

**MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OPERATING PERMIT TECHNICAL REVIEW DOCUMENT**

**Air, Energy & Mining Division
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CHS, Inc.
Laurel Refinery
803 Highway 212 South
P.O. Box 909
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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 7e (NO _x) Method 9 (opacity) Method 10 (CO) Method 11 (H ₂ S) Method 18 (VOC) Method 19 (Various) Method 22 (Visible Emissions) Method 25 (VOC) Method 201 (PM) Method 202 (PM)
Ambient Monitoring Required		X	
COMS Required	X		FCC Regenerator
CEMS Required	X		SO ₂ , H ₂ S, 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 #1821-42
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

Facility Compliance Requirements	Yes	No	Comments
			MACT GGGa), Subpart XX, Subpart GGG, Subpart GGGa, Subpart QQQ, Subpart IIII and Subpart JJJJ
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 ZZZZ and Subpart DDDDD.
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

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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. The current renewal application was received on April 2, 2019.

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 (SO₂) 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 SO₂ and oxides of nitrogen (NO_x). The application referred to significant SO₂ emission reductions that were expected by addition of the HDS project. These anticipated major SO₂ reductions were not committed to by Cenex under federally enforceable permit conditions and limitations. The contemporaneous emission decreases for SO₂ 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 SO₂ 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 SO₂ 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

Source	Pollutant	Previous Limit	New Limit
		2.11 lb/hr	2.90 lb/hr
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 SO₂ 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 SO₂ 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 SO₂ 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 (PM₁₀) 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 PM₁₀ 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 SO₂ 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 SO₂ 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 Trimethylpentane
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 SO₂, NO_x, CO, PM₁₀, 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 SO₂ annual emissions cap was calculated as follows:

Average refinery-wide SO₂ emissions in the period of April 1998 through 2000, added to the PSD/NAA significance level for SO₂ minus 0.1 tpy =

$$2940.4 \text{ tpy} + 40 \text{ tpy} - 0.1 \text{ tpy} = 2980.3 \text{ tpy} = \text{Annual emissions cap.}$$

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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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, PM₁₀, 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ (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

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

SO₂ allowed for the combustion of alkylation unit polymer in the Alkylation Unit Hot Oil Heater, the only unit that is part of the original SO₂ 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 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 SO₂ 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 SO₂ 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 (NO_x and SO₂), 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 NO_x 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 (H₂S) 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 H₂S Stripper will be replaced with higher capacity trays.
 - The overhead condenser and pump associated with the H₂S Stripper Overhead Drum will be modified.
 - A new “wild” naphtha product draw will be added to the H₂S 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.

#1 Crude Unit Revamp Project

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) (I-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 NO_x emission performance. The previous heater was physically capable of combusting refinery fuel gas but could not meet the existing oxides of nitrogen (NO_x) 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 (SO₂) 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 (H₂S/SO₂) 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 NO_x 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 NO_x 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 streams 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 NO_x 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 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 SO₂ 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 SO₂ Emissions Control Plan, as approved into the SIP: CHS requested corrections be made to the MAQP where the SO₂ 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 O₂ on the H-901 and H-902 heaters be removed. NO_x CEMS is required, including a flowrate monitor; however, the need for O₂ 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 O₂ 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 (SO₂) ton per rolling 12-month total limit and update the SO₂ 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 SO₂ 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 SO₂ emissions. This increase in sulfur content eliminated the operational compliance margin with the current Zone D SO₂ 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 SO₂ emissions at the refinery; the new Zone D SO₂ 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.

On February 21, 2019, the Department received an application from CHS for modification of MAQP #1821-41. The requested change proposed to modify the MAQP to reflect the final scope of the Grassroots Hydrocracker Project (GRHC) and modify two limits which were established as part of the GRHC. Portions of the project which were permitted as part of the GRHC were no longer going to be constructed including the New Hydrocracker and therefore, conditions associated with the New Hydrocracker were removed. The Hydrogen Reformer Heater permitted as part of the GRHC was given a CO limit to specifically cover periods of startup. The startup for the Hydrogen Reformer Heater took longer to startup and reach stable operation than the form of the current CO limit. The current limit of 41.6 lb/hr (hourly rolling 24-hr average) was not able to be achieved based on the allowable heat ramp of 50°- 90° F per hour. Recent data during startup indicated it takes approximately 36 hours and therefore, it was requested that the form of the limit be modified to be based on an hourly rolling 36-hour average. No change in the numeric limit was being requested. Related to the new Hydrocracker which is not being built, a Greenhouse Gas emissions multi-source total limit was included in the GRHC project. The CO_{2e} limit included the Hydrogen Reformer Heater, HC Reactors Heaters (H-801 and H-802), HC Fractionation Heater and the FCCU. The two remaining sources were the Hydrogen Reformer Heater and the modified FCCU. The scaled back GRHC project remained subject to PSD and the revised project emissions increase was greater than 75,000 tons per year CO_{2e}, therefore CO_{2e} limits are still required for the two remaining sources. In addition, the basis of the CO_{2e} limit for the Hydrogen Reformer Heater was updated based on the procedure in 40 CFR part 98 subpart P for Hydrogen Production. This used the 2018 actual fuel and feedstock consumption scaled to the unit's 40 MMSCFD hydrogen production and the actual carbon content and molecular weight of the refinery natural gas supply. Since the Hydrogen Reformer Heater can also use refinery fuel gas (RFG), potential emissions were also evaluated using the actual carbon content and molecular weight of RFG. This second alternative provides the highest potential emissions of CO_{2e}. Several minor administrative clarifications were also incorporated into the MAQP including conditions where initial source testing had been completed. **MAQP #1821-42** replaced MAQP #1821-41.

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 SO₂ 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 SO₂ 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 H₂S 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, SO₂SIP 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 SO₂ 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 SO₂ 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.

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 included 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 were 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 to reflect equipment names where equipment was now in service and is no longer “new” equipment. There were also a number of administrative changes to Operating Permit #OP1821-16 to reflect equipment names where equipment was now service and is no longer considered “new” equipment and where initial testing had 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** replaced Operating Permit #1821-16.

D. Current Permit Action

On April 2, 2019, the Department received an application for renewal of Operating Permit #OP1821-17. On October 3, 2019, correspondence was also received regarding requirements related to flares and the delayed coker for compliance with 40 CFR 63 Subpart CC. The Consent Decree requirements were also removed from the Operating Permit #OP1821-17, as the Consent Decree was terminated on December 21, 2018. **#OP1821-18** replaces Operating Permit #1821-17.

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 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 SO₂ 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 SO₂ 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 SO₂ 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 H₂S 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 H₂S CEMS for the Main Flare, as required by MAQP #1821-37.
- Violation #4. The Main Flare exceeded 162 ppmv of H₂S 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 H₂S 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 H₂S 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 SO₂ 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.

DEQ opted to not pursue formal enforcement with a letter dated January 11, 2019.

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. With the issuance of #OP1821-18, the Consent Decree requirements were removed as the Consent Decree was terminated on December 21, 2018.

CHS also provided a summary in the renewal application to address NSPS subparts IIII and JJJJ and 40 CFR 63 subpart ZZZZ. All compliance plan actions were completed as specified prior to issuance of the draft operating permit.

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 (BRU)
- Fluid Catalytic Cracking (FCC) Unit
- Alkylation/Butamer/Merox/Saturate Units
- Mild Hydrocracker (MHC) Unit
- Sulfur Recovery Units (SRUs) with Tailgas Treatment Units (TGTUs) and Tailgas Incinerators
- Ultralow Sulfur Diesel Unit
- Delayed Coker Unit
- Transfer Facilities (Truck Product Loading, Railcar Product Loading)
- Steam Generation Units
- Wastewater Treatment Units
- Miscellaneous Storage Tanks
- Sour Water Stripper Ammonia Combustor
- Flare Systems
- Hydrogen Plants
- Stationary Engines

B. Emission Units and Pollution Control Device Identification

Emission Unit ID	Description	Pollution Control Device/Practice
EU001	Plant-wide and Multiple Emitting Unit Limitations <ul style="list-style-type: none"> • Limits and Conditions associated with MAQP 1821-05 • Plant-wide Fuel Gas Combustion Device Limitations • SIP Multiple Emitting Unit Limitations 	MAQP Limits, Billings/ Laurel SO2 Stipulation. CEMS on Refinery Fuel Gas system; NSPS J – all FG combustion devices, except NSPS Ja units

EU002	# 1 Crude Unit and Naphtha Splitter <ul style="list-style-type: none"> • # 1 Crude Unit Preheater (CV-HTR-1) • # 1 Crude Unit Main Heater (CV-HTR-2) • # 1 Crude Unit Vacuum Heater (CV-HTR-4) • Low Pressure Vapor Recovery Compressor (C-401) 	LDAR – NSPS GGGa, MACT CC; MACT DDDDD NSPS Ja (CV-HTR-4) – H2S in RFG only
EU003	# 2 Crude Unit <ul style="list-style-type: none"> • # 2 Crude Unit Main Heater (2CV-HTR-1) • # 2 Crude Unit Vacuum Heater (2CV-HTR-2) 	LDAR – NSPS GGG, MACT CC, MACT DDDDD
EU004	<ul style="list-style-type: none"> • PDA Unit – SHUT DOWN 	
EU005	Naphtha Hydrotreating Unit <ul style="list-style-type: none"> • 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 – NSPS GGG, MACT CC MACT DDDDD MAQP limits – NHT Charge Heater Low NOx technology – NHT Charge Heater
EU006	Middle Distillate Unifiner – <i>SHUT DOWN</i>	

Emission Unit ID	Description	Pollution Control Device/Practice
EU007	Platformer Unit, including the Benzene Reduction Unit (BRU) <ul style="list-style-type: none"> • Platformer Heater (P-HTR-1) • Platformer Debutanizer Reboiler Heater (P-HTR-2) • Platformer Splitter Reboiler (P-HTR-3) • Benzene Reduction Unit Oily Water Sewer 	LDAR – NSPS GGGa (BRU), MACT CC, Low NOx technology (Platformer Splitter Reboiler) NSPS Ja – Platformer Splitter Reboiler (H ₂ S in RFG only) NSPS QQQ (BRU) MACT UUU, DDDDD MAQP limits – Platformer Splitter Reboiler
EU008	Fluid Catalytic Cracking (FCC) Unit <ul style="list-style-type: none"> • FCC Charge Heater (FCC-Htr-1) • FCC Regenerator (FCC-VSSL-1) 	LDAR – MACT CC, FCC Regenerator: SO ₂ /NO _x /CO CEMS and COMS; ESP (control device); NSPS J (PM, SO ₂), NSPS Ja (CO), MAQP limits, MACT UUU; Billings/Laurel SO ₂ Stipulation FCC Charge Heater: Low NOX Technology NSPS Ja, NO _x CEM, MACT DDDDD, MAQP limits
EU009	Alkylation/Butamer/Merox/Saturate Units <ul style="list-style-type: none"> • 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 – NSPS GGG MACT CC, DDDDD
EU010	Mild Hydrocracker (MHC) and Hydrogen Plant (100 Unit) <ul style="list-style-type: none"> • 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 – NSPS GGG (Hydrogen Plant), NSPS GGGa (MHC, compressors), MACT CC MAQP Limits (heaters) Low NOx Technology (on heaters) H-102: NSPS Ja, NO _x /CO CEM
EU011	Zone D SRU and TGTU and TGI <ul style="list-style-type: none"> • Tail Gas Incinerator (INC-401) 	MAQP Limits SO ₂ CEMS Billings/ Laurel SO ₂ Stipulation NSPS Ja MACT UUU
EU012	Zone A #1 and #2 SRU feeding one TGTU and TGI <ul style="list-style-type: none"> • Tail Gas Incinerator (SRU-AUX-4) 	SO ₂ CEMS, Billings/ Laurel SO ₂ Stipulation NSPS J, QQQ (TGTU) MACT UUU

EU013	<p>Steam Generation Units</p> <ul style="list-style-type: none"> Boiler #9 Boiler #10 Boiler #11 Boiler #12 	<p>MAQP Limits</p> <p>LDAR – NSPS GGG (10 & 11), NSPS GGGa (12)</p> <p>Low NOx Technology (Boilers #10, #11, and #12)</p> <p>NSPS Db (10, 11 and 12), Ja (12- H₂S in RFG only))</p> <p>MACT DDDDD</p> <p>CEMS: NO_x, CO (10, 11, 12)</p>
EU014	<p>Tank Farm (non-Wastewater):</p> <ul style="list-style-type: none"> Refinery MACT I Group 1 Storage Vessels Refinery MACT I Group 2 Storage Vessels Refinery MACT I Exempt vessels – pressure vessels, not organic HAP, not refining 	<p>Internal and External Floating Roofs, Fixed Roofs</p> <p>LDAR (MACT CC, BACT, as applicable)</p> <p>NSPS Kb</p> <p>UU (as applicable)</p> <p>MAQP limits</p>
EU015	<p>Transfer Facilities</p> <ul style="list-style-type: none"> Asphalt Loading Heater #1 Truck Product Loading Rack and VCU Railcar Product Loading Rack and VCU Railcar Gasoline Component Unloading 	<p>VCU (control device) on Light Product Truck Loading Rack and Railcar Loading Rack,</p> <p>LDAR – MACT CC, BACT</p> <p>Proper design and operating practices</p> <p>NSPS Ja, XX</p> <p>MACT CC (Loading rack), DDDDD</p> <p>MAQP limits</p>
EU016	<p>Wastewater Treatment Units</p> <ul style="list-style-type: none"> Separators <p>API separators: T-23A/B, TK-3437, TK-3447</p> <p>Separators – slop oil facilities: T-16, T-17, T-18</p> <p>Dissolved gas flotation units: TK-3448, TK-3458</p> <p>Other separators: TK-23, T-14</p> <ul style="list-style-type: none"> Storage Vessels <p>Wastewater: T-20, T-25, TK-25, TK-3436</p> <p>Slop oil: TK-44, TK-118</p> <p>Sour water: TK-128, TK-129</p> <p>Foam/sludge: TK-3449, TK-3450, TK-3451</p> <ul style="list-style-type: none"> Control Devices <p>F-3401A/B/C Activated carbon beds</p> <p>034IN0001 Wastewater Area Combustor</p>	<p>NSPS QQQ, Kb (as applicable)</p> <p>LDAR – BACT</p> <p>MACT CC</p>
EU017	<p>Flare Systems</p> <ul style="list-style-type: none"> Main Refinery Flare (FL-7202) Zone E Coker Flare (FL-7201) 	<p>Flare – Control Device, flare gas recovery system</p> <p>Billings/ Laurel SO₂ Stipulation (Main Refinery Flare)</p> <p>Billings/Laurel SO₂ FIP</p> <p>NSPS Ja</p> <p>MACT CC</p> <p>LDAR - BACT</p>

EU018	RCRA Units	Restrictions on Land Tillage (HWSA permit)
EU019	<p>Cooling Towers</p> <ul style="list-style-type: none"> • Cooling Towers #1, #2, #3 • Cooling Tower #5 • Cooling Tower #6 (Coker Cooling Tower) • Heat Exchange Systems associated with each cooling tower 	<p>MACT CC – heat exchange systems</p> <p>Mist eliminator (#6)</p>
EU020	Saturate Gas Concentration Unit – <i>naphtha splitter consolidated with EU002</i>	
EU021	<p>Ultra-Low Sulfur Diesel (ULSD) (900 Unit) and Hydrogen Plant (1000 Unit)</p> <ul style="list-style-type: none"> • Reactor Charge Heater (H-901) • Fractionator Reboiler (H-902) • Reformer Heater (H-1001) • C-901A/B Compressor • C-902A/B Compressor 	<p>LDAR – NSPS GGG, MACT CC</p> <p>NSPS Ja (H-1001), QQQ</p> <p>MACT DDDDD</p> <p>MAQP limits</p> <p>Low NOx technology (heaters)</p> <p>CEMs: NOx (H-901, H-902, H-1001) and CO (H-1001)</p>
EU022	<p>Delayed Coker Unit</p> <ul style="list-style-type: none"> • Coker Charge Heater (H-7501) • Coke Processing Operations • C-7601 compressor • Coke drum steam vent 	<p>LDAR – NSPS GGG, MACT CC</p> <p>NSPS QQQ</p> <p>MACT CC, DDDDD</p> <p>Reasonable precautions for coke processing</p> <p>Low NOx technology</p> <p>MAQP limits</p> <p>CEMS – CO (heater)</p>
EU023	Zone E SRU, TGTU and TGI	<p>NSPS J</p> <p>MACT UUU</p> <p>MAQP limits</p> <p>CEMs – SO2</p>
EU024	Ammonia Combustor	<p>SCR</p> <p>NSPS Ja</p> <p>MAQP limits</p> <p>CEMs – NOx, SO2</p>

EU025	Hydrogen Plant #3 Hydrogen Reformer Heater (067HT0001)	SCR on Reformer Heater LDAR – NSPS GGGa, MACT CC NSPS – Ja, QQQ MACT – DDDDD MAQP limits CEMs – NOx, CO
EU026	Stationary Engines <ul style="list-style-type: none"> • Emergency Generators Admin 1 EG (021-GN-0204) Zone C DCS EG (024-SG-001) Zone E DCS EG (075-SG-001) CCB EG1 (002-SG-002) CCB EG2 (002-SG-003) Zone B DCS EG (004-SG-025) Westside Complex EG (002-SG-001) Zone D DCS EG (065-SG-003) Zone A DCS EG (004-SG-001) Truck Terminal EG (LrlTermGen) Admin 3 EG (021-GN-1031) • Diesel Fire Water Pump Engines East Fire Pump #1 (EG-2205) East Fire Pump #2 (EG-2206) Tank 134 East Pump (P-2207) Tank 134 West Pump (P-2208) West Diesel Pump (P-2204) • Emergency Plant Air Compressors Zone C Plant Air Compressor (024CO0064) Zone E Plant Air Compressor (026CO0004) 	NSPS IIII , JJJJ MACT ZZZZ

C. Categorically Insignificant Sources/Activities

Appendix A of Operating Permit #OP1821-18 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 #1821-43 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 May 24, 2020. The Department provided a 30-day public comment period on the draft operating permit from May 26, 2020 to June 25, 2020. The comments and issues received by June 25, 2020, along with the Department's response are summarized below.

G. Draft Permit Comments

Summary of Public Comments (None Received)

Summary of Permittee Comments

Reference in Draft Permit	CHS Comments	Department Response
II. Summary of Emission Units (page 2), also in TRD page 48	In the permit application, we proposed a number of updates to the Summary of Emissions Units table included in the operating permit and technical review document (TRD). To complete the updates, we suggest the following:	Each of these were updated in the OP and TRD
	EU007: In the NSPS Ja row, add "H ₂ S in RFG only" in parentheses behind Platformer Splitter Reboiler.	
	EU011: Delete "Low NO _x Technology" from the Pollution Control Device column.	
	EU012: Relocate "QQQ (TGTU)" to the NSPS J line and separate with a comma.	
	EU013: Delete #1 Fuel Oil Heater (CV-HTR-9). Clarify NSPS Ja reference with the following: Ja (12 – H ₂ S in RFG only)	
	EU015: Delete the "s" in Truck Loading Rack	
	EU017: In the Pollution Control Device column, move "(Main Refinery Flare)" directly behind "Billings/Laurel SO ₂ Stipulation"	

	EU019: In the Pollution Control Device column, delete “LDAR”	
	EU026: Update the equipment numbers associated with the following emergency generators: Admin 1 EG (021-GN-0204) and Admin 3 EG (021-GN-1031)	
III.B.1.a and b (page 13)	This section includes a list of the equipment that is subject to the Multiple Emitting Unit Limitations that were established as part of MAQP 1821-05. We suggest the following updates:	Removed
	· Reference to the #1 Fuel Can Heater (#1 Fuel Oil Heater) in 1.a can be removed. It is no longer in service. Additionally, reference to this heater can be removed from the list of equipment under the heading of Section III.N for EU013 (page 80).	
	· The natural gas fired turbine on the platformer recycle compressor (1.b) has replaced with an electric motor. As a result, it (i.e., platformer recycle turbine) is no longer an emissions source and can be removed or noted as such. Additionally, reference to this compressor (Platformer Recycle Compressor Turbine (C-4772)) can be removed from the list of equipment under the heading of Section III.H. for EU007 (page 36).	
III.B.30 (page 24)	This condition includes quarterly report submittal details. Note that the MAQP is currently being updated to require electronic submittal rather than hard copies provided to the Helena and appropriate regional DEQ offices. We suggest this condition be updated to reflect the change in MAQP reporting requirements. This comment also applies to conditions F.25, H.37, I.60, K.61, L.35, M.38, N.58, O.40, O.41, V.52, V.54, W.37, X.25, Y.19 and Z.31.	Updated
III.C (page 26)	Reference to the Low Pressure Vapor Recovery (LPVR) Compressor (C-401) should be added to the list of equipment under the heading of Section III.C. for EU002.	Updated
III.C.8 (page 27)	For clarity, we suggest that this condition and the summary table be updated to indicate that the #1 Crude Unit Vacuum Heater (CV-HTR-4) is only subject to the H ₂ S in fuel gas requirements of NSPS subpart Ja and not the process heater NO _x requirements.	Updated
III.C.16 (page 28)	Reference to 40 CFR 60 subpart GGG can be removed from this condition. The #1 Crude Unit is subject to subpart GGGa.	Removed
III.F (page 31)	In the equipment list under this section heading, “formerly MDU Charge Heater” should be placed in parentheses.	Updated
III.F.27.f (page 35)	There is a semi-colon at the end of this condition that can be replaced.	Updated
III.H.6 (page 39)	We suggest the second sentence of this condition be reworded as follows for clarity:	Updated
	“This heater is also subject to the H ₂ S in fuel refinery gas limit but is not subject to process heater NO _x requirements because it is rated less than 40 MMBtu/hr.”	

III.H.24 (page 40)	To be consistent with the MAQP, this condition and section summary table (rows H.8, 9 and 12) should be updated to indicate NOx and CO testing of the Platformer Splitter Reboiler is required once every five years.	Updated
III.H.37.b (page 41)	As part of the recent MAPQ update, the NOx emission reporting requirements for the Platformer Splitter Reboiler were removed. As a result, this condition can be removed from the operating permit.	Removed
III.I summary table (page 45)	In the row for condition I.20, the compliance demonstration frequency for the FCC Charge Heater opacity requirement should be updated to “As Required by the Department and Section III.A.1”.	Updated
III.I.42 (page 50)	To be consistent with the recent updates to the refinery’s MAQP, the required frequency of the FCCU regenerator PM stack test should be updated to once every three years. The section summary table (rows I.16 and 17) should also be updated. Additionally, reference to Method 7 for NOx should be deleted from row I.16 of the summary table.	Updated
III.I.43 (page 50)	To be consistent with the recent updates to the refinery’s MAQP, the required frequency of the FCC Charge Heater NOx and CO stack test should be updated to once every three years. The section summary table (rows I.21, 22 and 24) should also be updated.	Updated
III.I (page 53)	At the end of Section I, a note was added to reference the combined CO _{2e} limit included in Section III.Z that is applicable to the Hydrogen Reformer Heater (067HT0001) and FCCU Regenerator. To prevent this comment from being overlooked, we suggest it be moved to the beginning of the section, such as under the section equipment list.	Updated
III.K (page 56)	In the operating permit renewal application (page 11), we requested applicability to 40 CFR 63 subpart CC be added for the Mild Hydrocracker. It appears that this may have been started because a reference to “pumps, valves and other equipment in HAP service” was added under the Section K heading but no subpart CC conditions were added. We suggest a series of subpart CC conditions be added to the permit. Conditions Z.17, 24, 29, 34 and 36.e can be used as a starting point.	Added new conditions for 40 CFR 63 applicability
	Additionally, we suggest the reference to “pumps, valves and other equipment in HAP service” be removed from the equipment list under the Section K heading. Most all process areas of the refinery have similar applicability, but the equipment lists typically just include point sources.	Removed
III.K.26, 45 and 57 (pages 61-65)	This CO emissions limit for the H-102 Reformer Heater has been removed from the MAQP. As such, it can be removed from the operating permit. Related conditions K.45 and K.57 can also be removed. Finally, reference to condition K.26 should be removed from conditions K.61.d, e, and f, and reference to condition K.57 should be removed from condition K.64.e. Corresponding updates to the section summary table should also be made.	Removed

III.K.34 (page 62)	To be consistent with the recent updates to the refinery's MAQP, the required frequency of the Fractionator Feed Heater (H-202) NOx and CO stack test should be updated to once every three years. The section summary table (rows K.7 and 8) should also be updated.	Updated
III.K.35 (page 62)	To be consistent with the recent updates to the refinery's MAQP, the required frequency of the Reactor Charge Heater (H-201) NOx and CO stack test should be updated to once every three years. The section summary table (rows K.12 and 13) should also be updated.	Updated
III.K.36 (page 62)	To be consistent with the recent updates to the refinery's MAQP, the required frequency of the Reformer Heater (H-101) NOx and CO stack test should be updated to once every three years. The section summary table (rows K.17 and 18) should also be updated.	Updated
III.K.44 (page 63)	To be consistent with the recent updates to the refinery's MAQP, we suggest the following update to the H-102 Reformer Heater NOx and CO stack testing requirement:	Updated
	"The H-102 Reformer Heater shall be tested annually once every three years , in conjunction with the annual CEMS/CERMS RATA performance testing...."	Updated
	The section summary table (rows K.24, 25 and 27) should also be updated.	
III.L (pages 66 – 69)	The following references to E-407 can be removed from this section. It is no longer a fuel gas fired unit contributing emissions to INC-401.	Updated
	· List of equipment in section L heading (page 66)	
	· Summary table row for condition L.9 (page 66)	
	· Conditions L.1, 2 and 4 (page 67)	
	· Conditions L.5 and 13 (page 68)	
	· Conditions L.17 and 19 (page 69)	
III.L.17 (page 69)	To be consistent with the recent updates to the refinery's MAQP, the required frequency of the Zone D SRU Incinerator (INC-401) stack tests should be updated to once every three years for SO ₂ and once every six years for NOx. The section summary table (rows L.10, 11, 12 and 13) should also be updated.	Updated
III.M.24 (page 77)	To be consistent with the recent updates to the refinery's MAQP, the required frequency of the Zone A TGI (SRU-AUX-4) stack tests should be updated to once every three years for SO ₂ and once every six years for NOx. The section summary table (rows 5 – 10) should also be updated.	Updated
III.N.14 and 18 (pages 83 - 84)	As part of the recent update to the refinery's MAQP, the NOx limits for Boilers 11 and 12 changed. As such, these conditions and section summary table should be updated to reflect the new limits:	Updated
	· 6.27 lb/hr, rolling 365-day average	
	· 27.5 tons/rolling 12-calendar month total	

	Additionally, the Boiler 12 limit of 0.02 lb/MMBtu-HHV, on a rolling 365-calendar day average can be removed from condition N.18 and the summary table.	
III.N.31 (page 85)	To be consistent with the recent updates to the refinery's MAQP, we suggest the following update to Boiler 10 stack testing condition N.31:	Updated
	“Boiler #10 shall be tested for NO _x and CO, and VOC concurrently (using Methods 7- and 10, 18, and 19, respectively , in accordance with Section III.A.2 (ARM 17.8.106)) at a minimum of every 5 years or another testing/monitoring schedule as may be approved by the Department, and shall be conducted for both natural gas and refinery fuel gas (ARM 17.8.1213). Testing for VOC shall be at the request of the Department. ”	
	The section summary table (row N.11) should also be updated.	
III.N.35 (page 85)	To be consistent with the recent updates to the refinery's MAQP, the required frequency of the Boiler #11 NO _x and CO stack test should be updated to once every three years. The section summary table (rows N.14 and 15) should also be updated.	Updated
III.N.36 (page 85)	To be consistent with the recent updates to the refinery's MAQP, the required frequency of the Boiler #12 NO _x and CO stack test should be updated to once every three years. The section summary table (rows N.18 and 19) should also be updated.	Updated
III.N.38 (page 85)	This Boiler 10 condition should reference Section III.N.31 but not III. N.35.	Updated
III.N.40 (page 86)	Reference to Boiler #11 can be added to this condition. It is also subject to the NSPS subpart Db NO _x limit that requires the use of F-factor values to demonstrate compliance.	Updated
III.O (page 89)	In the list of tanks under the EU014 – Tank Farm (non-Wastewater) heading, please make the following updates to reflect current status:	Updated
	· Move Tank 93 from the Group 1 list to the Group 2 list.	
	· Delete Tank 68 from the Group 2 list. The tank has been demo'd.	
III.O summary table (page 90)	Reference to Tanks 140 and 141 should be removed from the list of tanks in the row for condition O.7.	Updated
III.O.1 (page 91)	This condition identifies tanks that are subject to NSPS subpart Kb. Please add Tanks 83 and 110 to the list of subject tanks. These tanks were both modified during 2019.	Updated
	In row O.1 of the section summary table, Tanks 83 and 110 should be added and Tanks 126 and 127 should be removed. Tanks 126 and 127 are not subject to NSPS Kb.	
III. O.35 and O.36 (page 94)	Reference to storage tanks 140 and 141 can be removed from this condition because they did not end up being installed as part of the project that resulted in the new LDAR applicability.	Updated

III.P.16 (page 100)	Reference to storage tanks 140 and 141 and the propane loading rack can be removed from this condition and the section summary table. These facilities did not end up being installed as part of the project that resulted in the total VOC emissions limit.	Updated
III.Q (page 104)	In the list of equipment under the EU016 – Wastewater Treatment Units heading, please change wastewater storage vessel TK- 3446 to TK- 3436 .	Updated
III.Q summary table (page 104)	In the row for condition Q.6, we suggest that the “Permit Limit” cell be clarified, as follows: “A program meeting the requirements of 40 CFR 60 Subpart GGGa.”	Updated
III.R.3 (page 108)	For consistency with the MAQP, we suggest the following sentence of this condition be deleted:	Updated
	“The initial plan must be developed prior to, and implemented upon startup of, the Replacement Main Refinery Flare.”	
III.R.16 (page 110)	We suggest this NSPS Ja flare monitoring condition be removed as it duplicates the requirements of condition R.11.	Updated
III.V.11 (page 118)	The CO lb/hr limit for the Reactor Charge Heater (H-901) was recently removed from the MAQP. As a result, it should be removed from this condition and the summary table. The annual CO limit was incorrectly removed from the Proposed Permit draft and has been added back to this condition.	Updated
III.V.15 (page 118)	The CO lb/hr limit for the Fractionator Reboiler (H-902) was recently removed from the MAQP. As a result, it should be removed from this condition and the summary table. The annual CO limit was incorrectly removed from the Proposed Permit draft and has been added back to this condition.	Updated
III.V.35 (page 120)	The second sentence of this condition should be updated as follows:	Updated
	Compliance with the H-901 and H-902 CO emission limits shall be determined from emissions factors generated from the annual most recent CO stack test testing requirement (CO testing, concurrent with NOx testing).	
III.V.36 (page 120)	To be consistent with the recent updates to the refinery’s MAQP, the required frequency of the Reactor Charge Heater (H-901) NOx and CO stack test should be updated to once every three years. Note that the section summary table doesn’t require an update because it doesn’t currently reference the stack testing requirements.	Updated
III.V.37 (page 120)	To be consistent with the recent updates to the refinery’s MAQP, the required frequency of the Fractionator Heater (H-902) NOx and CO stack test should be updated to once every three years. Note that the section summary table doesn’t require an update because it doesn’t currently reference the stack testing requirement.	Updated
III.V.41 (page 121)	To be consistent with the recent updates to the refinery’s MAQP, the required frequency of the Reformer Heater (H-1001) NOx and CO stack test should be updated to once every three years. The section summary table (rows V.20, 21 and 23) should also be updated.	Updated

III.V.53	In the recent MAQP update, the CO emissions reporting requirement for the H-901 and H-902 heaters was removed. As such, this reporting requirement should be removed from the operating permit.	Updated
III.W summary table (page 126)	In the row for condition W.13, the VOC and PM10 emissions limits should be updated to be based on a monthly rolling 12-month total , not a 12-month average .	Updated
III.W.13.a (page 128)	This limit on the coke drum steam vent pressure (5 psig or lower) was removed from the MAQP during the recent permit update. As such, it can be removed from the operating permit and section summary table.	Updated
III.W.13.d (page 128)	We suggest the following edit to this condition:	Updated
	“CHS shall either de-pressure each coke drum to a closed blowdown system until either...”	
III.W.19 (page 129)	To be consistent with the recent updates to the refinery’s MAQP, the required frequency of the Coker Charge Heater (H-7501) NOx and CO stack test should be updated to once every three years. The section summary table (rows W.8 and 9) should also be updated.	Updated
III.W.26 (page 130)	The definition of “P” was revised in the recent update to the MAQP. For this reason, the new definition should be incorporated into the operating permit, as follows:	Updated
	· P = 5-minute rolling average coke drum pressure (psig) as determined just prior to initiating steps to isolate the coke drum prior to venting, draining or deheading.	
III.W.27 (page 130)	The first sentence of this coke drum steam vent compliance demonstration condition can be deleted. It is related to condition W.13.a that has been removed from the MAQP.	Updated
	The second sentence should be updated as follows:	
	“...based on the 5-minute rolling average pressure or temperature calculated...”	
III.W.37.h (page 131)	The second part of this reporting condition, “and any instances that the drum is not depressurized at below 5 psig”, can be deleted as the referenced limit has been removed.	Updated
III.X. 12 and 13 (page 134)	To be consistent with recent updates to the refinery’s MAQP for the Zone E SRU/TGTU/TGI stack, condition X.12 should be updated to require SO ₂ testing once every three years and condition X.13 should be updated to require NOx testing once every six years. The section summary table (rows X.3 and 6) should also be updated.	Updated
III.Y summary table (page 137)	In the row for condition Y.4, the ammonia test frequency for the Ammonia Combustor should be updated to “once every four years” rather than “as required by the Department”.	Updated
III.Y.19 and 21 (page 139)	For consistency with the MAQP, we suggest the following changes to the following Ammonia Combustor reporting conditions:	Updated

	Y.19: Relocate the requirements of Y.21.b to become part of condition Y.19. These are specific requirements of the MAQP quarterly report.	
	Y.21: In place of Y.21.b, include a MAQP quarterly report condition similar to what is included in other areas of the permit. For example: “Summary of compliance with unit emission limits and conditions and dates that quarterly reports were submitted as required by Section III.Y.19.”	
III.Z summary table (page 140)	In the row for condition Z.7, limit 3) should be updated to be based on a rolling 36 -hr average.	Updated
III.Z summary table (page 140)	In the “Compliance Demonstration Method” cell for condition Z.8, we suggest the following update:	Updated
	“Method 18 and Method 25 or another method as agreed in writing ”	
III.Z.10 (page 142)	This condition includes the total CO _{2e} limit that applies to the Hydrogen Reformer Heater (067HT0001) and FCCU regenerator. For clarification, we suggest that “Section III.I” be added in parentheses behind “FCCU regenerator”.	Updated
III.Z.20.c (page 144)	We suggest this condition be updated as follows:	Updated
	“VOC – EPA Method 18 and 25 or another methodology as agreed in writing between CHS and the Department. As requested by the Department.”	
III.Z.20.f (page 144)	This condition defines the compliance demonstration method for the total CO _{2e} limit applicable to the Hydrogen Reformer Heater (067HT0001) and FCCU regenerator. We suggest the following addition to the condition:	Updated
	“For the FCCU regenerator, compliance shall be demonstrated following the calculation procedures of 40 CFR part 98 subpart Y.”	
III.Z.20 (page 144)	To be consistent with recent updates to the refinery’s MAQP, the following stack test frequency updates should be made to this condition:	Updated
	a. “NO _x – Annually Every three years from the date of the last source test using EPA Method 7, in conjunction with annual CEM/CERMS RATA...” and “...for NO _x /O ₂ and CO (EPA Methods 7 and 10), concurrently,...”	
	b. “CO – Annually Every three years from the date of the last source test using EPA Method 10 in conjunction....”	
	d. “PM ₁₀ /PM _{2.5} – EPA Method 5 or 201 and 202. Once every four six years.”	
	Additionally, the section summary table (rows Z.3, 7 and 9) should be updated.	
III.Z.31 and 36 (pages 145 – 146)	For consistency with the MAQP, we suggest the following changes to these two Hydrogen Plant #3 reporting conditions:	Updated
	Z.31: Relocate the requirements of Z.36.g to become part of condition Z.31. These are specific requirements of the MAQP quarterly report.	

	Z.36.g: In place of Z.36.g, include a MAQP quarterly report condition similar to what is included in other areas of the permit. For example: “Summary of compliance with unit emission limits and conditions and dates that quarterly reports were submitted as required by Section III.Z.31.”	
III.AA (pages 146 – 147)	Update the equipment numbers associated with the following emergency generators in the equipment list and regulatory applicability table: Admin 1 EG (021-GN-0204) and Admin 3 EG (021-GN-1031)	Updated
III.AA.1 (page 148)	For clarity, we suggest the following equipment numbers be added to the fire pump engine references:	Updated
	· Tank 134 East Pump (P-2207)	
	· Tank 134 West Pump (P-2208) · West Diesel Pump (P-2204)	
III.AA.2 (page 148)	This condition should reference “EU026: Stationary Engines” rather than “EU014 Stationary Reciprocating Internal Combustion Engines”.	Updated
III.AA.3 (page 148)	The equipment number associated with Admin 3 EG should be updated to 021-GN-1031.	Updated
III.AA.4, 8, 12 and 16.a.(page 148)	We suggest that these conditions related to diesel fuel sulfur content be removed from the permit because conditions AA.1 (NSPS IIII) and AA.2 (MACT ZZZZ) address fuel requirements more generally. Note that the fuel requirements are applicable based on the age and size of the diesel engine and not all of the refinery’s stationary diesel engines are subject to the requirements.	These were not updated as the basis for these could not be determined and therefore could not be removed without further determination.
III.AA.6 (page 148)	We suggest this condition be shortened as follows because none of the CHS engines are subject to Table 5 requirements:	Updated
	“CHS shall demonstrate compliance with 40 CFR 63 Subpart ZZZZ through the applicable compliance requirements of 40 CFR 63 Subpart ZZZZ, including any applicable requirements in the tabulated initial and continuous compliance requirements of Table 5 and Table 6 of 40 CFR 63 Subpart ZZZZ, respectively. ”	
III.AA.15 (page 149)	This condition should reference 40 CFR 60 Subpart JJJJ instead of Subpart IIII. Reference to this condition should also be added to the section summary table in the row for condition AA.3.	Updated
III.IV.A (page 151)	This section lists the requirements that are not applicable to the CHS Laurel refinery. We suggest the following updates to the summary table:	Updated
	· Add 40 CFR 55, 57 and 59	
	· Update the first row of the 40 CFR 60 section to Subparts B, C, Cb = Cf	
Technical Review	In the facility compliance requirements summary table, we suggest that Method 22 (visible emissions) be added to the list of source tests required.	Updated

Document (TRD) (page 1)		
TRD (page 42)	In the final paragraph of Section I.C. related to the operating permit history, we suggest the following update to the 5 th sentence: “...to reflect equipment names where equipment was now in service and is no longer considered “new” equipment...”	Updated
TRD (page 46)	The first section on this page discusses Violation Letter # VL-20180122-00279. The final sentence of the discussion indicates that the DEQ was reviewing the violations for possible referral to the Enforcement Division. Note that in a letter dated January 11, 2019, CHS was informed that DEQ had decided not to pursue a formal enforcement action regarding the violations.	Updated
TRD (page 46)	At the bottom of this page, DEQ included a summary of the operating permit conditions included in the renewal application that were not being met at the time the application was submitted. The first bullet item related to the stationary engine requirements of NSPS subparts IIII and JJJJ and 40 CFR 63 subpart ZZZZ requirements. We suggest that it be noted that all compliance plan actions were completed as specified prior to issuance of the draft operating permit.	Updated
TRD III.A (page 54)	The first sentence identifies where the operating permit limits and standards originated. We suggest you consider whether reference to the USEPA Consent Decree should be removed since it has been closed and whether the Federal Implementation Plan (FIP) for the Billings/Laurel Area (40 CFR 52.1392) should be added.	Updated
TRD IV (page 56)	This page includes a table that lists requirements that CHS has historically identified as non-applicable but are not being included as non-applicable in the permit. We suggest the following updates to the table: · Remove 40 CFR 63, Subpart ZZZZ from the table. Applicability has been incorporated into the operating permit (new section III.AA). · Consider whether the consent decree should remain in the table since it has been closed. · Remove ARM 17.8.324(2) from the table. Applicability is included in Section III.A.16 of the permit. · We agree that ARM 17.8, Subchapter 8 is applicable to the refinery. We suggest these requirements be incorporated into the operating permit, as appropriate.	Updated
TRD V.A (page 57)	We suggest the following updates to the third paragraph related to the MACT CC flare requirements:	Updated

	<p>“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 has transitioned to that of MACT CC. At such time, As of January 30, 2019, the MACT CC flare design and operation requirements are applicable and 40 CFR 60.18 and 40 CFR 63.11 requirements are no longer applicable. would not be applicable through the NSPS and MACT standards. A streamlining of demonstration with Existing 40 CFR 60.18 and 63.11 conditions in the MAQP requirements will be necessary to appropriately accommodate the transition of eliminating reference to 40 CFR 60.18 and 40 CFR 63.11 were replaced with MACT CC requirements as part of MAQP 1821-43.”</p>	
TRD.V.A (page 57)	<p>For clarity, we suggest the following update to the third bullet item on the page:</p> <p>“Continuous Periodic benzene monitoring at the refinery fenceline to improve the management of fugitive emissions”</p>	Updated
TRD.V.A (page 57)	<p>We suggest the following update to the final paragraph of this discussion:</p> <p>“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 #1821-18, CHS will have has incorporated some all elements of the RSR.” and additional elements will be included in the upcoming Title V renewal.”</p>	Updated

Department Comments: A number of cross-references were updated in the summary tables and conditions on the Decision Permit where previous permitting updates had not correctly updated cross reference numbering.

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 #OP1821-18.

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	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.

Applicable Requirement	Reason
Consent Decree CV-03-153-BLG-RFC (entered 2/23/04)	The Consent Decree closed in December 2018, and therefore requirements from the CD (Appendix F) have been removed from #OP1821-18.
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, the flare design and operation requirements of 40 CFR 60.18 and 63.11 has transitioned to that of MACT CC. As of January 30, 2019, the MACT CC flare design and operation requirements are applicable and 40 CFR 60.18 and 40 CFR 63.11 requirements are no longer applicable. Existing 40 CFR 60.18 and 63.11 conditions in the MAQP were replaced with MACT CC requirements as part of MAQP 1821-43.

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;
- Periodic 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;

With the issuance of OP #1821-18, CHS will have incorporated all elements of the RSR.

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.