MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OPERATING PERMIT TECHNICAL REVIEW DOCUMENT

Air, Energy & Mining Division
1520 E. Sixth Avenue
P.O. Box 200901
Helena, Montana 59620-0901

CHS, Inc.
Laurel Refinery
803 Highway 212 South
P.O. Box 909
Laurel, Montana 59044-0909

The following table summarizes the air quality programs testing, monitoring, and reporting requirements applicable to this facility.

Facility Compliance Requirements	Yes	No	Comments
Source Tests Required	X		Methods 5/5B/5F (PM) Methods 6/6C (SO_2) Method 7 (NO_x) Method 9 (opacity) Method 10 (CO) Method 11 (H_2S) Method 18 (VOC)
Ambient Monitoring Required		X	
COMS Required	X		FCC Regenerator
CEMS Required	X		SO_2, H_2S, NO_x, CO
Schedule of Compliance Required		X	
Annual Compliance Certification and Semiannual Reporting Required	X		
Monthly Reporting Required		X	
Quarterly Reporting Required	X		
Applicable Air Quality Programs			
ARM Subchapter 7 Montana Air Quality Permits (MAQP)	X		MAQP #1821-41
New Source Performance Standards (NSPS)	X		40 CFR 60, Subpart A, Subpart J, Subpart Ja, Subpart Db, Subpart Kb, Subpart UU, Subpart VV (as required by MACT CC or GGG), Subpart VVa (as required by MACT GGGa), Subpart GGG, Subpart GGGa, Subpart QQQ.
National Emission Standards for Hazardous Air Pollutants (NESHAPS)	X		40 CFR 61, Subpart A, Subpart FF
Maximum Achievable Control Technology (MACT)	X		40 CFR 63, Subpart A, Subpart R (as required by Subpart CC), Subpart CC, Subpart UUU, Subpart DDDDD.

Facility Compliance Requirements	Yes	No	Comments
Major New Source Review (NSR) – includes Prevention of Significant Deterioration (PSD) and/or Non-attainment Area (NAA) NSR	X		
Risk Management Plan Required (RMP)	X		
Acid Rain Title IV		X	
Compliance Assurance Monitoring (CAM)		X	
State Implementation Plan (SIP)	X		Billings/Laurel SO_2 Control Plan

TABLE OF CONTENTS

SECTION I. GENERAL INFORMATION 4

A. PURPOSE 4
B. FACILITY LOCATION 4
C. FACILITY BACKGROUND INFORMATION 4
D. CURRENT PERMIT ACTION 41
E. TAKING AND DAMAGING ANALYSIS 42
F. COMPLIANCE DESIGNATION 43

SECTION II. SUMMARY OF EMISSION UNITS 46

A. FACILITY PROCESS DESCRIPTION 46
B. EMISSION UNITS AND POLLUTION CONTROL DEVICE IDENTIFICATION 46
C. CATEGORICALLY INSIGNIFICANT SOURCES/ACTIVITIES 49

SECTION III. PERMIT CONDITIONS 50

A. EMISSION LIMITS AND STANDARDS 50
B. MONITORING REQUIREMENTS 50
C. TEST METHODS AND PROCEDURES 50
D. RECORDKEEPING REQUIREMENTS 50
E. REPORTING REQUIREMENTS 51
F. PUBLIC NOTICE 51
G. DRAFT PERMIT COMMENTS 51

SECTION IV. NON-APPLICABLE REQUIREMENT ANALYSIS 57

SECTION V. FUTURE PERMIT CONSIDERATIONS 58

A. MACT STANDARDS 58
B. NESHAP STANDARDS 59
C. NSPS STANDARDS 59
D. RISK MANAGEMENT PLAN 59
E. COMPLIANCE ASSURANCE MONITORING (CAM) PLAN 59
F. PREVENTION OF SIGNIFICANT DETERIORATION AND TITLE V GREENHOUSE GAS TAILORING RULE 59

SECTION I. GENERAL INFORMATION

A. Purpose

This document establishes the basis for the decisions made regarding the applicable requirements, monitoring plan, and compliance status of emission units affected by the operating permit proposed for this facility. The document is intended for reference during review of the proposed permit by the U.S. Environmental Protection Agency (EPA) and the public. It is also intended to provide background information not included in the operating permit and to document issues that may become important during modifications or renewals of the permit.

Conclusions in this document are based on information provided in the original application submitted to the Montana Department of Environmental Quality Air Quality Bureau (Department) by Cenex Harvest States Cooperatives on July 10, 1995, the application for renewal submitted by CHS, Inc. (CHS) on May 12, 2006, and the significant modification applications submitted by CHS on October 10, 2007; February 25, 2008; November 7, 2008; February 27, 2009; August 13, 2009; September 17, 2009; March 31, 2010; July 27, 2010; November 1, 2010; April 12, 2011; November 8, 2011; June 4, 2012; and January 22, 2013, renewal application received April 15, 2013, and the more recent modification applications received on August 13, 2013, October 21, 2013, June 23, 2016, and the significant modification received on October 27, 2017, with an addendum on November 15, 2017.

B. Facility Location

The CHS-Laurel Refinery is located at the South ½, Section 16, Township 2 South, Range 24 East, Yellowstone County. This legal description refers to a physical address of 803 Highway 212 South, Laurel, Montana.

C. Facility Background Information

Montana Air Quality Permit History

On May 11, 1992, Cenex was issued **Montana Air Quality Permit (MAQP) #1821-01** for the construction and operation of a hydro-treating process to desulfurize Fluidized Catalytic Cracking Unit (FCCU) feedstocks. The existing refinery property lies immediately south of the City of Laurel and about 13 miles southwest of Billings, Montana. The new equipment for the desulfurization complex is located near the western boundary of the existing refining facilities.

The Hydrodesulfurization (HDS) process is utilized to pretreat FCCU feeds by removing metal, nitrogen, and sulfur compounds from these feeds. The proposed HDS unit also improved the quality of refinery finished products including gasoline, kerosene, and diesel fuel. The HDS project significantly improved the finished product quality by reducing the overall sulfur contents of liquid products from the Cenex Refinery. The HDS unit provided low sulfur gas-oil feedstocks for the FCCU, which resulted in major reductions of sulfur oxide emissions to the atmosphere. However, only a minor quantity of the proposed sulfur dioxide (SO_2) emission reductions were made federally enforceable.

The application was not subject to the New Source Review (NSR) program for either nonattainment or Prevention of Significant Deterioration (PSD) since Cenex chose to "net out of major modification review" for the affected pollutants due to contemporaneous emission reductions at an existing emission unit.

The application was deemed complete on March 24, 1992. Additional information was received on April 16, 1992, in which Cenex proposed new short-term emission rates based upon modeled air quality impacts.

The basis for the permit application was due to a net contemporaneous emission increase that was less than the significant level of 40 tons per year for SO_2 and oxides of nitrogen (NO_x). The application referred to significant SO_2 emission reductions that were expected by addition of the HDS project. These anticipated major SO_2 reductions were not committed to by Cenex under federally enforceable permit conditions and limitations. The contemporaneous emission decreases for SO_2 and NO_x, which were made federally enforceable under this permitting action, amount to approximately 15.5 and 23.7 tons per year, respectively. Construction of the HDS/sulfur recovery complex was completed in December 1993, and the 180-day shakedown period ended in June 1994.

MAQP #1821-02 was issued on February 1, 1997, to authorize the installation of an additional boiler (#10 Boiler) to provide steam for the facility. Cenex submitted the original permit application for a 182.50-million British thermal unit per hour (MMBtu/hr) boiler on February 9, 1996. This size boiler is a New Source Performance Standard (NSPS)-affected facility and the requirements of NSPS, Subpart Db, would have applied to the boiler. On November 15, 1996, Cenex submitted a revised permit application proposing a smaller boiler (99.90 MMBtu/hr). The manufacturer of the proposed boiler had not been identified; however, the boiler was to be rated at approximately 80,000 pounds (lbs) steam/hour with a heat input of 99.9 MMBtu/hour. The boiler shall have a minimum stack height of 75 feet above ground level. The boiler will be fired on natural gas until November 1, 1997, at which time Cenex will be allowed to fire refinery fuel gas in the boiler. The requirements of NSPS, Subpart Dc, apply to the boiler. The requirements of NSPS, Subpart J and GGG, also applied as of November 1, 1997. Increases in emissions from the new boiler were detailed in Section IV of the permit analysis for MAQP #1821-02. Modeling performed showed that the emissions increase would not result in a significant impact to the ambient air quality (see Section VI of the permit analysis).

Cenex also requested a permit alteration to remove the SO_2 emission limits (Section II.E.2.a of MAQP #1821-01) for the C-201B compressor engine because the permit already limits C-201B to be fired on either natural gas or unodorized propane. Cenex also requested that if the SO_2 emission limits could not be removed, the limits should be corrected to allow for the combustion of natural gas and propane. The Department altered the permit to allow for burning odorized propane in the C-201B compressor.

Cenex also requested a permit modification to change the method of determining compliance with the HDS Complex emitting units. MAQP #1821-01 required that compliance with the hourly (lb/hr) emission limits be determined through annual source testing and that the daily (lb/day), annual (ton/yr), and Administrative Rules of Montana (ARM) 17.8, Subchapter 8, requirements (i.e., PSD significant levels and review) be determined by using actual fuel-burning rates and the manufacturer's guaranteed emission factors listed in Attachment B. Cenex requested to use actual fuel-burning rates and fixed emission factors determined from previous source test data in order to determine compliance with the daily (lb/day) and annual (ton/yr) emission limits. The Department agreed that actual stack testing data is preferred to manufacturer's data for the development of emission factors. However, the Department required that the emission factor be developed from the most recent source test and not on an average of previous source tests. The permit was changed to remove Attachment B and rely on emission factors derived from the most recent source test, along with actual fuel flow rates for compliance determinations. However, in order to determine compliance with ARM 17.8, Subchapter 8, Cenex shall continue to monitor the fuel gas flow rates in both scf/hr and scf/year.

This permit (#1821-02) was written to maintain the language from the HDS Complex MAQP #1821-01, where possible, and to separate the HDS Complex MAQP #1821-01 requirements from the requirements for the current action (Boiler #10). The permit requirements from MAQP #1821-01 were included in MAQP #1821-02.

On June 4, 1997, Cenex was issued **MAQP #1821-03** to modify emissions and operational limitations on components in the HDS Complex at the Laurel refinery. The unit was originally permitted in 1992, but has not been able to operate adequately under the emission and operational limitations originally proposed by Cenex and permitted by the Department. This permitting action corrected these limitations and conditions. The new limitations established by this permitting action were based on operational experience and source testing at the facility and the application of Best Available Control Technology (BACT). The following emission limitations were modified by this permit.

Source	Pollutant	Previous Limit	New Limit
SRU Incinerator stack (E-407 & INC-401)	SO_2	291.36 lb/day	341.04 lb/day
	NO_x	2.1 ton/yr 11.52 lb/day 0.48 lb/hr	3.5 ton/yr 19.2 lb/day 0.8 lb/hr
Compressor (C201-B)	NO_x	18.42 ton/yr	30.42 ton/yr
		6.26 lb/hr	7.14 lb/hr
	CO	16.45 ton/yr	68.6 ton/yr
		5.15 lb/hr - when on natural gas	6.4 lb/hr - when on natural gas
	VOC	6.26 ton/yr	10.1 ton/yr
Fractionator Feed Heater (H-202)	SO_2	0.53 ton/yr	4.93 ton/yr
		0.135 lb/hr	1.24 lb/hr
	NO_x	6.26 ton/yr	8.34 ton/yr
		1.43 lb/hr	2.09 lb/hr
	CO	3.29 ton/yr	6.42 ton/yr
		1.00 lb/hr	1.61 lb/hr
	VOC	0.26 ton/yr	0.51 ton/yr
Reactor Charge Heater (H-201)	SO_2	0.214 lb/hr	1.716 lb/hr
		0.79 ton/yr	6.83 ton/yr
	NO_x	9.24 ton/yr	11.56 ton/yr
		2.11 lb/hr	2.90 lb/hr

Source	Pollutant	Previous Limit	New Limit
H-201 (cont.)	CO	4.86 ton/yr	8.89 ton/yr
		1.40 lb/hr	2.23 lbs/hr
	VOC	0.39 ton/yr	0.71 ton/yr
Reformer Heater (H-101)	SO_2	0.128 lb/hr	2.15 lb/hr
		0.48 ton/yr	3.35 ton/yr
	NO_x	6.16 lb/hr	6.78 lb/hr
	VOC	0.24 ton/yr	0.35 ton/yr
Old Sour Water Stripper	SO_2	304.2 ton/yr	290.9 ton/yr
	NO_x	125.7 ton/yr	107.9 ton/yr

Emission limitations in this permit are based on the revised heat input capacities for units within the HDS. The following changes were made to the operational requirements of the facility.

Unit	Originally Permitted Capacity	New Capacity
SRU Incinerator stack (E-407 & INC-401)	4.8 MMBtu/hr	8.05 MMBtu/hr
Compressor (C201-B)	1600 HP (short term) 1067 HP (annual average)	1800 HP (short term and annual average)
Fractionator Feed Heater (H-202)	27.2 MMBtu/hr (short term) 20.4 MMBtu/hr (annual avg.)	29.9 MMBtu/hr (short term) 27.2 MMBtu/hr (annual avg.)
Reactor Charge Heater (H-201)	37.7 MMBtu/hr (short term) 30.2 MMBtu/hr (annual avg.)	41.5 MMBtu/hr (short term) 37.7 MMBtu/hr (annual avg.)
Reformer Heater (H-101)	123.2 MMBtu/hr (short term and annual avg.)	135.5 MMBtu/hr (short term) 123.2 MMBtu/hr (annual avg)

It was determined that the emission and operational rates proposed during the original permitting of the HDS unit were incorrect and should have been at the levels Cenex was now proposing. Because of this, the permit action and the original permitting of the HDS had to be considered one project in order to determine the permitting requirements. When combined with the original permitting of the HDS, the emission increases of NO_x and SO_2 would exceed significant levels and subject this action to the requirements of the NSR/PSD program. During the original permitting of the HDS complex, Cenex chose to "net out" of NSR and PSD review by accepting limitations on the emissions of NO_x and SO_2 from the old sour water stripper (SWS). Because of the emission increases proposed in this permitting action, additional emission reductions had to occur. Cenex proposed additional reductions in emissions from the old SWS to offset the increases allowed by

this permitting action. These limitations would reduce the "net emissions increase" to less than significant levels and negate the need for review under the NSR/PSD program. The new emission limits for SO_2 and NO_x from the old SWS are 290.9 and 107.9 tons/year, respectively.

This permitting action also removed the emission limits and testing requirements for particulate matter less than 10 microns (PM_{10}) on the HDS Heaters (H-101, H-201, and H-202). These heaters combust refinery gas, natural gas and PSA gas. The Department determined that potential PM_{10} emissions from these fuels were minor and that emission limits and the subsequent compliance demonstrations for this pollutant were unnecessary. Also removed from this permit were the compliance demonstration requirements for SO_2 and volatile organic compounds (VOCs) when the combustion units are firing natural gas. The Department determined that firing the units solely on natural gas would, in itself, demonstrate compliance with the applicable limits.

This action would result in an increase in allowable emissions of VOC and carbon monoxide (CO) by 4.7 ton/yr and 60 ton/yr, respectively. Because of the offsets provided by reducing emissions from the old SWS, this permitting action would not increase allowable emissions of SO_2 or NO_x from the facility.

The following changes were made to the Department's preliminary determination (PD) in response to comments from Cenex.

1. The emission limits for the old SWS in Section II.D.2 were revised to ensure that the required offsets were provided without putting Cenex in a non-compliance situation at issuance of the permit. The compliance determinations of Section II.G.5 and the reporting requirements of Section II.H.1.d were also changed to reflect this requirement.

2. The CO emission limits for H-201 in Section II.D.6 were revised; the old limits were inadvertently left in the PD. The table in Section I.B of the analysis was also changed to reflect this.

3. Section III.E.2 was changed to clarify that the firing of natural gas would show compliance with the VOC emission limits for Boiler #10.

4. Section F of the General Conditions was removed because the Department had placed the applicable requirements from the permit application into the permit.

5. Numbering had been changed in Section III.

MAQP #1821-04 was issued to Cenex on March 6, 1998, in order to comply with the gasoline loading rack provisions of 40 CFR 63, Subpart CC - National Emission Standards for Petroleum Refineries, by August 18, 1998. Cenex proposed to install a gasoline vapor collection system and enclosed flare for the reduction of hazardous air pollutants (HAPs) resulting from the loading of gasoline. A vapor combustion unit (VCU) was added to the product loading rack. The gasoline vapors would be collected from the trucks during loading, then routed to an enclosed flare where combustion would occur. The result of this project would be an overall reduction in the amount of VOCs (503.7 tons per year (tpy)) and HAPs emitted, but CO and NO_x emissions would increase slightly (4.54 tpy and 1.82 tpy).

The product loading rack was used to transfer refinery products (gasoline, burner and/or diesel fuels) from tank storage to trucks, which transport gasoline and other products, to retail outlets. The loading rack consisted of three arms, each with a capacity of 500 gallons per minute (gpm). However, only two loading arms were presently used for loading gasoline at any one time. A maximum gasoline-loading rate of 2000 gpm, a maximum short-term rate, was modeled to account for future expansion.

Because Cenex's product loading rack VCU was defined as an incinerator under Montana Code Annotated (MCA) 75-2-215, a determination that the emissions from the VCU would constitute a negligible risk to public health was required prior to the issuance of a permit to the facility. Cenex and the Department identified the following hazardous air pollutants from the flare, which were used in the health risk assessment. These constituents are typical components of Cenex's gasoline.

1. Benzene
2. Toluene
3. Ethyl Benzene
4. Xylenes
5. Hexane
6. 2,2,4 Trimethlypentane
7. Cumene
8. Naphthalene
9. Biphenyl

The reference concentration for Benzene was obtained from EPA's Integrated Risk Information System (IRIS) database. The ISCT3 modeling performed by Cenex, for the hazardous air pollutants identified above, demonstrated compliance with the negligible risk requirement.

On September 3, 2000, **MAQP #1821-05** was issued to Cenex to revamp its No. 1 Crude Unit in order to increase crude capacity, improve product quality, and enhance energy recovery. The proposed project involved the replacement and upgrade of various heat exchangers, pumps, valves, towers, and other equipment. Only VOC emissions would be affected by the proposed new equipment. The capacity of the No. 1 Crude Unit was expected to increase by 10,000 or more barrels per stream day.

No increase in allowable emissions was sought under this permit application. The proposed project actually decreased VOC emissions from the No. 1 Crude Unit. However, increasing the capacity of the No. 1 Crude Unit was expected to increase the current utilization of other units throughout the refinery and thus may increase actual site-wide emissions, as compared to previous historical levels. Therefore, the permit included enforceable limits, requested by Cenex, on future site-wide emissions. The limits allowed emission increases to remain below the applicable significant modification thresholds that trigger the NSR program for PSD and Nonattainment Area (NAA) permitting.

The site-wide limits were calculated based on the addition of the PSD/NAA significance level for each particular pollutant to the actual refinery emissions from April 1998, through March 2000, for SO_2, NO_x, CO, PM_{10}, and total suspended particulate (TSP) minus 0.1 tpy, to remain below the significance level. A similar methodology was used for the VOC emissions cap, except that baseline data from the time period 1993 and 1999 were used to track creditable increases and decreases in emissions. The site-wide limits are listed in the following table.

Pollutant	Period Considered for Prior Actual Emissions	Average Emissions over 2-yr Period (tpy)	PSD/NAA Significance Level (tpy)	Proposed Emissions Cap (tpy)
SO_2	April 1998-March 2000	2940.4	40	2980.3
NO_x	April 1998-March 2000	959.5	40	999.4
CO	April 1998-March 2000	430.8	100	530.7
VOC	1993-1999	1927.6	40	1967.5
PM-10	April 1998-March 2000	137.3	15	152.2
TSP	April 1998-March 2000	137.3	25	162.2

For example, the SO_2 annual emissions cap was calculated as follows:

Average refinery-wide SO_2 emissions in the period of April 1998 through 2000, added to the PSD/NAA significance level for SO_2 minus 0.1 tpy =

2940.4 tpy + 40 tpy – 0.1 tpy = 2980.3 tpy = Annual emissions cap.

MAQP #1821-05 replaced MAQP #1821-04. This was the last permitting action for the initial Title V Operating Permit #OP1821-00.

MAQP #1821-06 was issued on April 26, 2001, for the installation and operation of eight temporary, portable Genertek reciprocating engine electricity generators and two accompanying distillate fuel storage tanks. Each generator is capable of generating approximately 2.5 megawatts of power. These generators are necessary because of the high cost of electricity. The operation of the generators will not occur beyond 2 years and is not expected to last for an extended period of time, but rather only for the length of time necessary for Cenex to acquire a more economical supply of power.

Because these generators would only be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of these generators is minor. In addition, the installation of these generators qualifies as a "temporary source" under the PSD permitting program because the permit will limit the operation of these generators to a time period of less than 2 years. Therefore, Cenex would not need to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, the Department required compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 would be ensured. In addition, Cenex would be responsible for complying with all applicable air quality standards. In order to keep this permitting action below the threshold of nonattainment area permitting requirements, Cenex requested a limitation to keep the project's potential emissions of SO_2 below 40 tons. MAQP #1821-06 replaced MAQP #1821-05.

MAQP #1821-07 was issued on August 28, 2001, to change the wording in Section VII.A.2, regarding the stack height on the temporary generators, to allow for the installation of mufflers on those stacks, thus increasing the total stack height. In addition, the Department modified the permit to eliminate references to the repealed odor rule (ARM 17.8.315), to correct conditions improperly referencing the incinerator rule (ARM 17.8.316), and to update a testing frequency on the product loading rack VCU based on the Title V permit term. MAQP #1821-07 replaced MAQP #1821-06.

On June 3, 2002, the Department received a request from Cenex to modify MAQP #1821-07 to remove all references to 8 temporary, portable electricity generators. The generators were permitted under MAQP #1821-06, with further clarification added in MAQP #1821-07 regarding generator stack height. The generators have not been operated since August 10, 2001, and Cenex has no intention of operating them in the future. The references to the generators were removed, and the generators are no longer included in Cenex's permitted equipment. **MAQP #1821-08** replaced MAQP #1821-07.

On March 13, 2003, the Department received a complete MAQP Application from Cenex to modify MAQP #1821-08 to add a new Ultra Low Sulfur Diesel (ULSD) Unit, Hydrogen Plant, and associated equipment to meet the EPA's 15 parts per million (ppm) sulfur standard for highway diesel fuel for 2006. The permit action removed the Middle Distillate Unifiner (MDU) charge heater, MDU stripper heater, MDU fugitives, and the #3 and #4 Unifier Compressors. The ULSD Unit included two heaters, four compressors, C-901 A/B and C-902 A/B, process drains, and fugitive piping components. The Hydrogen Plant included a single fired reformer heater, process drains, and fugitive piping components.

The treated stream from the ULSD Unit was separated into its constituent fuel blending products or into material needing further refining. The resulting stream was then stored in existing tanks and one new tank (128). Three existing tanks (73, 86, and 117) were converted to natural gas blanketed tanks to reduce emissions of VOCs from the ULSD Unit feed stock product streams. Cenex was to install a new Tail Gas Treatment Unit (TGTU) for both the Sulfur Recovery Unit (SRU) #1 and #2 trains that will be operational prior to startup of the ULSD Unit but technically are not part of this permitting action. **MAQP #1821-09** replaced MAQP #1821-08.

On July 30, 2003, the Department received a complete MAQP Application from CHS to modify MAQP #1821-09. The application was complete with the addition of modeling information provided to the Department on August 22, 2003. CHS requested to add a new TGTU and associated equipment for Zone A's SRU #1 and SRU #2 trains to control and reduce SO_2 emissions from this source. CHS submitted modeling to the Department for a determination of a minimum stack height for the existing SRU #1 and SRU #2 tail gas incinerator stack. CHS also submitted a letter to the Department to change the name on the permit from Cenex to CHS. The permit action added the new TGTU, set a minimum stack height for the tail gas incinerator stack, and changed the name on the permit from Cenex to CHS. **MAQP #1821-10** replaced MAQP #1821-09.

On June 1, 2004, the Department received two MAQP Applications from CHS to modify MAQP #1821-10. The applications were complete with the addition of requested information provided to the Department on June 16, 2004. In one application CHS requested to change the nomenclature for Reformer Heater H-801 to Reformer Heater H-1001. H-801 was previously permitted during the ULSD project (MAQP #1821-09), at 150-MMBtu/hr. CHS requested to change the size of Reformer Heater H-801 (H-1001) from 150-MMBtu/hr to 161.56-MMBtu/hr. In the other application CHS requested to increase the Plantwide Applicability Limit (PAL) for CO from 530.7 tons per year to 678.2 tons per year based on new information obtained by CHS. The new information was obtained after the installation of a CO continuous emission monitor (CEMS) on the FCCU Stack. Emissions of CO from the FCCU Stack were assumed to be zero until the installation of the CEMS. CHS also requested that specific emission limits, standards, and schedules required by the CHS Consent Decree be incorporated into the permit. **MAQP #1821-11** replaced MAQP #1821-10.

On December 15, 2004, the Department received a letter from CHS to amend MAQP #1821-11. The changes were administrative primarily related to changing routine reporting requirements from a monthly basis to quarterly. The changes to the permit were made under the provisions of ARM 17.8.764, Administrative Amendment to Permit. **MAQP #1821-12** replaced MAQP #1821-11.
On March 28, 2006, the Department issued **MAQP #1821-13** to CHS to build a new 15,000-barrel per day (BPD) delayed coker unit and associated equipment. The new delayed coker unit allows CHS to increase gasoline and diesel production by 10-15% by processing heavy streams that formerly resulted in asphalt (asphalt production is expected to decrease by approximately 75%, but the capability to produce asphalt at current levels was maintained and no emission credits were taken with respect to any possible reduction in asphalt production) without increasing overall crude capacity at the refinery. The delayed coker unit produces 800 short tons per day of a solid petroleum coke product. To accommodate the downstream changes created by the new delayed coker unit, several other units will be modified including the Zone D FCC Feed Hydrotreater, FCCU, ULSD Unit, and Hydrofluoric Acid (HF) Alky Unit. Other units will be added: Delayed Coker SRU/TGTU/Tail Gas Incinerator (TGI), Naphtha Hydrotreating (NHT) Unit, NHT Charge Heater, Boiler No. 11, Light Products Railcar Loading Facility, and two new tanks will be added to the Tank Farm. Other units will be shut down: the Propane Deasphalting Unit, Unifiner Compressors No. 1 and 2, No. 2 Naphtha Unifier Charge Heater and Reboiler, BP2 Pitch Heater, and Boilers No. 3 and 4. The VCU associated with the new Light Products Railcar Loading Facility and the Coker Unit TGI were subject to the requirements of 75-2-215, MCA and ARM 17.8.770, Additional Requirements for Incinerators. The Delayed Coker project and associated equipment modifications did not cause a net emission increase greater than significant levels and, therefore, does not require a NSR analysis. The net emission changes were as follows:

Constituent	Total Project PTE (ton/yr)	Contemporaneous Emission Changes (ton/yr)	Net Emissions Change (ton/yr)	PSD Significance Level (ton/yr)
NO_x	39.2	-7.5	31.8	40
VOC	-1.5	-53.3	-54.8	40
CO	106.7	-23.2	83.5	100
SO_2	39.7	0.0	39.7	40
PM	7.6	6.6	14.2	25
PM_{10}	6.7	6.6	13.3	15

The following is a summary of the CO emissions included in the CO netting analysis: Coker project (+106.7 TPY), emergency generator (+0.44 TPY, start-up in 2002), Zone A TGTU project (+8.3 TPY, initial startup at end of 2004), and ULSD project (-31.9 TPY, started up in 2005). MAQP #1821-13 replaced MAQP #1821-12.

On May 4, 2006, the Department received a complete application from CHS to incorporate the final design of three emission sources associated with the new 15,000 BPD delayed coker unit project permitted under MAQP #1821-13. The final design capacities have increased for the new NHT Charge Heater, the new Coker Charge Heater and the new Boiler No. 11. The application also includes a request to reduce the refinery-wide fuel oil burning SO_2 emission limitation. This reduction allows CHS to stay below the significance threshold for the applicability of the New Source Review-PSD program. The maximum firing rates are proposed to increase with the current permitting action. The following summarizes the originally permitted firing rates (MAQP #1821-13) and the new proposed firing rates for the heaters and the boiler:

NHT Charge Heater: 13.2 to 20.1 MMBtu-lower heating value (LHV)/hr (22.1 MMBtu-higher heating value (HHV)/hr)
Coker Charge Heater:129.3 to 146.2 MMBtu-LHV/hr (160.9 MMBtu-HHV/hr)
Boiler #11: 175.9 to 190.1 MMBtu-LHV/hr (209.1 MMBtu-HHV/hr)

CHS also requested several clarifications to the permit. Under MAQP #1821-13 several 12-month rolling limits were established for modified older equipment and limits for new equipment. CHS requested clarifications be included to determine when compliance would need to be demonstrated for these new limits. MAQP #1821-13 went final on March 28, 2006, and CHS is required to demonstrate compliance with the new limitations from this date forward. For the 12-month rolling limits proposed under MAQP #1821-13 and any changes to limitations under the current permit action, CHS would be required to demonstrate compliance on a monthly rolling basis calculated from March 28, 2006. For modified units the limitations will have zero emissions until modifications are made. New units will have zero emissions until start-up of these units. Start-up is defined as the time that the unit is combusting fuel, not after the start-up demonstration period. Some units have clearly designated compliance timeframes based on the consent decree. These limitations and associated time periods are listed within the permit.

The Department agreed that the heading to Section X.A.3 can include the "*Naphtha Hydrotreating Unit*"; Section D.1.c is based on a 30-day rolling average; Section X.D.7.a.ii should state that the SO_2 limit is based on a 12-hour average; and that Section XI.E.3 should be revised to remove the requirement for a stack gas volumetric flow rate monitor. The Department made some clarifications to the language in Section X.D.6.b. The Department's intent in permitting the coke pile with enclosures was to ensure that at no time would the coke pile be higher than the top of the enclosure walls at any point on the pile, not only the portion of the pile that is adjacent to the wall.

The Department did not believe it was necessary to designate the Sour Water Storage Tank as a 40 CFR 60 Subpart Kb applicable tank, when currently these regulations do not apply. If CHS makes changes in the future and 40 CFR 60 Subpart Kb becomes applicable to the tank, then CHS can notify the Department and the Department can include the change in the next permit action.

The Department received comments from CHS on the preliminary determination of **MAQP #1821-14** on June 21, 2006. The comments were editorial in nature and the changes were made prior to issuance of the Department Determination on MAQP #1821-14. CHS requested corrections to the PM, PM_{10}, NO_x netting values in Section II.G of the permit analysis, and the Department agreed that the edits were needed. CHS also requested further clarification to the requirements of Section X.D.6.b of the permit.

CHS stated that the coke pile will be dropped from two coke drums to a location directly adjacent to the highest walls of the enclosure area. The height of the dropped coke piles will not exceed the height of the wall. If CHS is required to relocate and temporarily store the coke at another location within the enclosure area, CHS will not pile the coke higher than the walls adjacent to the temporary storage location. MAQP #1821-14 replaced MAQP #1821-13.

On September 11, 2006, the Department received an application from CHS to incorporate the final design of emission sources associated with the new 15,000-BPD delayed coker unit project permitted under MAQP #1821-13 and revised under MAQP #1821-14. The changes include:

- Retaining Boiler #4 operations and permanently shutting down the CO Boiler;

- Modifying the FCCU Regenerator CO limit due to the air grid replacement;

- Rescinding the permitted debottleneck project for Zone D SRU/TGTU/TGI and revising the long term SO_2 potential to emit;

- Modifying the Zone E (Delayed Coker) SRU/TGTU/TGI - Incinerator design and NO_x limits;

- Rescinding the firing rate restriction and associated long-term emission limits, and revising VOC emission calculations for H-201 and H-202; and

- Removing the 99.9 MMBtu/hr restriction and reclassifying Boiler #10 as subject to NSPS Subpart Db.

On October 11, 2006, the Department received a request to temporarily stop review of the permit application until several additional proposals were submitted, which included:

- On October 24, 2006, the Department received a de minimis notification for stack design changes for the Delayed Coker Unit (Zone E) SRU Incinerator.

- On October 31, 2006, the Department received clarification on the ULSD project.

- On November 1, 2006, the Department received a request to limit the maximum heat rate capacity of the #2 N.U. Heater to below 40 MM BTU/hr in conformance with the CHS Consent Decree. CHS also requested that the Department re-initiate review of MAQP Modification #1821-15.

All of the above changes allowed CHS to stay below the significance threshold for the applicability of the New Source Review-PSD program. CHS also requested several clarifications to be included in the permit, and the Department suggested streamlining the permit's organization. **MAQP #1821-15** replaced MAQP #1821-14.

On October 10, 2007, the Department received an application from CHS to modify MAQP #1821-15 to incorporate the final design of the NHT Charge Heater. This heater was permitted as part of the refinery's delayed coker project permitted under MAQP #1821-13 and revised under MAQP #1821-14 and MAQP #1821-15. The modification to MAQP #1821-15 was requested to address an operating scenario that was overlooked during the delayed coker unit design process. This operating scenario is for the case in which the NHT unit is in operation, but the delayed coker unit is not. In this operating scenario, the characteristics of the naphtha being processed in the unit are such that additional heat input to the heater is required to achieve the design NHT Unit throughput. For this reason, CHS requested approval for an increase in the design firing rate of the NHT Charge Heater (H-8301). The following summarizes the permitted firing rates under MAQP #1821-15 and the new proposed firing rates for the NHT Charge Heater:

Maximum Firing Rate (LHV): 20.1 MMBtu-LHV/hr to 34.0 MMBtu-LHV/hr
Maximum Firing Rate (HHV): 22.1 MMBtu-HHV/hr to 37.4 MMBtu-HHV/hr

This change does not impact any of the other design conditions in the original delayed coker permit, including unit throughputs and operating rates. The application also includes a request to reduce the refinery-wide fuel oil burning SO_2 emission limitation. This reduction allows CHS to stay below the significance thresholds for the applicability of the New Source Review-PSD program. CHS also requested some administrative changes to the permit. **MAQP #1821-16** replaced MAQP #1821-15.

On February 25, 2008, the Department received a complete application from CHS to modify MAQP #1821-16 for the completion of two separate projects. For the first project, CHS proposed to construct a new 209.1 MMBtu-HHV/hr steam generating boiler (Boiler #12). This project includes the permanent shutdown of two existing boilers, Boilers #4 and #5, which have a combined capacity of 190 MMBtu-LHV/hr. The two existing boilers are being shutdown in part to meet the consent decree NO_x reduction requirements, as well as to generate NO_x offsets for this permitting action.[1] Due to the operational complexity of replacing two existing boilers with one new boiler in the refinery steam system, CHS requested to maintain the ability to operate the #5 Boiler for 1 year after initial start-up of Boiler #12. Combustion of fuel oil in the refinery boilers would also be eliminated primarily to generate NO_x offsets for this permitting action.

For the second project, CHS proposed an expansion of its railcar light product loading facilities. Although there would be no increase in refinery production from this expansion, the project would increase flexibility in the transportation of refinery products. After project completion, there would be a total of nine spots available at this loading rack for product loading into railcars. The railcar light product loading facility was originally permitted as part of the delayed coker project permitted under MAQP #1821-13 and revised under MAQP #1821-14, #1821-15, and #1821-16. This change does not require a modification to the originally permitted VCU since the maximum loading rate of 2,000 gallons per minute (gpm) will remain unchanged.

The application also included a request to reduce the limitation for SO_2 emissions from the combustion of alkylation unit polymer and fuel oil in all combustion devices from 127.6 TPY to 50 TPY (for alkylation unit polymer only since fuel oil combustion in refinery boilers will be eliminated). Although the potential to emit for the combustion of alkylation unit polymer in the Alkylation Unit Hot Oil Heater is estimated to be around 8.3 TPY for SO_2 (based on a specific gravity of 0.7 and a sulfur content of 1 wt%; the exact potential to emit has not been determined due to the variability of specific gravity and sulfur content), the allowable emissions are set at 50 TPY in this permitting action. According to ARM 17.8.801(24)(f), the decrease in actual emissions from the elimination of fuel oil combustion in refinery boilers is creditable for PSD purposes provided the old level of actual emission or the old level of allowable emissions, *whichever is lower*, exceeds the new level of actual emissions and the decrease in emissions is federally enforceable at and after the time that actual construction begins. Since the old level of actual emissions is lower than the old level of allowable emissions for combustion of fuel oil in refinery boilers, CHS requested a creditable reduction based on actual emissions from the boilers. This reduction resulted in a total of 50 TPY SO_2 allowed for the combustion of alkylation unit polymer in the Alkylation Unit Hot Oil Heater, the only unit that is part of the original SO_2 limitation for fuel oil combustion devices that will continue to operate. While it appears that the emissions from the combustion of alkylation unit polymer would be allowed to increase through this permitting action, it is important to note that physical modifications and/or changes in the method of operation would first have to occur for the Alkylation Unit Hot Oil Heater to emit more than its estimated potential of 8.3 TPY (note: the exact potential to emit has not been determined at this time). As acknowledged by CHS, a modification

[1] This is later clarified in the permit history for MAQP #1821-21. No creditable NOx emissions reductions from the shutdown of Boiler #4 and #5 were used in the permit for construction of new Boiler #12 (MAQP #1821-17).

and/or change in method of operation to this unit would require a permit modification. Therefore, the Department does not anticipate any increase in actual emissions from this unit, even though the allowable has been set at 50 TPY. In addition, should CHS eliminate or reduce the combustion of alkylation unit polymer in future permit actions in order to have a creditable decrease for PSD purposes, only the change in actual emissions would be available since the actual emissions will be lower than the allowable, unless a modification to the unit is made.

In addition, CHS requested that the permit CO emission limits for Boiler #11 be changed to 36.63 TPY and 15.26 lb/hr, based on a revised emission factor from performance test data completed in 2007 for Boiler #11 used to calculate the PTE. All of these changes allow CHS to stay below the significance thresholds for the applicability of the New Source Review-PSD program.

CHS also requested some additional administrative changes to the permit, including clarification of the applicability of 40 CFR 63, Subpart DDDDD: NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters to various sources given the fact that the federal rule was vacated on July 30, 2007. Although the federal rule has been vacated, the vacated federal rule remains incorporated by reference in ARM 17.8.103 and ARM 17.8.302 (with the applicable publication date specified in ARM 17.8.102) at the time of **MAQP #1821-17** issuance and as such, it remains an applicable requirement under state rules; each applicable permit condition has been marked 'State-Only Requirement'.

On April 1, 2008, CHS requested that the Department delay issuance of the preliminary determination for this permit application until additional information could be submitted regarding alternative coke handling practices. This additional information was submitted to the Department on April 3, 2008, with follow-up information received by the Department on April 14, 2008. CHS requested that an alternative coke handling process be included in MAQP #1821-17. The coke handling process, originally permitted as part of the delayed coker project, included the use of conveyors to transport coke to a crusher and to a railcar loading system. Because the system is enclosed, it is not possible to transport coke to the crusher and loading system without the use of the conveyors. CHS has since identified the need for an alternate coke handling method to be used when the conveyors are out of operation for either planned or unplanned maintenance. MAQP #1821-17 replaced MAQP #1821-16.

On November 7, 2008, the Department received a MAQP application from CHS for a benzene reduction project. In this application, CHS requested to modify MAQP #1821-17, to allow construction of a new Benzene Reduction Unit within the Laurel refinery to meet the requirements of the Mobile Source Air Toxics Rule (40 CFR 80, Subpart L). This rule requires that the refinery's average gasoline benzene concentration in any annual averaging period not exceed 0.62 volume percent, beginning January 1, 2011. This new unit will be inserted in the middle of the existing Platformer Unit. The new process will receive feed from the high pressure separator of the existing Platformer unit and produce a heavy platformate stream that will go directly to product storage and a light platformate stream that will be treated further. The light platformate stream, concentrated with benzene, will undergo a benzene hydrogenation reaction to convert the benzene to cyclohexane. This stream will then be fed to the existing Platformer Unit's debutanizer.

Because the Benzene Reduction Unit includes a hydrogenation reaction, hydrogen is required for the process. For this reason, modification to the existing 1,000 Unit Hydrogen Plant is planned. This modification will essentially increase hydrogen production in the amount needed in the new process and includes the addition of a steam superheater and an Enhanced Heat Transfer Reformer (EHTR). In the existing process, hydrogen is produced by mixing natural gas and the hydrogen-rich

Platformer Unit off gas stream with saturated steam. However, in the modified process, only natural gas will be used. Additionally, the steam used will be super-heated to supply additional heat to the primary reformer by means of a higher inlet process gas temperature. This modified process will allow for an increase in the process feed gas flow at the same reformer heat duty. As a result, more hydrogen will be produced in the reformer without increasing the firing rate, and thus, emission rate, of the H-1001 Reformer Heater. For this reason, the H-1001 Reformer Heater is not a project affected emission unit.

In this application, CHS also requested to make enforceable the retrofit of the Platformer Heater with low NO_x burners. This modification is being done to achieve Consent Decree required NO_x reductions. This modification is not required by the Benzene Reduction project; however, the retrofit of the Platformer Heater will occur during the construction phase of the Benzene Reduction project.

The Department reviewed this application and deemed it incomplete on December 1, 2008. The Department requested additional information to support the BACT analysis for the Platformer Splitter Reboiler. The Department received the requested follow-up information from CHS on December 15, 2008; the application was deemed complete as of this date.

In addition to making the requested changes, the Department has clarified the permit language for the bulk loading rack VCU regarding the products that may be loaded in the event the VCU is inoperable and deleted all references to 40 CFR 63, Subpart DDDDD: NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters, as it was removed from the ARM in October 2008. **MAQP #1821-18** replaced MAQP #1821-17.

On February 27, 2009, the Department received a complete MAQP application from CHS requesting clarification of an existing NO_x emissions limit for Boiler #12. In this application, CHS requested that the averaging period for the NO_x lb/MMBtu limit be specified as a 365-day rolling average. CHS submitted information to support this averaging period as the original basis for the BACT analysis conducted in MAQP #1821-17 for Boiler #12. **MAQP #1821-19** replaced MAQP #1821-18.

On August 13, 2009, the Department received a complete application from CHS requesting a modification to MAQP #1821-19. CHS proposed to retrofit the existing Boiler #10 with a lower NO_x control technology burner and to update the permit limits for this unit accordingly. This project was completed on a voluntary basis by CHS in order to improve environmental performance and boiler reliability. On September 17, 2009, the Department received a revision to this application addressing the SO_2 BACT analysis for both Boiler #10 and the recently permitted Platformer Splitter Reboiler. This application revision was submitted in consultation with the Department and revised the SO_2 BACT analysis to reflect the recently finalized NSPS Subpart Ja requirements. **MAQP #1821-20** replaced MAQP #1821-19.

On March 31, 2010, the Department received an application from CHS requesting a modification to MAQP #1821-20. Additional information was received on April 22, 2010, resulting in a complete application. The application and additional information included requests for several modifications within the permit.

During the issuance of MAQP #1821-17, it became apparent that the Department and CHS had differing interpretations of paragraphs 177 and 180 of the CHS Consent Decree (CD) with EPA and the State of Montana (Consent Decree CV-03-153-BLG-RFC). Based on these differing interpretations, CHS deemed it necessary to retroactively analyze previous permit actions, particularly associated with the Delayed Coker Project, where changes may be necessary as a result of interpreting the CD in an alternative manner. On October 26, 2009, CHS provided an analysis concluding that the Delayed Coker Project was properly permitted as a non-major modification under New Source Review (including both PSD and Non-attainment Area New Source Review (NNSR)). For four pollutants (CO, VOC, TSP, and PM-10), project related emissions increases determined under Step 1 of the required applicability analysis were below the applicable significance thresholds. For two pollutants (NOx and SO_2), the net emissions change, including project related emissions increases and contemporaneous emissions changes, were below the applicability significance thresholds. Following review, the Department concurred with CHS' analysis. However, as a result of this re-examination, including updates and changes to the original Delayed Coker Project emissions calculations, the following updates to MAQP #1821-20 were necessary to accurately reflect the refinery's overall process and individual emitting units.

1. Coke Drum Steam Vent

   The original Delayed Coker Permit application did not include an estimate of the emissions associated with depressurizing the coke drum as part of the decoking operation. Based on emissions quantified at another facility, CHS was able to estimate emissions from their Coke Drum Steam Vent. MAQP #1821-21 has been updated to include this emitting unit in addition to the limitations and conditions assigned to it.

2. FCCU Regenerator

   As part of the CD requirements, CHS completed catalyst additive trials at the FCCU in order to reduce NO_x emissions. Upon completion of the trials, CHS proposed short term (7-day rolling average) and long term (365-day rolling average) concentration-based NO_x limits to EPA. CHS proposed a long term concentration limit of 65.1 parts per million, volumetric dry (ppm_{vd}) on a 365-day rolling average basis and a short term concentration limit of 102 ppm_{vd} on a 7-day rolling average basis. EPA has agreed to these proposed limitations and these limits were included within MAQP #1821-21.

3. Boiler 12 and Railcar Light Product Loading Projects

   Originally permitted within MAQP #1821-17, the Boiler 12 and Railcar Light Product Loading Projects were included in the same permit application for administrative convenience only and should not be included as part of the Delayed Coker Project's emissions increase calculations. The Department agrees that the two projects were not substantially related and had no apparent interconnection to each other or to the Delayed Coker Project. The emissions calculations were updated to reflect this conclusion.

4. Shutdown Timing for #4 and #5 Boilers

   Included in the permitting action resulting in MAQP #1821-17 were shutdown dates for Boiler #4 and Boiler #5, which was tied to the initial startup of Boiler #12. Because emissions reductions from the boiler shutdowns were not required to avoid triggering the PSD requirements, the shutdown dates are no longer related to the startup of Boiler #12. The timing is driven by the CD, requiring all NO_x reduction projects (including shutdown of Boiler #4 and Boiler #5) to be completed by December 31, 2011.

5. Benzene Reduction Unit Project Updates

   As a portion of the plan to achieve required NO_x emissions reductions as outlined in the CD, CHS had elected to retrofit the Platformer Heater (P-HTR-1) with low NO_x burners. The proposed retrofit was included in the application for the Benzene Reduction Project (MAQP #1821-18). CHS has determined that the retrofit will no longer be necessary to achieve the CD required NO_x reductions. All emission limitation and monitoring, reporting and notification requirements were removed.

6. Boiler #11 and Boiler #12 BACT Analysis Update

   The original BACT analyses included in the permit applications associated with Boiler #11 and Boiler #12 did not specifically address CO emissions during startup and shutdown operations. During these operations, the boiler may experience an increase in CO emissions as a result of the ultra low NOx burner (ULNB) design. Based on an analysis of data collected during startup and shutdown operations for Boiler #11 and Boiler #12, a short term CO limit of 23 lb/hr on a 24-hour average basis, was included for periods of boiler startup and shutdown. Additionally, CHS proposed installation and operation of a volumetric stack flow rate monitor on Boiler #11 in order to be consistent with Boilers #10 and #12.

In addition to the aforementioned updates, CHS also requested a modification to the stack testing requirements to require stack testing every two years as opposed to annual stack testing for the following sources: Reactor Charge Heater (H-201), Fractionator Feed Heater (H-202), Reactor Charge Heater (H-901), Fractionator Reboiler (H-902), and NHT Charge Heater (H-8301). The Department approved this new testing schedule and MAQP #1821-21 was updated accordingly. Additionally, various miscellaneous administrative changes were requested and included in this permitting action. **MAQP #1821-21** replaced MAQP #1821-20.

On July 27, 2010, the Department received a request to administratively amend MAQP #1821-21. The Department had inadvertently failed to modify all pertinent sections within MAQP #1821-20 to reflect the December 31, 2011, shutdown date for Boiler #4 and Boiler #5. CHS had requested the Department to administratively amend the permit to reflect this shutdown date in all applicable sections within the permit. CHS also requested the Department administratively amend the permit to include a reference to parts per million, volumetric dry (ppmvd) units where hydrogen sulfide (H_2S) limits are expressed in grains per dry standard cubic feet (gr/dscf). The Department made the aforementioned administrative changes. **MAQP #1821-22** replaced MAQP #1821-21.

On November 1, 2010, the Department received an application from CHS requesting a modification to MAQP #1821-22.

"Mild Hydrocracker Project"

In this application, CHS proposed to convert the existing HDS Unit into a Mild Hydrocracker. Capacities of the existing 100 Unit Hydrogen Plant and the Zone D SRU/TGTU were proposed to be increased, the existing feed heater in the FCC Unit replaced and a rate-limiting pressure safety valve (PSV) in the NHT replaced. Collectively, these modifications are referred to as the "Mild Hydrocracker Project." The primary purpose in converting the existing HDS Unit into a Mild Hydrocracker was to produce an increased volume of higher quality diesel fuel by utilizing more hydrogen to convert gasoil into diesel.
The Mild Hydrocracker Project consists of several components. Within the HDS, the following changes were slated:

- As a result of a significant increase in hydrogen consumption, modifications to the existing hydrogen supply and recycle system will be required. The existing C-201B gas-fired reciprocating engine and hydrogen recycle compressor will be replaced with an electric driven make-up hydrogen compressor. Additionally, a new electric-driven recycle compressor (C-203) will be added.

- The first two reactors will continue to contain a hydrotreating catalyst. The third reactor will be split from one bed of catalyst to two beds of catalyst, containing both hydrotreating and hydrocracking catalyst.

- Equipment to be added or modified as a result of volume or heat impacts include the following:

    - A hydrogen bypass line will be added to allow for hydrogen addition both upstream and downstream of the H-201 Reactor Charge Heater.

    - Changes in the separation process downstream of the reactors: Two new drums will be added, Hot and Cold Low Pressure Separators, along with additional heat exchange, including two sets of process heat exchangers, one cooling water heat exchanger and one fin-fan cooler.

    - Trays within the H_2S Stripper will be replaced with higher capacity trays.

    - The overhead condenser and pump associated with the H_2S Stripper Overhead Drum will be modified.

    - A new "wild" naphtha product draw will be added to the H_2S Stripper Overhead Drum. This stream will be processed in the Crude Unit Naphtha Stabilizer and then routed to the NHT Unit.

    - A bypass line for hydrocarbon feed to the Fractionator around the H-202 Fractionator Feed Heater may be added as a result of improved heat integration.

    - The trays in the Fractionator will be replaced with higher capacity trays.

- A new flow loop on the Fractionator will be added returning a portion of the diesel draw to the Fractionator. The pump will also feed the Diesel Stripper. The loop will include a new pump, a fin-fan cooler and a steam generator.

- The trays in the existing Diesel Stripper will be replaced with higher capacity trays.

- New larger pump(s) will be added on the loop between the Diesel Stripper and the Diesel Reboiler. These pump(s) may also be used for diesel product.

- The Diesel Product Cooler (fin-fan) will be replaced with a higher capacity cooler.

- New higher capacity packing will be installed in the HP Absorber. Water circulation on the absorber will be eliminated.

Within the SRU, the following physical changes were proposed:

- Replace and upgrade the acid gas burner;

- Replace the reaction furnace and upgrade to higher pressure and temperature capability;

- Replace and upgrade the waste heat boiler for higher pressure steam generation;

- Replace and upgrade the three steam reheaters;

- Upgrade the #1 sulfur condenser; and

- Add new electric boiler feedwater pumps to accommodate the higher pressure steam generation.

Within the TGTU, the following physical changes were proposed:

- The trays in the quench tower and amine absorber will be replaced with higher vapor capacity trays;

- The cooling system will be improved through increased circulation and minor piping modifications to control the maximum temperature of the circulating amine; and

- The methyl diethanolamine amine (MDEA) used in the absorption section of the TGTU will be replaced with a proprietary high performance amine blend.

Within the 100 Unit Hydrogen Plant, the following changes were proposed:

- Addition of a new H-102 Reformer Heater to operate in parallel with the existing H-101 Reformer Heater;

- Modification of existing boiler feed water (BFW) pumps for increased capacity and a new larger condensate cooler;

- Addition of new pumps to circulate water through the steam generation coil on the new reformer heater;

- Modification of the existing steam drum internals to handle higher steam loads;

- Replace end of life trays within the deaerator tower with higher capacity trays;

- Replace the hot and cold condensate drums with upgraded internals and more corrosion resistant metallurgy;

- Replace absorbent and valves on the PSA skid; and

- Remove equipment related to the use of propane as the feed stream to the 100 Unit Hydrogen Plant.

"ULSD Burner Fuel Project"

The application also included information related to an additional project that is proposed to be completed at the refinery concurrent with the project discussed above. The project involves adding the flexibility to recover additional Burner Fuel, rather than Diesel Fuel, within the existing ULSD unit. The feed rate to the ULSD Unit will not increase with this project.

In addition to the aforementioned projects, CHS requested the Department incorporate several administrative changes.

MAQP #1821-23 replaced MAQP #1821-22.

On January 10, 2011, the Department received a request to administratively amend MAQP #1821-23. In review of the Department Decision for MAQP #1821-23 issued on December 30, 2010, CHS identified areas within the permit that required further clarification based on their comments submitted on the Preliminary Determination issued for MAQP #1821-23.

MAQP #1821-24 replaced MAQP #1821-23.

On April 12, 2011, the Department received an application from CHS for a modification to MAQP #1821-24. The modification request details proposed changes to a *de minimis* request approved by the Department on December 10, 2010 as well as proposed construction of two product storage tanks.

On December 6, 2010, the Department received a *de minimis* notification from CHS proposing construction of a new 100,000 barrel (bbl) storage tank (Tank 133) for the purpose of storing asphalt. Emissions increases as a result of the proposed project were calculated to be less than the *de minimis* threshold of 5 tpy, with no emissions from each of the regulated pollutants exceeding 1.44 tpy. Although CHS justified the project from an economics standpoint for asphalt service only, CHS determined that during the times of year that asphalt storage is not necessary, it would be advantageous to have the extra tank capacity available to store other materials, such as gas oil and diesel. These materials may accumulate in anticipation of or as a result of a unit shutdown. Within the April 12, 2011 application, CHS proposes installation of additional pumps and piping to allow for gas oil and diesel to be stored as well as asphalt as previously approved for Tank 133.

A separate project detailed within the April 12, 2011 application includes construction of two new product storage tanks, collectively referred to as the Tanks 135 and 136 Project. The Tanks 135 and 136 Project would include construction of two new 120,000 bbl external floating roof (EFR) product storage tanks and associated pumps and piping to allow more flexible storage of various gasoline and/or diesel components and finished products produced at the refinery. Tank 135 would be installed in the East Tank Farm located on the east side of Highway 212. With the current refinery piping configuration, this tank would store only finished gasoline and diesel products. Tank 136 would be installed in the South Tank Farm located on the west side of Highway 212. With the current refinery piping configuration, this tank would be available to store both component and finished gasoline and diesel products. To avoid restriction of service of the tanks, project emissions increase calculations were based conservatively on storage of gasoline year round as well as current maximum refinery production capability.

Within the April 12, 2011 application, CHS also provided supplemental information to the BACT analysis included in the original permitting application for the Coker Charge Heater (H-7501) originally permitted as a part of the Delayed Coker project (1821-13 with revisions 1821-14 through 1821-16). This supplemental information was submitted with the purpose of laying the foundation for a proposed additional short term CO emissions limit.

MAQP #1821-25 replaced MAQP #1821-24.

On November 8, 2011, the Department received an application from CHS for a modification to MAQP #1821-25. The application included three separate projects, grouped together into one action for administrative convenience. CHS proposed the following projects within this application:

1. #1 Crude Unit Revamp Project

2. Wastewater Facilities Project

3. Product Blending Project

The application also included the following:

1. Review of the regulatory applicability to existing Sour Water Storage Tanks 128 and 129.

2. Updates to the Mild Hydrocracker Project, which was permitted as part of MAQP #1821-23 and MAQP #1821-24.

3. Review of the regulatory applicability to the Product Storage Projects, which was permitted as part of MAQP #1821-25.

<u>#1 Crude Unit Revamp Project</u>

The #1 Crude Unit Revamp Project was proposed with the intention of improving the overall efficiency of the refinery by maximizing diesel and gas oil recovery in the atmospheric and vacuum processes at the #1 Crude Unit. The project would aid in accounting for changes in crude quality that have been evident historically and are expected in the future. Modifications in the vacuum process are expected to result in an improved separation of the diesel and gas oil components such that diesel will not be carried with the gasoil to units downstream of the Crude Unit. Modifications

in the vacuum process will result in the recovery of additional gas oil from the asphalt and improved quality of feed to the downstream Delayed Coker Unit.

The #1 Crude Unit Revamp Project includes the following key components:

- Improvements to the preheat exchanger trains to ensure additional heat can be added to the crude oil upstream of the atmospheric column.

- Modifications to the atmospheric column from the diesel draw downward and to the associated condensing systems.

- Existing dry vacuum process will be changed to a wet vacuum system through the addition of steam.

- Redesign and replacement of the existing vacuum column.

- Installation of new equipment to recover a diesel stream from the new vacuum column.

- Addition, replacement and/or redesign of overhead and product cooling systems.

Wastewater Facilities Project

The proposed Wastewater Facilities Project is slated to improve the overall performance of the refinery wastewater handling and treatment facilities and to address anticipated future wastewater discharge quality requirements. The project is comprised of the following components:

- Installation of new Three Phase Separator(s) to remove solids and free oil from wastewater generated at the crude unit desalters.

- Installation of new American Petroleum Institute (API) Separator(s) and Corrugated Plate Interceptor (CPI) Separator(s) to treat process wastewater generated at the older process units. The existing API Separator will be removed from service. As a note, emissions from the separators will be controlled with carbon canisters.

- Replacement of the existing activated sludge unit (ASU) (T-30). Replacement will be of the same size and will incorporate several design changes to improve the biological treatment efficiency.

- Installation of a second ASU and clarifier to be operated in parallel with the existing ASU and clarifier and will provide maintenance backup to the system.

- Installation of two new Sludge Handling Tanks to receive waste activated sludge from the clarifiers. The removed sludge will be dewatered and dried for offsite disposal.

- Installation of two new DAF Units to treat process wastewater from all of the process units. Emissions from the DAF Units will be controlled with carbon canisters. The existing DAF will be removed from service.

Product Blending Project

The objective of the Product Blending Project is to increase the volume of finished diesel and burner fuel available for sale. The project is comprised of the addition of new piping components; however, the changes will not result in a change to the operation of any process units at the refinery.

Additional Permit Changes

CHS conducted a review of regulatory applicability pertaining to sour water storage tanks 128 and 129, which were permitted as a result of CHS's permit application submitted on October 18, 2005, for the delayed coker project. Based on the review, CHS determined Tanks 128 and 129 to not be subject to 40 CFR 60 (NSPS) and also determined Tanks 128 and 129 to be labeled as Group 2 storage vessels as described within 40 CFR 63, Subpart CC. Therefore, CHS requested the permit, specifically the Title V Operating Permit, be updated to reflect these new determinations of regulatory applicability.

As part of MAQP #1821-23, CHS proposed to convert the existing Hydrodesulfurization (HDS) Unit into a Mild Hydrocracker. Since issuance of this permit, various portions of this project scope were modified, with only one change resulting in a change in the original project emissions calculations. Potential emissions increased slightly; however, continued to remain below significance levels with respect to Prevention of Significant Deterioration (PSD) review. A summary of the updated emissions inventory was included in the permit analysis for this permit action.

CHS additionally conducted a review of regulatory applicability pertaining to Tanks 133, 135, and 136. As part of the original permitting action (MAQP #1821-25) associated with these product storage tanks, CHS identified the applicability of NSPS Subpart GGGa to the piping components associated with the three new storage tanks. This applicability has been reevaluated. NSPS Subpart GGGa applies to affected facilities at petroleum refineries that are constructed, reconstructed or modified after November 7, 2006. Specifically, as stated within NSPS Subpart GGGa, the group of all the equipment (defined in §60.591a) within a process unit is an affected facility. The definition of "process unit," as defined in 60.590a(e) is as follows:

"*Process unit* means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product."

The applicability of NSPS Subpart GGGa has been determined to stop at the boundary of a process area and does not include piping components between the process area and storage tanks, therefore, eliminating the components associated with Tanks 133, 135, and 136 from being applicable to NSPS Subpart GGGa. Although this equipment is not specifically applicable under NSPS Subpart GGGa, the VOC BACT (Refinery Equipment) determination from MAQP #1821-25 stated that "an effective monitoring and maintenance program or Leak Detection and Repair (LDAR) program (as described under NSPS Subpart VVa) meeting the requirements of NSPS Subpart GGGa constitutes VOC BACT for equipment leaks from new components." The Department modified the requirements for institution of a monitoring and maintenance program to more accurately reflect the VOC BACT (Refinery Equipment) determination; thus removing the NSPS Subpart GGGa reference and including the pertinent language within the condition itself. The conditions are now reflective of only the BACT determination.

CHS also requested several various administrative changes and clarification additions.

MAQP #1821-26 replaced MAQP #1821-25.

On June 4, 2012, CHS Inc. submitted a permit application to the Department to modify MAQP # 1821-26 and Title V Operating Permit (OP) #OP1821-10. The application was submitted to modify two previously permitted refinery projects, and to construct a new gasoline and diesel truck loading facility as summarized below:

Mild Hydrocracker (MHC) Project Update. This permit action incorporated the final design and location of the Fluid Catalytic Cracking (FCC) Charge Heater being replaced as part of the MHC Project. The FCC Charge Heater was originally approved at 60 million british thermal units per hour (MMBtu/hr) as part of the MHC project (MAQP #1821-23). This permit application modified the size of the heater from 60 to 66 MMBtu/hr. In addition, the permit application reclassified the FCCU Reactor/Regenerator as a "modified" emitting unit rather than an "affected unit," and CHS requested to replace the existing Riser with a new Riser (and Riser design) as the current Riser was nearing the end of its mechanical life.

Benzene Reduction Unit (BRU) Project Update. This project involved a modification of the H-1001 Reformer Heater to achieve the design hydrogen production rate within the 1000 Unit Hydrogen Plant. Expansion of the 1000 Unit Hydrogen Plant was included in the MAQP #1821-18. However, the 1000 Unit Hydrogen Plant expansion changed the characteristics of the PSA tailgas (e.g. the heat content (Btu per standard cubic feet (Btu/scf) declined and the volume produced increased (standard cubic feet per minute (scfm)). According to CHS, the total heat input associated with the PSA tailgas remained nearly the same. As a result, the existing PSA tailgas burners on the H-1001 Reformer Heater could not handle the increased volume of PSA tailgas without excessive pressure drop and the 1000 Unit Hydrogen Plant production rate became limited by the volume of PSA tailgas that could be combusted. The permit modification replaced the PSA tailgas burner tips with tips that have larger ports such that all of the PSA tailgas generated could be combusted in H-1001. CHS proposed replacement of the supplemental fuel (e.g. natural gas, refinery fuel gas) burners in H-1001 to achieve improved NOx emission performance. The previous heater was physically capable of combusting refinery fuel gas but could not meet the existing oxides of nitrogen (NOx) permit limits while doing so. Additionally, the modified heater will have a higher maximum design firing rate (191.8 MMBtu-HHV/hr post project versus 177.7 MMBtu-HHV/hr) and a slight increase in the actual firing rate.

Gasoline and Distillate Truck Loading Facilities Project. This permit application also proposed the construction of new gasoline and distillate truck loading facilities, including new storage tanks, loading rack and VCU. The goal of the project was to improve safety and reduce truck congestion by relocating the gasoline and distillate truck loading operation to the east side of Highway 212. As proposed by CHS, the existing truck loading rack and associated equipment will be permanently removed from service within 180 days of startup of the new loading facility. The permit modification also added a new propane storage and loading facility.

In addition to those items mentioned above, this permit action included miscellaneous updates and amendments. CHS requested to discontinue use of the sulfur dioxide (SO_2) Continuous Emissions Monitoring System (CEMs) on the H-1001 stack because H-1001 was subject to 40 Code of Federal Regulations (CFR) 60, Subpart Ja which included exemptions from hydrogen sulfide/sulfur dioxide (H_2S/SO_2) monitoring requirements for fuel gas streams that are inherently low in sulfur content. The primary fuel to H-1001, PSA tailgas is inherently low in sulfur content. CHS already monitors the H2S content of the refinery fuel gas (RFG) to be combusted in H-1001 as supplemental fuel, which would meet the monitoring requirements of Subpart Ja.

CHS requested that the Department remove condition IV.E.4 which requires the use of statistically significant F-factor values in determining compliance with NOx and carbon monoxide (CO) limits for the H-102 Reformer Heater. Rather, CHS proposed that results of the required performance testing be used to calculate an appropriate emission factor to demonstrate ongoing compliance with NOx and CO limits.

CHS also requested several various administrative changes and clarification additions.

MAQP #1821-27 replaced MAQP #1821-26.

On November 14, 2012, CHS Inc. submitted a request to the Department to amend several items in the MAQP. CHS requested that the Department remove existing gasoline and distillate loading rack and associated VCU from the new VOC limit in Sections VI and XVI of the MAQP. CHS provided clarification that they intend to permanently shut down the existing propane loading rack but not the existing propane storage facilities as was previously stated in the CHS permit application. In MAQP #1821-27, CHS proposed replacement of the burners in the H-1001 Reformer Heater. However, the firing rate and associated limits only apply once the heater has restarted after the retrofit. The Department clarified this by adding the limitations previously listed in MAQP #1821-26 back into the permit. In addition to those changes mentioned above, CHS requested several various administrative changes and clarifications.

MAQP #1821-28 replaced MAQP #1821-27.

On January 22, 2013, CHS Inc. submitted an application for a modification to MAQP #1821-28. As a result of the Mild Hydrocracker Project, the quantity of gasoil converted to diesel will generally increase and the quantity converted to gasoline will generally decrease. This will result in a lower rate of gasoline production at the FCCU and the downstream Alkylation Unit. According to CHS, these refinery gasoline component streams have relatively high octane ratings and are typically blended with gasoline component steams that have lower octane ratings to meet product octane specifications. CHS has determined that there may be times following the Mild Hydrocracker Project's startup that the refinery will not be able to produce enough of the higher octane gasoline components necessary to meet the minimum octane product specifications. As a result, CHS proposed to complete the Gasoline Component Unloading Project as included within the January 22, 2013 application. CHS also indicated that the impact from the MHC Project is not the only justification for completing the Gasoline Component Unloading Project. CHS anticipates that there may be other market-driven factors that will require CHS to increase or decrease the octane rating of its gasoline product in the future.

The January 22, 2013 application contained information necessary to incorporate permit changes associated with CHS's proposal to install the facilities necessary to unload various gasoline components from railcars to existing storage tanks such that these components can be blended into refinery products. The Gasoline Component Unloading project is considered an aggregate part of the previously approved Mild Hydrocracker Project and therefore, was evaluated as such for purposes of determining its regulatory applicability with respect to PSD applicability.

In addition to the proposed Gasoline Component Unloading project, CHS also requested the following changes to BACT permit conditions and monitoring requirements associated with the H-1001 Reformer Heater, FCC Charge Heater, and Gasoline and Distillate Truck Loading Rack VCU.

- For H-1001 and the FCC Charge Heater, CHS requested that permit conditions expressed in terms of MMBtu be removed from the permit and that permit limits in terms of mass (i.e. lb/hr and tons per rolling 12-calendar month total) be maintained.

CHS offered the following explanation for removal of these permit conditions:

> *The H-1001 Reformer Heater utilizes two fuel sources. The PSA tailgas fuel stream is generated within the 1000 Unit Hydrogen Plant and supplies the majority of the fuel required by the heater during normal operation. The supplemental fuel source is either refinery fuel gas (RFG) or natural gas. The RFG has a relatively consistent BTU content and is monitored through existing systems including an online process GC (i.e. not a CEM) and lab analysis of grab samples such that the composition and subsequently the BTU content of the RFG is characterized on a regular basis. In contrast, the PSA tailgas fuel stream has a BTU content that can vary significantly over the course of a day or week. Additionally, it does not have an online GC or a reliable grab sampling system such that its BTU content can be characterized in a frequent or accurate enough manner to be useful in assuring compliance with limits based on short term measurements of the fuel BTU content. CHS estimates that due to the sampling issues only 20% of the samples collected of the 1000 Unit PSA tailgas are valid samples. In consideration of this issue, CHS proposed in the comments to the Preliminary Determination for MAQP #1821-27 that a stack flue gas flow rate monitor be installed for use along with the existing NOx and CO CEM to demonstrate compliance with mass emission limits in place of the proposed limits expressed in terms of MMBtu. CHS believes this approach is appropriate for the following reasons:*
>
> - *The proposed mass emission limits were derived by simply multiplying the MMBtu-based limits together;*
> - *The mass limits better accomplish the goal of restricting the short and long term emissions from the H-1001 Reformer Heater through the use of continuous concentration and flow monitors rather than determining an average of a number of grab samples; and*
> - *The mass limits are expressed in terms the CHS Operations staff has the ability to monitor in order to ensure continuous and ongoing compliance.*

As requested, the Department removed the permit conditions expressed in terms of MMBtu for the H-1001 Reformer Heater and the FCC Charge Heater.

- As included within the application for MAQP #1821-27, CHS proposed to install a new gasoline and distillate truck loading facility, which included an associated VCU as the control device for vapors displaced from the truck during the loading process. CHS identified BACT for the loading rack as a VCU that controls VOC emissions to a

maximum of 10 mg/l of gasoline product loaded. The new loading rack is subject to 40 CFR 63, Subpart CC (NESHAP for Petroleum Refineries) requirements, which requires the loading rack to the meet the requirements of 40 CFR 63 Subpart R. CHS requested that the BACT permit monitoring requirement be updated to more closely reflect the Subpart R requirement. The Department modified the condition as requested.

MAQP #1821-29 replaced MAQP #1821-28.

On April 15, 2013, CHS Inc. submitted an application for a modification to MAQP #1821-29. The application was submitted concurrently with CHS's request for renewal of Operating Permit OP1821-10 and included the following:

- 40 CFR 60, Subpart J applicability updates: Conditions indicating NSPS Subpart J applicability to all CHS Refinery's fuel gas combustion devices were updated to reflect NSPS Subpart Ja requirements, where necessary.

- Clarification of 40 CFR 60, Subpart Ja applicability: Specific to Boiler #12, CHS requested that the MAQP be clarified to reflect that Boiler #12 meets the NSPS Subpart Ja definition of a "fuel gas combustion device" requiring compliance with the SO_2 emission limit or the H2S in fuel gas limit.

- Railcar Light Product Loading Rack NESHAP applicability: Based on the facility's SIC code, 40 CFR 63, Subpart CC applies to the light product loading racks and 40 CFR 63, Subpart R does not apply. CHS requested clarification of this applicability within the MAQP.

- 40 CFR 60, Subpart GGGa applicability updates: The MAQP identified applicability of NSPS Subpart GGGa to refinery fuel gas supply lines to Boiler #12. However, because Boiler #12 commenced construction after November 7, 2006, it is subject to NSPS Subpart GGGa.

- 40 CFR 60, Subpart VV/VVa applicability updates: NSPS Subpart VV or VVa apply to affected facilities in the Synthetic Organic Chemical Manufacturing Industry (SOCMI). The CHS refinery is not classified as a SOCMI industry. The LDAR rules that apply to the CHS refinery include NSPS Subparts GGG and GGGa and MACT Subpart CC. Each of these rules reference specific conditions in NSPS Subpart VV and VVa, CHS proposed reference only GGG or GGGa.

- Consent Decree reference updates: Several conditions in the MAQP still contained references to the consent decree where obligations have been met. CHS requested to have these references removed.

- References to Billings/Laurel SO_2 Emissions Control Plan, as approved into the SIP: CHS requested corrections be made to the MAQP where the SO_2 SIP was referenced incorrectly.

- "Plant-Wide" Emissions Limits: Since issuance of MAQP #1821-05, inadvertently, changes have been made to the original list of emitting units to be included in these emission caps for each pollutant. Additionally, as a result of the addition and removal of

various emitting units since the creation of these emission caps, the term "plant-wide" is no longer appropriate. CHS requested the list be corrected and the term "plant-wide" removed from the permit.

- Administrative Amendments: CHS requested various administrative changes be incorporated into the MAQP.

MAQP #1821-30 replaced #MAQP 1821-29.

On August 13, 2013, the Department of Environmental Quality's Air Resources Management Bureau received from CHS an application for modification of the MAQP and the associated Title V permit to modify limits for the H-901 and H-902 process heaters.

The H-901 heater is fired on refinery fuel gas, and its function is to heat the feed into the hydrogenation reactor, which serves to remove sulfur from the process stream. The sulfur reducing process occurs through what is called the Ultra Low Sulfur Diesel (ULSD) reactors. Heat is required by the H-901 process heater to assure the Ultra Low Sulfur Diesel reaction occurs with the appropriate sulfur removal efficiency required to make low sulfur fuels specifications.

The H-902 heater is also fired on refinery fuel gas, and this heater heats the sulfur- reduced process stream for fractionation and stripping back into naphtha, #1, and #2 diesel. An increased amount of heat from the H-902 heater provides for increased recovery of #1 diesel by allowing for increased stripping rates.

Due to changes in the quality of crude oil and the ULSD feed, which affects the sulfur removal process, increased market demand for #1 diesel, and other changes which have affected the refinery fuel gas system characteristics; CHS proposed to increase emissions limits on the H-901 and H-902 heaters. The H-901 and H-902 mass rate-based emission limits were originally determined in MAQP #1821-09. These limits were based on the heat input rate of the heaters, and the emissions rate guarantee of the ultra low oxides of nitrogen (NO_x) burner design selected as BACT. The design of the burners was based on a NO_x pound per million British Thermal Units (lb/MMBtu) guarantee. In the MAQP #1821-09 application, the maximum rated heat input capacity of the heaters were presented based on the maximum expected process heat input requirements of the heaters at that time. Limitations in the form of tons per rolling twelve (12) month period and pound per hour were accepted by CHS based on the expected needs of the burners.

CHS proposed to increase the heat input component of the emission limit calculation, maintaining the Ultra-Low NO_x Burner performance on a lb/MMBtu basis, and allowing for a higher firing rate in each heater. The proposed increased NO_x, carbon monoxide (CO), and volatile organic compounds (VOC) emission limits are based on an increase in maximum heat rate input from 27.46 million British thermal units per hour (MMBtu/hr) to 32.60 MMBtu/hr on the H-901 heater, and from 55.26 to 65.10 MMBtu/hr on the H-902 heater, on a higher heating value basis. CHS did not request to increase allowable oxides of sulfur limits.

CHS also proposed to monitor emissions rates from the H-901 and H-902 heaters through use of Continuous Emissions Monitoring Systems (CEMS). This method supports increased compliance monitoring abilities for CHS, allowing for quicker compliance status determinations. At the request of CHS, the Department incorporated this compliance demonstration method.

Because this action relaxed previously assigned permit limits at a major source, CHS presented a Prevention of Significant Deterioration (PSD) look-back to fulfill the requirements of ARM 17.8.827. This rule requires that if a permit limit is relaxed, it must be demonstrated that PSD was not circumvented during previous permit actions that relied on the more stringent permit limit. Because the heaters' capacities are larger than originally presented in 2003, CHS provided demonstration that if the associated increased capacity had been recognized in the 2003 application, and also in association with other associated projects applied for after 2003, it would not have made the ULSD project or the other associated projects subject to PSD. This analysis is included within the application on file with the Department.

MAQP #1821-31 replaced MAQP #1821-30

On October 21, 2013, CHS Inc. submitted concurrent applications for a modification to MAQP #1821-31 and OP1821-12. When the modification was received, permit actions were also under way for updates OP1821-13 and OP1821-14. According to Department policy, permit actions are assigned numbers according to the order in which they are received, regardless of when they are issued. Therefore, OP1821-15, may be issued before either of the actions under OP1821-13 and OP1821-14.

Under the request, CHS proposed to add a new 100,000 barrel (approximately 4,040,000 gallons) intermediate storage tank. The proposed tank was identified as Tank 146 and would be a vertical fixed roof tank capable of storing sour gas oil, sweet gas oil, light coker gas oil, or raw diesel. Due to the physical properties of sweet and sour gas oil, a steam coil was also proposed be installed in Tank 146 to reduce the viscosity to a point for pumping purposes.

MAQP #1821-32 replaced MAQP #1821-31.

On July 31, 2014, the Department received from CHS an application for replacement of the main refinery flare. The flare was reaching the end of its mechanical life, and was in need of replacement. The replacement flare is subject to New Source Performance Standards (NSPS) Subpart Ja (40 CFR 60 Subpart Ja), as well as 40 CFR 60.18 (Control Device and Work Practice Standards) and 40 CFR 63.11 (Control Device and Work Practice Requirements). Proposed as part of the main flare replacement project, was installation of a flare gas treatment and recovery system. Vent gases captured in the recovery system will be directed to amine treatment for removal of reduced sulfur compounds and returned to the refinery fuel gas system to be burned in fuel gas combustion units (displacing natural gas usage). During times when the amount of captured vent gases exceeds the flare gas recovery system capacity, the gases would pass through the liquid seal of the flare for destruction of the gas by combustion in the flare. Combustion of these gases is necessary to destroy the various components which would otherwise have potential to be emitted in amounts which would pose serious threat to human health and the environment.

CHS submitted as part of the flare replacement application a proposal to replace the current Zone D Sour Water Stripper with a new Two Stage Sour Water Stripper. The Zone D Sour Water Stripper was undersized for the amount of nitrogen content being seen in some crude oil supplies to CHS. Because flare gas recovery will result in additional sour water which must be treated, the needed upsizing of the Zone D Sour Water Stripper could also be determined related to the current flare project from a New Source Review (NSR) perspective, as sizing of the Sour Water Stripper would need to include the additional needs created by the flare gas recovery system. The new Sour Water Stripper allows the refinery to increase wash rates. The process generates two vent streams; one rich in reduced sulfur compounds that will be processed at the Sulfur Recovery Units, and one rich in ammonia, which will have some reduced sulfur and hydrocarbon as well. The ammonia stream will

be sent to a caustic-based scrubber and ammonia combustor. The combustor is subject to Montana Code Annotated 75-2-215 incinerator review, as well as Best Achievable Control Technology review. Selective Catalytic Reduction control technology was required to control Oxides of Nitrogen from the combustion process, and waste heat in the ammonia combustor exhaust used to generate steam.

On August 27, 2014, the Department received supplemental information from CHS regarding additional scope of the flare gas recovery project. CHS proposed that the Zone E Flare (known as the Coker Flare), be equipped with a seal and necessary piping to provide for recovery of the Zone E flare gases. Zone E flare gas could go to the same refinery fuel gas treatment and recovery system, or through the Zone E Amine unit and to Zone E refinery fuel gas consumers.

In addition, administrative updates were made to remove language pertaining to timing of applicability of certain conditions or initial testing and notification requirements which are no longer applicable. Changes recognized in these updates include completion of conversion of the hydrodesulfurization unit to the mild hydrocracker, replacement of the C-201B compressor with an electrically driven compressor, update of the #1 Crude Unit's NSPS applicability, completion of the H-1001 burner retrofit, and installation of the new FCC charge heater. **MAQP #1821-33** replaced MAQP #1821-32.

On November 7, 2014, the Montana Department of Environmental Quality (Department) received from CHS an application for three separate projects, as discussed below:

Crude Blending Project:

Over time, the quality of the crude oil supply to CHS has declined and become more variable. CHS proposed to install two new crude oil storage tanks each with a capacity of approximately 200,000 barrels. The tanks, used in conjunction with existing crude oil storage tanks, would provide improved segregation of crude oils with different characteristics such that an optimum crude oil blend can be supplied to the #1 and #2 Crude Units. As a result of optimizing the crude feed quality, the feed rate to each of the Crude Units may be able to increase by as much as 3,000 barrels per day, therefore, the increased utilization of the crude units, as well as the Ultra-Low Sulfur Diesel, Naphtha Hydrotreater, and Platformer Units, are accounted for in the project review. With exception of the new tanks and related piping, no physical modifications to existing equipment were proposed.

Tank 147 Project:

CHS installed a new 100,000 barrel capacity fixed roof tank (Tank 147) to be used for the storage of intermediate products. Installation of this tank allows CHS to better manage inventories during maintenance outages and to reduce the frequency of service changes for tanks that have multiple service capabilities.

This tank is insulated and heated to keep the intermediate at a workable viscosity, and designed with a natural gas blanketing system to avoid oxygen from contacting the stored intermediate products, to avoid downstream fouling. This project resulted in more tanks in dedicated service, but not in the ability to process additional crude oil or produce additional product on an annual basis.

Coke Trucking Project:

CHS added truck shipping of Petroleum Coke to the refinery. At times, due to railcar availability issues, the refinery must reduce production rates due to the limited petroleum coke storage. This project utilized the existing railcar loading system to load trucks when needed. This project did not require modification of any existing emission unit; however, the addition of fugitive road dust emissions is expected.

Administrative Changes:

CHS submitted to the Department the specification sheets for the flare gas recovery system compressors. The specification sheets demonstrate to the Department's satisfaction the size requirements identified in MAQP #1821-33. CHS suggested, and the Department agrees, that demonstration of compliance with the design of the flare gas recovery system compressors is most straightforward by requiring the make and model noted on the specification sheets to be installed. The condition regarding size of the compressors was replaced with language requiring that the specific make and model compressors be installed.

CHS also requested that the 'new' flare be referred to utilizing different terminology, for clarification purposes from an NSPS perspective. The Department updated the permit language as requested.

CHS requested that the requirement to monitor O_2 on the H-901 and H-902 heaters be removed. NO_X CEMS is required, including a flowrate monitor; however, the need for O_2 monitoring is not necessary because the relevant emissions limit for this condition is on a lb/hr basis. The Department removed the requirement for the NO_X CEMS as required by this condition to include an O_2 monitor. **MAQP #1821-34** replaced MAQP #1821-33.

On September 16, 2015, the Department received an application from CHS for a large expansion to the existing refinery. Throughout the permit, the project will be referred to as the Grassroots Hydrocracker Project (GRHC). The permit action includes information submitted to process the MAQP application for both New Source Review and Prevention of Significant Deterioration (PSD) requirements. The primary objective of the GRHC project is to increase the diesel production capacity at the refinery. The GRHC will expand diesel production with the addition of a new Hydrocracker (HC) Unit and supporting Hydrogen Plant (HRU). To accommodate the new HC, modifications will be made within the existing #1 Crude Unit (#1 CRU), Mild Hydrocracker (MHC) and Fluidized Catalytic Cracking Unit (FCCU). To allow for increased product shipment by rail, the capability of the existing light product railcar loading rack will be expanded. The GRHC will also include the installation of two new tanks and an increase in the amine treatment capacity at the refinery.

The new HC will be designed to process approximately 25,000 barrels per day of feed. The unit will include three fired heaters including two identical Reactor Feed Heaters each with a design heat input capacity of 75 MMBtu/hr (HHV) and a Fractionator Feed Heater with a design heat input of 126.3 MMBtu/hr (HHV).

The new HRU will include a fired heater with a design heat input capacity of 562 MMBtu/hr (HHV). The reformer type hydrogen unit will be designed to provide up to 40 MMSCFD of hydrogen. In addition to supporting the increased hydrogen demand associated with the project, the new HRU will also increase the reliability of the hydrogen supply at the refinery. Although not related to the GRHC project, the application also included a request to modify the short term NOx

permit limit for H-102. This change would provide for a 0.43 lb/hr increase in NOx and account for higher concentrations of H2 in the fuel gas. This proposed change was also included in the modeling analysis for the GRHC and included in the BACT analysis where H-102 and other conventional heaters were all proposed for a 0.035 lb/MMBtu BACT limit.

Note: An application assigned **MAQP #1821-35** was submitted but later withdrawn and therefore, MAQP #1821-35 does not exist. **MAQP #1821-36** replaced MAQP #1821-34.

On August 1, 2016, the Department received from CHS an application for modification of the Montana Air Quality Permit. CHS proposed to increase the size of the crude blending tanks originally permitted in MAQP #1821-34. Because, over time, the quality of the primary crude oil supply to the Laurel Refinery has declined and become more variable, the utilization of process units downstream of the crude units has declined as the feed rate to the crude units has declined. The crude blending project was originally permitted in MAQP #1821-34. The proposed permit modification (MAQP #1821-37) was to provide improved segregation of crude oils with different characteristics with the goal of enabling blending of the crude oil to allow more utilization of the existing refining process. No physical change was proposed to any other refining equipment. As a result of increased utilization of existing capacity, an increase in actual emissions was expected from the operational change. The project did not trigger the Prevention of Significant Deterioration (PSD) program because increases in actual emissions were less than PSD program thresholds. The tanks were subject to Best Available Control Technology (BACT) review through Montana's minor source permitting program which was presented in the Permit Analysis section of the permit. This action permitted the increase in crude oil tank sizes and reviewed the action as if the tanks were new emission sources.

In addition, CHS proposed various administrative changes to the permit to remove notification and reporting requirements associated with previous projects which were completed. The requirements that were fulfilled and are no longer necessary were updated accordingly. **MAQP #1821-37** replaced MAQP #1821-36.

On May 11, 2017, the Department of Environmental Quality – Air Quality Bureau (Department) received from CHS an application for modification of MAQP #1821-37. CHS proposed two separate unrelated projects within the same application. The first project would have added a thermal combustor (incinerator) to control emissions from the water oil separators, dissolved flotation units, and a new wastewater surge tank. On May 25, 2017, CHS submitted a letter withdrawing this portion of the project while confirming the modification for the second project. The second project increased the amount of petroleum coke shipped off-site using trucks. The MAQP limited the number of trucks to 1000 trucks per year on a rolling 12-month basis. This equated to 43,500 tons based on each truck carrying 43.5 tons of petroleum coke. CHS requested to increase the allowable truck shipments to a total of 175,200 tons of coke per year determined monthly on a rolling 12-month total. This was calculated based on 5,840 trucks on a rolling 12-month basis assuming 30 tons per truckload. No physical change was proposed to any other refining equipment. As a result of increased utilization of existing capacity, an increase in actual emissions was expected from the shipping change from rail to trucks. The project did not trigger the Prevention of Significant Deterioration (PSD) program because increases in actual emissions are less than PSD program thresholds. **MAQP #1821-38** replaced MAQP #1821-37.

On July 27, 2017, the Department received an application from CHS for modification of their Montana Air Quality Permit. The requested change provided for a new type of catalyst to be installed into the Ultra Low Sulfur Diesel (ULSD) reactor. The new catalyst resulted in additional

hydrogen usage due to its higher reaction rates. The additional hydrogen required came from the new hydrogen plant which was part of MAQP #1821-36 issued on December 16, 2015, as part of the Grass Roots Hydrocracker Project (GRHC). Since the catalyst change was not possible without the additional hydrogen produced from the GRHC Project, this project was technically dependent upon the original GRHC Project. Therefore, this application updated the GRHC project to include the catalyst change-out, updates the netting analysis, and all elements required for a complete Prevention of Significant Deterioration (PSD) application. Actual emissions used for the analysis were determined to be representative of normal source operation. All elements associated with PSD permit applications were followed, including public notice to Federal Land Managers. The Best Available Control Technology (BACT) analysis submitted in this revised PSD action also re-established a new construction time-frame for the GRHC Project. From the date of issuance of the final MAQP, the BACT analysis remains effective for another 18-month period. **MAQP #1821-39** replaced MAQP #1821-38.

On May 17, 2018, the Department received an application from CHS for modification of their Montana Air Quality Permit. The requested change proposes to increase the sulfur dioxide (SO_2) ton per rolling 12-month total limit and update the SO_2 Best Available Control Technology (BACT) limits for the Zone D Sulfur Recovery Plant (SRP). The requested changes are largely the result of unforeseen impacts from the installation of the Flare Gas Recovery System in 2015 which provided for large facility-wide reductions in SO_2 but increased the process variability in the gas stream exiting the Zone D tail gas treatment unit (TGTU) and upon combustion in the tail gas incinerator (TGI) results in higher SO_2 emissions. This increase in sulfur content eliminated the operational compliance margin with the current Zone D SO_2 annual limit. Further, the requested changes address short-term operation during normal operation of the SRP and aligned the short-term BACT limit with averaging periods and concentration consistent with 40 CFR 60 Subpart Ja, for sulfur plants; and for startups and shutdowns proposes practices consistent with 40 CFR 63 Subpart UUU - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units as BACT. As these proposed changes span several projects dealing with Zone D SO_2 emissions at the refinery; the new Zone D SO_2 annual limit was reviewed relative to previous Non-attainment Area New Source Review (NNSR) decisions to ensure the earlier prevention of significant deterioration (PSD) NNSR determinations would not have resulted in any of those projects becoming a major modification. This review confirmed the previous permitting actions analyzed within this action continue to be non-major modifications under PSD and NNSR. **MAQP #1821-40** replaced MAQP #1821-39.

On September 7, 2018, the Department received an application from CHS for modification of MAQP #1821-40. The requested change proposed to add a thermal combustor as a control option for the API separator and Dissolved Air and Nitrogen Flotation (DAF/DNF) vents. Going forward this equipment will be referred to as the Dissolved Gas Flotation (DGF) vents. Currently, the DGF vents are controlled using carbon adsorption. This request allows for either a thermal combustor or carbon adsorption to be used to control the emissions. The purpose of the request was to address the high cost of carbon replacement and provide an additional emissions control option. CHS provided an analysis of the proposed project, and associated emissions increases, and demonstrated the project is below Prevention of Significant Deterioration (PSD) thresholds. The thermal combustor was expected to have a higher control efficiency versus carbon but each control option would be approved for control. Because the thermal combustor meets the definition of an incinerator under MCA 75-2-103(11), CHS also provided a human health risk demonstration for the project. **MAQP #1821-41** replaced MAQP #1821-40.

Title V Operating Permit History

CHS's Title V **Operating Permit #OP1821-00** was issued final & effective on November 11, 2001. On May 12, 2006, the Department received an application for the renewal of Title V Operating Permit #1821-00. The application was deemed administratively complete on June 12, 2006 and technically complete on July 11, 2006. Permit #OP1821-01 incorporates all applicable source changes since the issuance of Permit #OP1821-00, including:

- Addition of three new emitting units: #EU021 (ULSD and Hydrogen Plant), #EU022 (Delayed Coker Unit), and #EU023 (Zone E SRU and TGTU);

- Incorporation of Consent Decree CV-03-153-BLG-RFC requirements. This included updating the Title V Operating Permit with a number of specific new emission limits and monitoring requirements which had been included in the most recent MAQP #1821-15, as well as adding a general requirement for CHS to comply with the relevant applicable terms and conditions of the Consent Decree (most importantly, the Affirmative Relief/Environmental Projects, Subsections A-M, (excluding the stipulated penalty components)); and

- Inclusion of new regulations impacting CHS, including three MACT standards: 40 CFR 63, Subpart UUU, Subpart ZZZZ, and Subpart DDDDD.

On October 4, 2007, CHS appealed Operating Permit #OP1821-01 on the basis of the inclusion of the entire Consent Decree CV-03-153-BLG-RFC. CHS' contention was that ARM 17.8.1211(2) only allows consent decree requirements to be included that are as a result of non-compliance with a specific rule or regulatory requirement. The Department included the Consent Decree because it considered the Consent Decree requirements as relevant terms and conditions required to be included in the Title V Operating Permit. The following language (and changes to the permit as described below) satisfy both CHS and the Department with respect to inclusion of Consent Decree requirement into the Title V Operating Permit:

> *"CHS has entered into a Consent Decree (United States et al v. CHS Inc., Civil Action CV-03-153-BLG-RFC (D. Mont. February 23, 2004)). Certain consent decree emission limits, standards, and schedules have been incorporated as term and conditions of the permit, into the appropriate sections of this permit. Other consent decree requirements are considered program enhancements and are not included as terms or conditions of the permit. These requirements, found in Appendix F of the permit, may be enforced by the State of Montana and the United States Environmental Protection Agency pursuant to the provisions of the consent decree."*

Operating Permit #OP1821-01 replaced Operating Permit #OP1821-00.

On October 10, 2007; February 25, 2008; November 7, 2008; and February 27, 2009, the Department received significant modification applications from CHS. The significant modifications included:

- An increase in the firing rate of the NHT Charge Heater (H-8301) to address an operating scenario that was overlooked during the delayed coker unit design process **(application #OP1821-02**);

- The installation of a new steam generating boiler (Boiler #12), expansion of the existing railcar light product loading facilities, as well as an alternative coke handling practice **(application #OP1821-03**);

- The construction of a Benzene Reduction Unit to comply with the Mobile Source Air Toxics Rule **(application #OP1821-04**); and

- Clarification of the averaging period applicable to the Boiler #12 NO_x permit limit (#OP1821-05).

All of these significant modifications were issued under Operating Permit #OP1821-05. **Operating Permit #OP1821-05** replaced Operating Permit #OP1821-01.

The following series of applications and supplemental information triggered MAQP actions and subsequently called for modifications to Operating Permit #OP1821-05.

- August 13, 2009: CHS proposed retrofitting the existing Boiler #10 with a lower NO_x control technology burner and to update the permit limits for this unit accordingly. This project was completed on a voluntary basis by CHS in order to improve environmental performance and boiler reliability.

- September 17, 2009: This information comprised of a revision to the August 13, 2009 application addressing the SO_2 BACT analysis for both Boiler #10 and the recently permitted Platformer Splitter Reboiler. This application revision was submitted in consultation with the Department and revised the SO_2 BACT analysis to reflect the recently finalized NSPS Subpart Ja requirements. (These modifications would have been issued under **Operating Permit #OP1821-06**; however, were combined with the two modification requests that follow.)

- March 31, 2010: CHS proposed modifications associated with the results of retroactively analyzing previous permit actions, particularly associated with the Delayed Coker Project. This application and additional information included requests for several modifications within the permit. These requests have been outlined above within the MAQP history outlining the changes that resulted in MAQP #1821-21.

- July 27, 2010: This administrative amendment request consisted of the addition of ppm_{vd} units where H_2S limits are expressed in gr/dscf and also included the December 31, 2010 shutdown date for Boiler #4 and Boiler #5.

Operating Permit #OP1821-07 incorporated these aforementioned MAQP actions and replaced Operating Permit #OP1821-05.

On November 1, 2010, the Department received an application from CHS requesting a modification to Operating Permit #OP1821-07.

The application outlined CHS's proposal to convert the existing HDS Unit into a Mild Hydrocracker. As part of this project, referred to as the "Mild Hydrocracker Project", the capacities of the existing 100 Unit Hydrogen Plant and the SRU/TGTU will be increased, the existing feed

heater in the FCC Unit will be replaced and a rate-limiting pressure safety valve (PSV) in the Naphtha Hydrotreating Unit (NHT) will be replaced.

The application also included information related to an additional project that is proposed to be completed at the refinery concurrent with the Mild Hydrocracker Project. The project involves adding the flexibility to recover additional Burner Fuel, rather than Diesel Fuel, within the existing ULSD unit. The feed rate to the ULSD Unit will not increase with this project. This project is referred to as the "ULSD Burner Fuel Project."

In addition to the aforementioned projects, CHS requested the Department to incorporate several administrative changes.

A detailed description of the various components of these projects is included in the MAQP history for the actions resulting in MAQP #1821-23 and MAQP #1821-24.

Operating Permit #OP1821-08 replaced Operating Permit #OP1821-07.

On April 12, 2011, the Department received an application from CHS for a modification to MAQP #1821-24 and Air Quality Operating Permit OP1821-07. As referenced in the permit history above, OP1821-07 was updated with a modification as requested on November 1, 2010, thus this application resulted in a modification of OP1821-08. The modification request detailed proposed changes to a *de minimis* request approved by the Department on December 10, 2010, as well as proposed construction of two product storage tanks.

On December 6, 2010, the Department received a *de minimis* notification from CHS proposing construction of a new 100,000 barrel (bbl) storage tank (Tank 133) for the purpose of storing asphalt. Emissions increases as a result of the proposed project were calculated to be less than the *de minimis* threshold of 5 tpy, with no emissions from each of the regulated pollutants exceeding 1.44 tpy. Although CHS justified the project from an economics standpoint for asphalt service only, CHS determined that during the times of year that asphalt storage is not necessary, it would be advantageous to have the extra tank capacity available to store other materials, such as gas oil and diesel. These materials may accumulate in anticipation of or as a result of a unit shutdown. Within the April 12, 2011 application, CHS proposed installation of additional pumps and piping to allow for gas oil and diesel to be stored as well as asphalt as previously approved for Tank 133.

A separate project detailed within the April 12, 2011 application included construction of two new product storage tanks, collectively referred to as the Tanks 135 and 136 Project. The Tanks 135 and 136 Project included construction of two new 120,000 bbl external floating roof (EFR) product storage tanks and associated pumps and piping to allow more flexible storage of various gasoline and/or diesel components and finished products produced at the refinery. Tank 135 would be installed in the East Tank Farm located on the east side of Highway 212. With the current refinery piping configuration, this tank would store only finished gasoline and diesel products. Tank 136 would be installed in the South Tank Farm located on the west side of Highway 212. With the current refinery piping configuration, this tank would be available to store both component and finished gasoline and diesel products. To avoid restriction of service of the tanks, project emissions increase calculations were based conservatively on storage of gasoline year round as well as current maximum refinery production capability.

Within the April 12, 2011 application, CHS also provided supplemental information to the BACT analysis included in the original permitting application for the Coker Charge Heater (H-7501)

originally permitted as a part of the Delayed Coker project (MAQP #1821-13 with revisions MAQP #1821-14 through MAQP #1821-16). This supplemental information was submitted with the purpose of laying the foundation for a proposed additional short term CO emissions limit.

Operating Permit #OP1821-09 incorporated these aforementioned MAQP actions and replaced Operating Permit #OP1821-08.

On November 8, 2011, the Department received an application from CHS for a significant modification to Operating Permit #OP1821-09. The application included three separate projects, grouped together into one action for administrative convenience. CHS proposed the following projects within this application:

1. #1 Crude Unit Revamp Project

2. Wastewater Facilities Project

3. Product Blending Project

The application also included the following:

1. Review of the regulatory applicability to existing Sour Water Storage Tanks 128 and 129.

2. Updates to the Mild Hydrocracker Project, which was permitted as part of MAQP #1821-23 and MAQP #1821-24.

3. Review of the regulatory applicability to the Product Storage Projects, which was permitted as part of MAQP #1821-25.

Each of these application components are thoroughly described within the Montana Air Quality Permit History section above.

Operating Permit #OP1821-10 incorporated the permit conditions and changes associated with these projects and reviews and replaced Operating Permit #OP1821-09.

On June 4, 2012, CHS submitted concurrent applications for a modification to MAQP #1821-26 and a significant modification to Operating Permit #1821-10. The permit application proposed modifications to two previously permitted refinery projects (Mild Hydrocracker Project and the Benzene Reduction Unit Project) and the addition of a new gasoline and diesel truck loading facility. CHS submitted several clarifications and additional information through November 14, 2012, including an administrative amendment for MAQP #1821-27.

Operating Permit #OP1821-11 incorporated the permit conditions and changes associated with these projects and replaced Operating Permit #OP1821-10.

On January 22, 2013, CHS Inc. submitted concurrent applications for a modification to MAQP #1821-28 (details included above within Montana Air Quality Permit History section) and a significant modification to Operating Permit #1821-11. CHS determined there may be times following the Mild Hydrocracker Project's startup that the refinery will not be able to produce enough of the higher octane gasoline components necessary to meet the minimum octane product specifications. CHS proposed permit changes associated with CHS's proposal to install the facilities

necessary to unload various gasoline components from railcars to existing storage tanks such that these components can be blended into refinery products. The permit action also included the revision to the existing H-1001 and FCC Charge heater (FCC-Charge Heater-NEW) limits and clarification of the BACT limit for the VCU associated with the new gasoline and distillate truck loading rack.

Operating Permit #OP1821-12 replaced Operating Permit #OP1821-11.

On August 13, 2013, the Department received from CHS an application for modification of the MAQP and the associated Title V Permit to increase allowable emissions of NO_X, CO, and VOC from the H-901 and H-902 process heaters. Please see the MAQP #1821-32 action description in the MAQP history for details of this project. Because the Department had not yet addressed the Title V Operating Permit Renewal request, assigned Operating Permit #OP1821-13, this H-901 and H-902 process heater permit action was assigned **Operating Permit #OP1821-14**. Operating Permit #OP1821-13 will be issued at a later date, but when it is issued, will represent the most up to date Operating Permit even though Operating Permit #OP1821-14 and Operating Permit #OP1821-15 will already have been issued.

On October 21, 2013, CHS Inc. submitted concurrent applications for a modification to MAQP #1821-31 and Operating Permit #OP1821-12. At the time of receipt, permit actions are also under way for updates Operating Permit #OP1821-13 and Operating Permit #OP1821-14. According to Department policy, permit actions are assigned numbers according to the order in which they are received, regardless of when they are issued. Therefore, Operating Permit #OP1821-15 may be issued before either of the actions under Operating Permit #OP1821-13 and Operating Permit #OP1821-14.

Under Operating Permit #OP1821-15, CHS proposed to add a new 100,000 barrel (approximately 4,040,000 gallons) intermediate storage tank. The proposed tank is identified as Tank 146 and will be a vertical fixed roof tank capable of storing sour gas oil, sweet gas oil, light coker gas oil, or raw diesel. Due to the physical properties of sweet and sour gas oil, a steam coil will also be installed in Tank 146 to reduce the viscosity for pumping purposes. NSPS Subpart Kb is not applicable to Tank 146 due to the vapor pressure of materials stored in the tank.

This proposed action has also included language from Proposed Operating Permit #OP1821-14, which completed the EPA Proposed Review period on February 27, 2014. The language included from Proposed Operating Permit #OP1821-14 was from Section III.V. **Operating Permit #OP1821-15** replaced Operating Permit #OP1821-14.

On April 15, 2013, the Department received from CHS an application for renewal of the Title V Operating Permit. Updates included reference to greenhouse gas reporting; updates and clarifications to applicability of MACT and NSPS including MACT CC and DDDDD and NSPS J, Ja, Kb, QQQ, GGG and GGGa; removal of emitting units no longer in service or on site; consent decree regulatory reference updates, SO_2 SIP reference updates, and updates as needed to address inconsistencies between MAQP and OP. The permit application detailing the requested changes is on file with the Department. **Operating Permit #OP1821-13** replaced Operating Permit #OP1821-15.

On June 23, 2016, the Department received from CHS a modification application for the Title V Operating Permit. The action updated the Title V to reflect several projects which had been permitted and installed. This permit action updated the permit to reflect the main flare replacement

of MAQP #1821-34; and modification of NO_X limits for the H-102 heater which occurred in MAQP #1821-36. This action also included several updates which occurred through de minimis approvals, including external floating roof tank modifications to include slotted guide poles on several tanks, and new asphalt loading tanks. Administrative updates were made as well to remove redundancies in reporting requirements, fix administrative errors associated with cross reference tables, and other miscellaneous improvements as requested in the application.

The application included the submission of a compliance plan for conditions in which noncompliance was expected as a result of temporary shutdown of the newly constructed flare gas recovery and treatment system. Due to structural issues (cracked welds) discovered by CHS, the system was shut down to allow for repair. CHS expected potential non-compliance with several SO_2 related emissions limitations. However, as this application was submitted in June 2016, and CHS was able to quickly resolve the issue and resume operation of the system, the compliance plan is no longer relevant or necessary. Therefore, the Department did not incorporate the compliance plan into the operating permit.

Also included in the application was a request to remove Appendix G from the permit. Appendix G of the operating permit included the Zone D SRU Compliance Plan relating to the 31.1 tons of SO_2 per rolling 12-month total limit. The plan and the requirement to submit progress reports was requested to be removed from the operating permit due to successful demonstration that the Zone D SRU had attained compliance with the 12-month rolling total limit and had maintained compliance for seven consecutive months or more. As of May 1, 2017, CHS had been in continuous compliance with this limit for a total of 22 months. For this reason, the Zone D SRU Compliance Plan was removed from the operating permit.

Several permit updates will be required in the future to update the Title V to reflect currently approved projects which had not finished construction or had not yet been in operational status for one year. CHS included the status of those projects in the application. Operating Permit **#OP1821-16** replaced Operating Permit #1821-13.

D. Current Permit Action

On October 27, 2017, the Department received a modification request, for an operating permit revision for equipment which had commenced operation within the last 12 months. The request includes changes for numerous MAQP modifications, de minimis changes and new requirements from revised regulations including 40 CFR 63 Subpart CC and 40 CFR Subpart UUU. Permit conditions changing are related to equipment permitted under MAQP #1821-33, MAQP #1821-34, MAQP #1821-35, MAQP #1821-36, MAQP #1821-37 and MAQP #1821-38. New and modified requirements associated with MAQP #1821-40 were also incorporated. There were also a number of administrative changes to Operating Permit #OP1821-16 to reflect equipment names where equipment is now in service and is no longer considered "new" equipment and where initial testing has been completed satisfying permit conditions. Additionally, on November 15, 2017, an addendum to the modification of Operating Permit #OP1821-16 was received to incorporate applicable requirements from the FIP for the Billings/Laurel Area found at 40 CFR 52.1392. The FIP was published in the federal register on April 21, 2008, primarily dealing with elements of the Main Refinery Flare. Operating Permit **#OP1821-17** replaces Operating Permit #1821-16.

E. Taking and Damaging Analysis

House Bill (HB) 311, the Montana Private Property Assessment Act, requires analysis of every proposed state agency administrative rule, policy, permit condition or permit denial, pertaining to an environmental matter, to determine whether the state action constitutes a taking or damaging of private real property that requires compensation under the Montana or U.S. Constitution. As part of issuing an operating permit, the Department is required to complete a Taking and Damaging Checklist. As required by 2-10-101 through 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment.

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)
	X	4. Does the action deprive the owner of all economically viable uses of the property?
	X	5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)].
		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?
		5b. Is the government requirement roughly proportional to the impact of the proposed use of the property?
	X	6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action)
	X	7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally?
	X	7a. Is the impact of government action direct, peculiar, and significant?
	X	7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?
	X	7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

Based on this analysis, the Department determined there are no taking or damaging implications associated with this permit action.

F. Compliance Designation

The most recent compliance monitoring report, dated September 28, 2018, documented a full compliance evaluation (FCE), with any partial evaluations (PCE), and any investigations conducted for the period from December 10, 2014, to September 28, 2018. As documented in the report, it was determined that CHS was in compliance with the terms and conditions of Operating Permit #OP1821-16 and with Montana Air Quality Permit #1821-40. The following findings and recommendations were included within the compliance monitoring report and summarized below:

Violation Letter #VL-20160510-00133

On May 17, 2016, DEQ issued Violation Letter #VL-20160510-00133 to CHS. CHS failed to continuously operate numerous CEMS, including the Zone E SRU CEMS, the #10 Boiler CEMS, the Main Flare CEMS, and the Coker Flare CEMS, as required by MAQP #1821-37 and Operating Permit #OP1821-13. CEMS for the Zone E SRU, Boiler #10, the Main Flare, and the Coker Flare were not operating for approximately 10.5 to 54 percent of the time the during the 4th Quarter 2015. CEMS at the refinery are used to determine compliance with state and federal air quality standards and must operate for sufficient amounts of time to monitor compliance with the standards.

CHS responded to the CEMS operational issues during the 4th Quarter 2015 by repairing and improving the reliability of the monitors. The Zone E SRU SO_2 analyzer (CEMS) vent-line was reportedly plugging excessively, causing the analyzer to repeatedly fail. CHS subsequently added additional purging to the system to correct the problem. As a result, the unavailability of the Zone E SRU CEMS was reduced from 10.5 percent in the 4th Quarter 2015 to 1.3 percent for the 1st Quarter of 2016. Similarly, a detector for the Boiler #10 CEMS was reportedly replaced, and the unavailability of the Boiler #10 CEMS was reduced from approximately 22.7 percent in the 4th quarter 2015 to 0.0 percent for the 1st Quarter of 2016. The downtime for the Main Flare CEMS (46.9 percent) and Coker Flare CEMS (54 percent) was attributed by CHS to extreme variability of the gas composition and the extreme monitoring environment from the new Main Flare and Flare Gas Recovery System (FGRS). The unavailability of the Main Flare CEMS was reduced from 46.9 percent in the 4th Quarter 2015 to 10.3 percent in the 1st quarter of 2016. Similarly, for the Coker Flare CEMS, the unavailability of the system was reduced from approximately 54 percent in the 4th Quarter 2015 to 13 percent for the 1st Quarter of 2016. CHS reportedly increased the number of purges of the systems to reduce contamination/ plugging and initiated a project to re-route off-gases from the Disulfide Separator to a heater (instead of routing to the main flare system). In addition, CHS was also looking at installing an additional CEMS upstream of the water seal of the Coker Flare to minimize the impact of moisture to the equipment.

DEQ reviewed the violations identified in Violation Letter #VL-20160510-00133 and referred them to the Enforcement Division for formal enforcement. In a letter to CHS from DEQ (dated May 1, 2018), the Administrative Order on Consent (Docket No. AQ-17-04) was eventually resolved for the violations described in Violation Letter #VL-20160510-00133.

Violation Letter #VL-20161011-00174

On October 12, 2016, Violation Letter #VL-20161011-00174 was issued to CHS and included a total of eight violations as shown below.

• Violation #1. On July 16, 2016, an incident at the refinery caused the formation of elemental sulfur in the Tail Gas Treatment Unit (TGTU) on July 16, 2016. The sulfur was reportedly dislodged within the TGTU causing the tail gas quench tower to plug and water to carry over into the tail gas amine system, which created excess SO_2 emissions to be emitted from the Zone D SRU stack. CHS reported that the event triggered the exceedance of the 113.2 ppmvd daily rolling 365-day average for SO2.

• Violation #2. On June 16, 2016, the Flare Gas Treatment and Recovery System at the refinery was shut down because of cracked welds discovered by CHS. The FGRS was offline until on July 28, 2016. The shutdown of the FGRS caused an increase in the amount of sulfur-containing vent gas directed to the Main Flare and Coker Flare, which resulted in an increase in SO_2 emissions. Because the FGRS was not operating for the period from June 16, 2016, to July 28, 2016, CHS was out of compliance with MAQP #1821-37 for that time period. CHS alleged that the event triggering Violation #2 was the result of a malfunction.

• Violation #3. The Main Flare H_2S CEMS did not function for a total of 182 of the 2184 hours of operation (10.3%) during the 1st Quarter of 2016 and 112 of the 2184 hours of operation (5.1%) during the 2nd Quarter of 2016. Therefore, CHS failed to continuously operate the H_2S CEMS for the Main Flare, as required by MAQP #1821-37.

• Violation #4. The Main Flare exceeded 162 ppmv of H_2S determined hourly on a 3-hour average basis for nonexempt releases on three occasions totaling 15 hours during the 1st Quarter of 2016 and four occasions totaling 162 hours during the 2nd Quarter of 2016.

• Violation #5. The Coker Flare H2S CEMS did not function for a total of 182 of the 2184 hours of operation (8.3%) during the 1st Quarter of 2016 and 284 of the 2184 hours of operation (13%) during the 2nd Quarter of 2016. Therefore, CHS failed to continuously operate the H2S CEMS for the Coker Flare, as required by MAQP #1821-37.

• Violation #6. The Coker Flare exceeded the 162 ppmv H_2S 3-hour average (for nonexempt releases) on five separate occasions totaling 38 hours during the 1st Quarter of 2016 and two occasions totaling 12 hours during the 2nd Quarter of 2016.

• Violation #7. The Zone D Fuel Gas H_2S CEMS did not function for a total of 101 of the 1776 hours of operation (5.7%) during the 2nd Quarter of 2016. Therefore, CHS failed to 15 continuously operate the H2S CEMS for the Zone D Refinery Fuel Gas, as required by MAQP #1821-37.

• Violation #8. Operating Permit #OP1821-13 required that the Reformer Heater (H-1001) be tested annually for NO_x and CO, concurrently. Testing was due on or before January 13, 2015. CHS did not complete the annual compliance testing in 2015 and was out of compliance with Operating Permit #OP1821-13.

DEQ reviewed the violations identified in Violation Letter #VL-20161011-00174 and referred them to the Enforcement Division for formal enforcement. In a letter to CHS from DEQ (dated May 1, 2018), the Administrative Order on Consent (Docket No. AQ-17-04) was eventually resolved for the violations described in Violation Letter #VL-20161011-00174.

Violation Letter #: VL-20180122-00279

On February 5, 2018, Violation Letter #VL-20180122-00279 was issued to CHS that included a total of two violations as summarized below.

• Violation #1. The two-stage sour water stripper SO_2 CEMS did not function as required for a total of 202 of the 2208 hours of operation (9.1%) during the 3rd Quarter of 2017.

• Violation #2. The two-stage sour water stripper NO_x CEMS did not function as required for a total of 202 of the 2208 hours of operation (9.1%) during the 3rd Quarter of 2017.

Violations identified in Violation Letter VL-20180122-00279 are being reviewed by DEQ for possible referral to the Enforcement Division.

Consent Decree (Case No. 1:03-cv-00153-RFC)

On July 6, 2016, EPA sent a letter to CHS regarding stipulated penalties (assessed under the Consent Decree) for 21 acid gas flaring/tail gas flaring incidents at the refinery for the period of January 2013 through January 2016. CHS accepted the EPA's determination for 10 of the 21 flaring incidents. Representatives from the EPA, DEQ, and CHS met on September 29, 2016, to discuss the remaining 11 flaring incidents and calculations for the penalties. Based on this meeting and subsequent communications, the EPA revised the determinations and/or penalty assessments of the remaining 11 flaring incidents. On March 7, 2017, EPA provided CHS with revised calculations and stipulated penalties assessments for the 11 flaring incidents in which CHS completed payment of the revised stipulated penalties.

In a letter to the EPA (dated September 21, 2017), CHS submitted a certification of completeness to seek termination of the Consent Decree. CHS stated that they satisfied all requirements of the Consent Decree. EPA responded to CHS's request in a letter (dated January 25, 2018) asking CHS to address/review 12 incidents of Acid Gas Flaring and/or Tail Gas Incidents from June of 2016 through November of 2017 within 30 days. CHS subsequently provided supplemental information to EPA (dated February 6, 2018), in which EPA responded (in a letter dated March 21, 2018), assessing stipulated penalties totaling $6,100 pursuant to Section XII of the Consent Decree. At the time of this report, the termination review process for the Consent Decree was ongoing.

Overall, the CHS refinery is in compliance with the terms and conditions of the Operating Permit and the referenced applicable requirements as of the date of this permit action. The Department made this determination based on information gathered at the time of the facility visit(s), the observations made during the facility visit(s), the review of the reports submitted by CHS during the review period, and the review of the compliance certifications submitted by CHS during the review period. DEQ will continue to review the history of excess emissions reports, startup/shutdown conditions, CEMS operation, FGRS operation, process upsets, and malfunction events in the future to determine if any enforcement response is warranted.

SECTION II. SUMMARY OF EMISSION UNITS

A. Facility Process Description

CHS is a petroleum refinery located in Laurel, Montana. The refining process distills crude oil using heat. This distillation separates the crude oil into its component parts. The refiner then cracks some of the heavier molecules by applying heat in the presence of a catalyst to make the reaction take place. These raw products are then treated in several ways to take out impurities. Finally, the proper liquids and additives are blended to create the desired product. The major processing equipment includes:

- Crude Units and Naphtha Splitter
- Naphtha Hydrotreaters (NHT) (*previously Unifiners*)
- Platformer (Naphtha Reformer)
- Benzene Reduction Unit
- Fluid Catalytic Cracking (FCC) Unit
- Alkylation/Butamer/Merox/Saturate Units
- Hydrodesulfurization (HDS) Unit and Hydrogen Plant
- Four Sulfur Recovery Units (SRUs) with Three Tailgas Treatment Units (TGTUs) and Tailgas Incinerators
- Ultralow Sulfur Diesel Unit and Hydrogen Plant
- Delayed Coker Unit
- Transfer Facilities (Truck Product Loading, Railcar Product Loading)

B. Emission Units and Pollution Control Device Identification

Emission Unit ID	Description	Pollution Control Device/Practice
EU001	Plant-wide and Multiple Emitting Unit Limitations	MAQP #1821-05 Limits, Billings/ Laurel SO_2 Stipulation, and MACT LDAR program, where applicable. CEMS on Refinery Fuel Gas Header(s).

Emission Unit ID	Description	Pollution Control Device/Practice
EU002	# 1 Crude Unit and Naphtha Splitter • # 1 Crude Unit Preheater (CV-HTR-1) • # 1 Crude Unit Main Heater (CV-HTR-2) • # 1 Crude Unit Vacuum Heater (CV-HTR-4)	LDAR, Billings/ Laurel SO_2 Stipulation
EU003	# 2 Crude Unit • # 2 Crude Unit Main Heater (2CV-HTR-1) • # 2 Crude Unit Vacuum Heater (2CV-HTR-2)	LDAR, Billings/ Laurel SO_2 Stipulation
EU004	PDA Unit – *SHUT DOWN*	
EU005	Naphtha Hydrotreating Unit • NHT Charge Heater (H-8301) • NHT Reboiler Heater #1 (H-8302) • NHT Reboiler Heater #2 (H-8303) • NHT Splitter Reboiler Heater (H-8304) • Makeup Hydrogen Compressor (C-8302A) • Recycle Hydrogen Compressor (C-8302B)	LDAR, Billings/ Laurel SO_2 Stipulation
EU006	Middle Distillate Unifiner – *SHUT DOWN*	
EU007	Platformer Unit, including the Benzene Reduction Unit • Platformer Heater (P-HTR-1) • Platformer Debutanizer Reboiler Heater (P-HTR-2) • Platformer Splitter Reboiler (P-HTR-3) • Platformer Recycle Compressor Turbine (C-4772) • Benzene Reduction Unit Oily Water Sewer	LDAR, Billings/ Laurel SO_2 Stipulation, Low NO_x technology (Platformer Heater and Platformer Splitter Reboiler), NSPS Subpart QQQ
EU008	Fluid Catalytic Cracking (FCC) Unit • FCC Charge Heater (FCC-Heater-NEW) • FCC Regenerator (FCC-VSSL-1)	LDAR, SO_2 CEMS, Low NO_X Technology (on heater), Billings/ Laurel SO_2 Stipulation
EU009	Alkylation/Butamer/Merox/Saturate Units • Alkylation Unit Hot Oil Belt Heater (ALKY-HTR-1) • Group 1 Miscellaneous Process Vents (Alkylation Unit Butamer Stabilizer Off Gas and Disulfide Separator Off Gas)	LDAR, Billings/ Laurel SO_2 Stipulation
EU010	Mild Hydrocracker and Hydrogen Plant (100 Unit) • Reformer Heater (H-101) • Reformer Heater (H-102) • Reactor Charge Heater (H-201) • Fractionator Feed Heater (H-202) • Recycle Hydrogen Compressor (C-203) • Makeup Hydrogen Compressor (C-204A/B)	LDAR, MAQP #1821-29 Limits, Low NO_x Technology (on heaters), Billings/ Laurel SO_2 Stipulation
EU011	Zone D SRU and TGTU and TGI • Tail Gas Incinerator (INC-401)	MAQP #1821-29 Limits, Low NO_x Technology, SO_2 CEMS, Billings/ Laurel SO_2 Stipulation

Emission Unit ID	Description	Pollution Control Device/Practice
EU012	Zone A #1 and #2 SRU feeding one TGTU and TGI • Tail Gas Incinerator (SRU-AUX-4)	SO_2 CEMS, Billings/ Laurel SO_2 Stipulation
EU013	Steam Generation Units • #1 Fuel Oil Heater (CV-HTR-9) • Boiler #9 • Boiler #10 • Boiler #11 • Boiler #12	MAQP #1821-05 Limits LDAR and Low NO_x Technology (Boilers #10, #11, and #12), Billings/ Laurel SO_2 Stipulation
EU014	Tank Farm (non-Wastewater): • MACT Group 1 Storage Vessels • MACT Group 2 Storage Vessels • Exempt – pressure vessels • Exempt – not organic HAP • Exempt – not refining	Internal and External Floating Roofs, Fixed Roofs, LDAR (as applicable)
EU015	Transfer Facilities • Asphalt Loading Heater #1 • Truck Product Loading Rack and VCU • Railcar Product Loading Rack and VCU • Railcar Gasoline Component Unloading	VCU on Light Product Truck Loading Racks and Railcar Loading Rack, LDAR, Billings/ Laurel SO_2 Stipulation, proper design and operating practices
EU016	Wastewater Treatment Units • Wastewater Treatment Unit (old) • Wastewater Treatment Unit (new) • Wastewater Tanks: Tank 23, Tank 25, Tank 44, Tank 118, Tank 119, Tank 128, and Tank 129 • Wastewater Separators: Desalter Wastewater Three-Phase Separator(s), API Separator(s), CPI Separator(s), Dissolved Air Flotation (DAF) Units • New Wastewater Treatment Unit Vessels	Enclosed conveyance and other wastewater controls for affected equipment per NSPS QQQ, NSPS Kb (as applicable)
EU017	Flare Systems • Main Refinery Flare (FL-7202) • Zone E Coker Flare (FL-7201)	Flare, Billings/ Laurel SO_2 Stipulation
EU018	RCRA Units	Restrictions on Land Tillage (HSWA permit)
EU019	Cooling Towers • Cooling Towers #1, #2, #3 • Cooling Tower #5 • Cooling Tower #6 (Coker Cooling Tower) • Heat Exchange Systems associated with each cooling tower	LDAR

Emission Unit ID	Description	Pollution Control Device/Practice
EU020	Saturate Gas Concentration Unit – *naphtha splitter consolidated with EU002*	
EU021	Ultra-Low Sulfur Diesel (ULSD) (900 Unit) and Hydrogen Plant (1000 Unit) • Reactor Charge Heater (H-901) • Fractionator Reboiler (H-902) • Reformer Heater (H-1001) • C-901A/B Compressor • C-902A/B Compressor	LDAR
EU022	Delayed Coker Unit • Coker Charge Heater (H-7501) • Coke Processing Operations • C-7601 compressor	LDAR, reasonable precautions for coke processing
EU023	Zone E SRU, TGTU and TGI	LDAR
EU024	Ammonia Combustor	SCR
EU025	Hydrogen Plant #3	SCR on Reformer Heater

C. Categorically Insignificant Sources/Activities

Appendix A of Operating Permit #OP1821-17 lists insignificant emission units at the facility. The permittee is not required to update a list of insignificant emission units; therefore, the emission units and/or activities may change from those specified in Appendix A.

SECTION III. PERMIT CONDITIONS

A. Emission Limits and Standards

Emission limits and standards in the Title V permit were established from preconstruction permits, the Billings/Laurel SIP, NSPS requirements, NESHAP requirements, MACT requirements, and the USEPA Consent Decree entered February 2004. The following is a list of preconstruction permit numbers: #9-091868, #56-091569, #55-091569, #105-042970, #129-062270, #272-061171, #363-112971, #364-112971, #362-112971, #499-102372, #540-030773, #664-112073, #665-112073, #674-121973, #800-041675, #1111, #1161, #1176, #1175, #1168, #1169, #1170, #1173, #1174, #1317, #1552, #1821-29. Permits #14-110768, #1171, and #1172 were revoked. MAQP #1821-41 is the most recent Montana Air Quality Permit in place.

B. Monitoring Requirements

ARM 17.8.1212(1) requires that all monitoring and analysis procedures or test methods, required under applicable requirements, be contained in operating permits. In addition, when the applicable requirement does not require periodic testing or monitoring, periodic monitoring must be prescribed that is sufficient to yield reliable data from the relevant time period that is representative of the source's compliance with the permit.

The requirements for testing, monitoring, recordkeeping, reporting, and compliance certification sufficient to assure compliance, does not require the permit to impose the same level of rigor for all emission units. Furthermore, it does not require extensive testing or monitoring to assure compliance with the applicable requirements for emission units that do not have significant potential to violate emission limitations or other requirements under normal operating conditions. When compliance with the underlying applicable requirement for an insignificant emissions unit is not threatened by lack of regular monitoring and when periodic testing or monitoring is not otherwise required by the applicable requirement, the status quo **(i.e., no monitoring)** will meet the requirements of ARM 17.8.1212(1). Therefore, the permit does not include monitoring for insignificant emission units.

The permit includes periodic monitoring or recordkeeping for each applicable requirement. The information obtained from the monitoring and recordkeeping will be used by the permittee to periodically certify compliance with the emission limits and standards. However, the Department may request additional testing to determine compliance with the emission limits and standards.

C. Test Methods and Procedures

The operating permit may not require testing for all sources if routine monitoring is used to determine compliance, but the Department has the authority to require testing if deemed necessary to determine compliance with an emission limit or standard. In addition, the permittee may elect to voluntarily conduct compliance testing to confirm its compliance status.

D. Recordkeeping Requirements

The permittee is required to keep all records listed in the operating permit as a permanent business record for at least 5 years following the date of generation of the record.

E. Reporting Requirements

Reporting requirements are included in the permit for each emission unit, and Section V of the operating permit, "General Conditions", explains the reporting requirements. However, the permittee is required to submit quarterly reports, semi-annual monitoring and annual monitoring reports to the Department and to annually certify compliance with the applicable requirements contained in the permit. The reports must include a list of all emission limit and monitoring deviations, the reason for any deviation, and the corrective action taken as a result of any deviation.

To eliminate redundant reporting, a source may reference previously submitted reports (with at least the date and subject of the report) in the semi-annual and annual reports instead of resubmitting the information in quarterly, and/or other reports. However, a source must still certify continuous or intermittent compliance with each applicable requirement annually.

F. Public Notice

In accordance with ARM 17.8.1232, a public notice was published in the *Billings Gazette* newspaper on or before December 4, 2018. The Department provided a 30-day public comment period on the draft operating permit from December 4, 2018, to January 3, 2019. ARM 17.8.1232 requires the Department to keep a record of both comments and issues raised during the public participation process. The comments and issues received by January 3, 2019, were summarized, along with the Department's responses, in the Permit.

G. Draft Permit Comments

Summary of Public Comments
(none received)

Summary of Permittee Comments

Section as Numbered in Draft Permit	Comment	Department Responses
A.26	In our application, we requested that a new permit condition to be added to cover the Refinery Sector Rule requirements related to miscellaneous maintenance process vents that are located throughout the refinery. We have previously identified the Group 1 Process Vents (MPV) and incorporated requirements associated with them in the appropriate sections of the permit based on location within the refinery. As such we suggest that the term "maintenance" be added to the condition. Additionally, because August 1, 2018 has passed, reference to it can be removed from the condition. also question whether this condition should be included in Section III.A of the permit (Facility-Wide) or in Section III.B of the permit (Multiple Emitting Unit Limitations).	Changed as requested
A.27	This new condition requires we comply with the new fenceline monitoring provisions of MACT CC by January 30, 2018. Since the date has passed, it does not need to be referenced in the condition.	Changed as requested

I.16	The NSPS subpart J PM limit for the FCC Regenerator is correctly identified in the Section I summary table for condition I.16 as 1.0 lb PM/1000 lb of coke. The condition itself should be updated from 1 lb PM to 1.0 lb PM.	Changed as requested
Section K summary table, row for K.9, K.14 and K.19	With this Title V modification, VOC stack testing requirements for the H-201, H-202 and H-101 heaters have been eliminated. For this reason, reference to stack testing related conditions K.37, K.47 and K.59 can be removed from the summary table rows for conditions K.9, K.14 and K.19 (VOC limits for H-201, H-202 and H-101).	Changed as requested
Section K summary table, row for K.19	Reference to conditions K.21, K.40, K.55, K.63 (duplicate) and K.64 (duplicate) should be removed from the row for condition K.19 (VOC limit for H-101). It appears they inadvertently added as part of this permit update	Changed as requested
Section K summary table, row for K.25	Condition K.25 is the CO limit for the H-102 heater. Because the heater does not have CO CEM, the summary table should not reference CEM condition K.43.	Changed as requested
Section O summary table, row for O.15	For the new asphalt Tank 152, compliance demonstration condition O.28 should be referenced instead of O.19.	Changed as requested
O.35 and O.36	Tank 152 should be added to the list of tanks included in conditions O.35 and O.36. No update to the summary table is required.	Changed as requested
Section P summary table, row for P.3	In the "Permit Limits" column of the row for condition P.3, the limit on the VCU stack height should be clarified that it applies to the truck rack VCU.	Changed as requested
P.17 and P.46.b	These conditions can be removed from the permit. They are initial notification requirements that were completed in 2013. The notification requirements are no longer in the refinery's MAQP.	Removed as requested
Section Y summary table, row for Y.2	In the "Compliance Demonstration - Frequency" column of the row, "40 CFR 60 subpart VV" should be replaced with "ongoing".	Changed as requested
Section Y summary table, row for Y.4	In the "Permit Limit" column of the row, the ammonia limit should be clarified as 10 ppmv at 3% O_2.	Changed as requested
Section Y summary table, row for Y.5	Reference to SO2 mass emission limit Y.6 should be added to this row in the summary table.	Changed as requested
Section Y summary table, row for Y.7	A row for the NSPS subpart Ja condition Y.7 should be added to the summary table or it should be referenced as part of the row for condition Y.5 (and Y.6).	Changed as requested
Y.10	This source testing condition should be clarified, as follows: " ... for NH3 utilizing methodology as agreed in writing by CHS and the Department, on an every four year basis .... "	Changed as requested
Y.12	This compliance demonstration condition should be updated to indicate that the stack	Changed as requested

	flowrate monitor is used along with the SO2 CEM to demonstrate compliance with the SO_2 mass emission limit in condition Y.6.	
Y.14 and 17	We question whether condition Y.17 is necessary as it seems to restate part of what is required in condition Y.14.	Left unchanged, revisit in renewal
Y.15	The condition should be clarified as follows: " ... and stack flowrate monitor."	Changed as requested
Y.19	Note that Section XXI of MAQP 1821-41 does not currently include the requirement to submit a quarterly emissions report. We have, however, been including deviations from the ammonia combustor limits in the quarterly report. We will request this reporting requirement be added to the Ammonia Combustor section of the MAQP during its next update.	Left unchanged, revisit in renewal
Y.21	This condition seems to have been cut and pasted from another section of the operating permit. We suggest that it be updated as follows: a. A summary of any source tests required and submitted to the Department the reporting period, which shall include the date the source test was performed, the date the source test report was submitted to the Department, and noting if the test indicated compliance or noncompliance with associated limits; ~~b. A summary of the records required by Section III.V.32~~; c. Emissions reports for SO_2 and NOx emissions from the H 901, H-902 Ammonia Combustor. The reports shall include: i. A summary of any excess emissions ii. Reasons for any excess emissions with mitigative measures utilized and corrective action taken to prevent recurrence, and iii. Compliance determinations with associated limits d. Summary of compliance with 40 CPR Subpart Ja during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CPR 60 Subpart Ja.	Changed as requested
Section Z summary table, rows Z.3, and 4, Z.7, and Z.13	Condition Z.20 relating to CEMs should be referenced in these rows of the summary table. Also, in item 3) of the "Permit Limit" column for the Z.3 and 4 row, reference to "shutdown" should be removed	Changed as requested
Section Z summary table, rows for Z.3 and 4, Z.7, Z.8 and Z.9	The initial source testing of the new Hydrogen Reformer Heater for NOx, CO, VOC and PM10/PM2.5 has been completed. The reference to the "Initial Source Test" can be removed from the "Compliance Demonstration - Frequency" columns of these rows in the summary table.	Removed as requested

Section Z summary table, row for Z.10	We question whether conditions Z.21 and Z.22 should be referenced in the summary table for this condition since there are no CEMs or stack testing required for CO_2e.	Removed as requested
Section Z summary table, row for Z.14	We suggest reference to condition Z.20 be added to this row in the summary table since NSPS subpart Ja includes CEMs requirements.	Changed as requested
Section Z summary table, row for Z.15	The "Pollutant/Parameter" column in this row for LDAR condition Z.15 should be updated to indicate that NSPS subpart GGGa applies to the Hydrogen Plant #3 and the compressors in Hydrogen Plant #3. Additionally, we question whether source testing requirement Z.22 and MAQP quarterly report condition Z.26 should be referenced in this row.	Left unchanged since NSPS references source testing
Section Z summary table, row for Z.16	We question whether source testing requirement Z.22 and MAQP quarterly report condition Z.26 should be referenced in this row relating to NSPS subpart QQQ.	Left unchanged since NSPS references source testing
Section Z summary table, row for Z.17	We question whether source testing requirement Z.22 and MAQP quarterly report condition Z.26 should be referenced in this row relating to MACT CC.	Left unchanged since NSPS references source testing
Z.	Applicability of 40 CFR 63 subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters) to the new Hydrogen Reformer Heater should be added to this section along with appropriate compliance demonstration, recordkeeping and reporting conditions.	Changed as requested. See other reference changes to accommodate inclusion of DDDDD
Z.3	This condition requires CHS to document and provide the required SCR operating temperature for the new Hydrogen Reformer Heater. Because the required communication was submitted on August 6, 2018, this condition is no longer required as written. However, as discussed on page 27 of our application for MAQP 1821-41, different SCR catalysts have different temperature requirements for safe and effective operation. For this reason, we suggest that this condition be updated to be consistent with condition XXIII.E.1.e. of MAQP 1821-41, as follows: CHS shall maintain documentation of the necessary catalyst operating temperature onsite for each type of catalyst used in the SCR. Additionally, reference to this condition should be added to the summary table in the row for condition Z.2 and item 3) in the "Permit Limit" column for the Z.2 row should be updated.	Changed as requested
Z.4c	This condition includes the NOx limit for the new Hydrogen Reformer Heater during periods of	Changed as requested

	startup. We suggest that the definition of startup be updated to be consistent with the definition in condition XXIII.E.1.d.iii. MAQP 1821-41, as follows: "Startup begins when fuel is first fired and startup ends when the SCR inlet reaches its required temperature and ammonia injection has been established."	
Z.10	This condition is a 12-month rolling total limit on the CO2e emissions from the new Hydrogen Reformer Heater (067HT0001). The limit value represents a portion of a multi-source total CO_2e emission limit that was incorporated into the refinery's MAQP as part of MAQP 1821-36 for the Grassroots Hydrocracker project. Because certain parts of the project are no longer going to be completed, the CO_2e limit in the MAQP will be revised. We suggest that the CO_2e limit for the new Hydrogen Reformer Heater be incorporated once it has been incorporated into the MAQP. It may make sense to maintain a modified version of this condition as a place-holder for the future limit. This would avoid having to remove or modify Z.1.f and other related conditions.	Left unchanged until renewal
Z.12	The condition should be clarified that it applies to the Hydrogen Reformer Heater.	Changed as requested
Z.14	This is the NSPS subpart Ja applicability condition. We question whether an NSPS subpart Ja "recordkeeping" requirement should be added.	Changed as requested
Z.15	This is the NSPS subpart GGGa applicability condition. We question whether an NSPS subpart GGGa "compliance demonstration" condition should be added. ·	GGGa compliance demonstration added
Z.16	This is the NSPS subpart QQQ applicability condition. We question whether NSPS subpart QQQ "compliance demonstration","recordkeeping" and "reporting" conditions should be added.	QQQ additional conditions added
Z.17	This is the 40 CFR 63 subpart CC applicability condition. We question whether 40 CFR 63 subpart CC "compliance demonstration","recordkeeping" and "reporting" conditions should be added.	CC additional conditions added
Z.19.a – e	The initial source testing required within the first 180 days of operation has been completed. For this reason, these conditions can be updated to exclude this language.	Removed as requested
Z.19	Condition Z.5 includes the SO_2 limits for the new Hydrogen Reformer Heater. We suggest that an SO_2 compliance demonstration requirement be added to condition Z.19. For SO_2, compliance with permit limits is determined with fuel consumption and an appropriate emission factor when natural gas is being fired or an H_2S CEM when RPG	Changed as requested

	is being fired. PSA tail gas fired in the heater is assumed to be sulfur free. If this comment is incorporated, reference to Z.19 should be added to the summary table row for condition Z.5.	
Z.23, Z.26 and Z.28-32	Conditions Z.23, Z.26 and Z.28-32 are reporting requirements related to the quarterly MAQP report. For permit consistency and ease of preparation of the semi-annual Title V compliance monitoring report and annual Title V compliance certification, we suggest that conditions Z.23 and Z.28-32 become part of condition Z.26. (i.e., Z.26.i. -vi.). We will propose a similar change be made to the MAQP during its next update.	Combined under Z.34
Z.34	It appears that this semi-annual monitoring report condition may have been cut off. We suggest that it be updated to include the summary of compliance requirement for NSPS subpart GGGa, NSPS subpart QQQ, 40 CFR 63 subpart CC and 40 CFR 63 subpart DDDDD. For consistency with other sections of the permit, it should also include a condition related to compliance with emission limits and conditions and dates quarterly reports were submitted.	Changed as requested
TRD-D. Current Permit Action (page 41)	Note that as part of this permit action, the new and modified requirements associated with MAQP #1821-40 (Zone D SRU SO2) were also incorporated.	Added additional description
TRD Section V (page 53)	This section (Future Permit Considerations) includes a discussion of the revisions made to the refinery MACT standards (MACT CC and MACT UUU) as part of the Refinery Sector Rules (RSR). This discussion was added to the operating permit TRD as part of OP 1821-16. Note that as part of the current permit update, a number of the new or modified requirements from the RSR are being incorporated into the operating permit. The remaining requirements will be incorporated as part of the upcoming permit renewal.	Added additional description

SECTION IV. NON-APPLICABLE REQUIREMENT ANALYSIS

CHS did not request a permit shield within this permit application. All regulatory requirements previously identified as non-applicable within previous permit actions are included in Section IV of Operating Permit #OP1821-17.

The following table outlines those requirements that CHS has identified historically as non-applicable in previous permit applications, but will not be included in the operating permit as non-applicable. The table includes both the applicable requirement and reason that the Department did not identify this requirement as non-applicable.

Applicable Requirement	Reason
40 CFR 60 Subpart D, Dc, Ka, XX, IIII	These are NSPS which may potentially be applicable to the source category the permittee is in
40 CFR 63 Subpart B	This is a procedural rule that has specific requirements that may become relevant to a major source during a permit span.
40 CFR 63, Subpart ZZZZ	This rule may be applicable to this source category within the term of the permit.
Consent Decree CV-03-153-BLG-RFC (entered 2/23/04)	The Consent Decree is required to be included in the Title V Operating Permit under ARM 17.8.1211.
ARM 17.8.324(2)	This is a generally applicable requirement that could apply to this source category
ARM 17.8.341	This is a general applicable requirement that could apply in the future.
ARM 17.8, SubChapter 8	This is major PSD source, therefore, shield from the PSD rules is inappropriate

SECTION V. FUTURE PERMIT CONSIDERATIONS

A. MACT Standards

In December 2015, the EPA issued a final rule that will further control toxic air emissions from petroleum refineries and disclose information about refinery benzene emissions to the public and neighboring communities via benzene fenceline monitoring. This rule further regulates flare efficiencies and upset emission events, and requires refineries to monitor emissions at key emission sources within their facilities and around their fencelines.

40 CFR 63 Subpart CC (MACT CC) was updated to include decoking operations as an affected unit, increase control requirements on tanks, increase flare monitoring, design, and operation requirements, increased process and maintenance vent control requirements, and require fenceline monitoring of benzene emissions which is expected to increase minimization of fugitive equipment leaks, amongst other changes.

Of note relevant to the current permit action, MACT CC will transition the flare design and operation requirements of 40 CFR 60.18 and 63.11 to that of MACT CC. At such time, the MACT CC flare design and operation requirements are applicable and 40 CFR 60.18 and 40 CFR 63.11 requirements would not be applicable through the NSPS and MACT standards. A streamlining of demonstration with MAQP requirements will be necessary to appropriately accommodate the transition of eliminating reference to 40 CFR 60.18 and 40 CFR 63.11.

40 CFR 63 Subpart UUU was also updated to require that flares receiving gas from the fuel gas system be subject to 40 CFR 63.670. MACT UUU updates regulation on Fluid Catalytic Cracking Units and Sulfur Recovery Units.

EPA also revised certain startup, shutdown, and malfunction provisions in refinery MACTs in order to ensure that the subparts are consistent with the court decision in Sierra Club v. U.S. EPA.

The overall rulemaking is referred to as the "Refinery Sector Rules" or "RSR" for short. The updates include:

- New emissions controls for refinery storage tanks, Catalytic Reforming Units, and Delayed Coker Units;
- Work practice standards to reduce emissions from atmospheric Pressure Relief Devices and flares;
- Continuous benzene monitoring at the refinery fenceline to improve the management of fugitive emissions;
- Elimination of exemptions to emission limits for uncontrolled releases during start-up, shutdown, and malfunction;

CHS has submitted a compliance extension request regarding some of the new rule requirements. The Title V permit is expected to be updated as necessary to reflect the conditions of relevant extension. With the issuance of OP #1821-17, CHS has incorporated some elements of the RSR and additional elements will be included in the upcoming Title V renewal.

B. NESHAP Standards

The Department is not aware of any proposed or pending NESHAP standards, in addition to those already listed, that may be applicable.

C. NSPS Standards

Included with the updates noted in the MACT section as the "RSR" were updates to NSPS J and Ja. These were technical corrections and clarifications.

D. Risk Management Plan

This facility does exceed minimum threshold quantities for any regulated substance listed in 40 CFR Part 68.115 for any facility process. Consequently, this facility is required to submit a Risk Management Plan.

If a facility has more than a threshold quantity of a regulated substance in a process, the facility must comply with 40 CFR Part 68 requirements no later than June 21, 1999; 3 years after the date on which a regulated substance is first listed under 40 CFR Part 68.130; or the date on which a regulated substance is first present in more than a threshold quantity in a process, whichever is later.

E. Compliance Assurance Monitoring (CAM) Plan

An emitting unit located at a Title V facility that meets the following criteria listed in ARM 17.8.1503 is subject to Subchapter 15 and must develop a CAM Plan for that unit:

- The emitting unit is subject to an emission limitation or standard for the applicable regulated air pollutant (other than emission limits or standards proposed after November 15, 1990, since these regulations contain specific monitoring requirements);
- The emitting unit uses a control device to achieve compliance with such limit; and
- The emitting unit has potential pre-control device emission of the applicable regulated air pollutant that are greater than major source thresholds.

CHS does not currently have any emitting units that meet all the applicability criteria in ARM 17.8.1503, and is therefore not currently required to develop a CAM Plan.

F. Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule

On May 7, 2010, EPA published the "light duty vehicle rule" (Docket # EPA-HQ-OAR- 2009-0472, 75 FR 25324) controlling greenhouse gas (GHG) emissions from mobile sources, whereby GHG became a pollutant subject to regulation under the Federal and Montana Clean Air Act(s). On June 3, 2010, EPA promulgated the GHG "Tailoring Rule" (Docket # EPA-HQ-OAR-2009-0517, 75 FR 31514) which modified 40 CFR Parts 51, 52, 70, and 71 to specify which facilities are subject to GHG permitting requirements and when such facilities become subject to regulation for GHG under the PSD and Title V programs.

Under the Tailoring Rule, any PSD action (either a new major stationary source or a major modification at a major stationary source) taken for a pollutant or pollutants other than GHG that was not final prior to January 2, 2011, would be subject to PSD permitting requirements for GHG if the GHG increases associated with that action were at or above 75,000 TPY of carbon dioxide equivalent (CO_{2e}) emissions. Similarly, if such action were taken, any resulting requirements would be subject to inclusion in the Title V Operating Permit. Starting on July 1, 2011, PSD permitting requirements would be triggered for modifications that were determined to be major under PSD based on GHG emissions alone, even if no other pollutant triggered a major modification. In addition, sources that exceed the 100,000 TPY CO_{2e} threshold under Title V would be required to obtain a Title V Operating Permit if they were not already subject.

The Supreme Court of the United States (SCOTUS), in its *Utility Air Regulatory Group v. EPA* decision on June 23, 2014, ruled that the Clean Air Act neither compels nor permits EPA to require a source to obtain a PSD or Title V permit on the sole basis of its potential emissions of GHG. SCOTUS also ruled that EPA lacked the authority to tailor the Clean Air Act's unambiguous numerical thresholds of 100 or 250 TPY to accommodate a CO_2e threshold of 100,000 TPY. SCOTUS upheld that EPA reasonably interpreted the Clean Air Act to require sources that would need PSD permits based on their emission of conventional pollutants to comply with BACT for GHG. As such, the Tailoring Rule has been rendered invalid and sources cannot become subject to PSD or Title V regulations based on GHG emissions alone. Sources that must undergo PSD permitting due to pollutant emissions other than GHG may still be required to comply with BACT for GHG emissions. CHS may be subject to GHG permitting requirements in the future.