State of Utah

SPENCER J. COX
Governor

DEIDRE HENDERSON
Lieutenant Governor

Department of
Environmental Quality

Tim Davis
Executive Director

DIVISION OF AIR QUALITY
Bryce C. Bird
Director

DAQE-IN101220084-25

December 4, 2025

Alec Klinghoffer
Big West Oil, LLC
333 West Center Street
North Salt Lake, UT 84054
alec.klinghoffer@bigwestoil.com

Dear Mr. Klinghoffer:

Re: Intent to Approve: Modification to Approval Order DAQE-AN101220081-24 to Add Rail-to-Truck Transloading
Project Number: N101220084

The attached document is the Intent to Approve (ITA) for the above-referenced project. The ITA is subject to public review. Any comments received shall be considered before an Approval Order (AO) is issued. The Division of Air Quality is authorized to charge a fee for reimbursement of the actual costs incurred in the issuance of an AO. An invoice will follow upon issuance of the final AO.

Future correspondence on this ITA should include the engineer's name, **John Jenks,** as well as the DAQE number as shown on the upper right-hand corner of this letter. John Jenks, can be reached at (385) 306-6510 or jjenks@utah.gov, if you have any questions.

Sincerely,

Jon L. Black
Jon Black (Dec 2, 2025 21:53:43 MST)

Jon L. Black, Manager
New Source Review Section

JLB:JJ:jg

cc: Davis County Health Department
EPA Region 8

STATE OF UTAH
Department of Environmental Quality
Division of Air Quality

INTENT TO APPROVE
DAQE-IN101220084-25
Modification to Approval Order DAQE-AN101220081-24 to Add Rail-to-Truck Transloading

Prepared By
John Jenks, Engineer
(385) 306-6510
jjenks@utah.gov

Issued to
Big West Oil, LLC - Big West Oil Refinery

Issued On
December 4, 2025

Jon Black (Dec 2, 2025 21:53:43 MST)

New Source Review Section Manager
Jon L. Black

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GENERAL INFORMATION

CONTACT/LOCATION INFORMATION

Owner Name
Big West Oil, LLC

Source Name
Big West Oil, LLC - Big West Oil Refinery

Mailing Address
333 West Center Street
North Salt Lake, UT 84054

Physical Address
333 West Center Street
North Salt Lake, UT 84054

Source Contact
Name: E. Faithe Schwartzengraber
Phone: (801) 296-7763
Email: faithe.schwartzengraber@bigwestoil.com

UTM Coordinates
422540 m Easting
4521051 m Northing
Datum NAD83
UTM Zone 12

SIC code 2911 (Petroleum Refining)

SOURCE INFORMATION

General Description
The Big West Oil, LLC (BWO) refinery processes crude oils and lesser quantities of other hydrocarbon feedstocks to produce primarily gasoline and diesel fuel along with other products, including fuel oil, propane, isobutane, gas oil, naphtha, and elemental sulfur. The refinery operates 24 hours per day and 365 days per year. The nominal capacity of the BWO refinery is approximately 33,000 barrels of crude oil per day. Processing units include Atmospheric Crude Distillation, Distillate Dewaxing, Distillate Hydrodesulfurization, Catalytic Cracking (MSCC), Alkylation (ALKY), Naphtha HDS, Naphtha Isomerization, Naphtha Reforming, Saturates Distillation Gas Plant, Butane Isomerization, Amine Absorber, and Sulfur Recovery Unit (SRU). Ancillary supporting units include the west and south refinery flares, truck loading racks, rail loading rack, refinery fuel gas system, cooling towers, and a wastewater treatment plant (WWTP).

NSR Classification
Minor Modification at Major Source

Source Classification
Located in Northern Wasatch Front O3 NAA, Salt Lake City UT $PM_{2.5}$ NAA
Davis County
Airs Source Size: A

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

NSPS (Part 60), K: Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978
NSPS (Part 60), Ka: Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984
NSPS (Part 60), Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984
NSPS (Part 60), GGG: Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006
NSPS (Part 60), 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
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), 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 Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters
Title V (Part 70) Major Source

Project Description

BWO has requested a modification to AO DAQE-AN101220081-24 to add transloading equipment as part of the Railcar Loading Facility controlled by a vapor combustion unit (VCU). The Project includes the following installations and modifications at the BWO refinery:

• Install rail-to-truck transloading equipment;
• Modification of existing VCU inlet piping to add emission streams from the proposed transloading equipment, although no modifications to the VCU itself are proposed; and
• Additional unpaved road traffic associated with the proposed transloading equipment.

SUMMARY OF EMISSIONS

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

Criteria Pollutant	Change (TPY)	Total (TPY)
Ammonia	0	118.22
CO_2 Equivalent	10.99	307807.56
Carbon Monoxide	0.01	450.59
Nitrogen Oxides	0	195.00
Particulate Matter - PM_{10}	0.62	119.99
Particulate Matter - $PM_{2.5}$	0.06	72.56
Sulfur Dioxide	0	140.00
Volatile Organic Compounds	-7.69	433.69

Hazardous Air Pollutant	Change (lbs/yr)	Total (lbs/yr)
1,2,4-Trichlorobenzene (CAS #120821)		19040
1,3-Butadiene (CAS #106990)	1	1580
1,4-Dichlorobenzene(P) (CAS #106467)		58
2,2,4-Trimethylpentane (CAS #540841)	112	78372
2-Acetylaminofluorene (CAS #53963)		0
2-Methynapthalene (CAS #91576)		1
7,12-Dimethylbenz(a)anthracene (CAS #57976)		1
Acenaphthene(TSP) (CAS #83329)		0
Acenaphthylene(TSP) (CAS #208968)		1
Acetaldehyde (CAS #75070)	1	811
Acrolein (CAS #107028)	2	980
Anthracene (CAS #120127)		1
Antimony (TSP) (CAS #7440360)		39
Arsenic (TSP) (CAS #7440382)		2
Benzene (Including Benzene From Gasoline) (CAS #71432)	36	23493
Benzo (B) Fluoranthene (CAS #205992)		0
Benzo (K) Fluoranthene (CAS #207089)		0
Benzo(A)Anthracene (CAS #56553)		0
Benzo(A)Pyrene (CAS #50328)		0
Benzo(Ghi)Perylene/Tsp (CAS #191242)		0
Beryllium (TSP) (CAS #7440417)		1
Biphenyl (CAS #92524)	2	1362
Cadmium (CAS #7440439)		59
Carbon Disulfide (CAS #75150)		3
Chrysene (TSP) (CAS #218019)		0
Cresols/Cresylic Acid (Isomers And Mixture) (CAS #1319773)		300
Cumene (CAS #98828)		1822
Ethyl Benzene (CAS #100414)		0
Fluoranthene (TSP) (CAS #206440)		14878
Formaldehyde (CAS #50000)	3	1
Generic HAPs (CAS #GHAPS)	740	5820
Hexane (CAS #110543)	80	877
Hydrochloric Acid (Hydrogen Chloride) (CAS #7647010)		22802

Hydrogen Cyanide (Hydrocyanic Acid) (CAS #74908)		39920
Indeno(1,2,3-Cd)Pyre (CAS #193395)		0
Lead (CAS #7439921)		3
Manganese (TSP) (CAS #7439965)		39
Mercury (TSP) (CAS #7439976)		19
Methyl Bromide (Bromomethane) (CAS #74839)		20
Methyl Tert Butyl Ether (CAS #1634044)		400
Methylcholanthrene (CAS #56495)		0
Methylene Chloride (Dichloromethane) (CAS #75092)		40
Naphthalene (CAS #91203)	4	3414
Phenanthrene (CAS #85018)		2
Phenol (CAS #108952)		260
Phosphorus (CAS #7723140)		39
Pyrene (CAS #129000)		0
Selenium (TSP) (CAS #7782492)		5
Styrene (CAS #100425)		1140
Toluene (CAS #108883)	88	63802
Xylenes (Isomers And Mixture) (CAS #1330207)	82	64522
	Change (TPY)	**Total (TPY)**
Total HAPs	0.59	178.09

PUBLIC NOTICE STATEMENT

The NOI for the above-referenced project has been evaluated and has been found to be consistent with the requirements of UAC R307. Air pollution producing sources and/or their air control facilities may not be constructed, installed, established, or modified prior to the issuance of an AO by the Director.

A 30-day public comment period will be held in accordance with UAC R307-401-7. A notification of the intent to approve will be published in the Salt Lake Tribune and Deseret News on December 7, 2025. During the public comment period, the proposal and the evaluation of its impact on air quality will be available for the public to review and provide comment. If anyone so requests a public hearing within 15 days of publication, it will be held in accordance with UAC R307-401-7. The hearing will be held as close as practicable to the location of the source. Any comments received during the public comment period and the hearing will be evaluated. The proposed conditions of the AO may be changed as a result of the comments received.

SECTION I: GENERAL PROVISIONS

The intent is to issue an air quality 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.

I.1	All definitions, terms, abbreviations, and references used in this AO conform to those used in the UAC R307 and 40 CFR. Unless noted otherwise, references cited in these AO conditions refer to those rules. [R307-101]
I.2	The limits set forth in this AO shall not be exceeded without prior approval. [R307-401]

I.3	Modifications to the equipment or processes approved by this AO that could affect the emissions covered by this AO must be reviewed and approved. [R307-401-1]
I.4	All records referenced in this AO or in other applicable rules, which are required to be kept by the owner/operator, shall be made available to the Director or Director's representative upon request, and the records shall include the two-year period prior to the date of the request. Unless otherwise specified in this AO or in other applicable state and federal rules, records shall be kept for a minimum of five years. [R307-401-8]
I.5	At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any equipment approved under this AO, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Director which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. All maintenance performed on equipment authorized by this AO shall be recorded. [R307-401-4]
I.6	The owner/operator shall comply with UAC R307-107. General Requirements: Breakdowns. [R307-107]
I.7	The owner/operator shall comply with UAC R307-150 Series. Emission Inventories. [R307-150]
I.8	The owner/operator shall submit documentation of the status of construction of the new Rail-to-Truck transloading equipment to the Director within 18 months from the date of this AO. This AO may become invalid if construction is not commenced within 18 months from the date of this AO or if construction is discontinued for 18 months or more. To ensure proper credit when notifying the Director, send the documentation to the Director, attn.: NSR Section. [R307-401-18]

SECTION II: PERMITTED EQUIPMENT

The intent is to issue an air quality 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.

II.A THE APPROVED EQUIPMENT

II.A.1	**Big West Oil Refinery** Source Wide
II.A.2	**H-101** FCC Heater
II.A.3	**H-301** 17.29 MMBtu/hr ALKY Heater, supplies the Isostripper Column
II.A.4	**H-402** #2 Crude Heater
II.A.5	**H-403** Crude Preflash Heater

II.A.6	**H-404** #1 Crude Heater with Ultra-Low Nox Burners (ULNB)
II.A.7	**H-601** 32.4 MMBtu/hr Unifiner Heater
II.A.8	**H-621, 622, 624** Reformer Heaters
II.A.9	**H-1001** (MIDW) Heater
II.A.10	**H-1002** Hydrodesulfurization (HDS) Reboiler
II.A.11	**H-1003** HDS Heater
II.A.12	**H-1102** Sulfur Removal Unit/Plant (SRU) and Tail Gas Incinerator
II.A.13	**Caustic Fuel Gas Scrubber** Thiolex fiber-film contactor system
II.A.14	**D-103** FCC Regenerator Combustion Gas Vent, includes: Pall Corporation flue gas blowback filter, 38,116 ACFM max flow rate, 198' stack as measured from the base of the stack
II.A.15	**#1 Boiler** Retrofitted with ULNB
II.A.16	**#6 Boiler** Retrofitted with ULNB
II.A.17	**Wabash Boiler** Equipped with LNB and FGR (Unit is a long term rental/replacement)
II.A.18	**Plant Flare #1** South Plant Flare
II.A.19	**Plant Flare #3** West Plant Flare
II.A.20	**VCU** Railcar Loading Facility and VCU

SECTION II: SPECIAL PROVISIONS

The intent is to issue an air quality 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.

II.B REQUIREMENTS AND LIMITATIONS

II.B.1	**Site-Wide Requirements**
II.B.1.a	Unless otherwise designated in specific source subsections, visible emissions from the following emission points shall not exceed the following values while in operation. A. Combustion sources without control facilities shall not exceed 10% opacity. B. Fugitive emissions shall not exceed 15% opacity. C. Refinery MCSS units and Plant Flare #1 [South] shall not exceed 20% opacity. D. Fugitive dust and all other sources shall not exceed 20% opacity. Opacity observations of emissions from stationary sources shall be conducted in accordance with 40 CFR 60, Appendix A, Method 9. [R307-201-3, R307-401-8(1)(a)]
II.B.1.b	The owner/operator shall use only plant gas and natural gas as fuels in the Amine Plant, Diesel Hydrotreater Unit, Distillate De-Waxing Unit, and Sulfur Recovery Unit. Fuel oil may be used as a backup fuel, but only during periods of natural gas curtailment. The use of diesel fuel meeting the specifications of 40 CFR 1090.305 is allowed in standby or emergency equipment at all times. If any other fuels are to be used, this AO shall be modified as required in accordance with R307-401, UAC. [R307-401-8(1)(a), SIP Section IX.H.12.b.iv]
II.B.1.c	The sulfur content of any fuel oil burned shall not exceed 0.0015 percent by weight as determined by ASTM Method D-4294-89 or an approved equivalent. The sulfur content shall be tested if directed by the Director. [R307-401-8(1)(a)]
II.B.1.d	Stack testing to show compliance with the emission limitations for the sources in this AO shall be performed in accordance with 40 CFR 60, Appendix A; 40 CFR 51, Appendix M; and R307-305-3, UAC. and SIP Section IX.H.11.e.i. Until such time as it is removed from service, the Wabash Boiler's NO_x emissions shall be monitored and recorded using a portable analyzer no less than once each month. The NO_x emissions shall also be used to determine the NO_x emission factor in accordance with II.B.8.c.2 and to calculate the plant-wide daily NO_x emissions in accordance with II.B.8.c.1. [R307-150]

II.B.1.d.1	A.	Sample Location: The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, or other EPA approved testing methods acceptable to the Director. Occupational Safety and Health Administration (OSHA) approvable access shall be provided to the test location.
	B.	Volumetric Flow Rate: 40 CFR 60, Appendix A, Method 2 or EPA Test Method No. 19 "SO_2 Removal & PM, SO_2, NO_x Rates from Electric Utility Steam Generators" or other EPA approved testing methods acceptable to the Director.
	C.	PM_{10}: 40 CFR 51, Appendix M, Methods 201a and 202, or other EPA approved testing methods acceptable to the Director. If a method other than 201a is used, the portion of the front half of the catch considered PM_{10} shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.
	D.	$PM_{2.5}$: 40 CFR 51, Appendix M, 201a and 202, or other EPA approved testing methods acceptable to the Director. The back half condensables shall be used for compliance demonstration as well as for inventory purposes. If a method other than 201a is used, the portion of the front half of the catch considered $PM_{2.5}$ shall be based on information in Appendix B of the fifth edition of the EPA document, AP-42, or other data acceptable to the Director.
	E.	SO_2: 40 CFR 60 Appendix A, Method 6C, or other EPA approved testing methods acceptable to the Director.
	F.	NO_x: 40 CFR 60 Appendix A, Method 7E, or other EPA approved testing methods acceptable to the Director.
	G.	Calculations: To determine mass emission rates (lb/hr, etc.) the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors to give the results in the specified units of the emission limitation.
	H.	Protocol: A stack test protocol shall be provided at least 30 days prior to the test. A pretest conference shall be held if directed by the Director.
	I.	Production Rate: The production rate during all compliance testing shall be no less than 90% of the maximum production rate achieved in the previous three years. If the desired production rate is not achieved at the time of the test, the maximum production rate shall be 110% of the tested achieved rate, but not more than the maximum allowable production rate. This new allowable maximum production rate shall remain in effect until successfully tested at a higher rate. The owner/operator shall request a higher production rate when necessary. Testing at no less than 90% of the higher rate shall be conducted. A new maximum production rate (110% of the new rate) will then be allowed if the test is successful. This process may be repeated until the maximum allowable production rate is achieved. [SIP Section IX.H.1, SIP Section IX.H.11]

II.B.1.e	For all continuous monitoring devices, the following shall apply: A. Except for system breakdown, repairs, calibration checks, and zero and span adjustments required under paragraph (d) 40 CFR 60.13, the owner/operator of an affected source shall continuously operate all required continuous monitoring systems and shall meet minimum frequency of operation requirements as outlined in R307-170 and 40 CFR 60.13. 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. B. The monitoring system shall comply with all applicable sections of R307-170; 40 CFR 13; and 40 CFR 60, Appendix B - Performance Specifications. [SIP Section IX.H.11.f]
II.B.2	**Conditions on the Sulfur Recovery Unit**
II.B.2.a	The owner operator shall either: A. Install and operate a sulfur removal units/plant (SRU) that is at least 95% effective in removing sulfur from the streams fed to the unit; or B. Install and operate a SRU that meets the SO_2 emission limitations listed in 40 CFR 60.102a(f)(1) or 60.102a(f)(2) as appropriate. [SIP Section IX.H.1.g.iii.A.II]
II.B.2.b	The owner/operator shall install, calibrate, maintain, and operate a continuous emissions monitoring system for monitoring the SO_2 content of the gas from the sulfur plant incinerator on the Claus Unit tail gas stream. The monitoring system shall comply with all applicable sections of R307-170-6, UAC; and 40 CFR 60, Appendix B, Specification 2. [R307-170]
II.B.2.c	The streams from the Amine plants (fuel gas desulfurization units) and the sour water overhead stripping operations shall be processed in the SRU. [R307-401]
II.B.2.c.1	Operating Specification or Performance Requirements Copies of the SRU Operating Instruction/Standard shall be made available to the Director upon request. [R307-401]
II.B.2.c.2	The owner/operator shall comply with a 95% recovery efficiency requirement for all periods of operation except during periods of scheduled startup, scheduled shutdown or malfunction of the SRU. Recovery efficiency shall be determined on a rolling 30-day average basis. [Consent Decree, SIP Section IX.H.1.g.iii.C]
II.B.2.c.3	Director Authority A. A request to determine SRU efficiency for any time period that may be questionable may be ordered by the Director. B. All records of SRU performance shall be maintained for a minimum of two years. [R307-401]
II.B.3	**Conditions on the FCC Unit and Regenerator**
II.B.3.a	Emissions of PM shall not exceed 0.5 lb / 1000 lb coke burned, on a three-hour average basis, except during startup, shutdown or malfunction. [40 CFR 60 Subpart J, Consent Decree, R307-401-8]

II.B.3.b	CO emissions from the FCC Unit shall not exceed 500 ppm by volume (dry basis), one-hour average at 0% oxygen. NO_x emissions for the FCC Unit shall not exceed the following concentrations: 40 ppmvd at 0% O_2 per 365-day rolling average; and 60 ppmvd at 0% O_2 per 7-day rolling average. SO_2 emissions for the FCC Unit shall not exceed the following concentrations: 25 ppmvd at 0% O_2 per 365-day rolling average; and 50 ppmvd at 0% O_2 per 7-day rolling average. These limits are not applicable during periods of startup, shutdown or malfunction. [Consent Decree]
II.B.3.c	The owner/operator shall install, calibrate, maintain, and operate a continuous monitoring system to measure the effluent FCC Unit CO, O_2, NO_x, SO_2 and CO_2 emissions. The monitoring system shall comply with all applicable sections of R307-170 and 40 CFR 60, Appendices A, B, and F. In lieu of the requirements of 40 CFR 60 Appendix F Sections 5.1.1, 5.1.3 and 5.1.4, BWO must conduct either a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each CEMS at least once every three years. BWO must also conduct Cylinder Gas Audits each calendar quarter during which a RAA or a RATA is not performed. [40 CFR 60Appendix A, B & F, R307-170]
II.B.3.d	The FCCU shall comply with an SO_2 emission limit of 25 ppmvd @ 0% excess air on a 365-day rolling average basis and 50 ppmvd @ 0% excess air on a 7-day rolling average basis. [SIP Section IX.H.11.g.i.A.I]
II.B.3.d.1	Compliance with the SO_2 limit shall be determined using a CEM as outlined in II.B.1.e. [SIP Section IX.H.11.g.i.A.II]
II.B.3.e	The FCCU shall comply with an emission limit of 0.5 pounds PM per 1000 pounds coke burn-off. [Consent Decree]
II.B.3.e.1	Compliance with the PM limit shall be determined by following the stack test protocol specified in 40 C.F.R. §60.106(b) to measure PM emissions on the FCCU. Stack tests shall be conducted at a minimum once every three years. [SIP Section IX.H.11.g.i.B.II]
II.B.3.f	Each owner or operator of an FCCU subject to NSPS Ja shall install, operate and maintain a continuous parameter monitor system (CPMS) to measure and record operating parameters from the FCCU and control devices as per the requirements of 40 CFR 60.105a(b)(1). Each owner or operator of an FCCU not subject to NSPS Ja shall install, operate and maintain a continuous opacity monitoring system to measure and record opacity from the FCCU as per the requirements of 40 CFR 63.1572(b) and comply with the opacity limitation as per the requirements of Table 7 to Subpart UUU of Part 63. [SIP Section IX.H.11.g.i.B.III]
II.B.4	**Conditions on Plant Flare #3 [West Plant Flare]**
II.B.4.a	The owner/operator shall use only natural gas as a primary fuel for the pilot light in Refinery Plant Flare #3 [West]. If any other fuel is to be used, an AO shall be required in accordance with R307-401, UAC. [R307-401-8(1)(a)]
II.B.4.b	Plant Flare #3 [West] is subject to the flare requirements of 40 CFR 63 Subpart CC. [40 CFR 63 Subpart CC]

II.B.5	**Conditions on the Amine Unit**
II.B.5.a	The Amine Plant shall reduce the H_2S content for all refinery plant gas. The H_2S content of any plant gas exiting the Amine Plant shall not exceed 0.10 grains/dscf (162 ppmv) based on a rolling three-hour average. [R307-401]
II.B.5.b	The owner/operator shall reduce the H_2S content of the refinery plant gas to 60 ppm or less as described in 40 CFR 60.102a. Compliance shall be based on a rolling average of 365 days. The owner/operator shall comply with the fuel gas monitoring requirements of 40 CFR 60.107a and the related recordkeeping and reporting requirements of 40 CFR 60.108a. As used herein, refinery "plant gas" shall have the meaning of "fuel gas" as defined in 40 CFR 60.101a, and may be used interchangeably. [SIP Section IX.H.11.g.ii.A]
II.B.5.c	The entire Diesel Hydrotreater H_2S gas stream shall be sent to the Amine or Caustic Scrubber unit to be treated with the plant fuel gas from other sources. [R307-401]
II.B.5.d	The owner/operator shall install, calibrate, maintain, and operate a continuous emission monitoring system for monitoring the H_2S content of the refinery plant gas located at the outlet of the Amine and Caustic Scrubber units. The monitoring system shall comply with all applicable sections of R307-170-6, UAC; 40 CFR 60 Subpart J; and 40 CFR 60, Appendix B, Performance Specification 7. [R307-170]
II.B.5.e	The owner/operator shall install and operate a caustic fuel gas scrubber system. This system shall be designed to treat a minimum of 10 MMSCFD of sour fuel gas. During periods of outage of either the amine unit or SRU, all plant sour fuel gas shall be treated by the caustic fuel gas scrubber. [R307-401-8]
II.B.6	**Conditions on the HDS Unit**
II.B.6.a	Vessel relief valves from the HDS unit shall be vented into the plant flare system to control emissions from the units in the event of a process-upset condition. [R307-401]
II.B.7	**Miscellaneous SIP Requirements**
II.B.7.a	The owner or operator shall comply with the requirements of 40 CFR 63.654 for heat exchange systems in VOC service. The owner or operator may elect to use another EPA approved method other than the Modified El Paso Method if approved by the Director. [SIP Section IX.H.11.g.iii]

II.B.7.a.1	The following applies in lieu of 40 CFR 63.654(b): A heat exchange system is exempt from the requirements in paragraphs 63.654(c) through (g) if it meets any one of the criteria in the following paragraphs (1) through (2) of this section. 1. All heat exchangers that are in VOC service within the heat exchange system that either: a. Operate with the minimum pressure on the cooling water side at least 35 kilopascals greater than the maximum pressure on the process side; or b. Employ an intervening cooling fluid, containing less than 10 percent by weight of VOCs, between the process and the cooling water. This intervening fluid must serve to isolate the cooling water from the process fluid and must not be sent through a cooling tower or discharged. For purposes of this section, discharge does not include emptying for maintenance purposes. 2. The heat exchange system cools process fluids that contain less than 10 percent by weight VOCs (i.e., the heat exchange system does not contain any heat exchangers that are in VOC service). [SIP Section IX.H.11.g.iii.A.I]
II.B.7.b	The owner/operator shall comply with the requirements of 40 CFR 60.590a to 60.593a. For units complying with the Sustainable Skip Period, previous process unit monitoring results may be used to determine the initial skip period interval provided that each valve has been monitored using the 500 ppm leak definition. [SIP Section IX.H.11.g.iv]
II.B.7.c	All hydrocarbon flares at petroleum refineries located in or affecting any $PM_{2.5}$ nonattainment area or any PM_{10} nonattainment or maintenance area within the State shall be subject to the flaring requirements of NSPS Subpart Ja (40 CFR 60.100a-109a), if not already subject under the flare applicability provisions of Ja. [SIP Section IX.H.11.g.v.A]
II.B.7.d	All major source petroleum refineries in or affecting any $PM_{2.5}$ nonattainment area or any PM_{10} nonattainment or maintenance area shall either A. Install and operate a flare gas recovery system designed to limit hydrocarbon flaring produced from each affected flare during normal operations to levels below the values listed in 40 CFR 60.103a(c), or B. Limit flaring during normal operations to 500,000 scfd for each affected flare. Flare gas recovery is not required for dedicated SRU flare and header systems, or HF flare and header systems. [SIP Section IX.H.11.g.v.B]

II.B.7.e	NO_x emissions to the atmosphere from the indicated emission points shall not exceed the following rates and concentrations. A. FCC Heater H-101: 0.16 lb/MMBtu. B. Reformer Heaters H-621, 622, 624: 0.08 lb/MMBtu. C. #1 Boiler: 0.035 lb/MMBtu. D. #6 Boiler: 0.035 lb/MMBtu. [SIP Section IX.H.12.b.i]
II.B.7.e.1	Initial NO_x stack testing has been performed for the #1 Boiler and #6 Boiler. Subsequent stack testing shall be conducted at least once within a three year period from the date of the last stack test. Initial compliance testing for FCC Heater H-101, Reformer Heater H-621, Reformer Heater H-622, and Reformer Heater H-624 is required. The initial test shall be performed no later than December 31st, 2025. After the initial compliance test, stack testing shall be performed at least once within a three year period from the date of the last stack test. All stack testing shall be performed as outlined in SIP Section IX.H.11.e. [SIP Section IX.H.12.b.ii and iii]
II.B.7.e.2	In lieu of the stack testing requirements listed above, any units equipped with a CEMs shall determine compliance with the emission limits by the CEMs. For units equipped with CEMs, compliance shall be determined on a 30-day rolling average. The CEMs shall operate as outlined in SIP Section IX.H.11.f. [SIP Section IX.H.12.b.iv]
II.B.7.f	Alternate Startup and Shutdown Requirements A. During any day which includes startup or shutdown of the FCCU, combined emissions of SO_2 shall not exceed 1.2 tons per day (tpd). For purposes of this subsection, a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight. B. The total number of days which include startup or shutdown of the FCCU shall not exceed ten per 12-month rolling period. [SIP Section IX.H.12.b.v]
II.B.8	**Daily and Annual SIP CAP Requirements**
II.B.8.a	The owner/operator shall abide by all applicable requirements of Sections IX.H.1 and IX.H.11 of the Utah State Implementation Plan as most recently adopted by the Air Quality Board. [SIP Section IX.H.1, SIP Section IX.H.11]
II.B.8.b	Combined emissions of PM_{10} from all stationary emission points shall not exceed 1.037 tons per day (tpd). [SIP Section IX.H.2.a.i]

II.B.8.b.1	Compliance with the source-wide PM_{10} Cap shall be determined for each day as follows: A. For purposes of this subsection, a "day" is defined as a period of 24 hours commencing at midnight and ending at the following midnight. B. Total 24-hour PM_{10} emissions for the emission points shall be calculated by adding the daily results of the PM_{10} emissions equations listed below for natural gas, plant gas, and fuel oil combustion. These emissions shall be added to the emissions from the cooling towers and the FCCs to arrive at a combined daily PM_{10} emission total. C. The equation used to determine emissions from these units shall be as follows: Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton) The daily PM_{10} emissions from the FCC shall be calculated using the following equation: E = FR * EF Where: E = Emitted PM_{10} FR = Feed Rate to Unit (kbbls/day) EF = emission factor (lbs/kbbl), established by the most recent stack test D. Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources. E. Daily gas consumption shall be measured by meters that can delineate the flow of gas to the boilers, furnaces, and the SRU incinerator. F. Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions. [SIP Section IX.H.2.a.i.C]

II.B.8.b.2	For purposes of demonstrating compliance with the source-wide PM_{10} Cap, the following default emission factors shall be used. These emission factors shall be applied to the relevant quantities of fuel combusted, unless adjusted by performance testing as discussed below. A. Natural gas: Filterable PM_{10}: 1.9 lb/MMscf Condensable PM_{10}: 5.7 lb/MMscf B. Plant gas: Filterable PM_{10}: 1.9 lb/MMscf Condensable PM_{10}: 5.7 lb/MMscf C. Fuel Oil: The PM_{10} emission factor shall be determined from the latest edition of AP-42 or other EPA approved methods. D. Cooling Towers: The PM_{10} emission factor shall be determined from the latest edition of AP-42 or other EPA approved methods. E. FCC Stacks: The PM_{10} emission factor shall be established by stack test. F. Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel. G. The default emission factors listed above apply until such time as stack testing is conducted as outlined in Condition II.B.1.d. H. PM_{10} stack testing on the FCC shall be performed initially no later than January 1, 2019, and at least once every three years thereafter. Stack testing shall be performed as outlined in Condition II.B.1.d. [SIP Section IX.H.2.a.i.A, SIP Section IX.H.2.a.i.B]
II.B.8.c	Combined emissions of NO_x shall not exceed 0.80 tons per day (tpd) and 195 tons per rolling 12-month period. [SIP Section IX.H.2.a.ii]

II.B.8.c.1	Compliance with the source-wide NO_x Cap shall be determined for each day as follows: A. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight. B. Total 24-hour NO_x emissions shall be calculated by adding the emissions for each emitting unit. C. The emissions for each emitting unit shall be calculated by multiplying the hours of operation of a unit, feed rate to a unit, or quantity of each fuel combusted at each affected unit by the associated emission factor, and summing the results. D. Daily plant gas consumption at the furnaces, boilers and SRU incinerator shall be measured by flow meters. E. The equations used to determine emissions shall be as follows: NO_x = Emission Factor (lb/MMscf) * Gas Consumption (MMscf/24 hrs)/(2,000 lb/ton) Where the emission factor is derived from the fuel used. F. Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources. G. The daily NO_x emissions from the FCC shall be calculated using a CEM as outlined in Condition II.B.1.e. H. Total daily NO_x emissions shall be calculated by adding the results of the above NO_x equations for natural gas and plant gas combustion to the value for the FCC. I. Results shall be tabulated for each day, and records shall be kept which include the meter readings (in the appropriate units) and the calculated emissions. [SIP Section IX.H.2.a.ii.C]
II.B.8.c.2	For purposes of demonstrating compliance with the source-wide NO_x Cap, the following default emission factors shall be used. These emission factors shall be applied to the relevant quantities of fuel combusted, unless adjusted by performance testing as discussed below. A. Natural gas: shall be determined from the latest edition of AP-42 or other EPA approved methods. B. Plant gas: assumed equal to natural gas. C. Diesel fuel: shall be determined from the latest edition of AP-42 or other EPA approved methods. D. Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel. E. The default emission factors apply until such time as stack testing is conducted as outlined in Condition II.B.1.d. [SIP Section IX.H.2.a.ii.A, SIP Section IX.H.2.a.ii.B]
II.B.8.d	Combined emissions of SO_2 shall not exceed 0.60 tons per day and 140 tons per rolling 12-month period. [SIP Section IX.H.2.a.iii]

II.B.8.d.1	Compliance with the source-wide SO_2 Cap shall be determined for each day as follows: A. For purposes of this subsection a "day" is defined as a period of 24-hours commencing at midnight and ending at the following midnight. B. Total daily SO_2 emissions shall be calculated by adding the daily SO_2 emissions for natural gas and plant fuel gas combustion, to those from the FCC and SRU stacks. C. The daily SO_x emissions from the FCC shall be calculated using a CEM as outlined in Condition II.B.1.e. D. Daily natural gas and plant gas consumption shall be determined through the use of flow meters. E. Daily fuel oil consumption shall be monitored by means of leveling gauges on all tanks that supply combustion sources. F. Results shall be tabulated for each day, and records shall be kept which include CEM readings for H_2S (averaged for each day), all meter readings (in the appropriate units), fuel oil parameters (density and wt% sulfur for each day any fuel oil is burned), and the calculated emissions. [SIP Section IX.H.2.a.iii.B]
II.B.8.d.2	For purposes of demonstrating compliance with the source-wide SO_2 Cap, the emission factors derived from the most current performance test shall be applied to the relevant quantities of fuel combusted. The default emission factors to be used are as follows: A. Natural Gas - 0.60 lb SO_2/MMscf gas. B. Plant Gas: The emission factor to be used in conjunction with plant gas combustion shall be determined through the use of a CEM as outlined in Condition II.B.1.e. C. SRUs: The emission rate shall be determined by multiplying the sulfur dioxide concentration in the flue gas by the flow rate of the flue gas. The sulfur dioxide concentration in the flue gas shall be determined by CEM as outlined in Condition II.B.1.e. D. Fuel oil: The emission factor to be used for combustion shall be calculated based on the weight percent of sulfur, as determined by ASTM Method D-4294-89 or EPA approved equivalent acceptable to the Director, and the density of the fuel oil, as follows: EF (lb SO_2/k gal) = density (lb/gal) * (1000 gal/k gal) * wt. % S/100 * (64 lb SO_2/32 lbs) E. Where mixtures of fuel are used in a Unit, the above factors shall be weighted according to the use of each fuel. [SIP Section IX.H.2.a.iii.A]

PERMIT HISTORY

This Approval Order shall supersede (if a modification) or will be based on the following documents:

Supersedes	AO DAQE-AN101220081-24 dated May 6, 2024
Is Derived From	NOI dated July 29, 2024

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 Environmental Protection Agency 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 - Title 40 of the Code of Federal Regulations Part 98, Subpart A, Table A-1
COM	Continuous opacity monitor
DAQ/UDAQ	Division of Air Quality
DAQE	This is a document tracking code for internal Division of Air Quality use
EPA	Environmental Protection Agency
FDCP	Fugitive dust control plan
GHG	Greenhouse Gas(es) - Title 40 of the Code of Federal Regulations 52.21 (b)(49)(i)
GWP	Global Warming Potential - Title 40 of the Code of Federal Regulations Part 86.1818-12(a)
HAP or HAPs	Hazardous air pollutant(s)
ITA	Intent to Approve
LB/YR	Pounds per year
MACT	Maximum Achievable Control Technology
MMBTU	Million British Thermal Units
NAA	Nonattainment Area
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NOI	Notice of Intent
NO_x	Oxides of nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PM_{10}	Particulate matter less than 10 microns in size
$PM_{2.5}$	Particulate matter less than 2.5 microns in size
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
R307	Rules Series 307
R307-401	Rules Series 307 - Section 401
SO_2	Sulfur dioxide
Title IV	Title IV of the Clean Air Act
Title V	Title V of the Clean Air Act
TPY	Tons per year
UAC	Utah Administrative Code
VOC	Volatile organic compounds