Technical Analysis Report

for the terms and conditions of

Minor Permit No. AQ0035MSS07

Issued to:
Tesoro Alaska Company, LLC, Kenai Pipeline Company, and Tesoro Logistics Operations, LLC (Tesoro)

for
Kenai Refinery, Kenai Pipeline Terminal (KPL), and Nikiski Terminal

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Alaska Department of Environmental Conservation
Air Permits Program

INTRODUCTION

This Technical Analysis Report (TAR) provides the Alaska Department of Environmental Conservation's (Department's) basis for issuing Minor Permit AQ0035MSS07 to Kenai Refinery, Kenai Pipeline Terminal (KPL), and Nikiski Terminal.

The Department is issuing this Minor Permit No. AQ0035MSS07 to incorporate certain emission limits or standards and other requirements mandated by Consent Decree (CD) Civil No. Civ. SA-16-cv-00722, filed July 18, 2016, as agreed to by the Permittee and the United States Department of Justice. The Department intends to incorporate the revisions issued under this minor permit, using the integrated review procedures described in 18 AAC 50.326(c)(1), into the Title V operating permit renewals for the Kenai Refinery (AQ0035TVP03), KPL (AQ0033TVP04), and Nikiski Terminal (AQ0036TVP04).

1. STATIONARY SOURCE DESCRIPTION

The Kenai Refinery, KPL, and Nikiski Terminal are owned and operated by the Tesoro Alaska Company, LLC, Kenai Pipeline Company, and Tesoro Logistics Operations, LLC, respectively. These three facilities are aggregated and deemed one major source, in accordance with 40 C.F.R. 71.2 because they are under a common control, are interdependent and support facilities, and are located contiguously to each other.

The Kenai Refinery processes crude oil into a variety of petroleum products. Crude oil and other feedstocks are transported to the refinery through the KPL by ocean tanker, barge, pipeline or tanker truck. The KPL is a marine vessel loading and crude oil storage facility owned by Kenai Pipeline Company, a subsidiary of Tesoro Alaska Company, LLC. The crude is then pumped into bulk storage tanks at the refinery. The refinery includes an underground pipeline system that extends from the refinery to the Kenai Pipeline facility, as well as, the Anchorage and Nikiski Terminals. The Nikiski Terminal is a bulk petroleum terminal which receives fuel products into storage tanks such as gasoline, jet fuel and diesel fuel via piping from the Kenai Refinery. The petroleum products are loaded into tank truck cars for transport to consumers.

Tesoro currently operates the Kenai Refinery, KPL, and Nikiski Terminal under Operating Permits AQ0035TVP02 Revision 9, AQ0033TVP03, and AQ0036TVP03, respectively. Kenai Refinery's Permit No. AQ0035TVP02 Revision 9 includes Title I permit conditions carried over from an expired Air Quality Control Permit-to-Operate No. 9323-AA008, Construction Permit Nos. 9923-AC010 and 035CP04, and Minor Permit Nos. AQ0035MSS01, AQ0035MSS02, AQ0035MSS04 through AQ0035MSS06, and AQ0035MSS09. KPL's Permit No. AQ0033TVP03 includes Title I permit conditions carried over from Construction Permit No. 0023-AC010.

2. APPLICATION DESCRIPTION

Tesoro Alaska Company Kenai Refinery (Tesoro) and other settling defendants entered into agreement with the United States Environmental Protection Agency (EPA) under Consent Decree Civil No. Civ. SA-16-cv-00722 (CD), filed July 18, 2016. Paragraphs 154 and 155 of the CD require Tesoro to obtain from the Department a federally-enforceable Title I permit that incorporates certain requirements mandated by the CD, as well as, apply for Title V permit modification or renewal that would carry forward those requirements from the Title I permit.

Tesoro submitted its application for a minor permit on March 27, 2017 requesting modification of the most recent or most relevant Title I permit to establish federally-enforceable Consent Decree requirements, under the authority of Alaska Statutes (AS) 46.14.280(a)(1)(B). The application also requests that the CD requirements applicable to each of the aggregated facilities (Kenai Refinery, KPL and Nikiski Terminal) be incorporated into each facility's corresponding Title V permit.

Tesoro submitted the following addenda to the minor permit application: On May 8, 2017, Tesoro submitted a request to add a new emissions unit, EU ID 10, to the KPL emissions unit inventory to assign a specific EU ID for the stationary source's component leaks subject to NSPS Subpart GGGa/VVa, rather than generically referring to the whole facility. On June 16, 2017, Tesoro submitted an addendum requesting the removal and/or revision of the several existing conditions of Title V Permit AQ0035TVP02 Revision 8 for the Kenai Refinery that are redundant to conditions requested with this minor permit incorporating the federally enforceable Consent Decree requirements.

3. CLASSIFICATION FINDINGS

Based on the review of the application, the Department finds that:

1. This project is classified under 18 AAC 50.508(6) because Tesoro requested to incorporate the CD requirements as revision to existing Title I permit conditions. Construction Permit 9923-AC010, Revision 1 (issued December 31, 2002) is the most recent Title I permit issued to Tesoro that has relevance to the CD requirements. This permit addresses PSD requirements including, but not limited to, limits for H_2S content of fuel gas burned at the stationary source as Best Available Control Technology (BACT) for SO_2 emissions. The CD requires additional measures to reduce emissions of SO_2, among others, from the stationary source, through compliance with the applicable requirements of NSPS Subparts J and Ja.

   Because compliance with the SO_2 BACT requirements is also demonstrated through compliance with the applicable requirements of NSPS Subpart J (and Subpart Ja, for newly affected EU IDs 119 and 133) and NSPS Subpart GG (now replaced by Subpart KKKK for the new dual fuel-fired replacement turbine units, EU IDs 32A and 33A), a revision to the SO_2 BACT requirements is necessary for consistency. Specifically, the Department has included the averaging period for fuel gas H_2S content limit consistent with that of the federal NSPS Subparts J and Ja, and replaced reference to NSPS Subpart GG with NSPS Subpart KKKK.

4. APPLICATION REVIEW FINDINGS

Based on the review of the application, the Department finds that:

1. Tesoro's application for a minor permit for the Kenai Refinery contains the elements listed in 18 AAC 50.540.

2. In addition to the specific requirements for the Kenai Refinery, the application also addresses specific applicable requirements for the other aggregated facilities - the Kenai Pipeline Terminal (KPL) and the Nikiski Terminal.

3. The CD was issued to settle alleged violation by Tesoro due to major modifications to the Refinery and operating such modifications without obtaining and/or complying with the Clean Air Act's (CAA's) Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) requirements, regulations promulgated thereunder, and/or the Alaska State Implementation Plan (SIP) requirements and regulations regarding

installing and operating pollution control technology, emission limits and associated monitoring, recordkeeping, and reporting. The alleged violations on specific NSPS (40 C.F.R. 60) and NESHAP (40 C.F.R. 61 for Pollutant Type and 40 C.F.R. 63 for Source Categories) rules include:

- The Leak Detection and Repair ("LDAR") requirements found at:
  - 40 C.F.R. Part 60, Subpart GGG (Equipment Leaks of VOC in Petroleum Refineries);
  - 40 C.F.R. Part 61, Subpart FF (Benzene Waste Operations); and
  - 40 C.F.R. Part 63, Subpart CC (Petroleum Refineries);
- The flaring requirements found at:
  - 40 C.F.R. Part 60 Subparts GGG and GGGa (Equipment Leaks of VOC in Petroleum Refineries);
  - 40 C.F.R. Part 60 Subpart J (Petroleum Refineries);
  - 40 C.F.R. Part 61 Subpart FF (Benzene Waste Operations);
  - 40 C.F.R. Part 63, Subpart CC (Petroleum Refineries);
  - 40 C.F.R. Part 63, Subpart UUU (Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units);
  - 40 C.F.R. 60.18 (General control device and work practice requirements, as referenced in Subparts J, Ja, GGG and GGGa);
  - 40 C.F.R. 63.11 (Control device and work practice requirements); and
- The following NSPS and NESHAP Subparts:
  - 40 C.F.R. Part 60, Subpart GG (Stationary Gas Turbines);
  - 40 C.F.R. Part 60, Subpart QQQ (VOC Emissions from Petroleum Refinery Wastewater Systems);
  - 40 C.F.R. Parts 60, 61, and 63, Subpart A (General Provisions for the above NSPS and NESHAPs)

4. As part of its injunctive relief provisions, the CD requires that Tesoro comply with the enhanced leak detection and repair (ELDAR) program of the Clean Air Act, as specified in the CD, in addition to the LDAR requirements already in place for the stationary source under the applicable NSPS and NESHAP subparts. The CD requires Tesoro to comply with these federal requirements by upgrading the existing flare units and continuous monitoring systems, installing flare gas recovery systems, establishing stationary source-wide flaring limit and new compliance monitoring scheme; thus, revising the terms and conditions of the existing relevant Title I permit.

5. Although the consent decree addresses only the Kenai Refinery, Tesoro interpreted it to also apply to the KPL and Nikiski Terminal, inasmuch as, these three facilities are deemed one stationary source. Therefore, the Department is issuing Minor Permit No. AQ0035MSS07 to include the applicable requirements specific for each of the three aggregated stationary sources.

6. The Department is processing the request as a significant modification to each of the operating permits because revising a limit and associated monitoring requirements in the operating permit is a substantive change and does not qualify for a minor modification.

7. The Department addressed the request for addition of EU ID 10 to the KPL facility by adding the emission unit in Table 1.

8. The Department addressed the request for removal of redundant Title V operating permit conditions in the Kenai Refinery's Title V renewal permit AQ0035TVP03.
9. The requested changes under 18 AAC 50.508(6) do not result in increase of potential emissions of regulated air pollutants.
10. The Department is incorporating the CD requirements, using the integrated review provisions of 18 AAC 50.326(c)(1), into the Title V operating permits, as follows: (a) Kenai Refinery's renewal Permit No. AQ0035TVP03; (b) KPL's renewal Permit No. AQ0033TVP04; and (c) Nikiski Terminal's renewal Permit No. AQ0036TVP04. Tesoro may not operate under Minor Permit No. AQ0035MSS07 until the Department issues the renewed operating permits.

5. PERMIT CONDITIONS

The bases for the conditions imposed in Minor Permit AQ0035MSS07 are described below.

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18 AAC 50.544(a)(1) requires the Department to identify the stationary source, Permittee, and contact information.

Section 1 and Condition 1: Emissions Unit Inventory

The EUs authorized and/or restricted by this permit are listed in Table 1. Except as noted elsewhere in this permit, the information in Table 1 is for identification purposes only. Condition 1 is a general requirement to comply with AS 46.14 and 18 AAC 50 when installing a replacement EU.

Section 2: Revisions to Previous Permit Actions

Conditions 2 and 3, Stationary Source-specific requirements

Condition 2 provides the means to rescind and replace parts of Condition 45 of Construction Permit No. 9923-AC010 Revision 1.

Condition 3 of this Minor Permit AQ0035MSS07 replaces that part of Condition 45 of Construction Permit No. 9923-AC010 Revision 1 that pertains to the Refinery gas H_2S limits. Condition 45 of Construction Permit No. 9923-AC010 Revision 1 requires compliance with the BACT limits for sulfur compound emissions. The condition references Condition 43.4 (which provides the state SO_2 emissions standards applicable to the stationary source) and Exhibit B.E.1 & 2 (which provides the fuel sulfur content and H_2S limits) as BACT for SO_2 emissions. For the purposes of this minor permit, the particular fuel sulfur content limit being rescinded and replaced in this permit pertains to the refinery gas H_2S limits found in Condition 43.4.1 and Exhibit B, Sections E.1 and E.2 of Construction Permit No. 9923-AC010 Revision 1.

The initial Title V permit corrected the typographical errors on Refinery gas H_2S content limit (from "162 ppm or 238 mg/dscm" to "162 ppmv or 230 mg/dscm") and units (from "dry standard cubic feet" to "dry standard cubic meter") as administrative amendment to Construction Permit No. 9923-AC010 Revision 1. The initial Title V permit also clarified that the H_2S limit is applicable to fuel gas (FG) which is a combination of refinery gas (RG), natural gas (NG) and liquefied petroleum gas (LPG) burned at the stationary source. These corrections have been carried forward through Title V Permit No. AQ0035TVP02 Revision 6 and Revision 8, as well as into this Minor Permit No. AQ0035MSS07. A three-hour rolling average basis was added in Condition 3 of this minor permit, to be consistent with the provisions of the state and NSPS Subparts J and Ja SO_2 standards applicable to fuel gas burned at a petroleum refinery. In addition, the Permittee is required to comply with the emissions reductions measures imposed by the CD in Condition 6, as well as, the relevant requirements of NSPS Subpart KKKK, to ensure compliance with the BACT limits for sulfur compound emissions.

Section 3: Requirements Mandated by Consent Decree

Conditions 4 through 33, Emission Unit-specific requirements

Conditions 4 through 33 are emission unit-specific terms and conditions required by the CD. These include the flaring requirements and enhanced leak detection and repair (ELDAR) program of the CAA, in addition to the LDAR requirements already in place for the stationary source under NSPS Subparts J, Ja, and GGGa/VVa.

Condition 4 requires that no later than October 1, 2016, all "covered process units" (as defined by 40 C.F.R. §63.641 Subpart CC and 40 C.F.R. §60.591a Subpart GGGa) at the three aggregated facilities (Kenai Refinery, KPL, and Nikiski Terminal) are subject to and must comply with the applicable requirements of NSPS Subparts GGGa and VVa, instead of NSPS Subpart GGG and VV. The affected emission units at the Kenai Refinery are EU IDs 96 – 104, 111, 112, 117, 119, and 126 – 128. The affected emissions units at KPL (EU ID 10) and Nikiski Terminal (EU ID 9) include equipment leaks from piping systems used to convey liquids into and out of storage tanks, as well as to load products into marine vessels (at KPL) and tank truck loading rack (at Nikiski Terminal). These piping systems consist of piping, flanges, valves, pumps, and other connectors that are fugitive sources of VOC emissions.

Conditions 6 through 30 provide the specific CD requirements as additional requirements for compliance with the NSPS Subparts J and Ja affected emission units; i.e., the Refinery Flare (EU ID 42) and Fuel Gas System (EU IDs 1 – 11, 17 – 20, 25, 27 – 29, 101, 115, 116, 119, and 133) at the Kenai Refinery, to be accomplished on certain dates. Although not specifically required in the CD, the Department added Condition 25 (Flare Tip Velocity (Vtip)) to reflect the applicable requirements from 40 C.F.R. 63.670(d), (k), and (l) to provide better organization and continuity of condition requirements.

Condition 31 through 33 include prohibitions pertaining to emissions credit netting associated with any emission reductions resulting from the new flaring limitations, emissions controls, and monitoring requirements mandated by the CD.

APPENDIX I through APPENDIX VII are provided at the end of this TAR to supplement the CD requirements incorporated as conditions in this permit.

Section 4: Standard Permit Conditions

Conditions 34 through 39, Standard Permit Conditions

18 AAC 50.544(a)(5) requires each minor permit issued under 18 AAC 50.542 to contain the standard permit conditions in 18 AAC 50.345, as applicable. 18 AAC 50.345(a) clarifies that subsections 18 AAC 50.345(c)(1) and (2), and (d) through (o), may be applicable for a minor permit.

The Department included all of the minor permit-related standard conditions of 18 AAC 50.345 in Minor Permit AQ0035MSS07. The Department incorporated these standard conditions as follows:

- 18 AAC 50.345(c)(1) and (2) is incorporated as Condition 34 of Section 4 (Standard Permit Conditions); and
- 18 AAC 50.345(d) through (h) is incorporated as Conditions 35 through 39, respectively, of Section 4 (Standard Permit Conditions).

APPENDIX I - Definitions

The following terms used in this Permit, when capitalized, shall be defined, solely for purposes of this Permit and the reports and documents submitted pursuant thereto, as follows:

An *"Acid Gas Flaring Event"* shall mean the continuous or intermittent combustion of Acid Gas and/or Sour Water Stripper Gas in the Kenai SRU Flare that results in the emission of SO_2 equal to, or in excess of, 500 pounds in any 24-hour period; provided, however, that if 500 pounds or more of SO_2 has been emitted in a 24-hour period and Acid Gas Flaring continues into subsequent, contiguous, non-overlapping 24-hour period(s), each period of which results in emissions equal to, or in excess of, 500 pounds of SO_2, then only one Acid Gas Flaring Event shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of flaring within the Acid Gas Flaring Event.

"Assist Air" shall mean all air that intentionally is introduced prior to or at a flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame. Assist Air includes Premix Assist Air and Perimeter Assist Air. Assist Air does not include the surrounding ambient air.

"Assist Steam" shall mean all steam that intentionally is introduced prior to or at a flare tip through nozzles or other hardware conveyance for the purposes including, but not limited to, protecting the design of the flare tip, promoting turbulence for mixing or inducing air into the flame. Assist Steam includes, but is not necessarily limited to, Center Steam, Lower Steam, and Upper Steam.

"Automatic Control System" shall mean a system that utilizes programming logic to automate the operation of the instrumentation and systems required in Condition O of this Permit so as to produce the operational results required in Condition Q of this Permit.

"Available for Operation" shall mean, with respect to a compressor within a FGRS, that the compressor is capable of commencing the recovery of Potentially Recoverable Gas as soon as practicable but not more than one hour after the need for a compressor to operate arises; the period of time, not to exceed one hour, allowed by this definition for the Startup of a compressor shall be included in the amount of time that a compressor is Available for Operation.

"Block Average" means the arithmetic mean of a measured or calculated parameter during a Block Average Period.

"Block Average Period" or *"Block Period"* means the uninterrupted period of time during which the Block Average must be calculated.

"Block Sum" means the sum total of the measured or calculated standard, exception, or triggering event during a Block Sum Period. Most often, the term "block sum" is not explicitly used; rather, the concept is implicit in the description.

"Block Sum Period" means the uninterrupted period of time during which the Block Sum must be calculated. Most often, the term "Block Sum Period" (and indeed the term "sum period") is not explicitly used; rather, the concept is implicit in the description.

"Capable of Receiving Sweep, Supplemental, and/or Waste Gas" shall mean, for a flare, that the flow of Sweep, Supplemental, and/or Waste Gas is/are not prevented from being directed to the flare by means of closed valves and/or blinds.

"Center Steam" shall mean the portion of Assist Steam introduced into the stack of a flare to reduce burnback.

"Combustion Efficiency" or *"CE"* shall mean a Flare's efficiency in converting the organic carbon compounds found in Vent Gas to carbon dioxide. Combustion Efficiency shall be calculated as set forth in Equation 1 in APPENDIX II of this Permit.

"Combustion Zone Gas" shall mean all gases and vapors found just after a flare tip. This gas includes all Vent Gas, Total Steam, and Premix Assist Air.

"Combustion Zone" shall mean the area of the flare flame where the Combustion Zone Gas combines for combustion.

"Day" or *"Days"* shall mean a calendar day or days. *"Working Day"* shall mean a day other than a Saturday, Sunday, or Legal holiday, as that term is defined by Federal Rule of Civil Procedure 6(a)(6). In computing any period of time under this Permit, where the last day would fall on a Saturday, Sunday, or Legal holiday, the period shall run until the close of business on the next Working Day.

"External Power Loss" shall mean a loss in the supply of electrical power to the Kenai Refinery that is caused by events occurring outside the boundaries of the refinery, excluding power losses due to an interruptible power service agreement.

"Flare" shall mean a combustion device lacking an enclosed combustion chamber that uses an uncontrolled volume of ambient air to burn gases. For the purposes of this Consent Decree, the definition of Flare includes, but is not necessarily limited to, Air-Assisted Flares, Steam-Assisted Flares, and non-assisted Flares.

"Flare Gas Recovery System" or *"FGRS"* shall mean a system of one or more compressors, piping, and associated water seal, rupture disk, or similar device used to divert Potentially Recoverable Gas from a flare and direct Potentially Recoverable Gas to a Fuel Gas System, to a combustion device other than the flare, or to a product, co-product, by product, or raw material recovery system or other system that avoids combustion of the gases.

"Flare Tip Velocity" or "Vtip" shall mean the velocity of gases exiting the Flare tip as defined in Equation 7 of Appendix C - 1.2.

"Force Majeure" shall mean any event arising from causes beyond the control of the Permittee, of any entity controlled by the Permittee, or of the Permittee's contractors, that delays or prevents the performance of any obligation under this Permit despite the Permittee's best efforts

to fulfill the obligation. The requirement that a Permittee exercise "best efforts to fulfill the obligation" includes using best efforts to anticipate any potential force majeure event and best efforts to address the effects of any such event (a) as it is occurring and (b) after it has occurred to prevent or minimize any resulting delay to the greatest extent possible. "Force Majeure" does not include a Permittee's financial inability to perform any obligation. The failure of a Permitting Authority to issue a necessary construction or operating permit in a timely fashion is a force majeure event where the Permittee submitted a timely and complete permit application and the failure of the Permitting Authority to issue the relevant permit is beyond the control of the Permittee.

"In Operation" shall mean any and all times that any gas (e.g. Waste Gas, Vent Gas, Purge Gas, Pilot Gas) is or may be vented to a flare. A flare that is In Operation is Capable of Receiving Sweep, Supplemental, and/or Waste Gas unless all Sweep, Supplemental, and/or Waste Gas flow is prevented by means of closed valves, and/or blinds.

"Kenai Main Refinery Flare" shall mean the emission unit labeled J-801 in Table A of the Kenai Refinery Title V permit.

"Kenai SRU Flare" shall mean the emission unit labeled SRU Flare in Table A of the Kenai Refinery Title V permit.

"Lower Steam" shall mean the portion of Assist Steam piped to an exterior annular ring near the lower part of a flare tip, which then flows through tubes to the flare tip, and ultimately exits the tubes at the flare tip.

"Malfunction" shall mean any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not Malfunctions.

"Net Heating Value" or *"NHV"* shall mean Lower Heating Value.

"Perimeter Assist Air" means the portion of Assist Air introduced at the perimeter of the flare tip or above the flare tip. Perimeter Assist Air includes air intentionally entrained in Lower and Upper Steam. Perimeter Assist Air includes all Assist Air except Premix Assist Air.

"Pilot Gas" shall mean gas introduced into a Flare tip that provides a flame to ignite the Vent Gas.

"Portable Flare" shall mean a flare that is not permanently installed that receives Waste Gas that has been redirected to it from a flare.

"Potentially Recoverable Gas" shall mean the Sweep Gas, Supplemental Gas introduced prior to a flare's water seal, and/or Waste Gas directed to a flare's FGRS or group of flares' FGRS. Purge Gas and Supplemental Gas introduced between a flare's water seal and a flare's tip is not Potentially Recoverable Gas. Hydrogen venting from the steam methane reformer (hydrogen plant) is not Potentially Recoverable Gas. Recycled hydrogen that bypasses the FGRS to reestablish hydrogen balance in the event that hydrogen demand declines or stops rapidly is also

not Potentially Recoverable Gas. Excess Fuel Gas and excess gases generated during Shutdown, in turnaround, and during Startup, caused by a gas imbalance that cannot be consumed by fuel gas consumers in the refinery, because there is not sufficient demand for the gas, is not Potentially Recoverable Gas. Nitrogen purges of Flaring Process Units that are being Shutdown, in turnaround and during Startup, or the nitrogen purging of operating flaring process units during a partial refinery turnaround scenario, that cause the NHV of the fuel gas at the exit of the mix drum to fall below 740 BTU/scf, shall not be considered Potentially Recoverable Gas, and may be routed around the FGRS.

"Premix Assist Air" means the portion of Assist Air that is introduced to the Vent Gas, whether injected or induced, prior to the flare tip. Premix Assist Air also includes any air intentionally entrained in Center Steam.

"Purge Gas" shall mean the minimum amount of gas introduced between a flare header's water seal and the flare tip necessary to prevent freezing and oxygen infiltration (backflow) into the flare. For a flare with no water seal, the function of Purge Gas is performed by Sweep Gas and, therefore, by definition, such a flare has no Purge Gas.

"Rolling Average" or *"y rolling average, rolled n"* requires: (i) the calculation of a Block Average during each Block Average Period of n length of time; and (ii) the calculation of the arithmetic mean of the Block Average values for the total number of Block Averages that equals y length of time.

"Rolling Average Period" means the total length of time for which the arithmetic mean of the Block Averages must be calculated.

"Rolling Sum" or *"y rolling sum, rolled n"* requires: (i) the calculation of a Block Sum during each Block Sum Period of n length of time; and (ii) the adding together of the Block Sum values for the total number of Block Sums that equals y length of time.

"Rolling Sum Period" means the total length of time for which the Block Sums must be added together.

"Shutdown" shall mean the cessation of operation of equipment for any purpose.

"SO_2 Monitor Trigger Event" shall mean the third Acid Gas Flaring Event ("Event") from the Kenai SRU Flare within any rolling 12-month period between the period starting January 1, 2013, and the Termination of this Consent Decree. A rolling 12-month period shall include the first Day of the month in which an Event occurs and runs to the last Day of the 11th subsequent month. A SO_2 Monitor Trigger Event will not include any Acid Gas Flaring Event caused by a *force majeure* event.

"Smoke Emissions" shall have the definition set forth in Section 3.5 of Method 22 of 40 C.F.R. Part 60, Appendix A.

"Standard Conditions" shall mean a temperature of 68 degrees Fahrenheit and a pressure of 1 atmosphere. Unless otherwise expressly set forth in this Permit or a Flare Appendix, Standard Conditions shall apply.

"Startup" shall mean the setting into operation of equipment for any purpose.

"Supplemental Gas" shall mean all gas introduced to the flare in order to improve the combustible characteristics of Combustion Zone Gas.

"Sweep Gas" shall mean, for a flare with a Flare Gas Recovery System, the minimum amount of gas necessary to maintain a constant flow of gas through the flare header in order to prevent oxygen buildup, corrosion or freezing in the flare tip or header; Sweep Gas in these flares is introduced prior to and recovered by the Flare Gas Recovery System. Sweep Gas may be added to certain FGRS bypass lines that contain gas that is not Potentially Recoverable Gas. For a flare without a flare Gas Recovery System, Sweep Gas means the minimum amount of gas necessary to maintain a constant flow of gas through the flare header in order to prevent oxygen buildup, corrosion or freezing in the flare header or tip and to prevent oxygen infiltration (backflow) into the flare tip.

"Total Steam" shall mean the total of all steam that is supplied to a flare and includes, but is not limited to, Lower Steam, Center Steam and Upper Steam.

"Total Steam Mass Flow Rate" or *"ṁs"* shall mean the mass flow rate of Total Steam supplied to a Flare. Total Steam Mass Flow Rate shall be calculated as set forth in Equation 3 in APPENDIX II of this Permit.

"Upper Steam," sometimes called ring steam, shall mean the portion of Assist Steam introduced via nozzles located on the exterior perimeter of the upper end of the flare tip.

"Vent Gas" shall mean all gas found just prior to the flare tip. This gas includes all Waste Gas and that portion of Sweep Gas that is not recovered, Purge Gas and Supplemental Gas, but does not include Pilot Gas, Total Steam, or Assist Air.

"Vent Gas Volumetric Flow Rate" or *"Qvg"* shall mean the cumulative volumetric flow rate of Vent Gas during the 15-minute Block Average Period in standard cubic feet.

"Visible Emissions" shall mean five minutes or more of Smoke Emissions during any two consecutive hours.

"Waste Gas" shall mean the mixture of all gases from facility operations at a Covered Refinery that is directed to a flare for the purpose of disposing of the gas. Waste Gas does not include gas introduced to a flare exclusively to make it operate safely and as intended; therefore, Waste Gas does not include Pilot Gas, Total Steam, Assist Air, or the minimum amount of Sweep Gas and Purge Gas that is necessary to perform the functions of Sweep Gas and Purge Gas. Waste Gas also does not include gas introduced to a flare to comply with regulatory requirements; therefore, Waste Gas does not include Supplemental Gas. Depending upon the instrumentation that measures Waste Gas, certain compounds (hydrogen, nitrogen, oxygen, carbon dioxide, carbon monoxide, and/or water (steam)) that are directed to a flare for the purpose of disposing of these compounds may be excluded from calculations relating to Waste Gas flow

APPENDIX II – General Equations

Equation 1: **“*Combustion Efficiency*” or “*CE*” (percent):**

$$CE = ([CO_2]/([CO_2] + [CO] + [OC])) * 100$$

where:

$[CO_2]$ = Concentration in volume percent or ppm-meters of carbon dioxide in the combusted gas immediately above the Combustion Zone

$[CO]$ = Concentration in volume percent or ppm-meters of carbon monoxide in the combusted gas immediately above the Combustion Zone

$[OC]$ = Concentration in volume percent or ppm-meters of the sum of all organic carbon compounds in the combusted gas immediately above the Combustion Zone, counting each carbon molecule separately where the concentration of each individual compound is multiplied by the number of carbon atoms it contains before summing (*e.g.*, 0.1 volume percent ethane shall count as 0.2 percent OC because ethane has two carbon atoms)

For purposes of using the *CE* equation, the unit of measurement for CO_2, CO, and OC must be the same; that is, if “volume percent” is used for one compound, it must be used for all compounds. “Volume percent” cannot be used for one or more compounds and “ppm-meters” for the remainder.

Equation 2: **[Reserved]**

Equation 3: ***“Total Steam Mass Flow Rate” or “$\dot{m}_s$”***

$$\dot{m}s = Qs\text{-}rate * \left(\frac{18}{385.3}\right)$$

where:

$Q_{s\text{-}rate}$ = Total Steam Volumetric Flow Rate

385.3 = Conversion factor, standard cubic feet per pound-mole

Equation 4: ***"Vent Gas Mass FlowRate"* or "*$Q_{mass\text{-}rate}$*":**

$$Q_{mass\text{-}rate} = Q_{vg} * \left(\frac{MW_{vg}}{385.3}\right)$$

where:

$Q_{vg\text{-}rate}$	=	Vent Gas Volumetric Flow Rate
MW_{vg}	=	Molecular Weight, in pounds per pound-mole, of the Vent Gas, as measured by the Vent Gas Average Molecular Weight Monitoring System or Analyzer
385.3	=	Conversion factor, standard cubic feet per pound-mole

Equation 5: "Maximum Tip Velocity" or "V_{max}":

$$\text{Log10 (Vmax)} = \frac{NHVvg + 1{,}212}{850}$$

where:

V_{max}	=	Maximum allowed Flare Tip Velocity, ft/sec
NHV_{vg}	=	Net heating value of Vent Gas, as determined by Equation 1 or Equation 2 in APPENDIX III, BTU/scf.
1,212	=	Constant.
850	=	Constant.

Equation 6: Mass Flow to Volumetric Flow Rate or "Q_{vol}":

$$Q_{vol} = \frac{(Q_{mass} * 385.3)}{MWt}$$

where:

Q_{vol}	=	Volumetric flow rate, standard cubic feet per second
Q_{mass}	=	Mass flow rate, pounds per second
385.3	=	Conversion factor, standard cubic feet per pound-mole
MWt	=	Molecular weight of the gas at the flow monitoring location, pounds per pound-mole

APPENDIX III – Calculating NHV_{cz} and NHV_{dil}

Determine the Net Heating Value of the Vent Gas (NHV_{vg})

If compositional analysis data are collected as provided in Conditions 9.1 and 9.2 the Permittee shall determine the NHV_{vg} of a specific sample using the following equation.

Equation 1

$$\mathrm{NHVvg} = \sum_{i=1}^{n} (\mathrm{xi} * \mathrm{NHVi})$$

NHV_{vg}	=	Net heating value of Vent Gas, BTU/scf.
i	=	Individual component in Vent Gas.
n	=	Number of components in Vent Gas.
x_i	=	Concentration of component i in Vent Gas, volume fraction.
NHV_i	=	Net heating value of component i according to Table 1 of this appendix, BTU/scf. If the component is not specified in Table 1 of this appendix, the heats of combustion may be determined using any published values where the net enthalpy per mole of offgas is based on combustion at 25 °C and 1 atmosphere (or constant pressure) with offgas water in the gaseous state, but the standard temperature for determining the volume corresponding to one mole of Vent Gas is 20° C.

Direct Net Heating Value by Calorimeter Data without Hydrogen Analyzer

If direct net heating value by calorimeter monitoring data are collected as provided in Condition 9.3 but a hydrogen concentration monitor is not used, the Permittee shall use the direct output of the monitoring system(s) (in BTU/scf) to determine NHV_{vg} for the sample.

Direct Net Heating Value by Calorimeter Data with Hydrogen Analyzer

If direct net heating value by calorimeter monitoring data are collected as provided in Condition 9.3 and hydrogen concentration monitoring data are collected as provided in Condition 9.4, the Permittee shall use the following equation to determine NHV_{vg} for each sample measured via the net heating value calorimeter.

Equation 2

$$NHV_{vg} = NHV_{measured} + 938x_{H2}$$

where:

NHV_{vg}	=	Net heating value of Vent Gas, BTU/scf.
$NHV_{measured}$	=	Net heating value of Vent Gas stream as measured by the continuous net heating value calorimeter, BTU/scf.
x_{H2}	=	Concentration of hydrogen in Vent Gas at the time the sample was input into the net heating value calorimeter, volume fraction.
938	=	Net correction for the measured heating value of hydrogen (1,212 – 274), BTU/scf.

Required Time Period for 15-Minute Block Averages

Use set 15-minute time periods starting at 12 midnight to 12:15 AM, 12:15 AM to 12:30 AM and so on concluding at 11:45 PM to midnight when calculating 15-minute Block Averages.

Monitoring Elections

When a continuous monitoring system is used as provided in Conditions 9.1 or 9.3 and, if applicable, Condition 9.4, the Permittee may elect to determine the 15-minute Block Average NHV_{vg} using either the feed-forward or direct calculation methods below. The Permittee may choose to comply using the feed-forward calculation method for some flares at the petroleum refinery and comply using the direct calculation method for other flares.

However, for each flare, the Permittee must elect one calculations method that will apply at all times, and use that method for all continuously monitored flare vent streams associated with that flare. If the Permittee intend to change the calculation method that applies to the flare, the Permittee must notify the EPA and Applicable State Co- Plaintiff 30 Days in advance of such a change.

Feed-Forward Calculation Method

When calculating NHV_{vg} for a specific 15-minute block:

Use the results from the first sample collected during an event, (for periodic Vent Gas flow events) for the first 15-minute block associated with that event. If the results from the first sample collected during an event (for periodic Vent Gas flow events) are not available until after the second 15-minute Block Period starts, use the results from the first sample collected during an event for the second 15-minute Block Period associated with that event. For all other cases, use the results that are available from the most recent sample prior to the 15-minute Block Period for that 15-minute Block Period for all Vent Gas streams. For the purpose of this requirement, use the time that the results become available rather than the time the sample was collected. For example, if a sample is collected at 12:25 a.m. and the analysis is completed at 12:38 a.m., the results are available at 12:38 a.m. and these results would be used to determine compliance during the 15-minute Block Period from 12:45 a.m. to 1:00 a.m.

Direct Calculation Method

When calculating NHV_{vg} for a specific 15-minute Block Period:

If the results from the first sample collected during an event (for periodic Vent Gas flow events) are not available until after the second 15-minute Block Period starts, use the results from the first sample collected during an event for the first 15-minute Block Period associated with that event. For all other cases, use the arithmetic average of all NHV_{vg} measurement data results that become available during a 15-minute block to calculate the 15-minute Block Average for that period. For the purpose of this requirement, use the time that the results become available rather than the time the sample was collected. For example, if a sample is collected at 12:25 a.m. and the analysis is completed at 12:38 a.m., the results are available at 12:38 a.m. and these results would be used to determine compliance during the 15-minute Block Period from 12:30 to 12:45 a.m.

Grab Sample Option

When grab samples are used to determine Vent Gas composition:

Use the analytical results from the first grab sample collected for an event for all 15-minute Block Periods from the start of the event through the 15-minute block prior to the 15-minute block in which a subsequent grab sample is collected. Use the results from subsequent grab sampling events for all 15 minute Block Periods starting with the 15-minute Block Period in which the sample was collected and ending with the 15-minute Block Period prior to the 15-minute Block Period in which the next grab sample is collected. For the purpose of this requirement, use the time the sample was collected rather than the time the analytical results become available.

Measurement of Separate Gas Streams

If the Permittee monitors separate gas streams that combine to comprise the total Vent Gas flow, the 15-minute Block Average net heating value shall be determined separately for each measurement location according to the methods above and a flow-weighted average of the gas stream net heating values shall be used to determine the 15-minute Block Average net heating value of the cumulative Vent Gas.

Calculation Methods for Determining Combustion Zone Net Heating Value (NHV_{cz})

Direct Calculation Method

Except as specified in Condition 24.2.b for the feed-forward calculation method, determine the 15-minute Block Average NHV_{CZ} based on the 15-minute Block Average Vent Gas and assist gas flow rates using Equation 3. For periods when there is neither Assist Steam flow nor Premix Assist Air flow, $NHV_{cz} = NHV_{vg}$.

Equation 3

$$NHV_{cz} = \frac{(Q_{vg} * NHV_{vg})}{(Q_{vg} + Q_{s} + Q_{a,\ premix})}$$

Where:

NHV_{cz} = Net heating value of Combustion Zone Gas, BTU/scf.

NHV_{vg} = Net heating value of Vent Gas for the 15-minute Block Period, BTU/scf.

Q_{vg} = Cumulative volumetric flow of Vent Gas during the 15-minute Block Period, scf.

Q_s = Cumulative volumetric flow of Total Steam during the 15-minute Block Period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of Premix Assist Air during the 15-minute Block Period, scf.

Feed-Forward Calculation Method

Flares that use the feed-forward calculation methodology below and that monitor gas composition or net heating value in a location representative of the cumulative Vent Gas stream and that directly monitor Supplemental Gas flow additions to the flare must determine the 15-minute Block Average NHV_{cz} using Equation 4.

Equation 4

$$NHV_{cz} = \frac{(Q_{vg} - Q_{NG2} + Q_{NG1}) * NHV_{vg} + (Q_{NG2} - Q_{NG1}) * NHV_{NG}}{(Q_{vg} + Q_s + Q_{a,\ premix})}$$

where:

NHV_{cz} = Net heating value of Combustion Zone Gas, BTU/scf.

NHV_{vg} = Net heating value of Vent Gas for the 15-minute Block Period, BTU/scf.

Q_{vg} = Cumulative volumetric flow of Vent Gas during the 15-minute Block Period, scf.

Q_{NG2} = Cumulative volumetric flow of Supplemental Gas to the flare during the 15-minute Block Period, scf.

Q_{NG1} = Cumulative volumetric flow of Supplemental Gas to the flare during the previous 15-minute Block Period, scf. For the first 15-minute Block Period of an event, use the volumetric flow value for the current 15-minute Block Period, i.e., $Q_{NG1}=Q_{NG2}$.

NHV_{NG} = Net heating value of Supplemental Gas to the flare for the 15-minute Block Period determined according to the requirements in Condition D.e, BTU/scf.

Q_s = Cumulative volumetric flow of Total Steam during the 15- minute Block Period, scf.

$Q_{a,premix}$ = Cumulative volumetric flow of Premix Assist Air during the 15-minute Block Period, scf.

Calculation Methods for Determining the Net Heating Value Dilution Parameter (NHV_{dil})

The Permittee shall determine the net heating value dilution parameter (NHV_{dil}) as specified below for flares using either the feed-forward calculation method or the direct calculation method, as applicable.

Calculation Methods for Determining the Net Heating Value Dilution Parameter (NHV_{dil})

Direct Calculation Method

For flares using the direct calculation method, determine the 15-minute Block Average NHV_{dil} based on the 15-minute Block Average Vent Gas and Perimeter Assist Air flow rates using Equation 5 only during periods when the Perimeter Assist Air is used. For 15-minute Block Periods when there is no cumulative volumetric flow of Perimeter Assist Air, the 15-minute Block Average NHV_{dil} parameter does not need to be calculated.

Equation 5

$$NHV_{dil} = \frac{(Q_{vg} * Diam * NHV_{vg})}{(Q_{vg} + Q_s + Q_{a.\ premix} + Q_{a.\ perimeter})}$$

where:

NHV_{dil} = Net heating value dilution parameter, BTU/ft^2.

NHV_{vg} = Net heating value of Vent Gas determined for the 15-minute Block Period, BTU/scf.

Q_{vg} = Cumulative volumetric flow of Vent Gas during the 15-minute Block Period, scf.

Diam	=	Effective diameter of the unobstructed cross sectional area of the flare tip for Vent Gas flow, ft. Use the area as determined in Condition N.b.ii.a and determine the diameter as Diam = 2 x $(\text{Area}/\pi)^{0.5}$.
Q_s	=	Cumulative volumetric flow of Total Steam during the 15- minute Block Period, scf.
$Q_{a.premix}$	=	Cumulative volumetric flow of Premix Assist Air during the 15-minute Block Period, scf.
$Q_{a.perimeter}$	=	Cumulative volumetric flow of Perimeter Assist Air during the 15-minute Block Period, scf.

Feed-Forward Calculation Method

Flares that use the feed-forward calculation methodology and that monitor gas composition or net heating value in a location representative of the cumulative Vent Gas stream and that directly monitor Supplemental Gas flow additions to the flare must determine the 15-minute Block Average NHV_{dil} using the following equation only during periods when the Perimeter Assist Air is used. For 15-minute Block Periods when there is no cumulative volumetric flow of Perimeter Assist Air, the 15-minute Block Average NHV_{dil} parameter does not need to be calculated.

Equation 6

$$NHV_{dil} = \frac{[(Q_{vg} - Q_{NG2} + Q_{NG1}) * NHV_{vg} + (Q_{NG2} - Q_{NG1}) * NHV_{NG}] * Diam}{(Q_{vg} + Q_s + Q_{a.\ premix} + Q_{a.\ perimeter})}$$

where:

NHV_{dil}	=	Net heating value dilution parameter, BTU/ft^2.
NHV_{vg}	=	Net heating value of Vent Gas determined for the 15-minute Block Period, BTU/scf.
Q_{vg}	=	Cumulative volumetric flow of Vent Gas during the 15-minute Block Period, scf.
Q_{NG2}	=	Cumulative volumetric flow of Supplemental Gas to the flare during the 15-minute Block Period, scf.
Q_{NG1}	=	Cumulative volumetric flow of Supplemental Gas to the flare during the previous 15-minute Block Period, scf. For the first 15-minute Block Period of an event, use the Period, i.e., $Q_{NG1} = Q_{NG2}$.
NHV_{NG}	=	Net heating value of Supplemental Gas to the flare for the 15-minute Block Period determined according to the requirements in Condition 9.5, BTU/scf.

Diam	=	Effective diameter of the unobstructed cross sectional area of the flare tip for Vent Gas flow, ft. Use the area as determined in Condition 25.4.a and determine the diameter as Diam = 2 x $(Area/\pi)^{0.5}$
Q_s	=	Cumulative volumetric flow of Total Steam during the 15- minute Block Period, scf.
$Q_{a.premix}$	=	Cumulative volumetric flow of Premix Assist Air during the 15-minute Block Period, scf.
$Q_{a.perimeter}$	=	Cumulative volumetric flow of Perimeter Assist Air during the 15-minute Block Period, scf.

Table 1. Individual Compound Properties

Component	Molecular Formula	MWi (pounds per pound-mole)	CMNi (mole per mole)	NHVi (British thermal units per standard cubic	LFLi (volume %)
Acetylene	C_2H_2	26.04	2	1,404	2.5
Benzene	C_6H_6	78.11	6	3,591	1.3
1,2-Butadiene	C_4H_6	54.09	4	2,794	2.0
1,3-Butadiene	C_4H_6	54.09	4	2,690	2.0
iso-Butane	C_4H_{10}	58.12	4	2,957	1.8
n-Butane	C_4H_{10}	58.12	4	2,968	1.8
cis-Butene	C_4H_8	56.11	4	2,830	1.6
iso-Butene	C_4H_8	56.11	4	2,928	1.8
trans-Butene	C_4H_8	56.11	4	2,826	1.7
Carbon Dioxide	CO_2	44.01	1	0	∞
Carbon Monoxide	CO	28.01	1	316	12.5
Cyclopropane	C_3H_6	42.08	3	2,185	2.4
Ethane	C_2H_6	30.07	2	1,595	3.0
Ethylene	C_2H_4	28.05	2	1,477	2.7
Hydrogen	H_2	2.02	0	1,212[a]	4.0
Hydrogen Sulfide	H_2S	34.08	0	587	4.0
Methane	CH_4	16.04	1	896	5.0
Methyl-	C_3H_4	40.06	3	2,088	1.7
Nitrogen	N_2	28.01	0	0	∞
Oxygen	O_2	32.00	0	0	∞
Pentane+ (C5+)	C_5H_{12}	72.15	5	3,655	1.4
Propadiene	C_3H_4	40.06	3	2,066	2.16
Propane	C_3H_8	44.10	3	2,281	2.1
Propylene	C_3H_6	42.08	3	2,150	2.4
Water	H_2O	18.02	0	0	∞

[a] The theoretical net heating value for hydrogen is 274 BTU/scf, but for the purposes of the flare requirement in this Permit, a net heating value of 1,212 BTU/scf shall be used.

The sources for values in this table are Appendix to Subpart CC of Part 63 Table 12.

APPENDIX IV – List Of Compounds For GC Speciation

LIST OF COMPOUNDS A GAS CHROMATOGRAPH MUST BE CAPABLE OF SPECIATING*

Unless an alternative monitoring option is selected from Condition D, the gas chromatograph must be capable of speciating the Vent Gas into the following except as noted as optional below:

1. Hydrogen
2. Carbon monoxide (optional)
3. Methane
4. Ethane
5. Ethene (aka: ethylene)
6. Propane
7. Propene (aka: propylene)
8. 2-Methylpropane (aka: iso-butane)
9. Butane (aka: n-butane)
10. Butenes and 1,3 butadiene (these constituents will be measured on the same column and the reported result will be one value: the sum of the constituents. A net heating value of 2,690 btu/scf will be assumed.)
11. N-pentane. Use the response factor for n-pentane to quantify all C5+ hydrocarbons.
12. Acetylene (optional)
13. Propadiene (optional)
14. Hydrogen sulfide (optional)

*Outputs from the gas composition analyzer shall be on a mole percent or volume percent basis, except hydrogen sulfide may be on a parts per million basis.

APPENDIX V – Equipment and Instrumentation

EQUIPMENT AND INSTRUMENTATION TECHNICAL SPECIFICATIONS AND QUALITY ASSURANCE/QUALITY CONTROL REQUIREMENTS

These technical specifications are the minimally acceptable standards. Standards better than or beyond these are acceptable.

I. VENT GAS FLOW METER

1. Velocity Range: 0.1–250 ft/sec
2. Repeatability:

   ± 10% of reading over the velocity range 0.1 to 1.0 ft/s

   ± 1% of reading over the velocity range >1.0 to 250 ft/s
3. Design Accuracy: ± 5% initially to 40%, 60%, and 90% of monitor full scale as certified by the manufacturer
4. Operational Accuracy: ± 20 percent of flow rate at velocities ranging from 0.03 to 0.3 meters per second (0.1 to 1 feet per second). ± 5 percent of flow rate at velocities greater than 0.3 meters per second (1 feet per second).
5. Installation: Applicable AGA, ANSI, API, or equivalent standard
6. Flow Rate Determination: Must be corrected to one atmosphere pressure and 68 °F
7. QA/QC: Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer's specified maximum rated flow rate or install a new flow sensor. At least quarterly, inspect all components for leakage, unless the meter has a redundant flow sensor. Record the results of each calibration check and inspection. Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.
8. Pressure and Temperature Sensors: *See* Part IV below.

II. VENT GAS AVERAGE MOLECULAR WEIGHT ANALYZER (may be part of the Vent Gas Flow Meter)

Molecular Weight Range and Accuracy: 2 to 120 gr/grmol, ± 2%

III. STEAM FLOW METERS

For the new steam flow meters:

1. Repeatability: ± 5% of reading over the range of the instrument
2. Accuracy: ± 5 percent over the normal range of flow measured or 1.9 liters per minute (0.5 gallons per minute), whichever is greater, for liquid flow. ± 5 percent over the normal range of flow measured or 280 liters per minute (10

cubic feet per minute), whichever is greater, for gas flow. ± 5 percent over the normal range measured for mass flow.

a. Installation: Applicable AGA, ANSI, API, or equivalent standard

b. Flow Rate Determination: Must be corrected to one atmosphere pressure and 68 °F

c. QA/QC: Conduct a flow sensor calibration check at least biennially (every two years); conduct a calibration check following any period of more than 24 hours throughout which the flow rate exceeded the manufacturer's specified maximum rated flow rate or install a new flow sensor. At least quarterly, inspect all components for leakage, unless the CPMS has a redundant flow sensor. Record the results of each calibration check and inspection. Locate the flow sensor(s) and other necessary equipment (such as straightening vanes) in a position that provides representative flow; reduce swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

IV. VENT GAS FLOW METERS: PRESSURE AND TEMPERATURE SENSORS

1. Temperature monitor accuracy: ± 1 percent over the normal range of temperature measured, expressed in degrees Celsius C, or 2.8 degrees C, whichever is greater.

2. Temperature monitor QA/QC: Conduct calibration checks at least annually; conduct calibration checks following any period of more than 24 hours throughout which the temperature exceeded the manufacturer's specified maximum rated temperature or install a new temperature sensor. At least quarterly, inspect all components for integrity and all electrical connections for continuity, oxidation, and galvanic corrosion, unless the CPMS has a redundant temperature sensor. Record the results of each calibration check and inspection.

3. Locate the temperature sensor in a position that provides a representative temperature; shield the temperature sensor system from electromagnetic interference and chemical contaminants.

4. Pressure monitor accuracy: ± 5 percent over the normal range or 0.12 kilopascals (0.5 inches of water column), whichever is greater.

5. Pressure monitor QA/QC: Review pressure sensor readings at least once a week for straight line (unchanging) pressure and perform corrective action to ensure proper pressure sensor operation if blockage is indicated. Using an instrument recommended by the sensor's manufacturer, check gauge calibration and transducer calibration annually; conduct calibration checks following a period of more than 24 hours throughout which the pressure exceeded the manufacturer's specified maximum rates pressure or install a new pressure sensor. At least quarterly, inspect all components for integrity and all electrical connections for continuity, and all mechanical connections for leakage, unless the CPMS has a redundant pressure sensor. Record the results of each calibration check and inspection.

6. Locate the pressure sensor(s) in a position that provides a representative

measurement of the pressure and minimizes or eliminates pulsating pressure, vibration, and internal and external corrosion.

V. NET HEATING VALUE BY GAS CHROMATOGRAPH

A. General

1. Accuracy: As specified in Performance Specification 9 of 40 C.F.R. Part 60, Appendix B.
2. 8-Hour Repeatability:

   ± 0.5% of full scale for ranges between 2-100% of full scale;

   ± 1% of full scale for ranges between 0.05-2% of full scale;

   ± 2% of full scale for ranges between 50-500 ppm;

   ± 3% of full scale for ranges between 5-50 ppm;

   ± 5% of full scale for ranges between 0.5-5 ppm.
3. The minimum sampling frequency shall be one sample every 15 minutes.
4. The gas chromatograph shall be capable of speciating all gas constituents listed in APPENDIX IV, except those listed as optional or if an alternative monitoring option is selected within Condition D.
5. The sampling line temperature must be maintained at a minimum temperature of 60°C (rather than 120°C).
6. Where technically feasible, the sampling location should be at least two equivalent duct diameters downstream from the nearest control device, point of pollutant generation, or other point at which a change in the pollutant concentration or emission rate occurs. The location should not be close to air in-leakages. Where technically feasible, the location should also be at least 0.5 diameters upstream from the exhaust or control device.

B. Calibration Standards: Net Heating Value and Analyte Measurements

For the net heating value and analyte measurements, the gas chromatograph shall be operated and maintained in accordance with Performance Specification 9 (“PS9”) of Appendix B of 40 C.F.R. Part 60 except:

1. Follow the procedure in Performance Specification 9 of 40 C.F.R. Part 60, Appendix B, except that a single daily mid-level calibration check can be used (rather than triplicate analysis), the multi-point calibration can be conducted quarterly (rather than monthly).
2. Unless an alternative monitoring option is selected from Condition 9, the analytes to be used are except as noted as optional below:

   a. Hydrogen

   b. Carbon monoxide (optional)

   c. Methane

d. Ethane

e. Ethene (aka: ethylene)

f. Propane

g. Propene (aka: propylene)

h. 2-Methylpropane (aka: iso-butane)

i. Butane (aka: n-butane)

j. Butenes and 1,3 butadiene (these constituents will be measured on the same column and the reported result will be one value: the sum of the constituents.

k. N-pentane. Use the response factor for n-pentane to quantify all C5+ hydrocarbons.

l. Acetylene (optional)

m. Propadiene (optional)

n. Hydrogen sulfide (optional)

3. All of the calibration gases may be combined in one cylinder. If multiple calibration gases are necessary to cover all compounds, the Permittee must calibrate the instrument on all of the gases.

VI. NET HEATING VALUE BY CALORIMETER

A. General

1. Accuracy: ± 2% of span.
2. Repeatability: ± 1% of reading over full scale.
3. The minimum sampling frequency shall be one sample every 15 minutes.
4. Where feasible, select a sampling location at least two equivalent diameters downstream from and 0.5 equivalent diameters upstream from the nearest disturbance. Select the sampling location at least two equivalent duct diameters from the nearest control device, point of pollutant generation, air in-leakages, or other point at which a change in the pollutant concentration or emission rate occurs.

B. Calibration Standards and Quality Assurance

The net heating value calorimeter shall be operated and maintained in accordance with the following:

1. Calibration requirements should follow manufacturer's recommendations at a minimum
2. Temperature Control. Heat and/or cool the sampling system as necessary to ensure proper year-round operation.

VII. HYDROGEN ANALYZER

A. General

1. Accuracy: ± 2 percent over the concentration measured or 0.1 volume

percent whichever is greater.

2. The minimum sampling frequency shall be one sample every 15 minutes.

3. Select the sampling location at least two equivalent duct diameters from the nearest control device, point of pollutant generation, air in-leakages, or other point at which a change in the pollutant concentration occurs.

B. Calibration Standards and Quality Assurance

Calibration requirements should follow manufacturer's recommendations minimum.

VIII. CALCULATION OF INSTRUMENT DOWNTIME

A. Gas Chromatograph

1. For purposes of calculating the 5% of instrument downtime allowed in any six month period pursuant to Condition 13, the time used for gas chromatograph calibration and validation activities required by Subparagraph V.B. of this Flare Appendix may be excluded.

2. Any hour that meets the requirements as set forth below shall not be counted toward instrument downtime. Specifically:

   a. For a full operating hour (any clock hour where the flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas)), if there are at least four valid data points to calculate the hourly average (that is, one data point in each of the 15-minute sector of the hour), then there is no period of instrument downtime;

   b. For a partial operating hour (any clock hour where the flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas)), if there is at least one valid data point in each 15-minute sector of the hour in which the flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas) to calculate the hourly average, then there is no period of instrument downtime; and

   c. For any operating hour in which required maintenance or quality assurance activities on the instruments or monitoring systems associated with the flare are performed:

      i. If the flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas) in two or more 15-minute quadrants of the hour and if there are at least two valid data points separated by at least 15 minutes to calculate the hourly average, then there is no period of instrument downtime; or

      ii. If the flare is In Operation (e.g., Capable of Receiving Sweep, Supplemental and/or Waste Gas) in only one 15- minute quadrant of the hour and if there is at least one valid data point to calculate the hourly average, then there is no period of instrument downtime.

B. <u>Net Heating Value Calorimeter</u>

1. For purposes of calculating the 5% of instrument downtime allowed in any six month period pursuant to Condition 13, the time used for NHV calorimeter calibration and validation activities required by Subparagraph V.B.1 of this Flare Appendix may be excluded.

2. Any hour that meets the requirements of 40 C.F.R. § 60.13(h)(2) shall not be counted toward instrument downtime. Specifically:

   (i) For a full operating hour (any clock hour where the flare is Available for Operation for 60 minutes), if there are at least four valid data points to calculate the hourly average (that is, one data point in each of the 15-minute quadrants of the hour), then there is no period of instrument downtime;

   (ii) For a partial operating hour (any clock hour where the flare is Available for Operation for less than 60 minutes), if there is at least one valid data point in each 15-minute quadrant of the hour in which the flare is Available for Operation to calculate the hourly average, then there is no period of instrument downtime; and

   (iii) For any operating hour in which required maintenance or quality assurance activities on the instruments or monitoring systems associated with the flare are performed:

      (A) If the flare is Available for Operation in two or more quadrants of the hour and if there are at least two valid data points separated by at least 15 minutes to calculate the hourly average, then there is no period of instrument downtime; or

      (B) If the flare is Available for Operation in only one quadrant of the hour and if there is at least one valid data point to calculate the hourly average, then there is no period of instrument downtime.

APPENDIX VI - Nelson Complexity Index

Determining Refinery-Specific and Industry-average Complexity <u>Through Use Of The Nelson Complexity Index</u>

DEFINITIONS:

"Applicable EIA Annual Refinery Publication" shall mean the Annual EIA Refinery Publication that was the most recent one posted on EIA's website prior to a refinery's request for an increase in flaring caps.

"Applicable Form EIA-820" shall mean the Form EIA-820 that forms the source for the requesting refinery's capacity information that is summarized and compiled in the Applicable Annual EIA Refinery Publication.

For example, if a refinery requests an increase in flaring caps in March of 2015, the "Applicable Form ElA-820," is the Form ElA-820 that the refinery submitted prior to February 15, 2014, for its capacities as of January 1, 2014, (and not the Form ElA-820 that the Refinery submitted prior to February 15, 2015, for its capacities as of January 1, 2015). This is because the Applicable EIA Annual Refinery Publication is the one published in June of 2014 (i.e., the last one published prior to March of 2015).

"Applicable O&GJ Refining Survey" shall mean the survey that is published in December of the year prior to the year of the Applicable EIA Annual Refinery Publication.

For example, if the Applicable EIA Annual Refinery Publication is the one published in June of 2014, then the Applicable O&GJ Refinery Survey is the one published in December of 2013 for capacities as of January 1, 2014.

"EIA" shall mean the United States Energy Information Agency.

"EIA Annual Publication of the Number and Capacity of Petroleum Refineries" or "EIA Annual Refinery Publication" shall mean the information posted on EIA's website on approximately June 21 of each year that compiles and summarizes the data submitted on the Form EIA-820s that each refinery submits prior to February 15 of that year. The most recent EIA Annual Refinery Publication is found at http://www.eia.gov/petroleum/refinerycapacity.

"Form EIA-820" shall mean the annual requirement that each refinery is required to submit to the EIA prior to February 15 of each year. The "Report Year" of a Form EIA-820 refers to the capacities that exist as of January 1 of the "Report Year." A copy of a typical Form EIA-820 is Attachment 1 to this Appendix.

"Oil & Gas Journal Worldwide Refining Survey" or "O&GJ Refining Survey" shall mean the survey that the Oil & Gas Journal publishes in December of each year that lists refining capacities as of January 1 of the following year. A copy of the national refining capacities listed in the December 2014 O&GJ Refining Survey for January 1, 2015 is Attachment 2 to this Appendix.

REFINERY COMPLEXITY: The complexity of the refinery is to be calculated using the following formula:

Equation 1

$$Complexity = \sum_{n=1}^{i} \frac{\text{NCIi} * \text{CAPi}}{\text{CAP}_{\text{DIST}}}$$

Where:

NCIi = The 2011 Nelson Complexity Index Coefficient shown in Table 1 below for Flaring Process Unit i.

CAPi = The throughput capacity for the Refinery's process unit i in barrels per calendar day, which shall be determined as follows:

(a) for a process unit that is not new or modified and for which the Applicable EIA Annual Refinery Publication lists total US throughput for that process, the capacity, in barrels per calendar day, that the refinery reported for process i on Part 6 or Part 7[/1] of the Applicable Form EIA-820. If the refinery did not report the capacity of process i in "barrels per calendar day," but instead reported it in "barrels per stream day," then "barrels per stream day" will be converted to "barrels per calendar day" by multiplying "barrels per stream day" by the following factors: 0.95 for a vacuum distillation unit and 0.9 for all other units; or

(b) for a process unit that is not new or modified, if and only if the Applicable EIA Annual Refinery Publication does not list total US throughput capacity for that process unit, then the refinery's capacity for that process unit, in barrels per calendar day, listed in the Applicable O&GJ Refining Survey.

(c) for a process unit that is new or modified, where the new or modified capacity was not reported on the Applicable Form EIA-820, the projected new or modified unit capacity that is set forth in the air permit application(s) for the post-Lodging modification.

CAP_{DIST} = The refinery's Atmospheric Crude Oil Distillation Capacity, in barrels per calendar day, which shall be determined as follows:

(a) if the post-Lodging modification does not affect the crude capacity, the Atmospheric Crude Oil Distillation Capacity, in barrels per calendar day, that

(b) if the post-Lodging modification does affect crude capacity, the projected, new capacity set forth in the air permit application(s) for the post-Lodging modification.

[/1] The references to particular "Parts" or "Codes" of Form EIA-820 are to the Parts and Codes as they exist for the Form EIA-820 that was used for Report Year 2014. *See* Attachment 2. To that extent that the "Parts" or "Codes" on Form EIA-820 are changed in the future, the intent of the Parties is that the "Parts" and "Codes" of future forms that correspond most closely to those found on the Form EIA-820 for Report Year 2014 will be used.

INDUSTRY AVERAGE COMPLEXITY: The Industry Average Complexity is to be calculated using the following formula:

Equation 2

$$Industry\ Average\ Complexity = \sum_{n=1}^{i} \frac{(\mathrm{NCIi} * \mathrm{ICAPi})}{\mathrm{ICAP_{DIST}}}$$

Where:

NCIi = The 2011 Nelson Complexity Index Coefficient shown in Table 1 below for process unit i

$ICAP_i$ = Total US throughput capacity, in barrels per calendar day, for process unit i which shall be determined as follows:

(a) From the Applicable EIA Annual Refinery Publication, the total US capacity of process unit i in barrels per calendar day. For the total US capacity of those process units that the EIA lists only in "barrels per stream day" and not in "barrels per calendar day," the "barrels per stream day" shall be converted to "barrels per calendar day" by multiplying "barrels per stream day" by the following factors: 0.95 for a vacuum distillation unit and 0.9 for all other units.[/2]

(b) If, and only if, the Applicable EIA Annual Refinery Publication does not list a total US throughput capacity for a process unit that the refinery operates, then the total US throughput capacity for that process unit listed in the Applicable O&GJ Refining Survey.

$ICAP_{DIST}$ = From the Applicable EIA Annual Refinery Publication, the total "Operable" US Atmospheric Crude Oil Distillation Capacity, in barrels per calendar day.[/3]

[/2] For example, for catalytic reforming, the total US capacity as of January 1, 2015, is 3,392,641 barrels per calendar day. *See* EIA Annual Refinery Publication at page 46. Note that the capacity for catalytic reforming on page 1 of Attachment 1 should *not* be used because that is listed in "barrels per stream day," not bpcd. For vacuum distillation, the total US capacity for 2015 is 8,979,485 barrels per stream day. *See id.* at page 46. This figure would be converted to 8,530,051 barrels per calendar day (8,979,485 x .95).

[/3] Total Operable US Atmospheric Crude Oil Distillation Capacity (total $ICAP_{DIST}$) of a January 1, 2015, is 17,967,088 barrels per calendar day. *See* id. at page 42.

Table 1: 2011 Nelson Complexity Index Coefficients

Refining Process	NCI Coefficients
Distillation Capacity	1.00
Vacuum Distillation	1.30
Thermal Processes	2.75
Coking	7.50
Catalytic Cracking	6.00
Catalytic Reforming	5.00
Catalytic Hydrocracking	8.00
Catalytic Hydrorefining	2.50
Catalytic Hydrotreating	2.50
Alkylation	10.00
Polymerization	10.00
Aromatics	20.00
Isomerization	3.00
Lubes	60.00
Asphalt	1.50
Hydrogen (MCFD)	1.00
Oxygenates	10.00
SulfurExtraction	240.00

APPENDIX VII - Refinery Specific Flare Cap Calculations

Refine	Calculation		Refinery Crude	Refiner y	US	Refinery/ US	30-Day Rolling	365-Day Rolling
Kenai	EIA/O&	(b/cd	65,	5.31	11.19	0.475	231,	154,2

Notes:

1) Data in barrels per calendar day (bled) are shown on the next page.

2) Nelson Complexity factors are shown on the next page, and are specified in Flare APPENDIX VI

Kenai Capacities and Factors

Process	Nelson Complexity Factors	Capacity (b/cd, except H2 and S)	Source (Note 1)	US Capacity (b/cd, except H2 and S)	Source (Note 1)
Atmospheric	1	65,000	Part 5, Tesoro's	17,924,630	EIA Website 2014
Vacuum	1.3	24,700	Part 6, Tesoro's	8,538,071	EIA Website 2014
Coking	7.5		Part 5, Tesoro's	2,686,917	EIA Website 2014
Catalytic	6		Part 5, Tesoro's	5,616,015	EIA Website 2014
Catalytic	6		Part 6, Tesoro's	68,301	EIA Website 2014
Reforming	5	10,500	Part 5, Tesoro's	3,419,407	EIA Website 2014
Hydrocracking	8	12,000	Part 5, Tesoro's	2,034,689	EIA Website 2014
Hydrotreating	2.5	22,050	Part 6, Tesoro's	15,385,086	EIA Website 2014
Alkylates	10		Part 7, Tesoro's	1,139,717	EIA Website 2014
Hydrogen	1000	12	Part 7, Tesoro's	2,785	EIA Website 2014
Sulfur (short	240	24	Part 7, Tesoro's	37,238	EIA Website 2014
Thermal	2.75		Part 6, Tesoro's	14,400	EIA Website 2014
Polymerization	10		O&GJ	71,870	O&GJ (12/5/2013),
Aromatics	20		Part 7, Tesoro's	266,860	EIA Website 2014
Isomerization	3	4,500	Part 7, Tesoro's	664,722	EIA Website 2014
Oxygenates	10		O&GJ	32,250	O&GJ (12/5/2013),
Lubes	60		Part 7, Tesoro's	216,216	EIA Website 2014
Asphalt	1.5	9,000	Part 7, Tesoro's	669,588	EIA Website 2014
Refinery / US Complexity		**5.31**		**11.19**	

Note 1: Capacities in barrels per calendar day (b/cd) are shown. US capacities as of 1/1/2014 from US EIA report "U.S. Number and Capacity of Petroleum Refineries" (published 6/25/2014 and available at www.eia.gov) were used preferentially, see Attachment 1, along with the corresponding Tesoro capacities as of 1/1/2014 submitted by Tesoro on Form EIA- 820 Annual Refinery Report Parts 5, 6 and 7, see Attachment 2. For processes where US capacities were not included on the US EIA report (i.e. Polymerization and Oxygenates), Oil & Gas Journal Worldwide Refining Survey (published 12/5/2013) calendar day capacities as of 1/1/2014 were used for both the US and Tesoro, see Attachment 3. Where b/cd data was not available in the EIA report, barrels per stream day (b/sd) data from EIA report were converted to b/cd for some processes using O&GJ factors (0.95 for vacuum distillation and 0.9 for any other processes) where noted.

ATTACHMENT 1
TYPICAL FORM EIA-820

eia Independent Statistics & Analysis
U.S. Energy Information Administration

OMB No. 1905-0165
Expiration Date: 05/31/2016
Version No.:2013.01

FORM EIA-820
ANNUAL REFINERY REPORT
REPORT YEAR 2014

This report is **mandatory** under the Federal Energy Administration Act of 1974 (Public Law 93-275). Failure to comply may result in criminal fines, civil penalties and other sanctions as provided by law. For further information concerning sanctions and data protections see the provision on sanctions and the provision concerning the confidentiality of information in the instructions. **Title 18 USC 1001 makes it a criminal offense for any person knowingly and willingly makes to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.**

PART 1. RESPONDENT IDENTIFICATION DATA

EIA ID NUMBER: 0316008101

If any Respondent Identification Data has changed since the last report, enter an "X" in the box: X

Company Name: Tesoro Refining & Marketing Company LLC
Doing Business As:
Site Name: Anacortes
Terminal Control Number (TCN): T-91-WA-4428

Physical Address (e.g., Street Address, Building Number, Floor, Suite):
10200 W. March Point Rd.
City Anacortes **State:** WA **Zip:** 98221 -

Mailing Address of Contact (e.g., PO Box, RR): If the physical and mailing addresses are the same, only complete the physical address.
19100 Ridgewood Parkway
City San Antonio **State:** TX **Zip:** 78259 -

Contact Name: Laurie Isaac
Phone No.: (210) 626-4224 **Ext:**
Fax No.: (210) 745-4431
Email address: Laurie.A.Isaac@tsocorp.com

PART 2. SUBMISSION/RESUBMISSION INFORMATION

If this is a resubmission, enter an "X" in the box:

A completed form must be received by February 18th of the designated report year.

Forms may be submitted using one of the following methods:

Email: OOG.SURVEYS@eia.gov

Fax: (202) 586-1076

Secure File Transfer:
https://signon.eia.doe.gov/upload/noticeoog.jsp

Questions? **Call:** 202-586-6281

Comments: Explain any unusual or substantially different aspects of your current year's operations that affect the data reported. For example, note new processing units, major modifications or retirement of processing units, sale of refinery, etc. (To separate one comment from another, press ALT+ENTER)

ATTACHMENT 2
O&G REFINING SURVEY

ATTACHMENT 2
O&G REFINING SURVEY

JANUARY 1, 2015

2014 Worldwide Refining Survey

Leena Koottungal
Survey Editor/News Writer

All figures in barrels per calendar day (b/cd)

All figures are as of January 1, 2015

LEGEND
Numbers identify processes in table

Coking
1. Fluid coking
2. Delayed coking
3. Other

Thermal process
1. Thermal cracking
2. Visbreaking

Catalytic cracking
1. Fluid
2. Other

Catalytic reforming
1. Semiregenerative
2. Cyclic
3. Continuous regen.
4. Other

Catalytic hydrocracking
1. Distillate upgrading
2. Residual upgrading
3. Lube oil manufacturing
4. Other

c. Conventional (high pressure) hydrocracking: (>100 barg or 1,450 psig)
m. Mild to moderate hydrocracking (<100 barg or 1,450 psig)

Catalytic hydrotreating
1. Pretreatment of cat reformer feeds
2. Other naphtha desulfurization
3. Naphtha aromatics saturation
4. Kerosine/jet desulfurization
5. Diesel desulfurization
6. Distillate aromatics saturation
7. Other distillates
8. Pretreatment of cat cracker feeds
9. Other heavy gas oil hydrotreating
10. Resid hydrotreating
11. Lube oil polishing
12. Post hydrotreating of FCC naphtha
13. Other

Alkylation
1. Sulfuric acid
2. Hydrofluoric acid

Polymerization/Dimerization
1. Polymerization
2. Dimerization

Aromatics
1. BTX
2. Hydrodealkylation
3. Cyclohexane
4. Cumene

Isomerization
1. C_4 feed
2. C_5 feed
3. C_5 and C_6 feed

Oxygenates
1. MTBE
2. ETBE
3. TAME
4. Other

Hydrogen

Production:
1. Steam methane reforming
2. Steam naphtha reforming
3. Partial oxidation

a. Third-party plant

Recovery:

4. Pressure swing adsorption
5. Cryogenic
6. Membrane
7. Other

NOTES

A Previously listed as Interoil
B Previously listed as Lion Oil Co.
C Previously listed as US Oil & Refining Co.
D Idle
E Previously listed as North Atlantic Refining Ltd.
F New
G Previously listed as Northern Tier Energy LLC
H Previously listed as ERG Reffinerie Medditerranee North
I Previously listed as Shell Refining (Australia) Pty. Ltd.

Capacity definitions:

Capacity expressed in barrels per calendar day (b/cd) is the maximum number of barrels of input that can be processed during a 24-hour period, after making allowances for the following: (a) Types and grades of inputs to be processed, (b) Types and grades of products to be manufactured, (c) Environmental constraints associated with refinery operations, (d) Scheduled downtime such as mechanical problems, repairs, and slowdown. Capacity expressed in barrels per stream day (b/sd) is the amount a unit can process when running at full capacity under optimal feedstock and product slate conditions. An asterisk (*) beside a refinery location indicates that the number has been converted from b/sd to b/cd using the conversion factor 0.95 for crude and vacuum distillation units and 0.9 for all downstream cracking and conversion units.

Hydrogen:

Hydrogen volumes presented here represent either generation or upgrading to 90+% purity.

Catalytic reforming:
1. Semiregenerative reforming is characterized by shutdown of the reforming unit at specified intervals, or at the operators's convenience, for in situ catalyst regeneration.
2. Cyclic regeneration reforming is characterized by continuous or continual regeneration of catalyst in situ in any one of several reactors that can be isolated from and returned to the reforming operation. This is accomplished without changing feed rate or octane.
3. Continuous regeneration reforming is characterized by the continuous addition of this regenerated catalyst to the reactor.
4. "Other" includes nonregenerative reforming (catalyst is replaced by fresh catalyst) and moving-bed catalyst systems.

REFINERY REMOVALS

Name	Location	Country	Crude b/cd	Reason
Caltex Australia Ltd.	Kurnell	Australia	135,000	Converting to fuel import terminal
Flint Hills Resources	North Pole	Alaska	132,050	Costs, contamination
Gulf Atlantic Operations	Alabama	US	20,000	
Italiana Energia E Servizi SPA (c)	Mantova	Italy	69,420	Converting to products logistics hub
LyondellBasell Industries	Berre l'Etang	France	105,000	Converting to terminal
Murco Petroleum Ltd.	Milford Haven	Wales, UK	135,000	Converting to terminal
Pertamina	Pangakalan Brandan, North Sumatra	Indonesia	4,750	

Oil & Gas Journal / Dec. 1, 2014

WORLDWIDE REFINING Company and refinery location	Charge capacity, b/cd Crude	Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Production capacity, b/cd Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (t/d)	Sulfur (t/d)	Asphalt
UNITED STATES																		
ALABAMA																		
Hunt Refining Co.—Tuscaloosa	72,000	15,000	[2]32,000	—	—	[1]7,200 [3]16,000	15,000	[1]10,000 [4]2,000 [5]20,000 [8]10,000	—	—	—	—	—	—	a [1]8.0 [4]8.0	500	120	14,000
Shell Chemical Co.—Saraland	79,000	28,000	—	—	—	[1]22,500	[4]30,000	[1]25,000 [9]18,000	—	—	—	[3]7,500	—	—	[6]6.0	—	20	—
Total	151,000	43,000	32,000	—	—	45,700	45,000	85,000	—	—	—	7,500	—	—	22.0	500	140	14,000
ALASKA																		
BP PLC—Prudhoe Bay	15,000	—	[3]15,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
ConocoPhillips—Kuparuk	14,500	—	[3]14,500	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Petro Star Inc.—North Pole	22,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Petro Star Inc.—Valdez	60,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Tesoro Corp.—Kenai	72,000	19,000	—	—	—	[1]12,000	c [1]12,500	[1]12,500	—	—	—	[3]4,000	—	—	a [1]13.0	—	19	1,000
Total	183,500	19,000	29,500	—	—	12,000	12,500	12,500	—	—	—	4,000	—	—	13.0	—	19	1,000
ARKANSAS																		
Cross Oil & Refining Co. Inc.—Smackover	7,000	3,000	—	—	—	—	—	[1]14,500	—	—	—	—	4,500	—	[1]2.5	—	—	1,500
Delek US Holdings Inc.—El Dorado[6]	80,000	64,000	19,000	—	[1]42,000	[3]31,000	—	[1]25,000 [2]23,000 [4]10,000 [5]54,000 [8]50,000	[2]13,500	—	2,200	[3]14,000	—	—	[1]39 [4]22.0	—	285	—
Total	87,000	67,000	19,000	—	42,000	31,000	—	166,500	13,500	—	2,200	14,000	4,500	—	63.5	—	285	1,500
CALIFORNIA																		
Alon USA—Paramount	70,000	59,800	—	—	—	[1]11,600	—	[1]14,500 [4]7,250 [5]13,500	—	—	—	[3]3,750	—	—	—	—	40	35,000
Chevron Corp.—El Segundo	269,000	161,000	[2]67,500	—	[1]65,000	[3]44,000	[1]46,000	[1]41,000 [2]13,000 [4]33,000 [5]36,000 [6]13,000 [8]65,000	[1]30,000	—	—	[1]7,000 [3]20,000	—	—	a [1]69.3	4,064	775	—
Chevron Corp.—Richmond	257,000	110,000	—	—	[1]80,000	[1]69,000	c [1]51,000 c [3]35,000 c [4]65,000	[1]58,000 [4]59,000 [5]30,000	[1]24,000	[1]3,700	—	[1]8,600 [3]28,000	16,000	—	[1]150.0 [4]20.0	—	600	—

Attachment 2

WORLDWIDE REFINING Company and refinery location	Charge capacity, b/cd Crude	Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Production capacity, b/cd Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (t/d)	Sulfur (t/d)	Asphalt
Phillips 66—Los Angeles (Carson and Wilmington)	138,700	78,000	[2]48,150	—	[1]45,000	[1]34,000	c [1]24,750	[11]30,000 [12]20,340 [1]50,850 [4]11,250 [5]28,800	[1]14,400	—	—	[1]8,550 [2]12,500	—	—	[1]100.0	2,000	340	—
Phillips 66—Rodeo and Santa Maria	120,000	87,000	[2]48,000	—	—	[1]31,000	c [1]38,000 [4]21,000	[8]50,000 [1]29,000 [5]32,000	—	—	—	[3]9,000	—	—	[1]130.0 [4]3.0	2,500	530	—
ExxonMobil Refining & Supply Co.—Torrance	149,500	98,000	[2]50,500	—	[1]83,500	[1]17,000	c [1]21,500	[6]15,000 [1]24,000 [7]17,500 [8]102,000	[2]24,500	—	—	—	—	—	[1]142.0 [6]9.0	3,050	380	—
Kern Oil & Refining Co.—Bakersfield	25,000	—	—	—	—	[1]3,000	—	[1]4,500	—	—	—	—	—	—	—	—	4.5	—
San Joaquin Refining Co. Inc.—Bakersfield	24,300	14,300	—	[2]10,000	—	—	—	[3]2,000 [5]6,500 [6]3,500	—	—	—	—	4,000	—	[1]4.2	—	6	6,500
Shell Oil Products US—Martinez	145,000	91,100	[2]25,000 [3]21,500	—	[1]68,870	[2]29,400	c [1]37,000	[9]1,800 [1]27,000 [3]19,000 [5]22,950 [11]9,000	[1]11,000	[2]2,470	—	[3]15,000	—	—	[1]101.0	1,150	360.0	15,000
Tesoro Corp.—Los Angeles	363,000	62,000	[2]40,000	—	[1]36,000	[1]32,500	c [1]32,000	[13]40,000 [1]35,750 [3]12,500 [4]15,000 [8]38,000	[1]12,000	—	—	[1]8,000	—	—	a [1]55.0 [4]55.0	1,615	265	—
Tesoro Corp.—Golden Eagle	166,000	144,000	[1]42,000	—	[1]66,500	[1]20,000 [3]22,000	c [1]32,000	[1]23,000 [3]9,000 [5]32,000 [6]14,000 [8]62,000 [12]27,000	[1]14,000	—	—	—	—	—	[1]74.0 a [1]31.0	1,500	140	—
Valero Energy Corp.—Benicia	170,000	78,500	[1]28,000	—	[1]69,000	[2]36,000	c [1]36,000	[13]5,500 [1]29,000 [3]11,000 [4]13,500	[1]17,100	[2]2,900	—	—	—	—	[1]131.5	1,080	275	5,000

Attachment 2

WORLDWIDE REFINING Company and refinery location	Crude	Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (t/d)	Sulfur (t/d)	Asphalt
	Charge capacity, b/cd								Production capacity, b/cd									
								[8]23,000							[4]46.3 [6]10.9			
Total	184,500	98,800	44,500	—	57,200	37,700	5,500	187,700	16,800	400	—	6,800	—	—	161.7	1,390	290	37,300
NEW JERSEY																		
Phillips 66—Linden	238,000	71,250	—	—	[1]130,500	[2]28,800	—	[1]28,800 [3]6,000 [5]97,200 [12]58,500	[1]16,000	—	—	[1]4,000	—	—	[1]19.8 [6]12.4	—	—	—
PBF Holding Co. LLC—Paulsboro	180,000	90,000	[2]27,000	—	[1]55,000	[3]30,000	—	[1]32,000 [4]27,500 [5]46,000 [11]750 [12]35,000	[2]11,200	—	—	—	11,500	—	[1]13.5 [4]9.0	1,470	230	16,000
Total	418,000	161,250	27,000	—	185,500	58,800	—	331,750	27,200	—	—	4,000	11,500	—	54.7	1,470	230	16,000
NEW MEXICO																		
Western Refining Inc.—Gallup	25,000	—	—	—	[1]7,000	[1]8,000	—	[1]7,500	[2]2,500	—	—	[3]5,000	—	—	—	—	2	—
HollyFrontier Corp.—Artesia	100,000	25,000	—	—	[1]27,000	[3]24,000	—	[7]4,000 [1]35,000 [4]2,400 [5]32,000 [8]28,000	[2]9,000	—	—	[3]11,000	—	—	9.0	—	110	5,000
Total	125,000	25,000	—	—	34,000	32,000	—	108,900	11,500	—	—	16,000	—	—	9.0	—	112	5,000
NORTH DAKOTA																		
Dakota Prairie Refining—Dickinson	20,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Tesoro West Coast Co.—Mandan	71,000	—	—	—	[1]25,700	[2]11,500	—	[1]12,000 [3]11,600	[2]4,200	[1]1,100	—	[3]4,800	—	—	—	—	15	—
Total	91,000	—	—	—	25,700	11,500	—	23,600	4,200	1,100	—	4,800	—	—	—	—	15	—
OHIO																		
BP-Husky*—Toledo	152,000	67,925	[2]31,500	—	[1]49,500	[2]37,800	c [1]27,900	[1]36,000 [5]19,350 [8]42,300	[1]10,350	—	—	—	—	—	—	2,006	351	9,000
Husky Energy Corp.*—Lima	160,000	49,400	[2]20,700	—	[1]36,000	c [2]49,500	[4]23,400	[1]56,700 [12]31,500	—	—	[1]6,300	[3]16,200	—	—	[5]10.4	800	100	—
Marathon Petroleum Co. LP—Canton	90,000	33,300	—	—	[1]24,700	[3]20,400	—	[1]29,000 [4]12,800 [5]20,900 [8]25,700	[2]7,100	—	—	—	—	—	—	—	89	14,100

WORLDWIDE REFINING Company and refinery location	Charge capacity, b/cd Crude	Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Production capacity, b/cd Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (t/d)	Sulfur (t/d)	Asphalt
Valero Energy Corp.—Port Arthur	350,000	145,000	[2]100,000	—	[1]80,000	[3]53,000	c [1]60,000 [4]45,000	[12]33,000 [1]52,000 [2]30,000 [4]30,000 [5]55,000 [8]65,000	[2]20,000	—	—	—	—	—	[1]105.0 [4]6.0	6,200	1,050	—
Valero Energy Corp.—Sunray	170,000	53,200	—	—	[1]54,465	[1]18,500 [3]28,900	c [2]29,500	[12]50,000 [1]39,844 [2]22,000 [5]32,368	[1]9,500	—	—	[3]7,000	—	12,200 32,700	—	—	60	—
Valero Energy Corp.—Texas City	250,000	130,000	[1]50,000	—	[2]80,000	[3]14,500	—	[12]3,400 [1]15,000 [4]36,000 [5]52,000 [10]110,000	[2]12,000	—	—	[3]6,500	—	12,500	a [4]60.0	3,000	890	—
Valero Energy Corp.—Three Rivers	100,000	35,000	—	—	[1]24,500	[1]11,000 [3]23,000	—	[12]50,000 [1]23,000 [4]11,000 [5]22,000 [8]20,000	[2]6,500	—	[1]18,000	—	3,200	—	[4]10.0	—	—	—
Western Refining Inc.—El Paso	128,000	34,700	—	—	[1]28,000	[1]18,000	—	[11]2,300 [1]18,300 [4]8,200 [5]11,300	[1]10,000	—	—	[1]2,500	—	—	—	—	20	4,800
WRB Refining LLC—Borger	143,000	76,000	[2]27,000	—	[1]50,000	[1]28,000	—	[1]37,000 [2]24,000 [5]27,000 [7]13,000 [8]70,000	[2]17,000	—	—	[1]16,000 [3]27,000	—	—	[1]83.0 [4]13.0	1,250	340	—
Total	5,206,600	2,231,797	868,415	—	1,695,245	1,007,150	539,600	4,725,842	334,960	11,200	215,819	108,600	83,750	18,500	856.3	41,308	11,724	52,467
UTAH																		
Big West Oil LLC—Salt Lake City	35,000	5,000	—	—	[1]11,500	[3]7,300	—	[1]9,000 [5]9,500	[2]2,500	—	—	[1]2,500 [3]1,700	—	—	—	—	4	—
Chevron Corp.—Salt Lake City	50,000	25,600	[2]8,100	—	[1]17,800	[1]9,400	—	[1]7,300 [5]10,200 [7]6,500	[2]4,500	—	—	[1]1,000	—	—	—	281	56	—

Attachment 2

WORLDWIDE REFINING Charge capacity, b/cd Vacuum Thermal Catalytic Catalytic Catalytic Catalytic Production capacity, b/cd Hydrogen Coke Sulfur Asphalt

WORLDWIDE REFINING Company and refinery location	Charge capacity, b/cd Crude	Vacuum distillation	Coking	Thermal operations	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Production capacity, b/cd Alkylation	Pol./Dim.	Aromatics	Isomerization	Lubes	Oxygenates	Hydrogen (MMcfd)	Coke (t/d)	Sulfur (t/d)	Asphalt
Petroleos de Venezuela SA—Puerto de la Cruz	195,000	—	—	—	[1]13,600	—	—	—	[2]4,100	—	—	—	—	—	—	—	17	—
Petroleos de Venezuela SA—San Roque, Anzoalegui	5,200	1,770	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	**1,282,100**	**585,780**	**144,900**	—	**231,800**	**49,500**	—	**389,700**	**65,800**	—	**2,000**	**20,700**	**12,020**	**12,830**	**147.8**	**5,200**	**1,471**	**36,000**
VIETNAM																		
Petrovietnam—Dung Quat	140,000	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Total	**140,000**	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
YEMEN																		
Aden Refinery Co.—Little Aden	130,000	10,500	—	—	—	[1]12,000	—	—	—	—	—	—	—	—	—	—	—	3,000
Yemen Oil Co.—Marib	10,000	—	—	—	—	[1]2,500	—	—	—	—	—	—	—	—	—	—	—	—
Total	**140,000**	**10,500**	—	—	—	**14,500**	—	—	—	—	—	—	—	—	—	—	—	**3,000**
ZAMBIA																		
Indeni Petroleum Refinery Co. Ltd.—Bwana Nkubwa Area, Ndola	23,750	2,280	—	—	—	[1]5,320	—	[7]8,550	—	—	—	—	—	—	—	—	—	5,527
Total	**23,750**	**2,280**	—	—	—	**5,320**	—	**8,550**	—	—	—	—	—	—	—	—	—	**5,527**

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Attachment 2