitrogen with oxygen and fuel NO_x which is produced from the oxidation of nitrogen-containing coke species deposited on the catalyst inside the reactor.

The following is a list of technologies for controlling NO_x emissions from a FCCU:

SNCR,
SCR,
LoTO_x, and
Catalyst additives and low NO_x combustion promoters.

All the options are technically feasible.

The remaining control options were ranked in order of reduction:

SNCR - 60 to 80% reduction
SCR - > 90% reduction
LoTox - >90% reduction with SCR
Catalyst additives and low NO_x combustion promoters - 45-95% reduction.

The SNCR system is a post-combustion control technology that reacts with urea or ammonia with flue gas without the presence of a catalyst to produce N₂ and H₂O. The typical operating temperature range for an SNCR is 1,600°F to 2,000°F. The SNCR temperature range is sensitive as the reagents can produce additional NO_x if the temperature is too high or removes too little NO_x if the reaction proceeds slowly if the temperature is too low. The NH₃ slip in SNCR applications can range from 10 to 100 ppmv. SNCR has been used successfully with CO boilers but are typically not used with full burn units due to low NO_x removal at temperatures below 1,400°F. In full burn units, such as proposed by Holly Refinery, the flue gas must be heated to 1,600 to 1,800°F to achieve NO_x removal rates of 50% and greater.

SCR is a post combustion control technology that injects ammonia in flue gas in the presence of a catalyst (typically vanadium or tungsten oxides) to produce N₂ and H₂O. An SCR is similar to SNCR with the exception that a catalyst is used to accelerate the reactions at lower temperatures. The ideal temperature range for an SCR is 600°F to 750°F with guaranteed NO_x removal rates of 90+%. Design considerations include targeted NO_x removal level, service life, pressure drop limitation, ammonia slip, space limitation, flue gas temperature, composition and SO₂ oxidation limit. SCR suppliers typically guarantee the performance of the unit for NO_x removal, service life, pressure drop, ammonia slip and SO₂ oxidation. Ammonia slip, referring to the amount of ammonia which passes through the process unreacted, is typically guaranteed to 10 ppmv.

The Belco LoTO_x technology is a selective, low temperature technology that uses ozone to oxidize NO_x to water soluble nitric pentoxide (N₂O₅). These higher oxides of nitrogen are

highly soluble. Inside a wet gas scrubber, the N_2O_5 forms nitric acid that is subsequently scrubbed by the scrubber nozzles and neutralized by the scrubber's alkali reagent. Since the process is applied at a controlled temperature zone in the wet gas scrubber, it can be used at any flue gas temperature. The controlled temperature zone in the wet gas scrubber is below 300°F. Since the LoTOx technology does not use a fixed catalyst bed, it can handle unit upsets without impacting overall reliability and mechanical availability. [Last updated June 4, 2013]

18. BACT review regarding FCCU (Unit 25) NO_x Emissions (continued)
The LoTOx technology generates ozone on demand based on the amount of NO_x in the flue gas. There is no storage of ozone required. Emission reductions using this process have been estimated to range from 80 to 95%.

Several vendors offer NO_x reducing catalyst additives and combustion promoters. Current NO_x additives affect the availability of nitrogen species to be oxidized and reduced and the performance of the additives is dependent on the application. Grace Davison's XNO_x is a combustion promoter additive that can reduce NO_x emission from 50-75% in the regenerator. Grace Davison's DENOX promoter can reduce NO_x emissions up to 60%. Engelhardt's CLEAN NO_x and OxyClean reduce NO_x emissions by 45%. INTERCAT's COP-NP can reduce emissions from approximately 40-65%. The NO_x combustion promoters (catalysts and additives) are added directly into the FCCU reactor and regenerator. These additives can withstand the harsh environment of the regenerator but do not have the same life as catalyst.

A benefit associated with the use of additives is flexibility. Additives can easily be added and removed from the operation depending on the refiner's needs but are more expensive than FCC catalysts with an average cost approaching \$20 per pound. The additional cost associated with the recommended usage rate of these additives may triple the current catalyst cost resulting in negative process unit economics. Higher removal rates may require more additive and that can impact yields, product quality and unit throughput.

SNCR is not feasible in this application because of the need to heat the flue gas to reach the optimum operating levels of the SNCR. The amount of NO_x reduction is also lower. Most EPA consent decree applications have achieved a 5 to 30% reduction with others in the industry achieving up to 70% depending on process conditions. A drawback of using SNCR technology is the potential formation of ammonium sulfate salts and resultant fouling. These salts will exist as small particulates.

SCRs operate in the temperature range of the regenerator flue gas coming out of the FCC. This control technology has a high NO_x reduction rate when compared to other NO_x control technologies. Although SCR offers high NO_x reduction rates, catalyst deactivation can occur from salt formation on the catalyst surface, cracks of the catalyst from the substrate material can occur from thermal stresses, and thermal degradation of the catalyst can occur at temperatures greater than 800°F. Other items that can lead to catalyst deactivation include erosion of the catalyst due to excessive catalyst fines loading and plugging of the catalyst system due to catalyst fines.

At the plants where SCR's have been installed, the majority of them have third stage separators or ESP's located before the SCR catalyst bed to protect against upsets in the FCC regenerator. Holly Refinery is not proposing either a third stage separator or ESP as part of the heavy crude processing project. LoTOx in conjunction with wet scrubbing systems has been demonstrated to

effectively reduce high levels of NO_x from a FCCU. The efficiency obtained from the combination of LoTOx and wet gas scrubbing systems is comparable to an SCR. Combustion promoters will not reduce the NO_x emissions alone to meet NO_x BACT levels. [Last updated May 13, 2013]

19. BACT review regarding FCCU (Unit 25) NO_x Emissions (continued)

A review of EPA's RBLC indicates that SCRs, and LoTOx in conjunction with wet scrubbing systems are used for the reduction of NO_x in a number of FCCUs. However, Holly Refinery is concerned about potential SCR problems such as fouling, plugging, poisoning and/or thermal degradation of the catalyst which could result in potential downtime for the SCR and possible the process. Addition concerns with the use of a SCR include conversion of SO₂ to SO₃ and formation of ammonium sulfate/sulfite particles that could deposit in the catalyst or ductwork.

Thus, Holly Refinery has chosen a LoTOx system in conjunction with a wet gas scrubber to reduce NO_x emissions in the regenerator flue gas. Holly Refinery has received a performance guarantee for NO_x emissions from the FCCU regenerator of 110 ppm per 365-day rolling average and 180 ppm per 7-day rolling average.

After reviewing the above BACT analysis, Holly Refinery's modeling analysis, Holly Refinery emission calculations, and the 2008 EPA Holly Refinery Consent Decree (paragraph 21); DAQ NSR recommends as BACT that NO_x emissions from the FCCU regenerator shall not exceed 40 ppm per 365-day rolling average and 80 ppm per 7-day average. This value was used in both the NO_x emission calculations and the modeling analysis submitted in the NOI and follows the EPA Holly Refinery Consent Decree.

As a note, per the 2008 EPA Consent Decree, the EPA will use data collected during the optimization and demonstration periods defined within the Consent Decree, and may establish NO_x concentration based emission limits based on a 7-day and 365-day rolling averages, no lower than 20 ppmvd at 0% O₂ on a 365-day rolling average basis and 40 ppmvd at 0% O₂ on a 7-day rolling average. Therefore, at a later date, the EPA may establish different limits from what are being proposed with this permit. [Last updated June 4, 2013]

20. BACT review regarding Tank VOC Emissions

Due to the processing of heavy crude at the refinery, several new tanks will be added or existing tanks modified to store the black and yellow wax crude or resultant products.

Internal floating roof (IFR) tanks are used to store high vapor pressure volatile organic liquid products at a refiner. Internal floating roof tanks use a fixed cone roof covering over the top of the tank along with an internal floating roof having at least a single seal system between the tank wall and floating roof cover.

Under NSPS regulations, control equipment is required when storing volatile organic liquids with maximum vapor pressure of 0.75 psia. Otherwise, control requirements generally are triggered at 1.5 psia. Tanks storing volatile organic liquids below the vapor pressure threshold are required to keep records of types of products stored and their vapor pressures, periods of storage and tank design specifications.

Because high vapor pressure volatile organic liquids must be stored in 'controlled tanks', the regulations define how these tanks are constructed and monitored. Tanks constructed after July

23, 1984 are required to operate in accordance with 40 CFR Part 60 Subpart Kb and are exempt from refinery MACT requirements (63.640(n)). Tanks constructed before that date and storing volatile organic liquids containing HAPS are required to meet the applicable Refinery MACT requirements of NESHAP 40 CFR 63 Subpart CC which refers to the control standards of 40 CFR Part 63 Subpart G.

Compliance options for VOC emission controls on tanks includes using a fixed roof with an IFR, an external floating roof meeting certain design specifications, and using a closed-vent system and control device that meet the requirements of 40 CFR Part 60 Subpart Kb.

The highest ranking control option for reducing emissions from storage tanks is a fixed roof in combination with an IFR with a vapor collection in a closed vent system routed to a control device. This design incorporates a roof structure that floats on the surface of the stored liquid with dual, flexible seals along the edge of the roof which eliminates working losses. The headspace between the floating roof and the top of the tank is filled with sweep gas that is vented under a slight vacuum. The breathing losses that escape through the tank are carried with the sweep gas to add on control device such as a thermal oxidizer or carbon adsorption unit.

The second effective option includes an IFR and dual rim seals. This option does not include sweep gas routed to a control device.

The third option used to control VOC emissions from storage tanks includes the use of an external floating roof with dual rim seals. This type of tank is similar to the IFR configuration without the enclosed headspace. The floating roof and seals act to reduce VOC losses. This control option has overall effectiveness equivalent to a tank which is equipped with an IFR and dual rim seals. The external floating roof design is commonly accepted control technology for tanks storing liquids with relatively low volatility.

The fourth option includes a fixed roof with vapor collection by a closed vent system routed to a control device. This design omits any control equipment such as a floating roof and relies on an end-of-pipe air pollution control device. [Last updated March 28, 2013]

21. BACT review regarding Tank VOC Emissions (continued)

Vapor losses from fixed roof vertical tanks are primarily due to changes in the atmospheric temperature and pressure as well as liquid level changes inside the tank. Due to the low volatility of the products to be stored, black wax and gas oil, Holly Refinery is proposing fixed roof tanks with no vapor recovery.

The cost of a vapor control system is a function of the vapor flow rate to the system. The flow rate is controlled by the rate at which liquids are pumped into the tank. The total annualized costs of installing a vapor control system by incineration is approximately \$425,000 (based on EPA estimates adjusted to 2011 dollars). If carbon adsorption were used for vapor control, the projected annualized costs would be approximately \$595,000. The volume of VOC vapors, expected to be approximately 6,242 pounds for the proposed tanks is insufficient to justify the installation of a vapor recovery system. In addition, if a vapor recovery system were utilized, energy usage will increase. If an incineration device is used, increased emissions would be expected from flaring. If activated carbon were used, a solid waste could also be generated.

Because of the low volatility of the products being stored, the installation of IFR and seals or an

external floating roof is also not warranted. The capital cost to install internal floating roof and controlled deck fittings is approximately \$30,000 per tank. For an external floating roof, the estimated capital cost would be over \$210,000.

Holly Refinery is proposing the following tank controls:

Tank 70: Storing heavy crude – Fixed roof

Tanks 71 and 72: Storing heavy crude – Remove IFR unless there is enough variation in vapor pressure that requires vapor control.

Tanks 89-97, 99, 139, and 140: Storing lube oil feed/product storage - Fixed roof

Tank 98: Storing high volatile liquids such as gasoline - IFR

Tanks 158 and 168: Storing low volatile liquids such as wastewater and sour water - External floating roof

Based on review of the above BACT analysis and volatility of stored product, DAQ NSR recommends the following as BACT: Tank 70 as a fixed roof until DAQ makes a determination further controls are required. Tanks 71 & 72 will keep existing IFR control in place until Holly Refinery can demonstrate to DAQ that vapor controls are not needed for heavy crude storage. Tanks 89-97, 99, 139, and 140 will be equipped with fixed roofs. Tank 98 will be equipped with an IFR with primary and secondary seals. Tanks 158 and 168 will be equipped with an external floating roof. [Last updated May 20, 2013]

22. BACT review regarding Loading Rack VOC Emissions

One existing LPG rail loading spot on the west track will be converted to load propane and one (1) additional rail spot for loading propane will be constructed on the west track. The crude truck unloading facilities will be expanded to accommodate twelve more truck bays. These loading/unloading racks will be sources of VOC emissions.

A small electric-driven compressor will be added to control loading emissions by recovering displaced relief gas from loading propane into rail cars.

Three add on control technologies to reduce VOC emissions from product loading racks include: carbon adsorption, condensation, and incineration. However, Holly Refinery is proposing to utilize a sump pump for the new truck unloading bays, removing the need for additional controls. The sump will be heated and appropriately sized to accommodate a spill. Transfer piping from the new unloading bays to Tank 126 will be installed (no other changes will be made to Tank 126).

Based on review of the above BACT analysis, DAQ NSR recommends the utilization of a vapor recovery system to control VOC loading emissions be BACT for the propane/LPG loading racks. [Last updated June 4, 2013]

23. BACT review regarding Emergency Generator Emissions (Diesel)

The emergency diesel generator will be operated only during interruptions in normal electrical power supply or for maintenance, testing, and operator training. The emergency generator will be limited to 50 hours of operation per year for maintenance and testing and will be EPA Tier III compliant. The primary pollutants in the exhaust gases include NO_x, CO, VOC, and PM.

NO_x Emissions

The following control technology options for controlling NO_x emissions from the emergency generator are categorized as combustion modifications and post-combustion controls. Combustion modifications include: ignition timing retard, air-to-fuel ratio, and derating. Post combustion controls include SCR, NSCR catalyst, and NO_x absorption systems.

NSCR catalysts are effective to reduce NO_x emissions when applied to rich-burn engines fired on natural gas, propane and gasoline. The proposed engine is a lean-burn engine. NO_x absorption is an experimental technology where no commercial applications were identified in EPA's RBLC. SCR has demonstrated to reduce NO_x emission by 70 to 90% while combustion modification has demonstrated to reduce NO_x emission by 50%. However, an improperly functioning SCR system can create excess ammonia emissions and add increased maintenance costs. A cost analysis was performed to determine the cost of control per ton of NO_x removal from SCR. Per EPA's cost effectiveness evaluation, that cost is approximately \$396,886.

CO and VOC Emissions

The following are technology options for controlling CO and VOC emissions from the emergency generator: GCP, NSCR, and oxidation catalyst. GCP refers to the operation of the engine at high combustion efficiencies which reduce the emissions of incomplete combustion. The proposed engine is designed to achieve maximum combustion efficiency. NSCR technology oxidizes CO and VOCs to CO₂ and water and is applicable to rich burn engines. The proposed engine is a lean burn engine. Oxidation catalyst technology can significantly reduce CO and VOC emissions. However, due to the limited hours of proposed operation of the emergency generator (50 hours per rolling 12-month period), the add-on control is not practical. A cost analysis was performed to determine the cost per ton of CO and VOC removal from a oxidation catalyst. The cost was estimated at \$500,000 per ton for both CO and VOC.

PM Emissions

The following are technology options for controlling PM emissions from the emergency generator: GCP, use of low sulfur fuels, diesel particulate filters, and diesel oxidation catalysts. A cost analysis was performed to determine the cost of control per ton of PM removal from particulate filters and oxidation catalysts. Per EPA's cost effectiveness evaluation, the costs are approximately \$348,278 per ton PM removal from particulate filters and approximately \$163,458 per ton PM removal from oxidation catalysts.

Based on review of the above BACT analysis for all pollutants and the fact that the generator will only operate for a maximum of 50 hours per rolling 12-month period, DAQ NSR recommends the following be BACT for the emergency generators: GCP, EPA Tier III compliance, 50 hour limitation of maintenance and readiness testing, and combustion of ultra-low sulfur fuel (15 ppm by weight of sulfur). [Last updated June 4, 2013]

24. BACT review regarding Emergency Generator Emissions (Natural Gas)
The emergency natural gas generators will be operating only during interruptions in normal electrical power supply or for maintenance, testing, and operator training. The emergency generators will be limited to 50 hours of operation per year for maintenance and testing and will be EPA compliant. The primary pollutants in the exhaust gases include NO_x, CO, VOC, and PM.

NO_x Emissions

Four control technologies to reduce NO_x emissions are: SCR, NSCR, lean burn technology, and GCP.

The add-on combustion control of NSCR is deemed technically infeasible since NSCR is commonly used with rich-burn IC engines and thus was eliminated from consideration since the proposed engines are designed for lean burning.

In lean burn engines, the combustion process is enhanced by pre-mixing the air and fuel upstream of the turbocharger before introduction into the cylinder. This creates a more homogeneous mixture in the combustion chamber. The microprocessor-based engine will regulate the fuel flow and air/gas mixture and ignition timing to achieve efficient combustion.

Combustion controls are integral in the combustion process as they are designed to achieve an optimum balance between thermal efficiency-related emissions (CO and VOC) and temperature related emissions (NO_x). Combustion controls will not create any energy impacts or significant environmental impacts. There are no economic impacts from combustion controls because they are part of the design for modern engines.

Holly Refinery proposes BACT for NO_x emissions from the proposed generators is the application of a lean burn engine and GCP. The proposed generators are EPA certified and the manufacturer lists a NO_x emission rate of 0.08 grams/HP-hr.

PM Emissions

GCP using natural gas is an available PM emission control method. Since there is little ash in natural gas that would contribute to the formation of PM, PM₁₀ or PM_{2.5}. There is no environmental, energy or economic impacts that would preclude the use of natural gas.

Holly Refinery proposes BACT for PM/PM₁₀/PM_{2.5} emissions is the use of natural gas and GCP.

CO and VOC Emissions

Three potential control technologies to reduce CO and VOC emissions are: combustion control techniques, oxidation catalysts, and NSCR as an add-on control device.

Optimization of the design, operation, and maintenance of an engine is one way to reduce CO and VOC emissions by maximizing the thermal oxidation of carbon which minimizes the formation of CO.

Holly Refinery estimated that the use of an oxidation catalyst on an 8,000 BHP engine for 500 hours per year would cost over \$8,000 per ton of pollutant reduction. The cost goes up exponentially as the engine size is reduced. Since the proposed engines are significantly smaller (approximately 190 HP) and the operating hours considerable less (50 per year), the costs for catalytic oxidation cannot be justified.

Combustion controls are integral in the combustion process as they are designed to achieve an optimum balance between thermal efficiency-related emissions (CO and VOC) and temperature related emissions (NO_x). Combustion controls will not create any energy impacts or significant

environmental impacts. There are no economic impacts from combustion controls because they are part of the design for modern engines.

Holly Refinery proposes BACT for CO and VOC emissions is GCP.

Based on review of the above BACT analysis and that these generators will only operate 50 hours per rolling 12-month period, DAQ NSR recommends compliance with the requirements of 40 CFR 60 Subpart JJJJ standards, an opacity limit of 10%, and GCP as BACT for NO_x, PM, CO and VOC emissions from the natural gas fired emergency generators. [Last updated June 4, 2013]

25. BACT review regarding Leaks (fugitives) VOC Emissions
Common strategies for VOC emissions from equipment leaks are based on work practices known as leak detection and repair (LDAR) programs. The requirements for the LDAR program for the Holly Refinery heavy crude processing project is set forth in 40 CFR Part 60 Subpart GGGa. These requirements apply to each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service.

Based on review of the above BACT analysis, DAQ NSR recommends the incorporation of the low-leak control requirements of GGGa into the existing LDAR be BACT. [Last updated May 13, 2013]

26. BACT review regarding South Flare Emissions
The flare system at Holly Refinery provides for the safe disposal of hydrocarbon gases which are vented automatically from process units through pressure relief valves, control valves or are manually vented. As part of the heavy crude processing project, the south flare at Holly Refinery will be reconstructed. Emissions from flares include carbon particles (soot), unburned hydrocarbons, NO_x, SO₂, CO, and VOC.

Flares operate primarily as air pollution control devices. The only technically feasible control options for emissions of all pollutants from flares are: (1) equipment design specifications and good combustion work practices such as minimization of exit velocity, ensuring adequate heat value of combusted gases, and minimizing the quantity of gases combusted; and (2) flare gas recovery systems.

A flare gas recovery system typically is installed upstream of the flare. A flare gas recovery system includes a seal system to allow for recovery of process gases vented to the flare. Compressors recover the vapors and the vapors are sent to the fuel gas treatment system for H₂S removal. After conditioning of the recovered vapors, the gases are combined with other plant fuel gas sources and are combusted in other devices that operate using fuel gas. Normally, the flare gas recovery system recovers all of the vent gas. There are conditions where the flare gas recovery system may not be sufficient to prevent flaring from process unit startup, shutdown, and malfunction events where large volume of process gases will be sent to the flare. Holly Refinery makes every effort to eliminate flaring from startups, shutdowns, and malfunctions.

For the top control technology, the use of a flare gas recovery system would involve economic and energy impacts. On March 21, 2013 Holly Refinery submitted a revised Flare Gas System Recovery Cost Effectiveness analysis for NO_x, CO, VOC, and GHGs. SO₂ emissions are estimated to less 0.1 ton per year; hence, no cost analysis was performed for this pollutant.

Based on a 10 year economic life and 6% depreciation, with a recovery estimate of \$5 per MMscf, the cost effectiveness (\$ per ton pollutant reduction) was approximately \$141,082 for NO_x, \$25,918 for CO, and \$151,494 for VOC. The 10 year economic life estimate is within range based on EPA's guidance for calculating amortized capital costs (Table 3.6). 40 CFR 60 Subpart Ja, the background summary for this subpart identifies the cost effectiveness for flare gas recovery to be approximately \$10,000 per ton criteria pollutant removal.

DAQ has determined that the estimated cost per ton removal for NO_x, CO, and VOC are not economically feasible.

Proper equipment design and work practices include minimizing exit velocity and the quantity of gases combusted and ensuring adequate heat value of combusted gases. Because the flare is located at a petroleum refinery, the flare must comply with the requirements and limitations presented in 40 CFR Part 60 Subpart Ja.

Based on review of the above BACT analysis, DAQ NSR recommends compliance with the requirements of 40 CFR 60 Subpart Ja as BACT for the South Flare. [Last updated May 20, 2013]

27. BACT review regarding Cooling Tower PM & VOC Emissions
This analysis consists of the additional Cooling Tower #10 and the addition of a cell to existing Cooling Tower #11.

PM Emissions

The control technologies to limit PM₁₀/PM_{2.5} drift from cooling towers are: Use of dry cooling heat exchanger units and high-efficiency drift eliminators.

Dry cooling has been employed at primary combined-cycle power plants as a means to reduce water consumption rather than as BACT for reducing PM₁₀ emissions. Holly Refinery provided a cost analysis outlining the substantial capital cost for this process. Because significant process changes would be required to utilizing this control technology, dry cooling was eliminated from being economically feasible.

All modern cooling towers are equipped with drift eliminators. The drift eliminator forces the exhaust air to make sharp turns before exiting. The momentum of entrained droplets carries the droplets to the drift eliminators surfaces where they coalesce and drip back into the tower. Typically, for cross-flow designs the drift rate will be less than 0.0005% because of the use of higher efficiency eliminators; counterflow and forced-draft counterflow designs routinely achieve 0.001%.

Based on review of the above BACT analysis, DAQ NSR recommends drift eliminators with vendor-guaranteed maximum total liquid drift of 0.0005 % of the circulating water flow rate as BACT.

VOC Emissions

An available technology for controlling VOC emission from cooling towers is the implementation of a heat exchanger leak detection and repair program. Holly Refinery already has implemented this program on the existing facility and will incorporate it for the proposed

modifications.

Based on review of the above BACT analysis, DAQ NSR recommends that a monthly monitoring program that complies with 40 CFR 63 Subpart CC be implemented to verify leak concentrations remain below 6.2 ppmv for VOCs. [Last updated June 4, 2013]

28. BACT review regarding Greenhouse Gas (GHG)
Potential GHG emissions from the stationary combustion sources such as process heaters and furnaces include primarily carbon dioxide (CO₂) with lesser amounts of nitrous oxide (N₂O) and methane (CH₄). The majority of the total GHG emissions, expressed at CO₂e are CO₂ emissions. CO₂ is a product of combustion of fuel containing carbon, such as refinery fuel gas and natural gas. Refinery fuel gas is a mixture of light C1 to C4 hydrocarbons, hydrogen, hydrogen sulfide (H₂S), and other gases.

Several control technologies are available for reducing GHG emissions from stationary combustion sources which include energy efficiency programs and systems, good combustion controls, low-carbon fuel, energy efficient design, and carbon capture and subsequent sequestration.

GCP for process heaters fired on refinery fuel include good air/fuel mixing in the combustion zone, good burner maintenance and operation, sufficient residence time to complete combustion, high temperatures and low oxygen levels in the primary combustion zone, proper fuel gas supply system design and operation, and excess oxygen levels high enough to complete combustion while maximizing thermal efficiency.

Gaseous fuels such as refinery fuel gas and natural gas reduces the CO₂ emissions during the combustion process relative to burning other solid fuels such as coal or distillate oils.

A highly efficient energy design requires less fuel for the process heaters. Elements of a highly energy-efficient design include combustion air controls by limiting excess air and combustion air preheat. Excessive amounts of combustion air in process heaters reduced the efficiency of process heat burners. This can be eliminated by installing instrumentation for monitoring and control the excess air levels in the combustion process. Air preheat is a method of recovering heat from the hot exhaust gas of a combustion process by heat exchange with the combustion air before it enters the combustion chamber. Preheating the combustion air reduces the amount of fuel required and ultimately lowers GHG emissions since less fuel is being combusted.

Carbon Capture and Subsequent Sequestration: CO₂ emissions can be captured through oxy-combustion and post-combustion methods. In oxy-combustion carbon capture, nearly pure oxygen is used for combustion instead of air which results in an exhaust gas that is comprised of mainly H₂O and concentrated CO₂. Since no refinery was identified that has applied this process to process heaters and the EPA states that this technology is still in the research phase, oxy-combustion CO₂ capture was eliminated from being technical feasible.

Post-combustion capture systems using solvent scrubbing and high temperature sorbents, ionic liquids, biological capture using algae ponds, and membrane technology were also identified as possible CO₂ control technologies. Post combustion capture is an 'end of pipe' technology which involves separating CO₂ from flue gas consisting mainly of nitrogen, water, CO₂ and other impurities. If a carbon capture technology could be utilized, after capture, a compression system

to compress the CO₂ is needed to prepare the CO₂ for transport to a permanent geological storage site such as oil and gas reserves and underground saline formations and to inject the captured CO₂ into the storage site.

Post-combustion CO₂ capture technologies such as using solvent scrubbing and high temperature sorbents, ionic liquids, biological capture using algae ponds, and membrane technology have not been demonstrated commercially at a refinery and the EPA states that these technology are still in the research phase, post-combustion CO₂ capture was eliminated from being technical feasible. [Last updated June 4, 2013]

29. BACT review regarding GHG (continued)

Through the use of chemical or physical absorption/adsorption processes, there are several sorbents and solvents under development for the separation of CO₂ from combustion flue gases. The most commercial of these processes uses monoethanolamine (MEA). In typical post combustion capture solvent-based scrubbing, the flue gas is cooled and cleaned of dust and other impurities before contacting with solvent, such as MEA. A CO₂ scrubbing column removes the CO₂ through absorption. Next, the CO₂ rich solvent is passed to a solvent regeneration column where heat transfer with hot steam releases CO₂ from the solvent, which results in solvent regeneration through the desorption process.

The MEA process requires a significant amount of power to operate pumps and blowers for gas and solvent circulation. Additional issues with the use of MEA are equipment corrosion, solvent degradation caused by the presence of dissolved O₂ and impurities, or reaction with SO₂, SO₃, and NO_x to produce non-regenerable heat-stable salts. The cost of capture in 2008 using MEA solvent absorption was estimated to be over \$100 per ton CO₂ avoided for oil refineries. A study presented in the International Journal of Greenhouse Gas Control explored the cost of routing refinery emission sources to a CO₂ capture plant. The study found that a typical refinery, CO₂ point sources are scattered around the site. The study concluded that 'many kilometers of additional ducting would be required to collect the CO₂. Both the capitol costs as well as the required blower duty will be of such a magnitude that this does not appear to be a feasible opportunity.'

If CO₂ were captured, it would have to be transported for subsequent sequestration. CO₂ can be transported in three states: gas, liquid, and solid. Applicable commercial-scale transport of CO₂ for Holly Refinery would consist of tanker trucks and/or pipeline. Transport by tanker trucks is not practical due to the large number of trucks needed and their associated exhaust emissions which include CO₂. Also, tank truck and rail options cost more than twice as much as a pipeline. Pipelines routinely carry large volumes of natural gas, oil, and water, for example, over large distances. Pipelines would be the best avenue for transport of CO₂ to a sequestration site although safety issues are of concern with a pipeline especially in populated areas. Pipeline leak or rupture would have significant safety, environmental and health impacts. Currently, the pipeline infrastructure in the area of the Holly Refinery does not exist for CO₂ transport. The nearest CO₂ pipeline in northeastern Utah is over 125 miles from the Holly Refinery. The cost to build a pipeline would be extreme; the labor and steel costs alone are estimated to be \$57,500 per mile per inch pipeline diameter.

CO₂ injection and storage into geological formations is a mitigation option. Injecting CO₂ into deep geological formations at carefully selected sites can store it underground for long periods of time. The cost of geological storage of CO₂ is highly site-specific, depending on factors such

as the depth of the storage formation and the number of wells needed for injection. Costs for storage, including monitoring, appear to lie in the range of 0.6-8.3 US\$/ton CO₂ stored. However, current and planned CO₂ geological storage locations in the United States are limited. The closest CO₂ storage project is proposed near Teapot Dome, Wyoming. CO₂ injection is also being used to enhance oil recovery in western and central Wyoming. [Last updated March 28, 2013]

30. BACT review regarding GHG (continued)
Because CO₂ capture has not been demonstrated commercially at a refinery at full scale, CO₂ transport infrastructure in the vicinity of Holly Refinery is not available, and Experience with large-scale geological CO₂ storage is limited; CO₂ capture, transport, and sequestration is not considered BACT and was eliminated as a feasible option. [Last updated May 14, 2013]
31. BACT review regarding GHG: Process Heaters
Based on the review of the above GHG BACT analysis, DAQ NSR recommends the following as BACT for GHG emissions for the process heaters: GCP including good air/fuel mixing in the combustion zone, good burner maintenance and operation, sufficient residence time to complete combustion, high temperatures and low oxygen levels in the primary combustion zone, proper fuel gas supply system design and operation, and excess oxygen levels high enough to complete combustion while maximizing thermal efficiency. Oxygen monitors and intake air flow monitors used to optimize the fuel/air mixture and limit excess air. Air preheater packages, consisting of a compact air-to-air heat exchanger installed at grade level through which the hot stack gases from the convection section exchange heat with the incoming combustion air be installed on the vacuum unit furnace (33H1).

The proposed crude unit (Unit 24) furnace (24H1) will not have a air preheater package installed. This is based on Holly Refinery's analysis of their existing crude unit's (Unit 8) furnace (8H1). Holly Refinery determined that there was very little energy savings when utilizing an air preheater for this application, making it cost-ineffective. [Last updated March 28, 2013]

32. BACT review regarding GHG: Boiler #11
Refinery fuel and/or natural gas will be utilized by Boiler #11 and has the lowest CO₂ emission rate of all fossil fuels. According to AP-42, natural gas has a CO₂ emission rate of 120 lb/MMBtu compared to distillate oil which has a CO₂ emission rate of 150 lb/MMBtu. Thus, natural gas is a top ranked low carbon containing fuel.

GCP includes operational and design elements to control the amount and distribution of excess air in the flue gas. This ensures that there is enough oxygen present for complete combustion. If sufficient combustion air supply, temperature, residence time, and mixing are incorporated in the combustion design and operation, CH₄ and N₂O emissions will be minimized. To improve boiler efficiency and reduce GHG emissions by 3 to 13 percent, insulation will be installed on Boiler #11 and improved insulation will be added to the existing boilers and distribution pipes. The reuse of steam condensate, which reduces the amount of feed water and the amount of energy needed since the condensate is preheated will be employed at the refinery. The estimated efficiency improvement by the installation of steam condensate return lines is up to 10%.

For proposed Boiler #11, Holly Refinery is proposing the use of a Nebraska Boiler Model NOS-A/S-55. Other boiler configurations are available and were examined for this project but due to

the larger cabin space, those boilers did not produce steam as efficiently as the proposed make/model for Boiler #11. Boiler #11 will utilize high efficiency TODD VARIFLAME burners and a welded-membrane wall design that creates a gas-tight furnace area. The burners are designed to use advanced fuel-staging and to provide the proper-air-to-fuel mixture throughout the full range of firing rates which maximizes combustion efficiency while minimizing the release of emissions. Boiler #11 design allows for higher steam generation and heat utilization with less fuel consumption, thus resulting in lower GHG emissions. The boiler also features a single-source integrated boiler and burner controls for more efficient operator-free handling of the boiler.

Holly Refinery is proposing that Boiler #11 will be equipped with instrumentation and controls that can achieve up to a 4% reduction in CO₂ emissions. And that Boiler #11 will be equipped with an O₂ analyzer and O₂ concentrations will be monitored and documented each shift. This boiler will also be equipped with a mechanical linkage that can be adjusted by a factory representative. This linkage increases/decreases air flow and fuel gas simultaneously keeping the excess percent O₂ constant.

Tuning of the burners will be performed periodically to insure efficient boiler operation. Through burner tuning, up to a 3% reduction of CO₂ emissions can be obtained.

Routine maintenance will be performed on the boiler to insure it is operating at maximum efficiency. The system will be periodically checked for air leaks since too much excess air leads to energy loss. Indications of air leakage will be present in higher O₂ levels as well as increased fuel consumption. Improved efficiency improvement from reducing air leakage problems can reduce CO₂ emissions ranging from 1 to 4 percent.

Available control technologies for the control of CH₄ and N₂O emissions are the same controls used for CO and VOC emissions. These controls include GCP including the use of LNB and FGR for the boiler. LNB are designed to control the mixing of air and fuel to reduce the peak temperatures of combustion. The use of LNB and FGR for the boiler is expected to achieve a CH₄ emission rate of 0.001 kg/MMBtu and a N₂O emission rate of 0.0001 kg/MMBtu.

Based on the review of the above BACT analysis, DAQ NSR recommends the use of low carbon containing fuels including natural gas in combination with the use of efficient steam boiler and GCP as BACT for control of GHG for Boiler #11. [Last updated March 28, 2013]

33. BACT review regarding GHG Equipment Leaks & Flares
Equipment Leaks:

Like VOC emissions, GHG emissions from equipment leaks will occur and Holly Refinery's LDAR program will provide effective control of GHG emissions. The requirements of the LDAR program use CH₄ as the reference compound for performing the required monitoring for leaks. Thus, the LDAR program already proposed as BACT for VOC emissions relies on a GHG as the basis for the monitoring and control requirements.

The most effective control strategy identified for GHG emissions from equipment leaks is a LDAR program. Identified leaks will be repaired as soon as practical. The use of this system will not result in any adverse energy or environmental impacts.

Based on the review of the above BACT analysis and because GHG emissions from equipment leaks is a very small percentage of the GHG emissions from combustion of fuel gas, DAQ NSR recommends the use of the LDAR program as BACT for control of GHG for equipment leaks.

South Flare:

Two control technologies were identified for minimizing GHG emissions from flaring activities. These are: proper flare operation and flare gas recovery systems. Proper flare operation leads to lower methane emissions and lower overall GHG emissions. The installation of a flare gas recovery system can reduce flaring by approximately 95% which offers the highest amount of emission reduction potential. The use of a flare recovery system is the most effective option followed by proper flare operation.

Flaring can be reduced by installation of a commercially available flare gas recovery system. The cost of installing a flare gas recovery system was looked at in reference to CO₂ and CH₄ which have global warming potentials of 1 and 21, respectively. For the top control technology, the use of a flare gas recovery system would involve an economic impact. The cost was estimated at approximately \$72 per ton CO₂e removal (based on estimated CO₂ and CH₄ emissions in short tons per year). Under the "Tailoring Rule", the EPA considers 100,000 tons of CO₂e equal to 100 tons of a criteria pollutant (equivalent ratio 0.001=100/100,000). Therefore, if a criteria pollutant control has a cost effectiveness threshold of approximately \$10,000 per ton, then the equivalent cost effectiveness for CO₂e control should be \$10/ton (\$10,000 x 0.001). Since the cost-effectiveness for criteria pollutant and GHG avoidance from flare gas recovery were considerable, this control technology has been eliminated from further consideration. Thus, the remaining control technology, proper flare operation is considered the most effective control for flaring at Holly Refinery

To insure proper flare operation, Holly Refinery will install flow meters and gas combustion monitors on the flare gas line which allows for improved flare gas combustion control and minimizes periods of poor flare combustion efficiencies. The combustion efficiency of the flare will be maintained by controlling the heat content of flare gas and steam or air-assist rates.

Based on the review of the above BACT analysis, DAQ NSR recommends the installation of flow meters and gas combustion monitors on the South Flare gas lines as BACT for control of GHG for the flares. [Last updated May 14, 2013]

34. BACT review regarding GHG FCCU (Unit 25)

In a refinery, the FCC unit converts heavy, lower-value hydrocarbon feedstock into lighter, more valuable products. FCC units account for 15-20% of refinery energy consumption and can be a significant source of CO₂ emissions.

Control technologies for reducing CO₂ emissions from a FCCU include: power/waste heat recovery, high-efficiency regenerators, post-combustion capture solvent-based scrubbing, and oxy-combustion.

Traditionally at power plants utilizing a post-combustion control technology with a formulated amine solvent such as MEA can achieve CO₂ recovery between 85-95%. Similar percentages of CO₂ recovery are can be achieved utilizing the oxy-combustion control technology. Power/waste heat recovery and high efficient regenerators are inherent in the design and operation of the

equipment at Holly Refinery and is considered the baseline condition.

Post-combustion capture using an amine solvent such as MEA has been demonstrated to reduce CO₂ emissions from coal-, oil-, and natural gas-fired units mainly at electrical generation facilities. MEA is used as a scrubbing agent to absorb CO₂ in the flue gas and then release it in a steam-heated regenerator. The released CO₂ gas is routed to the CO₂ compressor station for export.

A similar CO₂ capture efficiency can be obtained using oxy-combustion. Traditionally in a FCCU, air is used to regenerate the catalyst by burning off coke deposited on the catalyst during the conversion process. In the oxy-combustion mode, air is replaced by pure oxygen which is diluted with recycled CO₂ so that thermal balance and catalyst fluidization is maintained.

Both post-combustion capture using an amine solvent such as MEA and oxy-combustion are promising technologies but are challenging in a FCCU. A techno-economic evaluation was conducted of post-combustion amine absorption and oxy-combustion for CO₂ capture from a FCC regenerator by the CO₂ Capture Project sponsors. They determined that both processes were able to achieve the required recovery levels. The post-combustion option had lower capital costs and the oxy-combustion had lower operational costs leading to lower overall capture costs. However, with both of these control options, several technical issues still need to be resolved.

With post-combustion capture using an amine solvent such as MEA, the operating experience of existing plants shows a fairly high operating cost due to a high steam consumption and high MEA makeup. Because of the CO₂ scrubber, power usage is increased. Additional issues with the process include equipment corrosion, solvent degeneration caused by the presence of dissolved O₂ and other impurities or reaction with SO₂, SO₃ and NO_x to produce non-regenerable, heat-stable salts.

Although oxy-combustion may be preferred in regards to operating costs, a number of issues need to be addressed using this control technology for CO₂ capture. These issues include corrosion of equipment, thermal balance, catalyst attrition, and coke burn rate. Also health and safety issues need to be assessed due to the presence of gaseous oxygen on-site.

Even if these technologies were cost effective and energy efficient for capturing CO₂, the CO₂ would need to be transported and ultimately sequestered. As mentioned above, the transport by tanker trucks is not practical due to the large number of trucks needed and their associated exhaust emissions which include CO₂. Also, tank truck and rail options cost more than twice as much as a pipeline. While pipelines would be the best avenue for transport of CO₂ to a sequestration site although safety issues are of concern with a pipeline especially in populated areas, the nearest CO₂ pipeline in northeastern Utah is over 125 miles from Holly Refinery. The cost to build a pipeline would be extreme. [Last updated June 4, 2013]

35. BACT review regarding GHG FCCU (Unit 25) (continued)
Thus, while field demonstrations are being conducted on CO₂ capture technologies such as oxy-combustion, at this point in time, these control technologies are not cost effective, have not been demonstrated at full scale, have energy penalties, and pose environmental and safety risks. Due to these reasons, these CO₂ capture control technologies do not represent BACT.

Power/waste heat recovery and high-efficiency regenerators will be employed to reduce fuel

consumption and ensure complete combustion thus lowering GHG emissions.

Holly Refinery is proposing to install or upgrade power recovery or waste heat boilers to recover latent heat from the FCCU regenerator exhaust as a means of reducing GHG emissions. In addition, Holly Refinery is also proposing to install specially designed FCCU regenerators for high efficiency, complete combustion of catalyst coke deposits.

Based on review of the above BACT analysis, DAQ NSR recommends energy and high efficiency regenerators which allow for complete combustion of coke deposits as BACT for the control of GHG for the FCCU (Unit 25). GHG emissions will be limited source wide and verified through stack testing requirements to verify that emissions factors are not being degraded over time, thus efficiency of the regenerators can be monitored and maintained. [Last updated March 28, 2013]

Modeling Results:

A modeling analysis was reviewed by DAQ and is summarized in the Modeling Analysis Review of the Holly Refining and Marketing Company Refinery Located in Woods Cross, Utah memo dated October 9, 2012 (DAQE-MN101230041-12). Based on the results of the analysis, the reviewing modeler has determined that no additional conditions are needed in the AO to limit the air quality impact of the proposed source. Changes to PTE emissions since this October 2012 evaluation resulted in additional reductions, therefore, modeling was not re-evaluated.

The Holly Refinery Air Quality Modeling Assessment (AQIA) approach to addressing the cumulative impacts from surrounding sources including those from large sources, minor sources, urban sources, and natural or regional sources is justified. Holly Refinery modeling methodology included two EPA-allowed representative approaches to addressing cumulative impacts.

The first approach paired model-predicted impacts from the Holly Refinery with the 3-year average of the 98th percentile hourly daily-maximum concentration recorded at the DAQ's Bountiful air monitor located one mile northeast of the refinery site. This monitor is considered to be site-representative for this analysis; 1) due its close proximity to the subject source, 2) airborne contributions include those from nearby major sources, minor sources, urban sources, and natural or regional sources, and 3) it is located well within the transport area subject to impacts from hourly plumes. This approach is consistent with EPA above comment where "this approach may be appropriate in rare cases of relatively isolated sources where the available monitor can be shown to be representative of the ambient concentration levels in the areas of maximum impact from the proposed new source". Holly Refinery used this method to show a single isolated source whose maximum impacts occurred east of the plant site within the first mile of transport, and in the same general vicinity of the air monitor. The 3-year average of the 98th percentile value used represents the highest allowable background contribution allowable under the standard for use in a regulatory analysis.

Holly Refinery's second approach involved the inclusion of nearby major sources in the dispersion model. Hourly meteorology from the DAQ's Syracuse monitor was paired in time with hourly ozone levels measured at the Bountiful monitor to most accurately estimate the hourly formation of NO₂ levels. Model predicted impacts from Holly Refinery were paired with modeled impacts from other major sources, and the same hourly ambient measurement from the Bountiful NO₂ monitor, which accounted for impacts from distant large sources, minor sources, urban sources, and natural or regional

sources. This method is considered conservative since; 1) impacts from nearby major sources included in the model were also included in the monitored concentrations used to represent impacts from minor sources, urban sources, and natural or regional sources (double counting), and 2) all major sources included in the model were assumed to be emitting pollutants at the maximum hourly potential to emit. This method is consistent with EPA statement where: “Another situation where such an approach may be justified is where the modeled emission inventory clearly represents the majority of emissions that could potentially contribute to the cumulative impact assessment and where inclusion of the monitored background concentration is intended to conservatively represent the potential contribution from minor sources and natural or regional background levels not reflected in the modeled inventory”. [Last updated May 14, 2013]

RECOMMENDED APPROVAL ORDER CONDITIONS

The intent is to issue an air quality Approval Order (AO) authorizing the project with the following recommended conditions and that failure to comply with any of the conditions may constitute a violation of the AO. The AO will be issued to and will apply to the following:

Name of Permittee:

Permitted Location:

Holly Refining & Marketing Company - Woods
Cross LLC
1070 W 500 S
Woods Cross, UT 84087-1442

Holly Refining & Marketing Company - Woods
Cross LLC
393 South 800 West
Woods Cross, UT 84087-1435

UTM coordinates: 424,000 m Easting, 4,526,227 m Northing, UTM Zone 12

SIC code: 2911 (Petroleum Refining)

Section I: GENERAL PROVISIONS

- I.1 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.2 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 Approval Order 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.3 The owner/operator shall comply with UAC R307-107. General Requirements: Breakdowns. [R307-107]
- I.4 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.5 The limits set forth in this AO shall not be exceeded without prior approval. [R307-401]
- I.6 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.7 The owner/operator shall comply with UAC R307-150 Series. Inventories, Testing and Monitoring. [R307-150]

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 **Unit 4: Fluid Catalytic Cracking Unit (FCCU)**
8,880 bpd annual average capacity
 - II.A.3 **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 (LNB)
 - II.A.4 **4K1A: KVG Compressor West**
Electrical motor compressor engine
 - II.A.5 **4K1B: KVG Compressor East**
Electrical motor compressor engine
 - II.A.6 **4V82 FCC Scrubber**
Wet gas scrubber to control Unit 4 FCCU
 - II.A.7 **4-97-0010**
Oxygen Injection Skid
 - II.A.8 **FCC 34" Flue Gas Bypass**
34" Stack
 - II.A.9 **Unit 6: Catalytic Reforming Unit (Reformer)**
 - II.A.10 **6H1**
Reformer charge and reheater furnace/waste heat boiler
54.7 MMBtu/hr process furnace, fired on plant gas
 - II.A.11 **6H2: Prefractionator Reboiler Heater**
12.0 MMBtu/hr process furnace, fired on plant gas
 - II.A.12 **6H3: Reformer Reheat Furnace**
37.7 MMBtu/hr process furnace, fired on plant gas
 - II.A.13 **6K1 SVG Compressor East**
Electrical motor compressor engine
 - II.A.14 **6K2: SVG Compressor West**
Electrical motor compressor engine

- II.A.15 **Unit 7: Alkylation Unit**
- II.A.16 **7H1: HF Alkylation Regeneration Furnace**
4.4 MMBtu/hr process furnace, fired on plant gas
- II.A.17 **7H3: HF Alkylation Depropanizer Reboiler**
33.3 MMBtu/hr process furnace, fired on plant gas
- II.A.18 **Unit 8: Crude Unit**
45,000 bpd annual average capacity
- II.A.19 **8H1: Crude Furnace #1**
99.0 MMBtu/hr process furnace, fired on plant gas, equipped with next generation ultra-low NO_x burner (NGULNB)
- II.A.20 **Unit 9: Distillate Hydrosulfurization (DHDS) Unit**
- II.A.21 **9H1: DHDS Reactor Charge Heater**
8.1 MMBtu/hr process furnace, fired on plant gas
- II.A.22 **9H2: DHDS Stripper Reboiler**
4.1 MMBtu/hr process furnace, fired on plant gas
- II.A.23 **Unit 10: Solvent Deasphalting (SDA) Unit**
- II.A.24 **10H1: Asphalt Mix Heater**
13.2 MMBtu/hr process furnace, fired on plant gas
- II.A.25 **10H2: Hot Oil Furnace**
99 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and selective catalytic reduction (SCR) system
- II.A.26 **Unit 11: Straight Run Gas Plant (SRGP)**
- II.A.27 **11H1: SRGP Depentanizer Reboiler**
24.2 MMBtu/hr process furnace, fired on plant gas
- II.A.28 **11K2: SRGP Electric Compressor**
- II.A.29 **Unit 12:Naphtha Hydrodesulphurization (NHDS) Unit**
- II.A.30 **12H1: NHDS Reactor Charge Furnace**
50.2 MMBtu/hr process furnace, fired on plant gas, equipped with NGULNB
- II.A.31 **Unit 13: Isomerization Unit**
- II.A.32 **13H1: Isomerization Reactor Feed Furnace**
6.5 MMBtu/hr process furnace, fired on plant gas

- II.A.33 **Unit 16: Amine Treatment Unit**
- II.A.34 **Unit 17: Sulfur Recovery (SRU)**
- II.A.35 **SRU - Tailgas Incinerator**
For SRU under 20 LTPD
- II.A.36 **Unit 18: Sour Water Stripping (SWS) Unit**
- II.A.37 **Unit 19: Distillate Hydrodesulfurization Treatment (DHT)**
- II.A.38 **19H1: DHT Reactor Charge Heater**
18.1 MMBtu/hr Process Furnace, fired on plant gas, equipped with LNB
- II.A.39 **Unit 20: Gas Oil Hydrocracking (GHC) Unit**
- II.A.40 **20H1: Reactor Charge Heater**
14.9 MMBtu/hr process furnace, fired on plant gas, equipped with ultra-low NO_x Burners (ULNB)
Allows for expansion of Unit 19 (DHT)
- II.A.41 **20H2: Fractionator Charge Heater**
47.0 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB
- II.A.42 **20H3: Fractionator Charge Heater**
42.1 MMBtu/hr furnace, fired on plant gas, equipped with ULNB
- II.A.43 **Unit 21: NaSH Sour Gas Treatment Unit**
Sized at 50 long tons of sulfur per day
- II.A.44 **Unit 22: Sour Water Stripper/Ammonia Stripping Unit**
- II.A.45 **Unit 23: Benzene Saturation Unit**
- II.A.46 **23H1: Reformate Splitter Reboiler Heater**
21.0 MMBtu/hr heater, fired on plant gas, equipped with NGULNB
- II.A.47 **Unit 24: Crude Unit**
15,000 bpd annual average capacity
- II.A.48 **24H1: Crude Unit Furnace**
60.0 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB
- II.A.49 **Unit 25: FCCU**
8,500 bpd annual average capacity
- II.A.50 **25H1: FCC Feed Heater**
45 MMBtu/hr process furnace, fired on plant gas, equipped with ULNB

- II.A.51 **25FCC Scrubber**
Wet gas scrubber to control FCCU Unit 25 and SRU Unit 17
Equipped with LoTOx control technology
- II.A.52 **Unit 26: Poly Gasoline Unit**
- II.A.53 **Unit 27: Hydrocracker/Hydroisom Unit**
- II.A.54 **27H1: Reactor Charger Heater**
99.0 MMBtu/hr reactor charger heater, fired on plant gas, equipped with LNB and SCR
- II.A.55 **Unit 28: Sour Water Stripping Unit**
100 gallons per minute capacity
Under normal operations, effluent is sent to Unit 22 for ammonia removal
- II.A.56 **Unit 30: Hydrogen plant**
- II.A.57 **30H1 Hydrogen Reformer Feed Furnace**
123.1 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and SCR
- II.A.58 **30H2 Hydrogen Reformer Feed Furnace**
123.1 MMBtu/hr process furnace, fired on plant gas, equipped with LNB and SCR
- II.A.59 **Unit 33: Vacuum Unit**
- II.A.60 **33H1: Vacuum Furnace Heater**
130.0 MMBtu/hr heater, fired on plant gas, equipped with LNB and SCR
- II.A.61 **Unit 45: Asphalt Storage**
- II.A.62 **Unit 51: Steam Systems**
- II.A.63 **Boiler #4**
35.6 MMBtu/hr boiler, fired on plant gas
- II.A.64 **Boiler #5**
70.0 MMBtu/hr boiler, fired on plant gas, equipped with SCR
- II.A.65 **Boiler #8**
92.7 MMBtu/hr boiler, fired on plant gas, equipped with LNB and SCR
- II.A.66 **Boiler #9**
89.3 MMBtu/hr boiler, fired on plant gas, equipped with SCR
- II.A.67 **Boiler #10**
89.3 MMBtu/hr boiler, fired on plant gas, equipped with SCR
- II.A.68 **Boiler #11**

89.3 MMBtu/hr steam boiler, fired on plant gas, equipped with LNB and SCR

- II.A.69 **Unit 54: Cooling Towers**
All cooling towers implement the Modified El Paso Method utilizing a FID analyzer
- II.A.70 **Cooling Tower #4**
Built pre 1975
- II.A.71 **Cooling Tower #6**
Built pre 1975
- II.A.72 **Cooling Tower #7**
Re-built 2006
- II.A.73 **Cooling Tower #8**
Built pre 1975
- II.A.74 **Cooling Tower #10**
8,500 gallons per minute capacity induced draft multi-cell flow, equipped with high efficiency drift eliminators (permitted 2013)
- II.A.75 **Cooling Tower #11**
8,500 gallons per minute capacity induced draft multi-cell flow, equipped with high efficiency drift eliminators (permitted 2013)
- II.A.76 **Unit 56: Wastewater Treatment**
Oil/Water Separator
Induced Air Floatation Unit
Moving Bed Bioreactors
- II.A.77 **Unit 66: Flares**
- II.A.78 **Unit 66-1: Process Flare South**
17,000 standard cubic feet per hour
- II.A.79 **Unit 66-2: Process Flare North**
- II.A.80 **Unit 68: Tank Farm**
- II.A.81 **68H2: North In-tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 79, fired with natural gas
- II.A.82 **68H3: South In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 79, fired with natural gas
- II.A.83 **68H4: North West In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 59, fired on natural gas
- II.A.84 **68H5: North East In-Tank Asphalt Heater**

0.8 MMBtu/hr tank heater at Tank 59, fired on natural gas

- II.A.85 **68H6: South East In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 59, fired on natural gas
- II.A.86 **68H7: South West In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 59, fired on natural gas
- II.A.87 **68H10: North In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 139, fired on natural gas
- II.A.88 **68H11: South In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 139, fired on natural gas
- II.A.89 **68H12: North In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 140, fired on natural gas
- II.A.90 **68H13: South In-Tank Asphalt Heater**
0.8 MMBtu/hr tank heater at Tank 140, fired on natural gas
- II.A.91 **Tank 11: Petroleum Liquids (1932)**
9,868 bbl capacity storage tank with fixed roof
- II.A.92 **Tank 12: Petroleum Liquids (1932)**
9,868 bbl capacity storage tank with internal floating roof, primary seal
- II.A.93 **Tank 14: Petroleum Liquids (1932)**
2,539 bbl capacity storage tank with fixed roof
- II.A.94 **Tank 15: Petroleum Liquids (1932)**
5,181 bbl capacity storage tank with fixed roof
- II.A.95 **Tank 19: Petroleum Liquids (1933)**
7,463 bbl capacity storage tank with fixed roof
- II.A.96 **Tank 20: Petroleum Liquids (1935)**
7,504 bbl capacity storage tank with fixed roof
- II.A.97 **Tank 21: Petroleum Liquids (1935)**
354 bbl capacity storage horizontal storage tank
- II.A.98 **Tank 23: Petroleum Liquids (2001)**
14,600 bbl capacity storage tank with fixed roof
- II.A.99 **Tank 24: Petroleum Liquids (1936)**
15,016 bbl capacity storage tank with fixed roof
- II.A.100 **Tank 28: Petroleum Liquids (1941)**
29,663 bbl capacity storage tank with fixed roof

- II.A.101 **Tank 29: Petroleum Liquids (1938)**
336 bbl capacity storage tank with fixed roof
- II.A.102 **Tank 31: Petroleum Liquids (1940)**
29,756 bbl capacity storage tank with fixed roof
- II.A.103 **Tank 35: Petroleum Liquids (2001)**
105,000 bbl capacity storage tank with fixed roof
- II.A.104 **Tank 37: Petroleum Liquids**
3,217 bbl capacity storage tank with fixed roof
(under re-construction)
- II.A.105 **Tank 42A: Petroleum Liquids (1995)**
20 bbl capacity vertical storage tank
- II.A.106 **Tank 47: Petroleum Liquids (1947)**
30,129 bbl capacity storage tank with fixed roof
- II.A.107 **Tank 48: Petroleum Liquid (1948)**
29,782 bbl capacity storage tank with fixed roof
- II.A.108 **Tank 50: Petroleum Liquids (1948)**
700 bbl capacity horizontal storage tank
- II.A.109 **Tank 51: Petroleum Liquids (1948)**
580 bbl capacity horizontal storage tank
- II.A.110 **Tank 52: Petroleum Liquids (1948)**
1,008 bbl capacity storage tank with fixed roof
- II.A.111 **Tank 53: Petroleum Liquids (1948)**
1,008 bbl capacity storage tank with fixed roof
- II.A.112 **Tank 54: Petroleum Liquids (1948)**
1,008 bbl capacity storage tank with fixed roof
- II.A.113 **Tank 55: Petroleum Liquids (1948)**
1,008 bbl capacity storage tank with fixed roof
- II.A.114 **Tank 56: Petroleum Liquids (1948)**
1,008 bbl capacity storage tank with fixed roof
- II.A.115 **Tank 57: Petroleum Liquids (1948)**
1,008 bbl capacity storage tank with fixed roof
- II.A.116 **Tank 58: Petroleum Liquids (1949)**
15,229 bbl capacity storage tank with fixed roof

- II.A.117 **Tank 59: Petroleum Liquids (1948)**
30,019 bbl capacity storage tank with fixed roof
(converted 2013)
- II.A.118 **Tank 60: Chemical (1948)**
1,008 bbl capacity storage tank with fixed roof
- II.A.119 **Tank 61: Petroleum Liquids (1948)**
1,008 bbl capacity storage tank with fixed roof
- II.A.120 **Tank 63: Petroleum Liquids (1949)**
30,135 bbl capacity storage tank with fixed roof
- II.A.121 **Tank 64: Petroleum Liquids (1950)**
1,011 bbl capacity storage tank with fixed roof
- II.A.122 **Tank 65: Petroleum Liquids (1950)**
1,011 bbl capacity storage tank with fixed roof
- II.A.123 **Tank 70: Heavy Crude (1956)**
80,306 bbl capacity storage tank with fixed roof
(permitted for heavy crude 2013)
- II.A.124 **Tank 71: Heavy Crude (1969)**
67,155 bbl capacity storage tank with internal floating roof, primary and secondary seals
(permitted for heavy crude 2013)
- II.A.125 **Tank 72: Heavy Crude (1971)**
106,811 bbl liquids storage tank with internal floating roof, primary and secondary seals
(permitted for heavy crude 2013)
- II.A.126 **Tank 73: Petroleum Liquids (1975)**
1,077 bbl storage tank with fixed roof
- II.A.127 **Tank 74: Petroleum Liquids (1975)**
2,039 bbl storage tank with fixed roof
- II.A.128 **Tank 75: Petroleum Liquids (1975)**
2,039 bbl storage tank with fixed roof
- II.A.129 **Tank 76: Petroleum Liquids (1975)**
2,039 bbl storage tank with fixed roof
- II.A.130 **Tank 77: Petroleum Liquids (1983)**
5,141 bbl storage tank with fixed roof
- II.A.131 **Tank 78: Petroleum Liquids (1952)**
5,141 bbl storage tank with fixed roof

- II.A.132 **Tank 79: Petroleum Liquids (2006)**
10,000 bbl capacity storage tank with fixed roof
- II.A.133 **Tank 81: Chemical (2008)**
13,638 bbl capacity storage tank with fixed roof
- II.A.134 **Tank 82: Chemical (2008)**
13,638 bbl capacity storage tank with fixed roof
- II.A.135 **Tank 83: Chemical (2009)**
7,143 bbl capacity storage tank with fixed roof
- II.A.136 **Tank 85: Petroleum Liquids**
19,600 bbl capacity storage tank with internal floating roof
(under construction, permitted in 2010)
- II.A.137 **Tank 86: Petroleum Liquids**
109,660 bbl capacity storage tank with fixed cone roof
(under construction, permitted in 2010)
- II.A.138 **Tank 87: Petroleum Liquids**
109,660 bbl capacity storage tank with fixed cone roof
(under construction, permitted in 2010)
- II.A.139 **Tank 88: Petroleum Liquids**
26,730 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2010)
- II.A.140 **Tank 89: Petroleum Liquids**
26,730 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)
- II.A.141 **Tank 90: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)
- II.A.142 **Tank 91: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)
- II.A.143 **Tank 92: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)
- II.A.144 **Tank 93: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)

- II.A.145 **Tank 94: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)
- II.A.146 **Tank 95: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)
- II.A.147 **Tank 96: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)
- II.A.148 **Tank 97: Petroleum Liquids**
13,600 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)
- II.A.149 **Tank 98: Petroleum Liquids**
19,600 bbl capacity storage tank with internal floating roof
(under construction, permitted 2013)
- II.A.150 **Tank 99: Petroleum Liquids**
66,000 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)
- II.A.151 **Tank 100: Petroleum Liquids (1952)**
53,372 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.152 **Tank 101: Petroleum Liquids (1952)**
53,564 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.153 **Tank 102: Petroleum Liquids (1952)**
52,990 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.154 **Tank 103: Petroleum Liquids (1952)**
24,686 bbl capacity storage tank with fixed roof
- II.A.155 **Tank 104: Petroleum Liquids (1952)**
24,435 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.156 **Tank 105: Petroleum Liquids (1952)**
24,501 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.157 **Tank 106: Petroleum Liquids (1952)**
24,524 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.158 **Tank 107: Petroleum Liquids (1952)**
24,501 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.159 **Tank 108: Petroleum Liquids (1952)**

24,450 bbl capacity storage tank with external floating roof, primary and secondary seals

- II.A.160 **Tank 109: Petroleum Liquids (1952)**
24,490 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.161 **Tank 113: Chemical (1953)**
168 bbl capacity storage tank with fixed roof
- II.A.162 **Tank 114: Chemical (1953)**
65 bbl capacity storage tank with fixed roof
- II.A.163 **Tank 116: Chemical (1954)**
140 bbl capacity storage tank with fixed roof
- II.A.164 **Tank 117: Petroleum Liquids (1944)**
506 bbl capacity storage tank with no roof
- II.A.165 **Tank 118: Petroleum Liquids (1944)**
657 bbl capacity storage tank with fixed roof
- II.A.166 **Tank 121: Petroleum Liquids (1954)**
100,129 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.167 **Tank 122: Petroleum Liquids (1954)**
400 bbl capacity horizontal storage tank
- II.A.168 **Tank 123: Petroleum Liquids (1954)**
400 bbl capacity horizontal storage tank
- II.A.169 **Tank 124: Chemical (1950)**
550 bbl capacity horizontal storage tank
- II.A.170 **Tank 125: Chemical (1950)**
550 bbl capacity horizontal storage tank
- II.A.171 **Tank 126: Petroleum Liquids (1955)**
64,675 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.172 **Tank 127: Petroleum Liquids (1957)**
30,497 bbl capacity storage tank with fixed roof
- II.A.173 **Tank 128: Petroleum Liquids (1958)**
10,100 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.174 **Tank 129: Petroleum Liquids (1958)**
55,074 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.175 **Tank 130: Chemical (1958)**
952 bbl capacity horizontal storage tank

- II.A.176 **Tank 131: Petroleum Liquids (1958)**
65,159 bbl capacity storage tank with internal floating roof, primary and secondary seals
- II.A.177 **Tank 132: Petroleum Liquids (1960)**
24,455 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.178 **Tank 133: Petroleum Liquids (1949)**
1,582 bbl capacity horizontal storage tank
- II.A.179 **Tank 134: Petroleum Liquids (1949)**
1,582 bbl capacity horizontal storage tank
- II.A.180 **Tank 135: Petroleum Liquids (1962)**
44,154 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.181 **Tank 136: Petroleum Liquids (1962)**
806 bbl capacity horizontal storage tank
- II.A.182 **Tank 138: Petroleum Liquids (1963)**
44,247 bbl capacity storage tank with internal floating roof and primary seal
- II.A.183 **Tank 139: Petroleum Liquids (1965)**
14,957 bbl capacity storage tank with fixed roof
(modified 2013)
- II.A.184 **Tank 140: Petroleum Liquids (1965)**
14,857 bbl capacity storage tank with fixed roof
(modified 2013)
- II.A.185 **Tank 141: Petroleum Liquids (1965)**
1,618 bbl capacity horizontal storage tank
- II.A.186 **Tank 143: Petroleum Liquids (1968)**
4,008 bbl capacity storage pit with fixed roof
- II.A.187 **Tank 145: Petroleum Liquids (1974)**
3,985 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.188 **Tank 146: Petroleum Liquids (1974)**
3,985 bbl capacity storage tank with external floating roof, primary and secondary seals
- II.A.189 **Tank 147: Petroleum Liquids (1948)**
714 bbl capacity horizontal storage tank
- II.A.190 **Tank 148: Petroleum Liquids (1948)**
714 bbl capacity horizontal storage tank
- II.A.191 **Tank 149: Petroleum Liquids (1948)**

714 bbl capacity horizontal storage tank

- II.A.192 **Tank 150: Petroleum Liquids (1948)**
714 bbl capacity horizontal storage tank
- II.A.193 **Tank 151: Petroleum Liquids (1948)**
714 bbl capacity horizontal storage tank
- II.A.194 **Tank 152: Petroleum Liquids (1948)**
714 bbl capacity horizontal storage tank
- II.A.195 **Tank 153: Petroleum Liquids (1948)**
714 bbl capacity horizontal storage tank
- II.A.196 **Tank 158: Water**
64,315 bbl capacity wastewater storage tank with internal floating roof
(under construction, permitted 2013)
- II.A.197 **Tank 159: Petroleum liquids (1987)**
4,999 bbl capacity spherical storage tank
- II.A.198 **Tank 168: Water**
30,952 bbl capacity sour water feed storage tank with internal floating roof
(under construction, permitted 2013)
- II.A.199 **Tank 170: Petroleum Liquids**
66,000 bbl capacity storage tank with fixed cone roof
(under construction, permitted 2013)
- II.A.200 **Tank 171: Petroleum Liquids**
1,600 bbl capacity horizontal storage tank
(under construction, permitted 2013)
- II.A.201 **Tank 172: Petroleum Liquids**
1,600 bbl capacity horizontal storage tank
(under construction, permitted 2013)
- II.A.202 **Tank 173: Petroleum Liquids**
1,600 bbl capacity horizontal storage tank
(under construction, permitted 2013)
- II.A.203 **Tank 174: Petroleum Liquids**
1,600 bbl capacity horizontal storage tank
(under construction, permitted 2013)
- II.A.204 **Tank 301: Chemical (1968)**
176 bbl capacity storage tank with fixed roof
- II.A.205 **Tank 300: Chemical (1968)**

- 176 bbl capacity storage tank with fixed roof
- II.A.206 **Tank 302: Chemical (1968)**
176 bbl capacity storage tank with fixed roof
- II.A.207 **Tank 303: Chemical (1968)**
238 bbl capacity storage tank with fixed roof
- II.A.208 **Tank 304: Chemical (1968)**
368 bbl capacity storage tank with fixed roof
- II.A.209 **Tank 305: Chemical (1975)**
368 bbl capacity storage tank with fixed roof
- II.A.210 **Tank 306: Chemical (1975)**
514 bbl capacity storage tank with fixed roof
- II.A.211 **Tank 307: Chemical (1975)**
514 bbl capacity storage tank with fixed roof
- II.A.212 **Tank 308: Chemical (1975)**
157 bbl capacity storage tank with fixed roof
- II.A.213 **Tank 310: Chemical (1975)**
514 bbl capacity storage tank with fixed roof
- II.A.214 **Tank 312: Chemical (1975)**
14 bbl capacity vertical storage tank
- II.A.215 **Tank 313: Chemical (1975)**
143 bbl capacity storage tank with fixed roof
- II.A.216 **Tank 323: Petroleum Liquids (1992)**
14,686 bbl capacity storage tank with internal floating roof, primary seal
- II.A.217 **Tank 324: Petroleum Liquids (1947)**
714 bbl capacity horizontal storage tank
- II.A.218 **Tank 54-V4: Chemical (1972)**
76 bbl capacity horizontal storage tank
- II.A.219 **Tank 54-V5: Chemical (1974)**
131 bbl capacity horizontal storage tank
- II.A.220 **Tank 54-V7: Chemical (1990)**
72 bbl capacity storage tank with fixed roof
- II.A.221 **East Tank Farm (ETF) Portable Diesel Generator**
135 kW diesel fired generator

- II.A.222 **Unit 87: Loading/Unloading**
Sixteen (16) crude/gas oil/NGL truck unloading bays
One (1) NaHS truck loading spot
Two (2) NaHS/caustic rail car loading/unloading spots
Three (3) caustic truck unloading spot
Two (2) sulfur truck loading arms
One (1) fuel oil truck loading spot
One (1) fuel oil truck unloading spot
Four (4) fuel oil/asphalt rail car loading/unloading spots
Four (4) oil/diesel/caustic rail car loading/unloading and ethanol rail car unloading spots
- II.A.223 **Unit 87: Loading/Unloading (continued)**
Four (4) NGL rail car loading/unloading spots
Five (5) NGL/Olefin rail car loading/unloading spots
One (1) asphalt truck loading spot
One (1) diesel truck unloading spot
One (1) light cycle oil truck unloading spot
Two (2) propane truck loading spot
One (1) kerosene truck loading spot
One (1) gasoline truck unloading spot
Fourteen (14) fuel oil or asphalt loading spots
Twenty-four (24) lube oil loading spots
Two (2) bio diesel rail unloading spots
- II.A.224 **Ethanol Unloading**
Three (3) dedicated ethanol unloading areas which include:
One (1) 250 gpm truck unloading pump
One (1) 400 gpm LOD charge pump
One (1) 250 gpm LOD charge pump
Four (4) unloading arms
- II.A.225 **Emergency Equipment (Diesel)**
1. Diesel powered water well No. 3 (224 hp)
2. Caterpillar diesel fire pump No. 1 (393 hp)
3. Caterpillar diesel fire pump No. 2 (393 hp)
4. Detroit diesel fire pump (180 hp)
5. Three (3) diesel powered plant air backup compressors (220 hp each)
6. Diesel powered standby generator, Boiler House (Cummins Model QSM11-G4, 470 hp)
7. Diesel powered standby generator, Central Control Room (380 hp)
8. Diesel powered standby generator (540 hp)
- II.A.226 **Emergency Equipment (Natural Gas)**
Two (2) natural gas fired standby generators, Administration Bldg (142 kw each)
- II.A.227 **PM₁₀ Combustion Emissions Cap Sources**
PM₁₀ Combustion Sources: includes Unit 66: Flares, 4H1: FCC Feed Heater, 10H1: Asphalt Mix Heater, Boiler #8, 68H2: North In-tank Asphalt Heater, Unit 30: Hydrogen plant, Unit 33: Vacuum Unit, 30H1 Hydrogen Reformer Feed Furnace, 23H1: Reformate Splitter Reboiler

Heater, 68H7: South West In-Tank Asphalt Heater, Unit 6: Catalytic Reforming Unit (Reformer), Unit 8: Crude Unit, 6H2: Prefractionator Reboiler Heater, 9H1: DHDS Reactor Charge Heater, Unit 20: Gas Oil Hydrocracking (GHC) Unit, 68H10: North In-Tank Asphalt Heater, Unit 10: Solvent Deasphalting (SDA) Unit, Unit 12:Naphtha Hydrodesulphurization (NHDS) Unit, Unit 66-2: Process Flare North, 68H4: North West In-Tank Asphalt Heater, Unit 23: Benzene Saturation Unit, Unit 24: Crude Unit, 24H1: Crude Unit Furnace, 27H1: Reactor Charger Heater, 68H13: South In-Tank Asphalt Heater, Boiler #5, 19H1: DHT Reactor Charge Heater, Unit 19:Distillate Hydrodesulfurization Treatment , 20H2: Fractionator Charge Heater, 30H2 Hydrogen Reformer Feed Furnace, 25H1: FCC Feed Heater, 7H1: HF Alkylation Regeneration Furnace, 13H1: Isomerization Reactor Feed Furnace, Boiler #10, 33H1: Vacuum Furnace Heater, 68H12: North In-Tank Asphalt Heater, Emergency Equipment (Natural Gas), Unit 11: Straight Run Gas Plant (SRGP), 7H3: HF Alkylation Depropanizer Reboiler, 8H1: Crude Furnace #1, SRU - Tailgas Incinerator, FCC 34" Flue Gas Bypass, Emergency Equipment (Diesel), 20H1: Reactor Charge Heater, Boiler #9, Unit 25: FCCU, 68H11: South In-Tank Asphalt Heater, Unit 4: Fluid Catalytic Cracking Unit (FCCU), Unit 13: Isomerization Unit, 12H1: NHDS Reactor Charge Furnace, 9H2: DHDS Stripper Reboiler, 11H1: SRGP Depentanizer Reboiler, Boiler #4, 10H2: Hot Oil Furnace, Unit 17: Sulfur Recovery (SRU), Boiler #11, 25FCC Scrubber, Unit 9: Distillate Hydrosulfurization (DHDS) Unit, 6H1, 6H3: Reformer Reheat Furnace, Unit 66-1: Process Flare South, 68H3: South In-Tank Asphalt Heater, 68H5: North East In-Tank Asphalt Heater, 20H3: Fractionator Charge Heater, Unit 27: Hydrocracker/Hydroisom Unit, 68H6: South East 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. [R307-150]

II.B.1.b Holly Refinery shall provide a notification of any performance test date at least 30 days prior to the test. A pretest conference shall be held if directed by the Director. It shall be held at least 30 days prior to the test between the owner/operator, the tester, and the Director. 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 Director 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.c Visible emissions shall not exceed the following specifications:

All scrubbers: 15% opacity
All baghouses: 10% opacity
FCC Units/FCC Wet Gas Scrubbers: 20% opacity
8H1 Crude Furnace: 20% opacity
Flares: 20% opacity
All other combustion sources: 10% 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.d The amine plant shall reduce the H₂S content of the refinery fuel gas to 60 ppm (on an annual average) or less. The Holly Refinery 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.e The throughput of the catalytic cracking Unit 4 shall not exceed 3,250,000 barrels per rolling 12-month period. Compliance with the annual throughput limit shall be measured with a throughput flow meter. [R307-401]

II.B.1.f Compliance with the annual limitations shall be determined on a rolling 12-month total except where specifically exempted or otherwise provided for. No later than 20 days after the end of each month, a new 12-month total shall be calculated using data from the previous 12 months. [R307-401]

II.B.1.g The Holly Refinery shall notify the Director in writing when the installation of the new equipment has been completed and is operational. The new equipment includes the following:

Four (4) electric motor compressor engines (replacing gas driven engines)
Preflash tower (Unit 8)
SRU (Unit 17) emissions routed to 25FCC Scrubber
Fractionator charge heater (20H3)
Crude Unit (Unit 24) & Crude Unit Furnace (24H1)
FCCU (Unit 25), FCC feed heater (25H1), & 25FCC Scrubber
Poly gasoline unit (Unit 26)
Hydrocracker/Hydroisom Unit (Unit 27) & Reactor charger heater (27H1)
Sour water stripping unit (Unit 28)
Vacuum furnace heater (33H1)
In-tank asphalt heaters (68H6, 68H7, 68H10, 68H11, 68H12, & 68H13)
Cooling Tower #10 & expansion of Cooling Tower #11
Boiler #11

LNB & SCR installed on Boiler #8, 10H2, 30H1, & 30H2
Biodiesel loading spots
One (1) 540 hp (diesel) Emergency Generator
Two (2) 142 kW (natural gas) Emergency Generators
Truck Bays
South Flare

To ensure proper credit when notifying the Director, send your correspondence to the Director, attn: Compliance Section.

If installation has not been completed within 18 months from the date of this AO, the Director shall be notified in writing on the status of the installation. At that time, the Director shall require documentation of the continuous installation of the operation and may revoke the AO. [R307-401-18]

II.B.2 Conditions on the Fluid Catalytic Cracking Units (Unit 4 & 25)

II.B.2.a CO emissions from the FCC Units shall not exceed 500 ppm by volume (dry basis) one-hour average at 0% oxygen. [40 CFR 60 Subpart J]

II.B.2.a.1 Holly Refinery shall install, calibrate, maintain, and operate a continuous monitoring system to measure the effluent FCC Units CO emissions. The monitoring system shall comply with all applicable sections of R307-170 and 40 CFR 60, Appendix B. [R307-170]

II.B.2.b NO_x emissions for the FCC Units shall not exceed the following concentrations:

40 ppmvd per 365-day rolling average; and
80 ppmvd per 7-day rolling average

SO₂ emissions for the FCC Units shall not exceed the following concentrations:

25 ppmvd per 365-day rolling average; and
50 ppmvd per 7-day rolling average

[R307-401, 40 CFR 60 Subpart Ja]

II.B.2.b.1 Emissions of NO_x and SO₂ from the FCC Units 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, SO₂) and 3 (O₂). [R307-401, R307-170]

II.B.2.c The emissions of PM₁₀ from the FCC Unit 4 wet gas scrubber (4V82 FCC Scrubber) shall not exceed 0.50 lb/1000 lb coke burned.

The emissions of PM₁₀ from the FCC Unit 25 wet gas scrubber (25FCC Scrubber) shall not

exceed 0.30 lb/1000 lb coke burned.

Compliance shall be determined by a stack test to be performed every year. Holly Refinery shall conduct annual test no later than October 31st of each year. Upon demonstration through at least three (3) annual tests that the PM₁₀ limits are not being exceeded, Holly Refinery may request approval to conduct less frequently than annually.

Emissions of PM₁₀ shall be determined through use of 40 CFR 60, Appendix M, Method 201, 201a, 202, or other EPA-approved testing method, as acceptable to the Director.

The condensable particle emissions shall not be used for compliance demonstration, but shall be used for inventory purposes. [R307-401-8]

II.B.3 **Conditions on the SRU/Tail gas incinerator**

- II.B.3.a Under normal operating conditions, emissions from the sour water stripper Unit 28 shall be routed to the sour water stripper/ammonia stripping Unit 22 prior to treatment in the SRU Unit 17. [R307-401-8]
- II.B.3.b SRU off gas shall at all times be routed to the 4V82 FCC Scrubber or 25 FCC Scrubber (wet gas scrubbers) prior to being vented to the atmosphere. [R307-401-8]
- II.B.3.c Copies of the SRU (Unit 17) Operating Instruction/Standard shall be made available to the Director upon request. [R307-401]
- II.B.3.d Holly Refinery shall utilize monitors to measure volumetric flow rates from the wet gas scrubber stacks. 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.3.e The FCCU wet scrubbers (4V82 FCC Scrubber and 25FCC Scrubber) shall be equipped with a CEMS to measure SO₂ emissions. [40 CFR 60 Subpart Ja]
- II.B.3.f If sulfur input to the SRU (Unit 17) exceeds 20 long tons per day, NSPS Subparts A and J shall apply. [40 CFR 60 Subpart J]

II.B.4 **Conditions on Cooling Towers**

- II.B.4.a Holly Refinery shall perform monthly monitoring of Cooling towers 4, 6, 7, 8, 10, and 11 to identify leaks of total strippable VOC from heat exchange systems according to the following procedure. A leak is a total strippable VOC concentration (as methane) in the stripping gas of 6.2 ppmv or greater.

A monthly water sample will be collected and analyzed from each cooling tower return line to determine the total strippable VOC concentration (as methane) from the air stripping testing system using "Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources" Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003, or a comparable method approved by the Director.

If cooling tower testing results in a VOC concentration of 6.2 ppmv or greater, each heat exchanger shall be tested to identify which heat exchanger system is contributing to the excess. Both inlet and outlet of each heat exchanger shall be tested, any test method maybe used.

If a leak is detected, it must be repaired to reduce the measured concentration to below the applicable action level as soon as practicable, but no later than 45 days after identifying the leak. Verification of the repair shall be done through additional testing.

Monthly records shall include; date of inspection, cooling tower/heat exchanger inspected, total strippable VOC concentration, repairs, and follow up testing. Records shall be kept for all periods when the refinery is in operation. [R307-401-8, 40 CFR 63 Subpart CC]

II.B.5 **Conditions on Emergency Equipment**

II.B.5.a Emergency engine usage shall not exceed 600 hours total of operation for testing and maintenance purposes per rolling 12-month period.

Compliance with the rolling 12-month period limitation shall be determined on a rolling 12-month total. No later than 20 days after the end of each month, a new 12-month total shall be calculated using data from 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 Director or the Director'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 SIP emissions cap. [R307-401-8, 40 CFR 63 Subpart ZZZZ]

II.B.5.b The ETF portable diesel generator shall not be operated more than 1,100 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.

Compliance with the rolling 12-month period limitation shall be determined on a rolling 12-month total. No later than 20 days after the end of each month, a new 12-month total shall be calculated using data from 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 Director or the Director'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 SIP emissions cap. [R307-401]

II.B.5.c Holly Refinery shall use #1, #2 or a combination of #1 and #2 diesel as a fuel source for the diesel fuel fired emergency generators. The sulfur content of any fuel oil or diesel burned shall not exceed: 0.0015 percent by weight. Certification of fuels shall be either by Holly Refinery's own testing or test reports from the fuel marketer. [R307-401-8]

II.B.5.d Except for use in emergency and portable equipment, 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 testing and 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 (Units 4 and 25) regenerators 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. [R307-401-8]

II.B.6 **Conditions on SO₂ emissions sources**

II.B.6.a The emission of SO₂ into the atmosphere from all sources (excluding routine turnaround maintenance emissions) shall not exceed 110.3 tons per rolling 12-month period or 0.31 tons per day (tpd).

The routine turnaround maintenance period (maximum of every 3 years for a maximum of a 15 day period) for the SRU (Unit 17) shall only be scheduled during the period of April 1 through October 31. The projected SRU turnaround period shall be submitted to the Director by April 1 of each year in which a turnaround is planned. Notice shall also be provided to the Director 30 days prior to the planned turnaround.

Emissions of SO₂ shall be limited as follows:

Emission Points	Emissions (tpd)	Total Emissions (tpy)
4V82 FCC	0.05	17.7
25FCC Scrubber	0.05	17.7
All other sources	0.21	74.9

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

For all the above listed emission points a CEM shall be used to determine compliance as outlined in II.B.3.e.

Compliance with rolling 12-month period limitation shall be determined on a rolling 12-month total. No later than 20 days after the end of each month, a new 12-month total shall be calculated using data from the previous 12 months. The rolling 12-month total SO₂ emissions shall be used for inventory and compliance purposes. [R307-170]

II.B.6.b

SO₂ emissions into the atmosphere shall be determined by applying the following emission factors or emission factors determined from the most current performance testing 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

Plant gas - The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a CEM 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. Plant gas sulfur content shall not exceed 60 ppmv determined daily on a 365 successive calendar day rolling average basis. 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 Director.

Fuel Consumption shall be measured as follows:

Natural gas and 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 shall be as follows:

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

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

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

Total daily SO₂ emissions for the sources shall be calculated by adding 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. The daily SO₂ emissions shall be used for compliance purposes. [R307-401]

II.B.7 **Conditions on PM₁₀ emissions sources**

II.B.7.a PM₁₀ emissions from all combustion sources shall not exceed 47.5 tons per rolling 12-month period or 0.13 tpd.

PM₁₀ emissions from all other sources shall not exceed 100.3 tons per rolling 12-month period. [R307-401]

II.B.7.a.1 PM₁₀ emissions into the atmosphere shall be determined by applying the following emission factors or emission factors determined from the most current performance testing to the relevant quantities of fuel combusted in each unit.

4V82FCC Scrubber: 0.50 lb/1000 lb coke burned in the FCC Unit 4
25FCC Scrubber: 0.30 lb/1000 lb coke burned in the FCC Unit 25

Natural gas or Plant gas for all non-NSPS combustion equipment: 7.65 lb PM₁₀/MMscf

Natural gas or Plant gas for all NSPS combustion equipment: 0.52 lb PM₁₀/MMscf

PM₁₀ emissions from cooling towers shall be determined based on the following equation:

$$PM = CR * TDS/10^6 * DR/100 * p * 60 * 8760/2000$$

PM = PM₁₀ emissions in tpy

CR = Circulation Rate of water circulation rate of the cooling tower (gal/min)

TDS = Based on most current average of total dissolved solids (TDS) measurements collected from existing cooling tower water

P = density of water (lbs/gal)

DR = Drift Rate, drift loss of circulating water (%) = 0.0006 % (for Cooling Towers 4, 6, 7, & 8) and 0.0005 % (for Cooling Towers 10 & 11)

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 and plant gas consumption 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:

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

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

Total 24-hour PM₁₀ emissions for the sources 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. The daily PM₁₀ emissions shall be used for compliance. For the details of compliance demonstration, refer to Section IX.H.1.i(2) of the PM₁₀ SIP.

Compliance with rolling 12-month period limitation shall be determined on a rolling 12-month total. No later than 20 days after the end of each month, a new 12-month total shall be calculated using data from the previous 12 months. The rolling 12-month total shall be used for compliance and inventory purposes. [R307-401]

II.B.7.a.2 The emissions of PM₁₀ from the following NSPS Boilers and heaters shall not exceed 0.00051 lb/MMBtu. Holly Refinery shall conduct stack testing to verify the PM₁₀ emissions on the following NSPS heaters and boilers: 10H2, 19H1, 20H1, 20H2, 20H3, 23H1, 24H1, 25H1, 27H1, 30H1, 30H2, 33H1, Boilers #8, #9, #10, and #11.

Compliance shall be determined by a stack test to be performed every year. Holly Refinery shall conduct annual test no later than October 31st of each year. Upon demonstration through at least three (3) annual tests that the PM₁₀ limits are not being exceeded, Holly Refinery may request approval to conduct less frequently than annually.

Emissions of PM₁₀ shall be determined through use of 40 CFR 60, Appendix M, Method 201, 201a, 202, or other EPA-approved testing method, as acceptable to the Director. The condensable particle emissions shall be used for compliance demonstration and for inventory purposes. [R307-401-8]

II.B.8 **Conditions on NO_x emissions sources**

II.B.8.a NO_x emissions into the atmosphere from all sources shall not exceed 347.1 tons per rolling 12-month period or 2.09 tpd. [R307-401]

II.B.8.b

NO_x emissions shall be determined by applying the following emission factors or emission factors determined from the most current performance testing to the relevant quantities of fuel combusted.

Natural gas/refinery fuel gas combustion boilers and furnaces, 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:

Natural gas/refinery fuel gas combustion using Low NO_x burners (LNB): 41 lbs/MMscf

Natural gas/refinery fuel gas combusted using Ultra-Low NO_x burners: 0.04 lbs/MMbtu

Natural gas/refinery fuel gas combusted using Next Generation Ultra Low NO_x burners: 0.10 lbs/MMbtu

Natural gas/refinery fuel gas combusted burners using selective catalytic reduction (SCR): 0.02 lbs/MMbtu

All other natural gas/refinery fuel gas combustion burners: 100 lb/MMscf

All fuel oil combustion: 120 lbs/Kgal

Boiler #5: 0.03 lbs/MMBtu

Boiler #8: 0.02 lbs/MMBtu

Boilers #9 & #10 (SCR): 0.02 lbs/MMBtu

Boiler #11 (LNB & SCR): 0.02 lbs/MMBtu

Daily natural gas and 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:

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/MMBTU) * Burner Heat Rating (BTU/hr) * 24 hours per day /(2,000 lb/ton)

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

Flares:

The NO_x emissions from flares shall be determined using the following equation:

NO_x = F * HHV * EF * 10⁶ * 8760 / 2000

NO_x = Annual potential NO_x emissions from normal flaring (tpy)

F = Average non-upset flare throughput (scf/hr) based on most current monitored flare flow

HHV = Average higher heating value of flared gas (Btu/scf) based on most current monitored

flare flow

EF = Emission factor for NO_x from industrial flares in lb/MMBtu

Total 24-hour NO_x emissions for sources shall be calculated by adding the results of the above NO_x 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. The daily NO_x emissions shall be used for compliance purposes. See Section IX.H.1.i(2) of the PM₁₀ SIP for details of compliance determination.

Compliance with rolling 12-month period limitation shall be determined on a rolling 12-month total. No later than 20 days after the end of each month, a new 12-month total shall be calculated using data from the previous 12 months. The rolling 12-month total shall be used for compliance and inventory purposes. [R307-401]

II.B.8.c

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

The emissions of NO_x from 10H2, 27H1, 30H1, 30H2, 33H1, and Boilers #8, #9, #10 and #11 shall not exceed 0.020 lb/MMBtu on a three-hour average basis each. Compliance shall be determined by a stack test to be performed every three (3) years

The emissions of NO_x from heaters 20H1, 24H1, and 25H1 shall not exceed 0.04 lb/MMBtu on a three-hour average basis each. Compliance shall be determined by a stack test to be performed every three (3) years.

The emissions of NO_x from Boiler #5 shall not exceed 0.03 lbs/MMBtu on a three-hour averages basis. Compliance shall be determined by a stack test to be performed every three (3) years.

The emission of NO_x from stab-in heaters 68H6, 68H7, 68H10, 68H11, 68H12, & 68H13 shall not exceed 0.098 lb/MMBtu on a three-hour average basis each. Compliance shall be determined by a stack test to be performed every three (3) years.

Emissions of NO_x shall be determined through use of 40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D, 7E, or other EPA-approved testing method, as acceptable to the Director. [R307-401-8]

II.B.9

Conditions on CO Emission Sources

II.B.9.a

The CO emissions from process heaters 24H1, 20H3, 25H1, 27H1, 68H6, 68H7, 68H10, 68H11, 68H12, 68H13, and 33H1 shall not exceed 0.08 lb/MMbtu on a one-hour average basis each.

The CO emissions from Boiler #11 shall not exceed 0.037 lb/MMBtu.

For process heaters 24H1, 20H3, 25H1, 27H1, and 33H1, Holly Refinery shall conduct stack testing to verify the CO emissions. This stack testing shall be conducted at least once every

three (3) years from the date of this AO. Emissions of CO shall be determined through use of 40 CFR 60, Appendix A, Method 10 or other EPA-approved testing method, as acceptable to the Director. CO emissions shall be used for compliance and inventory purposes.

For process heaters 68H6, 68H7, 68H10, 68H11, 68H12, and 68H13, Holly Refinery shall conduct stack testing on a minimum of one (1) process heater to verify the CO emissions. This stack testing shall be conducted at least once every three (3) years from the date of this AO. Emissions of CO shall be determined through use of 40 CFR 60, Appendix A, Method 10 or other EPA-approved testing method, as acceptable to the Director. CO emissions shall be used for compliance and inventory purposes. [R307-401-8]

II.B.10 **Conditions on VOC Emission Sources**

II.B.10.a The VOC emissions from Boiler #11 shall not exceed 0.004 lb/MMBtu.

Holly Refinery shall conduct stack testing to verify the VOC emissions. This stack testing shall be conducted at least once every three (3) years from the date of this AO. Emissions of the VOC shall be determined through use of 40 CFR 60, Appendix A, Method 25, 25a, or other EPA-approved testing method, as acceptable to the Director. VOC emissions shall be used for compliance and inventory purposes. [R307-401-8]

II.B.10.b Within 180 days of commencing operation for storing heavy crude in each of Tanks 70, 71 and 72, Holly Refinery shall submit an analysis of the operating vapor pressure of these tanks to the Director for a determination on existing tank controls. Any existing tank controls shall not be removed until the Director finalizes this determination. [R307-401-8]

II.B.11 **Conditions on Green House Gases**

II.B.11.a Total plant wide emissions (excluding emissions covered under 40 CFR 98 Subpart MM - Suppliers of Petroleum Products) of GHG shall not exceed 1,003,300 short tons of CO₂e per rolling 12-month period. GHG emissions shall include combined emissions of CO₂, CH₄ and N₂O. Compliance with the rolling 12-month period shall be determined as follows:

Holly Refinery shall multiply the actual rolling 12-month heat input for all fuel gas combustion units by the appropriate emissions factor and global warming potential listed below to calculate emissions of each GHG. The sum of all GHG emissions from all fuel gas combustion units shall be used to evaluate compliance with the CO₂e limit. Actual heat input values of natural gas shall be determined by natural gas purchasing records. Actual heat input values of plant gas shall be determined through refinery testing and multiplied by monthly flow rates.

GHG	Emission Factor	Global Warming Potential
CO ₂	53.02 kg/MMBtu	1
CH ₄	0.001 kg/MMBtu	21
N ₂ O	0.0001 kg/MMBtu	310

Compliance with each limitation shall be determined on a rolling 12-month total. No later than

20 days after the end of each month, a new 12-month total shall be calculated using data from the previous 12 months.

Holly Refinery shall conduct stack testing to verify the CO₂ emissions from the fuel gas combustion equipment with heat input greater than or equal to 99.0 MMBtu/hr are no greater than the CO₂e emission factors listed above. This stack testing shall be conducted at least once every three (3) years from the date of this AO. CO₂ emissions shall be determined using the procedures outlined in 40 CFR 60 Appendix A, Method 3, 3A, or other EPA-approved test method, as acceptable to the Director.

Calculation, fuel purchase records, and stack test results verifying the CO₂e emission factors shall be recorded and maintained. [R307-401-8]

II.B.11.b Oxygen monitors and intake air flow monitors shall be installed on all heaters/burners greater than or equal to 99.0 MMBtu/hr. [R307-401-8]

II.B.11.c Air preheater package shall be installed on Unit 33H1. [R307-401-8]

II.B.11.d Flow meters and gas combustion monitors shall be installed on the South flare gas line to monitor flare combustion efficiency.

Flow meters shall be installed to monitor all fuel gas consumption at the Refinery. [R307-401-8]

II.B.11.e Holly Refinery shall install a vapor recovery system at the Unit 87 propane loading and unloading racks to control fugitive VOC emissions. [R307-401-8]

II.B.12 **Conditions on Wastewater Treatment**

II.B.12.a All applicable provisions of 40 CFR 60, NSPS Subpart QQQ, found at 40 CFR 60.690 to 60.699 (Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems) and 40 CFR 61, NESHAP Subpart FF, found at 40 CFR 61.340 to 61.359 (National Emission Standard for Benzene Waste Operations) apply to this installation. [40 CFR 60 Subpart QQQ, 40 CFR 61 Subpart FF]

II.B.12.b Emissions from any wastewater system control device installed to comply with 40 CFR 60 Subpart QQQ shall be monitored in accordance with 40 CFR 60.695. [40 CFR 60 Subpart QQQ]

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), Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

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), 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), UU: Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture

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), GGGa: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After 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

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

NESHAP (Part 61), A: General Provisions

NESHAP (Part 61), FF: National Emission Standard for Benzene Waste Operations

MACT (Part 63), A: General Provisions

MACT (Part 63), CC: National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

MACT (Part 63), UUU: National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

MACT (Part 63), ZZZZ: National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

MACT (Part 63), DDDDD: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Title V (Part 70) major source

REVIEWER COMMENTS

The AO will be based on the following documents:

Supersedes	DAQE-AN101230040 dated December 16, 2011
Incorporates	Notice of Intent dated May 23, 2012
Incorporates	Additional Information (Unit Designations) dated May 31, 2012
Incorporates	Additional Information (Equip Spec Sheets) dated June 18, 2012
Incorporates	Additional Information (NO ₂ to NO _x stack ratio) dated June 28, 2012
Incorporates	Additional Information (from NOI Completeness Cklist) dated July 5, 2012
Incorporates	Additional Information (Updated NOI) dated July 12, 2012
Incorporates	Additional Information (In Stack Ratio info) dated July 19, 2012
Incorporates	Additional Information (Modeling Analysis Update) dated July 30, 2012
Incorporates	Additional Information (Updated Emissions) dated August 28, 2012
Incorporates	Additional Information (BACT) dated October 17, 2012
Incorporates	Additional Information (GHG & BACT) dated October 18, 2012
Incorporates	Additional Information (emergency generators) dated October 23, 2012
Incorporates	Additional Information (NEI EF and flare info) dated March 21, 2013
Incorporates	Additional Information (Netting Analysis) dated April 1, 2013
Incorporates	Additional Information (Calculations) dated April 10, 2013
Incorporates	Additional Information (Corrected Netting Analysis) dated April 22, 2013
Incorporates	Additional Information (Boiler #8 CD) dated April 30, 2013

1. Comment regarding Complete Notice of Intent (UAC R307-401):
Holly Refinery submitted a Heavy Crude Processing NOI on May 23, 2012. Following this submittal, DAQ requested the following supplemental information: Manufacturer specification sheets for the boiler, wet gas scrubber and emergency generator, new unit designations, and additional storage tank modifications/removal information.

Following DAQ comparison of the May 23, 2012 NOI to the DAQ NOI (administrative) Completeness Checklist, on June 21, 2012, DAQ requested the following information: Additional clarification on explanation of emission reductions used, PSD and Nonattainment NSR applicability analysis methodology, clarification on replacement of ULNB with LNB and SCR technology on several heaters, BACT emission factors be utilized with emission calculations, enhancements to BACT analysis specifically to the Boiler GHG emissions, federal subpart applicability (40 CFR 63 Subpart CC), and NO₂ stack ratio testing data.

On July 5, 2012 Holly Refinery submitted a revised version of the Heavy Crude Processing NOI to address the June 21, 2012 DAQ requested information.

On July 6, 2012 DAQ requested additional clarification on the five (5) year contemporaneous period as well as the CO Boiler (Boiler #6) that had not been included in the July 5, 2012 NOI. This information was received by DAQ on July 13, 2012. An updated modeling analysis was received by DAQ on July 30, 2012.

The July 13, 2012 NOI was determined to be administratively complete on July 30, 2012 and a copy of this complete NOI and modeling analysis was mailed to each of the FLMs for a 60 day comment period, the 60 day comment period began on August 6, 2012. The reference to the NOI

in this engineering review refers to the Holly Refinery submitted NOI dated July 13, 2012.

On December 4, 2012 DAQ put out to public comment an ITA for the Heavy Crude Processing project. A public hearing was also held on January 3, 2013. Comments received during this public comment period resulted in changes to the proposed permit.

On March 21, 2013, April 1, 2013, April 10, 2013, and April 22, 2013 DAQ received additional information from Holly Refinery that has been incorporated into this permit. The additional information affects Section 3.0, Appendix A (Baseline Actual Emissions), Appendix B (Heavy Crude Processing Emissions), and Appendix C (Source Wide Emissions) of the July 2013 NOI. The Modeling analysis does not change as NO_x and HAP emissions have both decreased since originally modeled in 2012 and no other modeling requirements of R307-410 were triggered.

April 1, 2013: Appendix B was modified

April 10, 2013: Appendix C was modified

April 22, 2013: Appendix A and Section 3.0 (netting analysis) were modified

On April 30, 2013 Holly Refinery requested that the Boiler #8 2008 EPA Consent Decree NO_x limitation be incorporated into the permit. However, these limits had already been incorporated (see condition II.B.8.c) in the December 2012 ITA, no additional changes were made. [Last updated May 14, 2013]

2. Comment regarding Additional Equipment Changes:

On October 22 (and October 23), 2012, DAQ NSR received a request to add two (2) 142 kW (each) natural gas fired emergency generators that were not previously proposed in their NOI. These generators will be installed at the proposed administration building. Emissions from these generators have been included in all emission totals and evaluations.

On March 21, 2013 DAQ NSR received a request to remove the previously requested installation of the 14.1 MMBtu/hr hot oil heater (26H1) for the poly gasoline unit (Unit 26). On May 17, 2013 Holly Refinery informed DAQ that the heater will be installed, but it will be an electric heater.

On April 1, 2013 DAQ received a request to remove four (4) existing natural gas/plant gas fired compressor engines: 4K1A KVG Compressor West, 4K1B KVG Compressor East, 6K1 SVG Compressor East, and 6K2 Compressor West as they will be replaced with electric engines. [Last updated May 20, 2013]

3. Comment regarding Emission Calculations (Methodology):
Mobile Sources:

It is not a discretionary decision for DAQ to consider mobile sources when reviewing an NOI. DAQ's NSR Program is derived from Title I of the CAA. Title I addresses only major stationary sources and major modifications to stationary sources; Utah's SIP has expanded this program to include minor stationary sources and minor modifications to stationary sources. The CAA Title II, Emissions Standards for Moving Sources, addresses vehicle-based emissions, also known as mobile emissions. As mobile sources do not constitute a stationary source for regulation under Title I of the CAA nor DAQ's NSR permitting rules (R307-400), there is no requirement to address mobile source emissions as part of this permitting action.

Cooling Towers (Unit 54):

VOC emissions from cooling towers 4 through 8 were previously estimated using the uncontrolled emission factor listed in AP-42 Section 5.1 of 6 lb/10⁶ gal cooling water. In 2009, Holly Refinery began a voluntary daily monitoring program to detect VOC leaks into cooling water and to eliminate those leaks. In 2012, the monitoring method was replaced with monthly monitoring using the Texas El Paso method. With continued use of regular monitoring, it is proposed to utilize the "controlled" emission factor of 0.7 lb/10⁶ gallons cooling water in AP-42 Section 5.1. This method will also be implemented for cooling towers 10 and 11. PM emissions were estimated based on the methodology and particle size distributions presented by Joel Reisman and Gordon Frisbie's paper titled, Calculating Realistic PM₁₀ Emissions from Cooling Towers.

Emergency generator emissions are based on 50 hours each per rolling 12-month period. The ETF portable diesel generator will reduce its permitted hours from 1,300 to 1,100 hours per rolling 12-month period.

Diesel fired emergency generator emissions were based on EPA Tier III 40 CFR 60 Subpart III compliance and AP-42 Chapter 3.3.

Natural gas fired emergency generator emissions were based on AP-42 Table 3.2-2 (4-stroke lean burn) except where noted below:

NO_x, CO, and VOC emissions were based on manufacturer's guarantee.

NO_x = 0.08 grams/hp-hr
CO = 0.78 grams/hp-hr
VOC = 0.36 grams/hp-hr

In the past, Holly Refinery has relied upon EPA's AP-42 emission factors for PM₁₀ and PM_{2.5}. However, Holly Refinery is proposing to utilize PM₁₀ and PM_{2.5} emission factors for new (NSPS) combustion sources based on the 2006 EPA published National Emissions Inventory (NEI) Information. Older equipment (non NSPS) emissions will still rely on AP-42 emission factors. The NEI is a comprehensive and detailed estimate of air emissions from all air emissions sources which the EPA has been using starting in 2004 and continuing to the 2011 NEI currently under development by the EPA. The NEI documents state that the EPA believes that the current AP-42 factors for condensable emissions are too high based on some limited data from a pilot-scale dilution sampling method that is similar to EPA's CTM 39. The NEI is prepared every three (3) years by the US EPA based primarily upon emission estimates and emission model inputs provided by State, Local and Tribal air agencies and supplemented by data developed by the EPA. The NEI emission factors relied on in this review are primary PM₁₀ and primary PM_{2.5} (filterable plus condensable). [Last updated May 20, 2013]

4. Comment regarding Emission Calculations (Methodology) Continued:

Non NSPS boilers and heaters PTE's have been estimated using AP-42 emission factors. This is because Holly Refinery and DAQ are less confident this older equipment can verify these lower NEI emission factors. NSPS boilers and heaters (10H2, 19H1, 20H1, 20H2, 20H3, 23H1, 24H1, 25H1, 27H1, 30H1, 30H2, 33H1, 68H2, 68H3, 68H4, 68H5, 68H6, 68H7, 68H10, 68H11, 68H12, 68H13, Boilers #8, #9, #10, #11) PTE's have been estimated using NEI emission factors. This

equipment, with the exception of the relatively small tank heaters (68H2, 68H3, 68H4, 68H5, 68H6, 68H7, 68H10, 68H11, 68H12, 68H13) will have testing requirements to verify they are at or below the NEI emission factors.

Process Heaters (24H1, 20H3, 25H1, 27H1, & 33H1):

CO = 0.08 lb/MMbtu (BACT)

PM₁₀ = 0.52 lb/MMscf (NEI emission factor)

PM_{2.5} = 0.43 lb/MMscf (NEI emission factor)

SO₂ = 10.13 lb/MMScf (based on H₂S content of 60 ppmv)

NO_x = 0.04 lb/MMbtu (ULNB) or NO_x = 0.02 lb/MMbtu (LNB & SCR)

VOC= 0.0054 lb/MMbtu (AP-42 Chapter 1.4)

HAPs (AP-42 Chapter 1.4)

In-tank asphalt heaters (68H6, 68H7, 68H10, 68H11, 68H12, & 68H13): AP-42 Chapter 1.4

Process Heaters adding SCR (10H2, 30H1, 30H2): NO_x = 0.02 lb/MMbtu

Crude Furnace 8H1: Emissions will not be changed with addition of preflash tower.

Boiler #11:

CO = 0.037 lb/MMBtu (BACT)

PM₁₀ = 0.52 lb/MMScf (NEI emission factor)

PM_{2.5} = 0.43 lb/MMscf (NEI emission factor)

SO₂ = 10.13 lb/MMScf (based on H₂S content of 60 ppmv)

NO_x = 0.02 lb/MMbtu (LNB & SCR)

VOC= 0.004 lb/MMbtu (BACT)

HAPs (AP-42 Chapter 1.4)

Boiler #8 (addition of SCR): NO_x = 0.02 lb/MMbtu

FCC Unit 25 (FCC25 Scrubber):

CO = 500 ppm (35.35 lb/hr) (BACT)

PM₁₀/PM_{2.5} = 0.5 lb/1000 lbs of coke burn off (BACT)

SO₂ = 4.04 lb/hr (based on 25 ppmvd 365-day average)

NO_x = 4.55 lb/hr (based on 40 ppmvd)

Greenhouse Gas emissions were estimated based on 40 CFR Part 98, and listed in short tons per the Tailoring Rule.

Tanks emission estimates are based on EPA's TANKS 4.0.9d. Assumed that the K factor = 0.1 and 0.05% benzene in liquid for black wax crude (MSDS Silver Eagle Refining).

Sour Water Stripper Unit 28 emissions will be controlled through existing Units 22 & 17.

Emissions from loading/unloading of the heavy crude (black and yellow waxes) have been estimated through fugitive emission calculations. These fugitives include emissions from valves, fittings and tank atmosphere fluctuations (Tanks 70, 71 & 72 storage tanks).

Flare emissions were estimated based on AP-42 Chapter 13.5.

Fugitive emissions from valves, flanges, pump and compressor seals, process drains, cooling towers, and oil/water separators were estimated based on the following assumptions: only relieve valves that vent to the atmosphere were counted; same number of heavy liquid components as light liquid components, twice as many connectors as valves, leak rate is greater than 10,000 ppm; 2% of all components leaking; and year-long continuous leak.

Holly Refinery performed a water conservation and wastewater reduction study which indicated that there will not be an increase in emissions from wastewater treatment with this modification.

Unless stated otherwise: Until better data is available, all PM₁₀ is considered to be PM_{2.5}. [Last updated May 20, 2013]

5. Comment regarding Startup Shutdown Emissions:

In regards to establishing baseline emissions for PSD and Major NSR applicability, 40 CFR 52.21(b)(41)(ii)(d) states in lieu of using projected future actual emissions, a source may “elect to use the emissions unit’s potential to emit, in tons per year, as defined under paragraph (b)(4) of this section.” In regards to baseline actual emissions, 40 CFR 52.21(b)(48)(iii) states that “For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit’s potential to emit.”

Holly Refinery has proposed using PTE values, not projected future actual emissions in their analysis, and therefore Start Up (SU), Shut Down (SD) and malfunction emissions are not required to be included in the baseline. In addition, Units 24, 25 and 27 are all new units, therefore, their baseline actual emissions are zero; they do not include SU, SD, or malfunction emissions.

Based on the average actual shutdowns per year for the existing units between 2007 to 2011, the following number of SU and SD were estimated:

New Crude Unit 24: 2.4

New FCC Unit 25: 2.6

New Hydrocracker/Hydroisom Unit 27: 4.2

Based on these assumptions, the following total SU/SD emissions were estimated, in tons per year (note that Unit 26 has been removed from these calculations because it will now be an electric heater):

	Unit 24	Unit 25	Unit 27	Total
NO _x	0.15	0.46	0.97	1.58
CO	0.84	2.50	5.27	8.61
SO _x	0.00	0.01	0.02	0.03
PM ₁₀	0.01	0.04	0.02	0.12
PM _{2.5}	0.01	0.04	0.07	0.12
VOC	0.01	0.04	0.05	0.09

However, to be conservative and representative of potential increases in emissions from SU and

SD, DAQ and Holly Refinery have agreed to include these emissions in Step 1 of the PSD and NNSR applicability analysis.

Section 3.6 of the July 2012 NOI lists upset conditions for both the North and South Flares. These upset conditions (malfunctions) do not include normal process flow combustion at the flares and there is no reason to assume that upset condition emissions will be any greater after the project is complete than before the project. Although these emissions have not been included in the netting analysis, they are noted below for reference.

NO_x = 4 tpy

CO = 21 tpy

SO₂ = 120 tpy

VOC = 8 tpy [Last updated June 4, 2013]

6. Comment regarding Contemporaneous Period:

Holly Refinery submitted a NOI for the Heavy Crude Processing project on May 23, 2012. They submitted revised NOIs on July 5, 2012 and July 13, 2012 to incorporate DAQs requests for additional information. The July 13, 2012 NOI was declared administratively complete on July 30, 2012.

As noted in Note #1, DAQ NSR received additional information that included emissions used in PSD, Major NSR, and offsetting applicability analyses, therefore, contemporaneous projects have been modified to account for this additional information. DAQ NSR determined that this additional information, for purposes of DAQ NSR review, was declared administratively complete on May 6, 2013.

The five (5) year contemporaneous period prior to DAQ receiving a complete NOI includes projects from May 2008 through May 2013. Per 40 CFR 52.21, contemporaneous changes occur between the date five (5) years before construction of when the change commences/the increase occurs. Prior to the proposed approval of the Heavy Crude Processing project, DAQ uses the date that the NOI is complete to determine how far back the contemporaneous period extends to. The modifications that Holly Refinery received approval for during that time period are the following:

The June 8, 2007 approved AO (DAQE-AN1012300023-07) received by Holly Refinery for their modernization project, falls out of the contemporaneous period. This project was to facilitate Holly Refinery being able to process heavier crude from Canada which has high sulfur content. Although several of the changes approved for the modernization project have been implemented at the refinery, Holly Refinery is proposing within the Heavy Crude Processing project to remove several of the unconstructed/unmodified units because the refinery no longer needs to accommodate this heavier Canadian crude. Reductions from the removal of the unconstructed equipment have not been used for netting purposes. DAQ has determined that the 2007 modernization project as a whole is separate from the currently proposed use of the local eastern Utah crude (Heavy Crude Processing project), which is a highly paraffinic crude oil with lower sulfur content and therefore these two projects were not aggregated. However, increases in emissions from the installation of equipment approved in this 2007 Modernization AO, as they fall into the defined contemporaneous period, have been included in the netting analysis. Because the DAQ's verified actual emission data varies from the actual emissions Holly Refinery relied upon, the netting analysis DAQ used for PSD, Major NSR, and offsetting determinations is slightly different from Holly Refinery's netting analysis. [Last updated May 13, 2013]

7. Comment regarding Baseline Actual Emissions:
Baseline actual emissions for project affected sources were calculated by Holly Refinery in accordance with 40 CFR 52.21. These emissions are based on a consecutive 24-month period in the past 10 years as reported in the Holly Refinery annual emission inventory and provided in Appendix A of the May/July NOIs. DAQ reviewed actual emissions relied upon for netting analysis and made appropriate corrections based on Title V required inventory reports received by DAQ.

Baseline actual emissions were based on emission inventories reported by Holly Refinery over the past 10 years. The 24-month periods used per pollutant are as follows:

NO_x: January 2004 - December 2005
CO: January 2010 - December 2011
PM₁₀: January 2005 - December 2006
PM_{2.5}: January 2008 - December 2009
VOC: January 2007 – December 2008
SO_x: January 2005 – December 2006 [Last updated May 8, 2013]

8. Comment regarding Contemporaneous Projects:
As noted in Comment #6, the contemporaneous period for this project is May 2008 through May 2013. The following projects were identified as falling within this time period and need to be evaluated for purposes of aggregation. Although DAQ made the determination that these projects should not be aggregated with the Heavy Crude Processing project, emissions associated with these contemporaneous projects were included, when noted, in Step 2 of the netting analysis (see Comments 11, 12, and 13).

Although the 2007 Modernization project was not aggregated with this project (see Comment #6), the contemporaneous increases in emissions from the installation of equipment permitted with the 2007 Modernization project were included. This includes the following equipment installed and started operation between 2008 and 2013:

Gas Oil Hydrocracking Unit (GOHC) & Reactor Charge (Unit 20 and Unit 21)
Fractionator Reboiler (20H2)
Hot Oil Heater (10H2)
H2 Plant Furnace(30H1 and 30H2)
H2 Plant Deaerator Vent
Hydrogen fugitives
Asphalt Tank
Stab-in Heaters
New & Modified Tanks
Increases Tank throughput
Fugitives associated with installations

As a result of these installation, contemporaneous emission increases were as follows: NO_x +41.77 tpy and CO + 150.03 tpy.

DAQE-AN101230027-09 (dated 11/3/09): This AO was to incorporate Consent Decree requirements, reestablish 8H1 and 12H1 limits based on performance testing, and to install a new

portable electric generator for use as an emergency power supply. Emissions did not change with this modification.

DAQ has determined that DAQE-AN101230027-09 should not be aggregated with the Heavy Crude Processing project as the intents of both projects are separate and independent.

DAQE-AN101230031-10 (dated 1/12/10): This AO was to incorporate two (2) new 75,000 pound of steam/hour boilers #9 & #10. The purpose of these boilers was to provide additional steam supply when the expected steam production for the SRU was less than anticipated and supply from outside sources was delayed. Boiler #10 was installed to provide redundancy to Boiler #9. As a result of that modification, emissions from that AO were changed as follows: NO_x +15.65 tpy and CO + 28.94 tpy. While these increases were over the values from Holly Refinery's previous AO, the new totals were less than the existing limitations from section IX.H.2.f of the PM₁₀ SIP.

DAQ has determined that DAQE-AN101230031-10 should not be aggregated with the Heavy Crude Processing project as the intents of both projects are separate and independent. However, these emissions were determined to be contemporaneous emissions for purposes of a netting analysis. [Last updated May 15, 2013]

9. Comment regarding Contemporaneous Projects (continued):

DAQE-AN101230032-10 (dated 8/23/10): This AO was to incorporate NSPS Subpart A & J for CO emissions to the FCCU per their CD requirements. Emissions were not changed with this modification.

DAQ has determined that DAQE-AN101230032-10 should not be aggregated with the Heavy Crude Processing project as the intents of both projects are separate and independent.

DAQE-AN101230036-10 (dated 11/17/10): This AO was to incorporate Boiler #5 CD requirements to install SCR and to install a Benzene Saturation Unit 23 to meet a 2011 Federal limit requirement for a 0.262% benzene content in gasoline. As a result of this modification, emissions from that AO were changed as follows: NO_x + 0.64 tpy and CO + 7.57 tpy.

DAQ has determined that DAQE-AN101230036-10 should not be aggregated with the Heavy Crude Processing project as the intents of both projects are separate and independent. However, these emissions were determined to be contemporaneous emissions for purposes of a netting analysis.

DAQE-AN101230038-10 (dated 12/16/10): This AO was to incorporate NO_x and SO_x limitations as required in Holly Refinery's CD. Emissions did not change with this modification.

DAQ has determined that DAQE-AN101230038-10 should not be aggregated with the Heavy Crude Processing project as the intents of both projects are separate and independent.

DAQE-AN101230039-11 (dated 9/16/11): This AO was to incorporate three (3) dedicated ethanol unloading areas to support the EPA's renewable fuel standard by blending produced gasoline to a 10% ethanol concentration.

DAQ has determined that DAQE-AN101230039-11 should not be aggregated with the Heavy Crude Processing project as the intents of both projects are separate and independent. However, these emissions were determined to be contemporaneous emissions for purposes of a netting

analysis.

DAQE-AN101230040-11 (dated 12/16/12): This AO was to incorporate an additional 250 gpm charge pump at the ethanol unloading area. Holly Refinery had mistakenly not included within the previous AO. VOC emissions increased by 0.03 tpy.

DAQ has determined that DAQE-AN101230040-11 should be aggregated with DAQE-AN101230039-11 as both projects have the same intent, but that DAQE-AN101230040-11 should not be aggregated with the Heavy Crude Processing project as the intents of both projects are separate and independent. However, these emissions were determined to be contemporaneous emissions for purposes of a netting analysis. [Last updated May 15, 2013]

10. Comment regarding Contemporaneous Projects (continued): Contemporaneous actual reductions proposed with the Heavy Crude Processing Project include the following:

Removal of existing South Flare: This flare is being replaced and those PTE emission increases for the proposed new South Flare have been included as part of the Heavy Crude Processing project increases. Based on baseline actual emissions, reductions (from the removal) were estimated as follows: SO₂ - 4.90 tpy and VOC -4.29 tpy.

Conversion of Tanks 70, 71 & 72 from petroleum liquid storage to black and yellow wax crude storage. Based on baseline actual emissions, the reduction in VOC is - 0.58tpy.

Cooling Towers: VOC leak detection and repairs began in 2009 for existing cooling towers. With the implementation of monthly monitoring in accordance with 40 CFR 63 Subpart CC, it is appropriate for these units to utilize AP-42 Section 5.1 emission factors. Based on the control of these cooling towers, using baseline actual emissions, reductions were estimated at -39.28 tpy of VOCs.

Removal of Propane Pit Flare: In 2009 a new propane pit flare was installed at the Holly Refinery, this flare replaced the previous flare, adding air assist (to control smoke production) and pilot monitoring. The replacement flare meets the NSPS Subparts A & J requirements. Emission estimates from the NSPS compliant flare as compared to the flare prior to replacement did not change because reported emissions (prior to and after replacement) were based on AP-42 Section 13.5 (Industrial Flares) emission factors, bringing the flare into compliance did not adjust emissions. Four (4) new propane tanks are being proposed for construction (Tanks 171, 172, 173, and 174) to replace the propane pit; These proposed tanks will not be equipped with a flare. The reductions from the removal of the propane pit flare were estimated, based on baseline actual emissions, the following: NO_x – 5.30 tpy, VOC -1.89 tpy, PM₁₀ -0.93 tpy, PM_{2.5} – 2.19 tpy, CO – 129.27 tpy.

Rerouted SRU emissions to a wet gas scrubber: Holly Refinery is proposing to voluntarily reroute the SRU (Unit 17) emissions through a wet gas scrubber (either through the existing 4V82 FCC Scrubber or through the proposed 25 FCC Scrubber) instead of through the SRU Tailgas Incinerator. Reductions from rerouting these emissions, based on baseline actual emissions, are estimated as follows: NO_x – 0.85 tpy, SO₂ – 184.64 tpy, VOC – 0.05 tpy, PM₁₀ - 0.06 tpy, PM_{2.5} – 0.07 tpy, CO -0.76 tpy

Removal of four (4) gas driven compressor engines: Holly Refinery is proposing to replace the existing gas-driven compressor engines with electric motor compressor engines. In the case of power emergency when Holly Refinery does not have access to electrical power, the refinery will only operate the essential systems such as boilers and instrument air, to allow a safe shutdown of the refinery, additional emergency (generator) capacity is not required with the replacement of these compressor engines. These total reductions, based on baseline actual emissions, are estimated as follows: NO_x – 98.70, VOC – 1.37, PM₁₀ – 0.26, PM_{2.5} – 0.12, CO – 68.35.
[Last updated May 20, 2013]

11. Comment regarding PSD Applicability Analysis (Attainment Area) UAC R307-405: Davis County is attainment for the following pollutants: NO_x, SO_x, VOC, CO, and GHG. The project estimated increases are summarized below. Note that SU and SD emissions have been included. Also note that VOC emissions include 15.25 tpy of fugitive emissions. This netting analysis is based on the April 22, 2013 netting analysis submitted by Holly Refinery, including associated tables and emission calculations. Significance for criteria pollutants is defined in R307-101-2 and for GHGs in R307-405-3.

The project increases and SU and SD emissions were estimated as follows:

NO_x + 83.05 tpy > 40 tpy significance
SO₂ + 38.26 tpy < 40 tpy significance
VOC + 32.38 tpy < 40 tpy significance
CO + 343.27 tpy > 100 tpy significance
GHG + 279,610 tpy CO₂e > 75,000 tpy CO₂e

DAQ has adopted the Reform rule which requires sources that may be subject to PSD or Major NNSR permitting at an existing major source to go through the “net emission increase” analysis. This analysis has two components: The emissions increase from the project itself and the sum of the emissions increases and decreases of all projects implemented over the last five (5) years (the contemporaneous period) that were not otherwise considered in a PSD permit action. The net emissions increase is the sum of these two components. DAQ applied this two step methodology in evaluating PSD and major NNSR permitting applicability as well as applicable offsetting requirements.

H₂S, TRS, and sulfuric acid mist are regulated PSD pollutants; however, because the increases in emissions are less than 1.0 tpy and do not trigger a significant, a netting analysis was not required for these pollutants.

The project emissions increases from NO_x, CO and GHG are significant; therefore, Holly Refinery provided a netting analysis for NO_x and CO emissions looking back five (5) years at contemporaneous emission increases and decreases. The contemporaneous five (5) year period is defined in Comment 6 above and contemporaneous projects as discussed in Comments 8, 9, & 10 above.

NO_x and CO contemporaneous increase/decreases are as follows:

NO_x: + 58.72 tpy – 104.84 tpy = (46.12) tpy
CO: + 186.66 tpy – 198.38 tpy = (11.72) tpy

Therefore, the net emission increase for NO_x and CO are as follows:

NO_x: + 83.05 tpy (project) – 46.12 tpy (contemporaneous) = 36.93 tpy increase < 40 tpy significance

CO: + 343.27 tpy (project) – 11.72 tpy (contemporaneous) = 331.55 tpy increase > 100 tpy significance

PSD review is triggered for CO and GHG emissions. The analysis, considering contemporaneous emissions, netted Holly Refinery out of PSD review for NO_x.

Note: emissions within (parenthesis) are negative values, parenthesis were used in an attempt to emphasis negative values. [Last updated May 20, 2013]

12. Comment regarding NNSR Major Modification Applicability Analysis (Nonattainment Area) UAC R307-403:

Davis County is nonattainment for PM_{2.5} and Holly Refinery has been defined as a contributing source to the Salt Lake County PM₁₀ nonattainment area: Major NSR modifications for nonattainment pollutants trigger the requirements of Lowest Achievable Emission Rate (LAER). The project estimated increase/decreases have been summarized below, including SU and SD emissions. Significance for criteria pollutants is defined in R307-101-2:

Although PM_{2.5} is a subset of PM₁₀, it is reviewed independently. It is a separate regulated pollutant, which has a single defined precursor pollutant of its own, SO₂ (40 CFR 51, Appendix S). States may establish additional precursor pollutants to PM_{2.5} through a SIP process. However, DAQ must default to the values listed in Appendix S until such time as DAQ completes its PM_{2.5} SIP process. The significance amounts found in Appendix S for PM_{2.5} are as follows: 10 tpy of direct PM_{2.5} emissions and 40 tpy of sulfur dioxide emissions.

PM_{2.5} + 9.19 tpy < 10 tpy significance

SO₂ + 38.26 tpy < 40 tpy significance

The project emissions increases from PM_{2.5} and SO_x are not significant and do not trigger the requirements of R307-403-1 for LAER.

R307-421-2 established that the precursors for PM₁₀ are SO₂ and NO_x. Project increases for these pollutants are as follows:

PM₁₀ + 9.54 tpy < 15 tpy significance

SO₂ + 38.26 tpy < 40 tpy significance

NO_x + 83.05 tpy > 40 tpy significance

The project increase of NO_x was estimated at 83.05 tpy (see Comment 11) which is over significance. However, NO_x netted out of PSD review and the same analysis can be applied to net NO_x increases out of Major NSR.

NO_x: + 83.05 tpy – 46.12 tpy = 36.93 tpy increase < 40 tpy significance

The emissions increases from PM₁₀, SO_x and NO_x are not significant and do not trigger the requirements of R307-403-1 for LAER. [Last updated May 13, 2013]

13. Comment regarding NNSR Offset Applicability (UAC R307-420 & R307-421):
Holly Refinery is located in Davis County, a nonattainment area for PM_{2.5} and a maintenance area for Ozone. Holly Refinery impacts the PM₁₀ nonattainment area of Salt Lake County. NO_x, VOC, CO, GHG, and SO₂ are attainment in Davis County.

PM₁₀ Nonattainment Offsetting Area Requirements:

Under R307-401-421-2 PM₁₀ offsetting is applicable to new or modified sources that increase emissions. NO_x and SO_x are precursors to PM₁₀. The increase/decrease in emissions for the Heavy Crude Processing project for PM₁₀, NO_x, and SO_x includes SU and SD emissions and are summarized below:

$$\begin{aligned} \text{PM}_{10} &= 9.54 \text{ tpy} - 1.25 \text{ tpy} = 8.29 \text{ tpy} \\ \text{NO}_x &= 83.05 \text{ tpy} - 104.84 \text{ tpy} = (21.79) \text{ tpy} \\ \text{SO}_x &= 38.26 \text{ tpy} - 189.43 \text{ tpy} = (151.17) \text{ tpy} \end{aligned}$$

The total increase in emissions from all three combined equal 8.29 tpy, this is less than the 25 tpy offsetting requirement trigger. PM₁₀ offsetting requirements are not required for this project.

Ozone Maintenance Area Offsetting Requirements:

Under R307-401-420 Ozone offsetting is applicable to new or modified sources that have a "net" increase in emissions. NO_x and VOCs are precursors to Ozone. The net emission increase for NO_x is 36.93 tpy (see Comment 11). The net increase in VOC emissions is calculated below:

The increases in VOC emissions, including SU and SD and 15.25 tpy of fugitives, are as follows:

$$\text{VOC} + 32.38 \text{ tpy}$$

The VOC contemporaneous increase/decreases are as follows:

$$\text{VOC: } + 21.68 \text{ tpy} - 47.03 \text{ tpy} = (25.35) \text{ tpy}$$

Therefore, the net emission increase for VOC is as follows:

$$\text{VOC: } + 32.38 \text{ tpy (this project)} - 25.35 \text{ tpy (contemporaneous)} = 7.03 \text{ tpy increase} < 25 \text{ tpy (Ozone)}$$

For both NO_x and VOC, the net emission increases do not trigger significance so Ozone offsetting requirements were not triggered for this project.

PM_{2.5} Nonattainment Area Offsetting Requirements

For PM_{2.5} nonattainment area offsetting requirements, DAQ relies on 40 CFR 50 Appendix S and the February 17, 2011 DAQ published policy memo "Guidance for PM_{2.5} Offsetting Prior to Finalizing the SIP". The PM_{2.5} SIP for the Salt Lake City nonattainment area has not been finalized as of the date of this review. SO_x is the only designated precursor for PM_{2.5} in this interim period. Significant net emission increases in PM_{2.5} and SO_x will trigger offsetting requirements.

The net increases in SO₂ and PM_{2.5} are calculated below:

The increases in SO₂ and PM_{2.5} emissions, including SU and SD, are as follows:

SO₂: + 38.26 tpy

PM_{2.5}: + 9.19 tpy

The SO₂ and PM_{2.5} contemporaneous increase/decreases are as follows:

SO₂: + 40.87 tpy – 188.57 tpy = (148.57) tpy

PM_{2.5}: +1.54 tpy – 2.38 tpy = (0.84) tpy

Therefore, the net emission increase for SO₂ and PM_{2.5} are as follows:

SO₂: + 38.26 tpy (this project) – 148.57 tpy (contemporaneous) = (110.30) tpy < 40 tpy significance

PM_{2.5}: + 9.19 tpy (this project) – 0.84 tpy (contemporaneous) = 8.35 tpy < 10 tpy significance

PM_{2.5} offsetting requirements are not triggered for this project.

Note: emissions within (parenthesis) are negative values, parenthesis were used in an attempt to emphasize negative values. [Last updated May 14, 2013]

14. Comment regarding Modification to Existing SO₂ and PM₁₀ AO Limits:
Currently Holly Refinery has SO₂, PM₁₀, and NO_x AO emission limitations as well as 2005 PM₁₀ SIP CAPS. Source wide emissions from combustion sources at Holly Refinery cannot exceed the 2005 PM₁₀ SIP Cap limits, AO emissions limits can be adjusted (increases and decreases) if the emissions stay below the 2005 SIP Cap levels. DAQ NSR is proposing to modify the SO₂, PM₁₀ and NO_x AO emission limitations (not the 2005 SIP Caps) to reflect the proposed emission decreases resulting for the Heavy Crude Processing project. An effort has been made to remove previously excluded equipment and incorporate source wide AO emission limitations that fall below 2005 PM₁₀ SIP Cap limitations.

The current source wide SO₂ AO emission limit is at 956 tpy and 2.63 tpd excluding the North and South flares, the Propane Pit flare, and emergency equipment. The 2005 PM₁₀ SIP Cap limit was set at 4.714 tpd for external combustion process equipment. Based on the Updated Appendix C (April 10, 2013), the source wide SO₂ emissions (including proposed equipment) were estimated at approximately 110.3 tpy.

DAQ NSR is proposing to remove the exemptions from SO₂ limit for emergency equipment and flares and incorporate source wide SO₂ emission limits of 110.3 tons per rolling 12-month period and 0.30 tpd. This would reduce the existing AO SO₂ limit by approximately 726 tpy. The routine turnaround maintenance emissions for the SRU (Unit 17) have been excluded from the SO₂ emission limit which follows both the 1994 and 2005 PM₁₀ SIPs for all refineries.

The current source wide AO PM₁₀ emission limit is 47.56 tpy or 0.13 tpd excluding compressors, the North and South flares, the Propane Pit flare, and emergency equipment and a limit of 32 tpy and 0.09 tpd for the CO Boiler/FCC Scrubber. The 2005 PM₁₀ SIP Cap was set at 0.444 tpd (or 162 tpy) for external combustion process equipment. In the April 10, 2013 updated Appendix C,

the source wide PM₁₀ emissions from combustion (including proposed equipment) were estimated to be 47.5 tpy. All other (noncombustion) PM₁₀ emissions were estimated to be 100.3 tpy.

DAQ NSR is proposing to remove the exemptions from the PM₁₀ SIP Cap for emergency equipment and flares and incorporate a source wide PM₁₀ emission limit (to also include cooling towers). This would limit PM₁₀ emissions for all combustion process equipment (including FCC Scrubbers) to 47.5 tons per rolling 12-month period and for all other sources (cooling towers and tanks) to 100.3 tons per rolling 12-month period. This is a reduction of approximately 14.2 tpy from the 2005 SIP limit.

Holly Refinery is listed in the PM₁₀ SIP. That document established several emission limitations, one of which is a cap on PM₁₀ emissions. At the time the SIP was written, the cap on PM₁₀ emissions was established using only the filterable PM₁₀ emissions captured during stack testing. This limitation was then included in the AO (and subsequent revisions) issued to Holly Refinery.

UDAQ has since agreed that all future particulate (PM₁₀ and PM_{2.5}) limitations at all sources will also include the condensable fraction of particulate emissions (such as those found in the back half of a particulate sampling train or by reference test method 202). However, any limitation which is derived directly from the PM₁₀ SIP cannot be altered without similarly altering the SIP. Therefore, those limitations on SIP-listed sources will continue to retain the original "filterable emissions only" language, with the condensable emissions being used only for inventory purposes. Such is the case with Holly Refinery's PM₁₀ cap emission limit.

It is the intent of the Division to update these types of conditions once new SIP limitations are established in the PM_{2.5} SIP. [Last updated May 13, 2013]

15. Comment regarding Modification to Existing NO_x AO Limits:

The existing AO NO_x emission limit is 670 tpy or 2.09 tpd, excluding the North and South flares, the Propane Pit flare, and emergency equipment. The 2005 PM₁₀ SIP CAP was set at 2.20 tpd for external combustion process equipment and 693.0 tons per rolling 12-month period for gas fired compressor drivers and all external combustion process equipment, including the SRU tail gas incinerator. In the April 10, 2013 updated Appendix C, the source wide NO_x emissions (including proposed equipment) were estimated at approximately 341.1 tpy.

DAQ NSR is proposing to remove the exemptions from the NO_x limit for emergency equipment and flares and incorporate a source wide NO_x emission limit. This would limit NO_x emissions source wide to 341.1 tons per rolling 12-month period and 0.90 tpd. This would reduce the existing AO NO_x limit by approximately 329 tpy. [Last updated May 3, 2013]

16. Comment regarding Requirement/Condition Changes:

The following requirements/conditions are being proposed to be modified with this AO:

Because the CO Boiler (Boiler #6) is being removed and will not operate after this proposed AO is finalized, this boiler's opacity limitations as well as the SO₂ and PM₁₀ tons per year limitations have been removed from this permit. Both FCCU units will be required to be controlled with wet gas scrubbers. The emission limits previously outlined in II.B.6.b for the wet gas scrubber (4V82 Scrubber) has been moved to II.B.6.a with the other SO₂ limits.

The SRU and Tail Gas Incinerators #2 and #3 will not be constructed; therefore they have been

removed from the permit along with their associated tons per day and tons per year limitations. Limitations on the existing SRU (Unit 17) and Tail Gas Incinerator will remain in place as is. However, emissions from this unit will now be routed to the 25FCC Scrubber (wet gas scrubber) prior to being vented to the atmosphere. Emission limitations on the 25 FCC Scrubber include both FCC Unit 25 emissions and any other emissions routed through the scrubber, including but not limited to the SRU (Unit 17).

Holly Refinery requested to modify the PM emission factors for NSPS boilers and heaters. This emission factor is significantly smaller than the AP-42 emission factor previously relied on, therefore, stack testing requirements will be imposed on the NSPS heaters and boilers to verify these emission factors.

Testing for VOC leaks at all cooling towers and heat exchanges will be required on a monthly basis.

Per the 2008 EPA Consent Decree, Holly Refinery must comply, by no later than June 30, 2013, with a 0.5 lbs PM per 1000 pounds of coke burned. This limit has been included in the permit.

New and modified heaters will have NO_x stack testing requirements to verify emission factors.

The emergency generator limitation of 300 hours has been increased to 500 hours per rolling 12-month period (50 hours per generator). And the ETF portable diesel generator will reduce its permitted hours from 1,300 to 1,100 hours per rolling 12-month period.

The sour water stripper (Unit 28) emissions will be required to be controlled through the existing sour water stripper/ammonia stripping unit (Unit 22) prior to treatment in the existing sulfur recovery unit (Unit 17).

There are no federal or state requirements to establish throughput or production limitations. There is a throughput limit on the existing FCC Unit of 3,250,000 barrels per rolling 12-month period because the FCC Unit 4 has a larger capacity than the limitation. Because emissions for the FCC Unit 4 are based on this throughput, the limitation is in place. Emissions from the FCC Unit 25 were based on a full capacity of 8,500 barrels per day average capacity, the FCC Unit 25 will not have the capacity to exceed emissions beyond these 8,500 barrels per day, and therefore a limit is not required. [Last updated May 14, 2013]

17. Comment regarding Requirement/Condition Changes (continued):

Because PM emissions from this source are primarily from combustion, most of the emissions will be PM_{2.5}. However, PM stack testing requirements in this permit are based on PM₁₀ limitations. The basis for this is that any PM₁₀ collected would by default also be PM_{2.5} which is a more conservative approach and does not lead to any negative impacts while creating less of a regulatory burden on both the source and state compliance staff.

During normal operation, SRU (Unit 17) emissions will now be routed to either one of the two FCCU wet gas scrubbers rather than being routed to the tailgas incinerator to allow for greater SO₂ control. Because of this additional control, the following conditions have been removed from the Approval Order:

"The SRU (Unit 17) shall achieve 95% recovery efficiency for all periods of operation except

during periods of startup, shutdown or malfunction of the SRU."

"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 at least semiannually. The flow rate and the H₂S concentration values shall be used to determine the daily feed rate."

These requirements are still applicable as they apply in the 1994 PM₁₀ SIP and Holly Refinery's CD. However, due to the more stringent control of the wet gas scrubber(s), these limits are not applicable during normal operations as these wet gas scrubbers have a greater than 95% removal efficiency. [Last updated May 15, 2013]

18. Comment regarding HAP Emissions:

Holly Refinery provided an analysis in accordance with UAC R307-410-5 to determine which HAP emissions require modeling. Based on these results, benzene, formaldehyde, beryllium, cadmium, chromium, and chlorine were above ETV levels. Dispersion modeling for these identified HAPs was conducted and the results provided in Appendix L and summarized in Table 6-18 of the NOI.

Because a source wide HAP PTE inventory is not available, the Summary of Emission Totals for HAPs in the engineering review only includes HAP emissions from the Heavy Crude processing project. However, Holly Refinery has verified they are a major source of HAPs, exceeding the 25 tpy total for HAP emissions. [Last updated May 3, 2013]

19. Comment regarding State and Federal Applicability:

Holly Refinery is located four miles north of Salt Lake County and is defined as a contributing source for the Salt Lake County PM₁₀ nonattainment area. DAQ processes NOIs and issues AOs based on existing regulations. All requirements from a Utah SIP which pertain to the Holly Refinery have previously been incorporated into the AO issued to Holly Refinery, and with the exception of the SRU conditions discussed in Comment #17, such language remains in place in this most recent ITA. This AO will require compliance with rules consistent with the attainment status of the air shed where Holly Refinery is located.

Title V of the Clean Air Act of 1990 applies to Holly Refinery as a major source. The absence of a Title V permit does not negate the requirements of Holly Refinery, it is still subject to all AO conditions and federal regulations that would be included in the Title V permit. [Last updated May 13, 2013]

20. Comment regarding NSPS 40 CFR 60 Applicability:

40 CFR 60 Subpart Dc: Applies to each steam generating unit that commences construction, modification, or reconstruction after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr). The requirements of Subpart Dc apply to the proposed 89.3 MMBtu/hr boiler #11.

40 CFR 60 Subpart Ja: The provisions of this subpart apply to the new FCCU and fuel gas combustion devices, including flares and process heaters. Holly Refinery will comply with the

following emission limitations:

0.5 gram per kilogram (g/kg) coke burn-off (0.5 lb PM/1,000 lb coke burn-off) or, if a PM CEMS is used, 0.020 gr/dscf corrected to 0 % excess air for the newly constructed FCCU.

NO_x in excess of 80 parts per million by volume (ppmv), dry basis corrected to 0 % excess air, on a 7-day rolling average basis for the FCCU.

NO_x in excess of 40 parts per million by volume (ppmv), dry basis corrected to 0 % excess air on a 365-day rolling average basis for the FCCUs.

SO₂ in excess of 50 ppmv dry bases corrected to 0% excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 % excess air, on a 365-day rolling average basis for the FCCU.

CO in excess of 500 ppmv, dry basis corrected to 0 % excess air, on an hourly average basis.

The wet scrubber's three-hour rolling average pressure drop must not fall below the level established during the most recent performance test.

The wet scrubber's three-hour rolling average liquid-to-gas ratio must not fall below the level established during the most recent performance test.

For each new fuel gas combustion device, Holly Refinery will comply with either the emission limits or fuel gas concentration limit as presented below:

Holly Refinery shall not burn in any new fuel gas combustion device any fuel gas that contains H₂S in excess of 162 ppmv determined hourly on a three-hour rolling average basis and H₂S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

Holly Refinery shall not burn in any new fuel gas combustion device any fuel gas that contains H₂S in excess of 162 ppmv determined hourly on a three-hour rolling average basis and H₂S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

40 CFR 60 Subpart Kb: Storage tanks to be added or modified as part of this project, with a capacity greater than or equal to 75 cubic meters (m³) and that will be used to store volatile organic liquids for which construction commenced after July 23, 1984 are subject to the requirements of this subpart. The new tanks, as well as any existing tanks that are "reconstructed", will meet NSPS Subpart Kb technology standards (e.g., roof requirements, vent requirements, inspection schedules, etc.).

40 CFR 60 Subpart GGGa: This subpart applies to the affected process units (valves, pumps, pressure relief devices, sampling connections, etc.) constructed after November 7, 2006. This subpart requires minimum performance specifications, routine inspection and repair of all such fugitive components consistent with §60.482-1 through 60.482-10 (NSPS LDAR program). [Last updated May 14, 2013]

21. Comment regarding NSPS 40 CFR 60 Applicability and NESHAP 40 CFR 61 Applicability: 40 CFR 60 Subpart III: This subpart applies to stationary, compression ignition, internal combustion engines. The proposed diesel emergency generator falls under this rule. Holly

Refinery will purchase an engine that is certified to the emission standards (Tier III) specified in the rule and will install a non-resettable hour meter on the engine prior to startup. In addition, SO₂ emissions are required to be minimized by burning only ultralow sulfur diesel fuel with a maximum sulfur content of 15 ppm.

40 CFR 60 Subpart JJJJ: This subpart applies to stationary spark ignition internal combustion engines. The proposed natural gas fired emergency generators fall under this rule. The engines will be EPA certified and a non-resettable hour meter will be installed on the engine prior to startup.

This modification does not trigger any applicable requirements of 40 CFR 61. [Last updated May 3, 2013]

22. Comment regarding MACT 40 CFR 63 Applicability:

40 CFR 63 Subpart FF: This subpart applies to all petroleum refineries, regardless of the quantity of benzene processed. Refinery operators must determine the Total Annual Benzene (TAB) generated, as prescribed under §61.342(a). Refineries with a TAB greater than 10 Megagrams/year (Mg/yr) must comply with Subpart FF control requirements. Facilities with a TAB less than 10 Mg/yr, but greater than 1 Mg/yr must update their TAB calculations annually, and report these values to the US EPA. Facilities with a TAB less than 1 Mg/yr are required to submit to EPA an initial report, and are only required to submit future reports if there are changes in the waste-generating processes that could cause the TAB to increase to 1 Mg/yr or more.

40 CFR Part 63 Subpart UUU: This subpart establishes national emission standards for HAPs emitted from petroleum refineries. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

40 CFR 63 Subpart DDDDD: This subpart governs process heaters and boilers with a heat input of greater than 10 MMBtu/hr. The work practice standards and compliance requirements established in DDDDD may be applicable for the proposed process heaters or furnaces. Holly Refinery will comply with this standard following the final resolution of this proposed rule.

40 CFR 63 Subpart CC: This subpart relates to all heat exchange systems such as the proposed new cooling tower associated with petroleum refining process units. Samples from the cooling tower return line will be collected and analyzed to determine the total strippable VOC concentration (as methane) from the air stripping testing system using 'Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources' Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003.

40 CFR 63 Subpart ZZZZ: This subpart applies to stationary, compression ignition, internal combustion engines. The requirements of this subpart apply to the 540 hp diesel fired emergency generator. [Last updated May 3, 2013]

23. Comment regarding Secondary Impact Analysis:
Soils and Vegetation Analysis:

Pursuant to the Federal PSD regulation 40 CFR 52.21(o), an analysis of Air Quality Related Values including impairment to soils and vegetation that would occur from the Heavy Crude Processing project was addressed because this project is subject to PSD review.

A soil report and information on rangeland and forest vegetation classifications, productivity, and plant composition was included in Appendix M of the July 2012 NOI. No sensitive aspects of the soil and vegetation in the area surrounding the refinery were identified. CO is generally not phytotoxic. Consequently, the evaluation of the secondary NAAQS, which was established to protect public welfare including the prevention of damage to vegetation, can be used to demonstrate that the increase in CO from the proposed project will not result in harmful effects. The results of this analysis were provided in Table 7-1 of the July 2012 NOI. The analysis demonstrated that maximum ground level concentration associated is well below the EPA's screening concentration, concluding that the proposed project will not have an adverse impact on local soils and vegetation.

Growth Analysis:

The work force for the proposed Heavy Crude Processing project is expected to range from 50 to 100 jobs during the various phases of construction. With approximately 25 permanent positions being added. It is assumed that individuals that already live in the region will fill those positions. No new housing requirements are expected. Due to the small number of new position at the refinery, new commercial construction would not be necessary to support the permanent work force. Based on the growth expectations addressed in the analysis, no new significant emissions from secondary growth during the construction and operation of the Heavy Crude Processing project are anticipated. [Last updated May 3, 2013]

24. Comment regarding Greenhouse Gas Emissions:

Holly Refinery calculated their total increase in GHG emissions from the Heavy Crude Processing project to be 253,656 metric tons (279,610 short tons) per year CO₂e. With this increase, Holly Refinery's total GHG emissions (not including product emissions) are estimated at 910,186 metric tons (1,003,300 short tons) per year CO₂e. [Last updated May 6, 2013]

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 _{2e}	Carbon Dioxide Equivalent - 40 CFR Part 98, Subpart A, Table A-1
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
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
UDAQ	Utah Division of Air Quality (typically interchangeable with DAQ)
VOC	Volatile organic compounds