UNITED STATES COURT FOR THE
WESTERN DISTRICT OF TEXAS

THE UNITED STATES OF AMERICA, THE STATE OF ALASKA, THE STATE OF HAWAII, AND THE NORTHWEST CLEAN AIR AGENCY Plaintiffs, v. TESORO REFINING & MARKETING COMPANY LLC, TESORO ALASKA COMPANY LLC, TESORO LOGISTICS L.P., AND PAR HAWAII REFINING, LLC, Defendants.	Civ. No. SA-16-cv-00722

CONSENT DECREE

TABLE OF CONTENTS

WHEREAS, Plaintiff the United States of America ("United States"), by the authority of the Attorney General of the United States and through its undersigned counsel, acting at the request and on behalf of the United States Environmental Protection Agency ("EPA"), has simultaneously filed a complaint under the Clean Air Act ("CAA"), 42 U.S.C. § 7401 et seq. (the "Complaint"), and lodged this Consent Decree against defendants Tesoro Alaska Company LLC, Tesoro Logistics L.P., Tesoro Refining & Marketing Company LLC, and Par Hawaii Refining, LLC ("Settling Defendants") for alleged environmental violations at their refineries located in Anacortes, Washington; Kapolei, Hawaii; Kenai, Alaska; Mandan, North Dakota; Martinez, California; and Salt Lake City, Utah (the "Covered Refineries");

WHEREAS, the State of Alaska, the State of Hawaii, and the Northwest Clean Air Agency ("State Co-Plaintiffs") have joined in this matter alleging violations of their applicable state implementation plan ("SIP") provisions and/or other laws, rules, regulations, and permits incorporating and implementing CAA requirements;

WHEREAS, the United States and Tesoro Petroleum Corporation are among the parties to a consent decree entered on August 29, 2001, in the matter of *United States of America, et al. v. BP Exploration & Oil Co. et al.*, Civil Action No. 96-0095, which covers the Mandan, North Dakota, and Salt Lake City, Utah, refineries owned and operated by Defendant Tesoro Refining & Marketing Company LLC;

WHEREAS, the United States and Tesoro Refining & Marketing Company, Inc. (predecessor to Defendant Tesoro Refining & Marketing Company LLC) are among the parties to a consent decree entered on November 23, 2005, in the matter of *United States of America, et al. v. Valero Refining Co. et al., and Tesoro Refining & Marketing Company, Inc.*, Civil Action No. SA05CA0569-RF, which covers the Martinez, California, refinery owned and operated by Defendant Tesoro Refining & Marketing Company LLC;

WHEREAS, the Complaint alleges that Settling Defendants violated and/or continue to violate the Prevention of Significant Deterioration ("PSD") provisions in Part C of Subchapter I of the CAA, 42 U.S.C. §§ 7470-7492; the Nonattainment New Source Review ("NNSR") provisions in Part D of Subchapter I of the CAA, 42 U.S.C. §§ 7501-7515; the regulations implementing those CAA provisions; and federally-enforceable SIPs of Alaska, California, Hawaii, North Dakota, Utah, and Washington;

WHEREAS, the Complaint alleges that Settling Defendants made major modifications to the Covered Refineries and operated such modifications without obtaining and/or complying with the CAA's PSD and NNSR requirements, regulations promulgated thereunder, and/or SIP requirements and regulations, regarding installing and operating pollution control technology, emission limits, monitoring, recordkeeping, and reporting;

WHEREAS, the Complaint alleges that Settling Defendants violated and/or continue to violate the flaring requirements promulgated pursuant to Sections 111 and 112 of the CAA, 42 U.S.C. §§ 7411 and 7412, and found at 40 C.F.R. Part 60; Subparts A, GGG, GGGa, and J; 40 C.F.R. Part 61, Subparts A and FF; and 40 C.F.R. Part 63, Subparts A, CC, and UUU;

WHEREAS, the Complaint alleges that Settling Defendants violated and/or continue to violate the Leak Detection and Repair ("LDAR") requirements promulgated pursuant to Sections 111 and 112 of the CAA, 42 U.S.C. §§ 7411 and 7412, and found at 40 C.F.R. Part 60, Subpart GGG; 40 C.F.R. Part 61, Subpart FF; and 40 C.F.R. Part 63, Subpart CC;

WHEREAS, the Complaint alleges that Tesoro Refining & Marketing Company LLC violated and/or continues to violate at its Anacortes, Washington, refinery the Standards of Performance for Petroleum Refineries, 40 C.F.R. Part 60, Subparts A and J and the National Emission Standard for Benzene Waste Operations, 40 C.F.R. Part 61, Subpart FF ("Subpart FF");

WHEREAS, the Complaint alleges that Par Hawaii Refining, LLC violated and/or continues to violate at its refinery in Kapolei, Hawaii, the Standards of Performance for Petroleum Refineries, 40 C.F.R. Part 60, Subpart J; the Standards of Performance for Volatile Organic Liquid Storage Vessels, 40 C.F.R. Part 60, Subpart Kb; the General Provisions for these Standards of Performance, 40 C.F.R. Part 60, Subpart A; and the National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, 40 C.F.R. Part 63, Subpart CC;

WHEREAS, the Complaint alleges that Tesoro Alaska Company LLC, violated and/or continues to violate at its Kenai, Alaska refinery the Standards of Performance for Petroleum Refineries, 40 C.F.R. Part 60, Subpart J, the Standards of Performance for Stationary Gas Turbines, 40 C.F.R. Part 60, Subpart GG, the Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems, 40 C.F.R. Part 60, Subpart QQQ, the General Provisions for these Standards of Performance, 40 C.F.R. Part 60, Subpart A, and the National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, 40 C.F.R. Part 63, and UUU;

WHEREAS, the Complaint alleges that Tesoro Refining & Marketing Company LLC violated and/or continues to violate at its refinery in Martinez, California, the Standards of Performance for Sulfuric Acid Plants, 40 C.F.R. Part 60, Subpart H and the General Provisions for these Standards of Performance, 40 C.F.R. Part 60, Subpart A;

WHEREAS, the Complaint alleges that Settling Defendants violated the requirements of Title V of the CAA, 42 U.S.C. §§ 7661a(a), 7661b(c), and 7661c(a); the regulations promulgated thereunder, 40 C.F.R. §§ 70.1(b), 70.5(a) and (b), 70.6(a) and (c), and 70.7(b); and state regulations and operating permits issued under Title V of the CAA;

WHEREAS, EPA has issued several Notices of Violation and Findings of Violations (collectively "NOVs") to Settling Defendants relating to many of the claims asserted in the Complaint;

WHEREAS, Settling Defendants have waived any applicable federal or state requirements of statutory notice of the alleged violations;

WHEREAS, Settling Defendants have denied and continue to deny the violations alleged in the Complaint and NOVs;

WHEREAS, discussions between the United States, State Co-Plainitffs, and Settling Defendants (collectively, the "Parties") have resulted in the settlement embodied in this Consent Decree;

WHEREAS, the objectives of the Parties in entering into this Consent Decree are to further the purposes of the CAA as described in CAA Section 101, 42 U.S.C. § 7401, to protect public health, public welfare, and the environment, to have Settling Defendants perform the actions described below, and to ensure that Settling Defendants achieve and maintain compliance with the CAA, applicable state law, and the terms and conditions of applicable CAA permits;

WHEREAS, by entering into this Consent Decree, Settling Defendants are committed to proactively resolving environmental concerns related to operations at their refineries;

WHEREAS, the United States, State Co-Plaintiffs, and Settling Defendants anticipate that the installation and operation of pollution control technology and other measures required pursuant to this Consent Decree will achieve significant reductions of emissions from the Covered Refineries, thereby significantly improving air quality;

WHEREAS, notwithstanding the foregoing reservations, the Parties agree that: (a) settlement of the matters set forth in the Complaint is in the best interests of the Parties and the public; and (b) entry of this Consent Decree without litigation is the most appropriate means of resolving this matter;

WHEREAS, the Parties recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated at arms-length and in good faith and that this Consent Decree is fair, reasonable, and in the public interest;

WHEREAS, Settling Defendants consent to the simultaneous filing of the Complaint and lodging of this Consent Decree without any adjudication of any issue of fact or law;

NOW THEREFORE, with respect to the matters set forth in the Complaint, and in Section XVII of this Consent Decree (Effect of Settlement/Reservation of Rights), and before the taking of any testimony, without adjudication of any issue of fact or law, and upon the consent and agreement of the Parties to this Consent Decree, it is hereby ORDERED, ADJUDGED, and DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter of this action and over the Parties pursuant to 28 U.S.C. §§ 1331, 1345, and 1355. In addition, this Court has jurisdiction over the subject matter of this action pursuant to Sections 113(b) and 167 of the CAA, 42 U.S.C. §§ 7413(b) and 7477. For purposes of this Consent Decree, Settling Defendants admit that the Complaint states a claim upon which relief may be granted for injunctive relief and civil penalties against Settling Defendants under the Clean Air Act and applicable state law. Authority to bring this suit is vested in the United States Department of Justice by 28 U.S.C. §§ 516 and 519 and Section 305 of the CAA, 42 U.S.C. § 7605, and in State Co-Plaintiffs by

Section 304 of the CAA, 42 U.S.C. § 7604, Alaska Statute 46.23.020, Hawaii Revised Statutes Section 342B-44, and RCW 70.94.081 and 70.94.141.

2. Venue is proper in the Western District of Texas pursuant to Section 113(b) of the CAA, 42 U.S.C. § 7413(b), and 28 U.S.C. §§ 1391(b) and (c), and 1395(a). Settling Defendants consent to the personal jurisdiction of this Court and waive any objections to venue in this District.

3. Notice of the alleged violations and notice of the commencement of this action has been given to the States of Alaska, California, Hawaii, North Dakota, Utah, and Washington and Applicable Permitting Authorities in accordance with Sections 113(a)(1) and (b) of the CAA, 42 U.S.C. § 7413(a)(1) and (b).

II. APPLICABILITY AND BINDING EFFECT

4. The provisions of Sections I-XXIV of this Consent Decree shall apply to all Settling Defendants as defined herein and shall be binding upon the United States, State Co-Plaintiffs, and Settling Defendants, their agents, successors, and assigns.

5. Except as provided in Section XIV (Force Majeure), each Settling Defendant is responsible for ensuring that performance of the requirements set forth in Sections V, VI, IX, X, and XIII of this Consent Decree is undertaken at each Covered Refinery for which it is responsible for compliance pursuant to Paragraph 6 below in accordance with the deadlines and requirements contained in this Consent Decree and the appendices hereto. Settling Defendants shall provide a copy of the applicable provisions of this Consent Decree to each consulting or contracting firm that is retained to perform work required under this Consent Decree upon the later of execution of any contract relating to such work or within sixty (60) Days of the Date of Entry. Copies of the relevant portions of this Consent Decree do not need to be supplied to firms, including subcontractors, who are retained solely to supply materials or equipment to satisfy the requirements of this Consent Decree.

6. Settling Defendants Responsible for Compliance. The following table identifies the Settling Defendant responsible for compliance at each Covered Refinery.

Refinery	**Settling Defendant Responsible for Compliance with this Consent Decree**
Anacortes	Tesoro Refining & Marketing Company LLC
Kapolei	Par Hawaii Refining, LLC
Kenai	Tesoro Alaska Company LLC
Mandan	Tesoro Refining & Marketing Company LLC
Martinez	Tesoro Refining & Marketing Company LLC
Salt Lake City	Tesoro Refining & Marketing Company LLC

In addition, during the term of this Consent Decree, Tesoro Logistics L.P. shall be responsible for compliance with respect to all assets, facilities, and/or equipment that it owns or operates at one or more of the Covered Refineries. To the extent that such assets, facilities, and/or equipment is owned or operated by another Settling Defendant, such Settling Defendant shall also be responsible for compliance.

7. Effective from the Date of Entry of this Consent Decree until Termination pursuant to Section XXI below, Settling Defendants agree that the Covered Refineries are subject to this Consent Decree. Effective from the Date of Entry of this Consent Decree, Settling Defendants shall give written notice of this Consent Decree to any successors in interest to the owners or operators of any Covered Refinery prior to the transfer of ownership or operation of any portion of a Covered Refinery, and shall provide a copy of this Consent Decree to any such successor in interest unless the successor in interest is also a Settling Defendant under this Consent Decree. Settling Defendants shall notify the United States and the Applicable State Co-Plaintiff of any such successor in interest at least thirty (30) Days prior to any such transfer.

8. Prior to Termination of this Consent Decree pursuant to Section XXI below, Settling Defendants shall condition any transfer, in whole or in part, of ownership or operation of any Covered Refinery upon the execution by the transferee of a modification to this Consent Decree pursuant to Section XX (Modification), which makes the terms and conditions of this Consent Decree applicable to the transferee, but only to the extent that such terms and conditions affect the transferee's ownership or operation of the applicable Covered Refinery. No earlier than thirty (30) Days after giving notice of a successor in interest pursuant to Paragraph 7 above, the Settling Defendant transferring ownership or operation may file a motion to modify this Consent Decree in accordance with Section XX below with the Court to make the terms and conditions of this Consent Decree applicable to the transferee. A Settling Defendant transferring both ownership and operation shall be released from the obligations and liabilities of this Consent Decree unless the United States or the Applicable State Co-Plaintiff opposes the motion and the Court finds that the transferee does not have the financial and technical ability to assume the obligations and liabilities under this Consent Decree. Notwithstanding the foregoing, nothing in this provision mandates modification of this Consent Decree or notice to the United States or Applicable State Co-Plaintiff for transfer of ownership or operation of a Covered Refinery or part thereof by a Settling Defendant to Tesoro Logistics L.P.

III. OBJECTIVES

9. It is the purpose of this Consent Decree to further the objectives of the Clean Air Act.

10. The purpose of the affirmative relief in Sections V, VI, IX, and X of this Consent Decree is to reduce emissions that the United States and the State Co-Plaintiffs contend were in violation of the Clean Air Act. This affirmative relief is not in lieu of penalties.

IV. GENERAL DEFINITIONS

11. Except as expressly set forth elsewhere in this Consent Decree, the terms used in this Consent Decree shall have the meaning given to those terms in this Paragraph 11, or, if not defined in this Consent Decree, as defined in the Clean Air Act and the regulations promulgated thereunder. The following terms used in this Consent Decree shall be defined, solely for purposes of this Consent Decree and the reports and documents submitted pursuant thereto, as follows:

"100% Sulfuric Acid Produced" shall mean the combined measured acid flow rate and concentration for all product streams and the estimated amount of liquid that condenses from the acid mist in the Brinks Mist Eliminator Tank. For purposes of this definition, scrubber byproduct (if any) shall be considered to be included in "100% Sulfuric Acid Produced."

"12-hour rolling average" shall mean the arithmetic average of 12 contiguous one-hour averages (starting at the top of the hour).

"2005 Martinez Consent Decree" shall mean the consent decree entered by the United States Court for the Western District of Texas on November 23, 2005, in the matter of *United States of America, et al. v. Valero Refining Co., et al. and Tesoro Refining and Marketing Corp*., Civil Action No. SA05CA0569-RF, and any amendments thereto.

"24-hour average" shall mean the average emission rate over 24 hours from midnight to midnight.

"3-hour block average" shall mean the arithmetic average of 3 one-hour test runs.

"3-hour rolling average" shall mean the arithmetic average of 3 contiguous one-hour averages (starting at the top of the hour).

"30-day rolling average" shall mean the average daily emission rate or concentration during the preceding 30 Days that the unit(s) was operating.

"365-day rolling average" shall mean the average daily emission rate or concentration during the preceding 365 Days that the unit(s) was operating.

"7-day rolling average" shall mean the average daily emission rate or concentration during the preceding 7 Days that the unit(s) was operating.

"Acid Gas" shall mean any gas that contains hydrogen sulfide and is generated at a Covered Refinery by the regeneration of an amine scrubber solution, but does not include Tail Gas.

"Acid Mist" shall mean the pollutant sulfuric acid mist as measured by Method 8 of 40 C.F.R. Part 60, Appendix A consistent with 40 C.F.R. § 60.81(b), or an alternative EPA-approved method.

"ADEC" shall mean the Alaska Department of Environmental Conservation and any successor departments or agencies of the State of Alaska.

"Air-Assisted Flare" shall mean a Flare at any Covered Refinery that utilizes forced air piped to a Flare tip to assist in combustion. Air-Assisted Flares subject to the terms of this Consent Decree are set forth in Appendix C - 2.1 of this Consent Decree.

"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 Paragraph 137 of this Consent Decree so as to produce the operational results required in Paragraph 139 of this Consent Decree.

"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.

"BAAQMD" shall mean the Bay Area Air Quality Management District and any successor departments or agencies of the State of California.

"Baseload Waste Gas Flow Rate" shall mean, for a particular Covered Flare, the daily average flow rate, in scfd, to the Flare, excluding all flows during periods of Startup, Shutdown, and Malfunction. The flow rate data period that shall be used to determine Baseload Waste Gas Flow Rate for the Covered Flares is set forth in Paragraph 127.h.ii below. The Baseload Waste Gas Flow Rate shall be identified in the Initial Flare Management Plan due under Paragraph 127 below and may be updated in subsequent Flare Management Plans due under Paragraph 128 below.

"Block Average" as it pertains to the flaring requirements in Section VI.B, shall have the meaning set forth in Appendix C - 1.15 of this Consent Decree.

"Block Average Period" or "Block Period," as it pertains to the flaring requirements in Section VI.B, shall have the meaning set forth in Appendix C - 1.15 of this Consent Decree.

"Block Sum," as it pertains to the flaring requirements in Section VI.B, shall have the meaning set forth in Appendix C - 1.15 of this Consent Decree.

"Block Sum Period," as it pertains to the flaring requirements in Section VI.B, shall have the meaning set forth in Appendix C - 1.15 of this Consent Decree.

"BP/Amoco Consent Decree" shall mean the consent decree entered by the United States Court for the Northern District of Indiana on August 29, 2001, in the matter of *United States of America, et al. v. BP Exploration & Oil Co., et al.*, Civil Action No. 96-0095 and any amendments thereto as of the Date of Lodging.

"BTU/scf" shall mean British Thermal Unit per standard cubic foot.

"BTU/ft^2" shall mean British Thermal Units per standard square foot.

"Calendar Quarter" shall mean the three month period ending on March 31st, June 30th, September 30th, and December 31st.

"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.

"CD Emissions Reductions" shall mean any emissions reductions in NOx, SO_2, PM, PM_{10}, $PM_{2.5}$, TRS, reduced sulfur compounds, VOCs, CO, H_2S, and H_2SO_4 that result from any projects conducted, controls utilized, or any other actions taken to comply with this Consent Decree.

"CEMS/CMS Root Cause Failure Analyis" or "CMS Root Cause Failure Analysis" shall mean a process of analysis and investigation to determine the primary cause(s) for CEMS/CMS Downtime.

"CEMS" shall mean continuous emissions monitoring system.

"Center Steam" shall mean the portion of Assist Steam introduced into the stack of a Flare to reduce burnback. Diagrams illustrating the meaning and location of Center, Lower, and Upper Steam are set forth in Appendix C - 1.1 of this Consent Decree.

"Certified Low-Leaking Valves" shall mean valves for which a manufacturer has issued either: (i) a written guarantee that the valve will not leak above 100 ppm for

five years; or (ii) a written guarantee, certification or equivalent documentation that the valve has been tested pursuant to generally-accepted good engineering practices and has been found to be leaking at no greater than 100 ppm.

"Certified Low-Leaking Valve Packing Technology" shall mean valve packing technology for which a manufacturer has issued either: (i) a written guarantee that the valve packing technology will not leak above 100 ppm for five years; or (ii) a written guarantee, certification or equivalent documentation that the valve packing technology has been tested pursuant to generally-accepted good engineering practices and has been found to be leaking at no greater than 100 ppm.

"CGA" shall mean cylinder gas audit.

"Chronically Leaking" shall mean any valve that is part of the Covered Equipment, as defined in Section VI.A, that has leaked twice at a Screening Value above 5,000 ppm in any forty-eight month rolling period.

"CMS" shall mean continuous monitoring system.

"CO" shall mean carbon monoxide.

"Coke Drum" shall mean a pressurized vessel where coke is formed in the Martinez Refinery Delayed Coker. As of the Date of Lodging, the Martinez Refinery Delayed Coker has four Coke Drums.

"Coke Drum Overhead Pressure" shall mean the difference between the absolute pressure inside a Coke Drum and atmospheric pressure, expressed as psig, as measured on the Coke Drum overhead vapor line, during the coke steaming and quenching operations prior to commencing Coke Drum Venting.

"Coke Drum Steam Vent" or "Steam Vent" shall mean the vent and associated valves and piping on a Coke Drum that is used to vent vapors to the atmosphere. "Coke Drum Steam Vents" do not include the opening at the top of the Coke Drum used to insert the coke cutting device or the opening at the base of the Coke Drum used to discharge coke or water.

"Coke Drum Venting" shall mean the period between opening the Coke Drum's Steam Vent valves and visual verification of no significant steam exiting the steam vent to the atmosphere.

"Coke Pit/Pad Area" shall mean a walled area into which coke and Quench Water are discharged from the opening at the base of the Coke Drum after cooling and cutting.

"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 C - 1.2 of this Consent Decree.

"Combustion Unit" shall mean any stationary emissions unit that burns a fossil fuel.

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

"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.

"Compressor" shall mean with respect to a FGRS, a mechanical device designed and installed to recover gas from a Flare header. Types of FGRS compressors include reciprocating compressors, centrifugal compressors, liquid ring compressors, and liquid jet ejectors.

"COMS" shall mean continuous opacity monitoring system.

"Consent Decree" or "Decree" shall mean this Consent Decree, including all appendices attached to this Consent Decree.

"Covered Flare" shall mean a Flare listed in Appendix C - 2.1 of this Consent Decree.

"Covered Refineries" shall mean the following facilities, each one of which is a "Covered Refinery" as that term is used herein:

Anacortes Refinery
10200 W March Point Rd.
Anacortes, WA 98221

Kapolei Refinery
91-325 Komohana St.
Kapolei, HI 96707

Kenai Refinery
54741 Tesoro Rd.
Kenai, AK 99611

Mandan Refinery
900 Old Red Trail NE
Mandan, ND 58554

Martinez Refinery including its Sulfuric Acid Plant

150 Solano Way
Martinez, CA 94553

Salt Lake City Refinery or "SLC Refinery"
474 West 900 North
Salt Lake City, UT 84103

"Date of Entry" shall mean the date on which this Consent Decree is entered by the United States District Court for the Western District of Texas as indicated on the Court's docket.

"Date of Lodging" shall mean the date this Consent Decree is lodged with the United States District Court for the Western District of Texas for public comment pursuant to Paragraph 239 of this Consent Decree.

"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 Consent Decree, 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.

"DOR" shall mean Delay of Repair.

"Downtime" or "CEMS Downtime" or "CMS Downtime" shall mean the period of time during operation of the emission unit being monitored in which any of the required CEMS/CMS data are either not recorded or are invalid for any reason (e.g., monitor malfunctions, data system failures, preventive maintenance, unknown causes, etc.), but shall not include downtime associated with routine CEMS/CMS zero and span checks and Quality Assurance ("QA") and Quality Control ("QC") (collectively "QA/QC") activities required by this Consent Decree. CEMS/CMS data that meet the requirements of 40 C.F.R. § 60.13 shall be considered valid for purposes of determining Downtime.

"ELDAR Program" shall mean the Enhanced Leak Detection and Repair Program specified in Paragraphs 64-110 of this Consent Decree.

"Environmental Mitigation Project" or "Project" shall mean the projects identified in Section IX (Environmental Mitigation Projects) and Appendix D of this Consent Decree.

"EPA" or "U.S. EPA" shall mean the United States Environmental Protection Agency and any successor departments or agencies of the United States.

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

"FAT" shall mean field accuracy test as defined in BAAQMD regulations or procedures.

"FCCU" as used herein shall mean a fluidized catalytic cracking unit as that term is defined in 40 C.F.R. § 60.101a and any associated CO boiler(s) and waste heat boiler(s).

"FCCU Catalyst Regenerator" shall mean a fluid catalytic cracking unit catalyst regenerator, as defined in 40 C.F.R. § 60.101.

"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 "V_{tip}" shall mean the velocity of gases exiting the Flare tip as defined in Equation 7 of Appendix C - 1.2.

"Fuel Gas" shall have the meaning set out in 40 C.F.R. § 60.101a.

"Fuel Gas Combustion Device" or "FGCD" shall have the meaning set out in 40 C.F.R. § 60.101(g).

"Fuel Gas System" means the offsite and onsite piping and control system that gathers gaseous streams generated by refinery operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric. The gaseous streams can contain a mixture of methane, light hydrocarbons, hydrogen, and other miscellaneous species.

"H_2S" shall mean hydrogen sulfide.

"Hawaii DOH" shall mean the Hawaii Department of Health and any successor departments or agencies of the State of Hawaii.

"Heater F-201" shall mean the Heater at the Anacortes Refinery identified as either "F-201" or "source ID 05" as of the Date of Lodging of this Consent Decree.

"Hours of Applicability" shall have the meaning set forth in Paragraph 152.c below.

"In gas/vapor service" shall have the definition set forth in the applicable provisions of 40 C.F.R. Part 60, Subpart VVa.

"In light liquid service" shall have the definition set forth in the applicable provisions of 40 C.F.R. Part 60, Subpart GGGa.

"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.

"Initial Flare Management Plan" or "Initial FMP" shall mean the document submitted pursuant to Paragraph 127 below.

"Interest" shall mean interest calculated at the rate set forth at 28 U.S.C. § 1961.

"LDAR" shall mean Leak Detection and Repair.

"LDAR Audit Commencement Date" shall mean the first Day of the on-site inspection that accompanies an LDAR audit pursuant to Paragraphs 76-82 below.

"LDAR Audit Completion Date" shall mean one hundred twenty (120) Days after the LDAR Audit Commencement Date.

"LoTOx" shall mean a NOx control technology that includes a quench system, sufficient residence time, ozone injection ports, ozone generators, and oxygen supply, and that uses ozone to oxidize NOx which is then removed in a wet gas scrubber.

"Lower Heating Value" means the energy released as heat when a compound undergoes complete combustion with oxygen to form gaseous carbon dioxide and gaseous water.

"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. Diagrams illustrating the meaning and location of Center, Lower, and Upper Steam are set forth in Appendix C - 1.1 of this Consent Decree.

"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. This definition does not apply to Section VI.B (Requirements for Control of Flaring Events).

"Mandan Refinery FCCU" or "Mandan FCCU" shall mean the Fluid Catalytic Cracking Unit at the Mandan Refinery.

"Martinez Refinery Delayed Coker" or "Delayed Coker" shall mean the delayed coking unit at the Martinez Refinery. The Delayed Coker includes, but is not limited to, Coke Drums, the Quench Water System, and the associated coke handling systems.

"Martinez Refinery FCCU" or "Martinez FCCU" shall mean the Fluid Catalytic Cracking Unit at the Martinez Refinery and includes, but is not limited to, the Martinez FCCU Catalyst Regenerator and the Martinez FCCU CO Boiler (currently known as the No. 7 Boiler).

"Martinez Refinery Sulfur Recovery Plant" or "Martinez SRP" shall mean the Sulfur Recovery Plant at the Martinez Refinery and includes, but is not limited to, the Sulfur Recovery Unit, tail gas unit, incinerator, and Sulfur Pit.

"Martinez Refinery Sulfuric Acid Plant" or "Martinez SAP" shall mean a process unit engaged in the production of sulfuric acid and related products using the contact process at or adjacent to the Martinez Refinery.

"Method 21" shall mean the test method found at 40 C.F.R. Part 60, Appendix A-7, Method 21.

"Minimum Total Steam Rate" shall mean the Total Steam Mass Flow Rate, in standard cubic feet per minute or in pounds per hour, recommended by the manufacturer of the Flare's tip at the time of Flare tip installation, or such lower Total Steam Mass Flow Rate as determined by the Flare tip manufacturer after Flare tip installation upon re-examination of the tip's requirements.

"MMBtu" shall mean million British Thermal Units.

"Need for a Compressor to Operate" shall mean: (i) for a situation in which no Compressor within the FGRS is recovering gas: when a Potentially Recoverable Gas flow rate (as determined by Paragraph 124 below) to the Covered Flare(s) serviced by the FGRS exists; or (ii) for a situation in which one or more Compressors within the FGRS already are recovering gas: when the Potentially Recoverable Gas flow rate (determined on a 15-minute Block Average) exceeds the capacity of the operating Compressor(s).

"NESHAP" shall mean the National Emission Standards for Hazardous Air Pollutants codified at 40 C.F.R. Parts 61 and 63.

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

"Net Heating Value of Combustion Zone Gas" or "NHV_{cz}" shall mean the Lower Heating Value, in BTU/scf, of the Combustion Zone Gas in a Flare. NHV_{cz} is represented by Equations 3 and 4 in Appendix C - 1.3 of this Consent Decree.

"Net Heating Value Dilution Parameter" or "NHV_{dil}' shall mean the Net Heating Value Dilution Parameter as calculated by Equation 5 of Appendix C - 1.3 of this Consent Decree.

"Net Heating Value of Vent Gas" or "NHV_{vg}" shall mean the Lower Heating Value, in BTU/scf, of the Vent Gas directed to a Flare. NHV_{vg} is calculated as set forth in Equations 1 and 2 in Appendix C - 1.3 of this Consent Decree.

"New Limit(s) Based on Actuals" shall have the meaning set forth in Paragraph 133.f.i below.

"New Limit(s) Based on Projections" shall have the meaning set forth in Paragraph 133.a below.

"NOx" shall mean nitrogen oxides.

"NSPS" shall mean the New Source Performance Standards codified at 40 C.F.R. Part 60.

"NWCAA" shall mean the Northwest Clean Air Agency and any successor departments or agencies.

"O_2" shall mean oxygen.

"One-hour block average" shall mean the average hourly emission rate that commences at the start of a "clock" hour (e.g., beginning at 2:00 PM and ending at 3:00 PM).

"Opacity" shall have the same meaning as in 40 C.F.R. § 60.2.

"Par" shall mean Par Hawaii Refining, LLC.

"Parties" shall mean the United States, the State Co-Plaintiffs, and Settling Defendants.

"Paragraph" shall mean a portion of this Consent Decree identified by an Arabic numeral, including subparts thereof identified by lower case English letters, small Roman numerals, and all of the above listed indicators in parentheses.

"Passive FTIR" shall mean a Fourier Transform Infrared System that collects thermal (infrared) radiation emitted by a hot gas plume, and through the analysis of the

resulting emission spectrum, identifies and quantifies the compounds producing values proportional to the path-integrated gas concentrations.

"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.

"Permitting Authority" or "Applicable Permitting Authority" shall mean the following air permitting authorities for each Refinery:

Anacortes Refinery: NWCAA

Kenai Refinery: ADEC

Kapolei Refinery: Hawaii DOH

Mandan Refinery: North Dakota Department of Health

Martinez Refinery: BAAQMD

Salt Lake City Refinery: Utah Division of Air Quality

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

"Plaintiffs" shall mean the United States and the State Co-Plaintiffs.

"PM" shall mean particulate matter as measured by 40 C.F.R. Part 60, Appendix A-3, Method 5B or 5F (front half only).

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

"Potentially Recoverable Gas" shall mean the Sweep Gas, Supplemental Gas introduced prior to a Covered Flare's water seal, and/or Waste Gas directed to a Covered Flare's FGRS or group of Covered Flares' FGRS. Purge Gas and Supplemental Gas introduced between a Covered Flare's water seal and a Covered 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 provided that when the excess gas is routed around the

FGRS, no natural gas is being supplied to the Fuel Gas mix drum. 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. Subject to the requirements of Paragraph 126 below, the gas stream from the spent air vent from the Tesoro Mandan Refinery's Merox Unit regenerator vessel shall not be considered Potentially Recoverable Gas.

"ppm" shall mean parts per million.

"ppmvd" shall mean parts per million by volume, dry basis.

"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.

"Prevention Measure" shall mean an instrument, device, piece of equipment, system, process change, physical change to process equipment, procedure, or program to minimize or eliminate flaring.

"Project Dollars" shall mean Tesoro's expenditures and payments incurred or made in carrying out the Environmental Mitigation Projects identified in Section IX and Appendix D of this Consent Decree to the extent that such expenditures or payments both: (i) comply with the requirements set forth in Section IX and Appendix D of this Consent Decree; and (ii) constitute Tesoro's direct payments for such Projects, or Tesoro's external costs for contractors, vendors, and equipment. Tesoro shall not include its own personnel costs in overseeing the implementation of the Projects as Project Dollars.

"psig" shall mean pounds per square inch gauge, which is the difference between absolute pressure at the measurement point and atmospheric pressure.

"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.

"Quench Water" shall mean the water, in liquid phase, used to cool coke after it is formed in a Coke Drum.

"Quench Water Fill Time" shall mean the duration of time between: (i) the commencement of the initial addition of Quench Water to a Coke Drum; and (ii) the point at which the coke bed has been covered with water and the water addition rate drops below 100 gallons per minute.

"Quench Water Make-Up" shall mean the water, in liquid phase, added to the Quench Water System to compensate for water loss.

"Quench Water System" shall mean the system used to receive, manage, treat, or convey Quench Water commencing from the point of discharge from the Coke Drum drains continuing through the Coke Pit/Pad Area, maze (coke fines settling basin), clean water sump, and Quench Water Tank to the Coke Drums.

"Quench Water Tank" shall mean any tank that holds Quench Water.

"RAA" shall mean relative accuracy audit.

"RATA" shall mean relative accuracy test audit.

"Repair Verification Monitoring" shall mean the utilization of monitoring (or another method that indicates the relative size of the leak) by no later than the end of the next Day of each attempt at repair of a leaking piece of Covered Equipment as defined in Section VI.A below in order to verify that the leak is below the applicable leak definition or repair attempt threshold.

"Rolling Average," as it pertains to the Flaring Requirements in Section VI.B, shall have the meaning set forth in Appendix C - 1.15 of this Consent Decree.

"Rolling Average Period," as it pertains to the Flaring Requirements in Section VI.B, shall have the meaning set forth in Appendix C - 1.15 of this Consent Decree.

"Rolling Sum," as it pertains to the Flaring Requirements in Section VI.B, shall have the meaning set forth in Appendix C - 1.15 of this Consent Decree.

"Rolling Sum Period," as it pertains to the Flaring Requirements in Section VI.B, shall have the meaning set forth in Appendix C - 1.15 of this Consent Decree.

"SAP Shutdown" shall mean the period beginning at the time when feedstock is discontinued at the Martinez SAP and lasting until production ceases. For the purpose of this definition, "feedstock" shall include, but not be limited to, spent acid from the alkylation plant, hydrogen sulfide from diethanolamine unit strippers, sulfuric acid from the Martinez SAP, or gas vented from the Martinez SRP Sulfur Pit(s).

"SAP Startup" shall mean the period of time beginning when feedstock is first introduced to the Martinez SAP and lasting until 24 hours after the Martinez SAP has achieved a production rate of 100 tons of 100% Sulfuric Acid Produced per Day (1-hour average). For the purpose of this definition, "feedstock" shall include, but not be limited to, spent acid from the alkylation plant, hydrogen sulfide from diethanolamine unit strippers, sulfuric acid from the Martinez SAP, or gas vented from the Martinez SRP Sulfur Pit(s).

"SCFD" or "scfd" shall mean standard cubic feet per day.

"SCFM" or "scfm" shall mean standard cubic feet per minute.

"Scheduled Turnaround" shall mean the Shutdown of any emission unit or process unit that is scheduled at least six months in advance of the Shutdown, and the purpose of such Shutdown is to: (i) perform general equipment cleaning and repairs due to normal equipment wear and tear; (ii) perform required equipment tests and internal inspections; (iii) install any unit or equipment modifications/additions, or make provisions for a future modification or addition; and/or (iv) perform normal end of run catalyst changeouts or refurbishments.

"Screening Value" shall mean the highest emission level that is recorded at each piece of Covered Equipment as it is monitored in compliance with Method 21.

"Section" shall mean a portion of this Consent Decree identified by a Roman numeral.

"Settling Defendants" shall mean Tesoro, Tesoro Logistics L.P., and Par.

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

"SLC FCCU" shall mean the FCCU at the SLC Refinery located at 474 West 900 North, Salt Lake City, Utah 84103.

"Smoke Emissions" shall have the definition set forth in Section 3.5 of Method 22 of 40 C.F.R. Part 60, Appendix A. Smoke Emissions may be documented by either a person pursuant to Method 22 or by a video camera.

"SO_2" shall mean sulfur dioxide.

"Sour Water Stripper Gas" shall mean the gas produced by the process of stripping or scrubbing refinery sour water.

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

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

"State Co-Plaintiffs" shall mean the following States or Applicable Permitting Authorities in which the Covered Refineries subject to this Consent Decree are located that have joined as plaintiffs in this action and are referred to herein as the "Applicable State Co-Plaintiff" for the Covered Refinery in their jurisdictions: the State of Alaska for the Kenai Refinery, the State of Hawaii for the Kapolei Refinery, and the NWCAA for the Anacortes Refinery.

"Steam-Assisted Flare" shall mean a Flare that utilizes steam piped to a Flare tip to assist in combustion. Steam-Assisted Flares subject to the terms of this Consent Decree are set forth in Appendix C - 2.1 of this Consent Decree.

"Sulfur Pit" means the storage vessel in which sulfur that is condensed after each Claus catalytic reactor is initially accumulated and stored. A Sulfur Pit does not include secondary sulfur storage vessels downstream of the initial Claus reactor Sulfur Pits.

"Sulfur Recovery Plant" or "SRP" shall mean the collection of Sulfur Recovery Units that are fed by one common Acid Gas feed line.

"Sulfur Recovery Unit" or "SRU" shall mean a process unit that recovers sulfur from hydrogen sulfide by a vapor phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

"Sulfuric Acid Plant" or "SAP" shall mean a process unit engaged in the production of sulfuric acid and related products using the contact process.

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

"*S/VG*" or "Total-Steam-Mass-Flow-Rate-to-Vent-Gas-Mass-Flow-Rate Ratio" shall mean the ratio of the Total Steam Mass Flow Rate to the Vent Gas Mass Flow Rate.

"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.

"Tail Gas" shall mean the exhaust gas from the Claus train(s) of a Sulfur Recovery Plant and/or from the tail gas unit.

"Termination" shall be the date on which the Court orders that this Consent Decree (or a part thereof) terminates pursuant to Section XXI of this Decree.

"Tesoro" shall mean each of the following Tesoro entities: Tesoro Refining & Marketing Company LLC and Tesoro Alaska Company LLC, including their successors in interest and assigns.

"Tesoro Refineries" shall mean the Anacortes, Kenai, Mandan, Martinez, and Salt Lake City refineries listed above.

"Title V" shall mean Title V of the CAA, 42 U.S.C. § 7661-7661f.

"Title V Permit" shall mean the permit for a Covered Refinery issued by an Applicable Permitting Authority pursuant to Title V of the CAA, 42 U.S.C. § 7661-7661f.

"TOC" shall mean total organic compounds.

"Total Steam" or "S" 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 "$\dot{m}_s$" 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 C - 1.2 of this Consent Decree.

"Total Steam Volumetric Flow Rate" or "$Q_{s\text{-}rate}$" shall mean the volumetric flow rate of Total Steam supplied to a Flare, in scfm.

"Total Steam Volumetric Flow" or "Q_s" shall mean the cumulative volumetric flow of Total Steam during the 15-minute Block Average Period, in standard cubic feet.

"Ultra-Low NOx Burner" or "ULNB" shall mean those burners that are designed to achieve a NOx emission rate of less than or equal to 0.020 pound/MMBtu (Higher Heating Value) when firing natural gas at 3% stack oxygen at full design load without air preheat, even if upon installation actual emissions exceed 0.020 pound/MMBtu (Higher Heating Value).

"United States" shall mean the United States of America, including the United States Department of Justice and the EPA.

"Unobstructed Cross Sectional Area of the Flare Tip" or "$A_{tip\text{-}unob}$" shall mean the open, unobstructed area of a Flare tip through which Vent Gas and Center Steam pass. Diagrams of four common Flare types are set forth in Appendix C - 1.6 together with the equations for calculating the $A_{tip\text{-}unob}$ of these four types.

"Updated Flare Management Plan" or "Updated FMP" shall mean the document submitted pursuant to Paragraph 128 below as the annual update to the Initial FMP.

"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. Diagrams illustrating the meaning and location of Center, Lower, and Upper Steam are set forth in Appendix C - 1.1 of this Consent Decree.

"Variable Speed Drive" shall mean a piece of equipment that regulates the speed and rotational force, or torque output, of an electric motor and that outputs a variable frequency to a motor to allow it to operate at variable speeds between the motor's minimum and maximum speed.

"Variable Speed Motor" shall mean a motor that operates at continuously variable speeds between a minimum and maximum as regulated by a Variable Speed Drive.

"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.

For the purposes of calculating *S/VG* only, "Vent Gas Mass Flow Rate" or $Q_{mass\text{-}rate}$ shall mean the mass flow rate of Vent Gas directed to a Covered Flare. Vent Gas Mass Flow Rate shall be calculated as set forth in Equation 4 in Appendix C - 1.2 of this Consent Decree.

"Vent Gas Volumetric Flow" or "Q_{vg}" shall mean the cumulative volumetric flow rate of Vent Gas during the 15-minute Block Average Period in standard cubic feet.

"Vent Gas Volumetric Flow Rate" or "Qvg-rate" shall mean the volumetric flow rate of Vent Gas directed to a Covered Flare in wet scfm.

"Visible Emissions" shall mean five minutes or more of Smoke Emissions during any two consecutive hours. Visible Emissions may be documented either by a person pursuant to Method 22 or by a video camera.

"VOC" or "Volatile Organic Compounds" shall have the definition set forth in 40 C.F.R. § 51.100(s).

"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. Waste Gas also does not include gases received from the Hawaii Gas synthetic natural gas plant downstream of the FGRS at the Kapolei Refinery. 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; in the substantive provisions of this Section, the circumstances in which such exclusions are

permitted are specifically identified. Appendix C - 1.7 of this Consent Decree depicts the meaning of Waste Gas, together with its relation to other gases associated with Flares.

V. AFFIRMATIVE RELIEF APPLICABLE TO SPECIFIC REFINERIES

A. Anacortes Refinery

12. NSPS Applicability to Heater F-201. Heater F-201 at the Anacortes Refinery shall be considered an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and J, and shall be subject to and comply with the requirements of 40 C.F.R. Part 60, Subparts A and J, for H_2S by no later than January 1, 2016, unless it is fired only with natural gas.

13. BWON Auditing Provisions.

a. Current NESHAP Part 61 Subpart FF Status. The Tesoro Anacortes Refinery has a total amount of benzene in waste streams on an annual basis ("Total Annual Benzene" or a "TAB") of greater than 10 Mg/year and has currently elected to meet the requirements set forth at 40 C.F.R. § 61.342(c) (hereinafter referred to as the "2 Mg Compliance Option"). Nothing in this Paragraph prohibits Tesoro from implementing any other compliance option as set forth in 40 C.F.R. § 61.342.

b. One-Time Third-Party Review and Verification of Anacortes Refinery's TAB: Phase One of the Review and Verification Process. By no later than July 1, 2016, Tesoro will complete a third-party review and verification of the TAB at the Anacortes Refinery and its compliance with the 2 Mg Compliance Option set forth in 40 C.F.R. § 61.342(c) ("Phase One Review and Verification process"). Tesoro's Phase One Review and Verification process will include, but not be limited to:

i. an identification of each waste stream that is required to be included in the Anacortes Refinery's TAB (e.g., slop oil, tank water draws, spent caustic, desalter rag layer dumps, desalter vessel process sampling points, other sample wastes, maintenance wastes, and turnaround wastes (that meet the definition of waste under NESHAP Subpart FF));

ii. a review and identification of the calculations and/or measurements used to determine the flows of each waste stream for the purpose of ensuring the accuracy of the annual waste quantity for each waste stream;

iii. an identification of the benzene concentration in each waste stream, including sampling for benzene concentration at no less than 10 waste streams consistent with the requirements of 40 C.F.R. § 61.355(c)(l) and (3); and

iv. an identification of whether or not each waste stream is controlled consistent with the requirements of NESHAP Subpart FF.

c. By no later than sixty (60) Days after the deadline for completion of the Phase One Review and Verification process set forth in Paragraph 13.b. above, Tesoro will submit to EPA and NWCAA for comment a Benzene Waste Operations NESHAP Compliance Review and Verification report ("BWON Compliance Review and Verification Report") for the Anacortes Refinery that sets forth the results of the Phase One Review and Verification process, including but not limited to the items identified in Paragraph 13.b.i through b.iv above.

d. One-Time Review and Verification of the Anacortes Refinery's TAB: Phase Two of the Review and Verification Process. Based on EPA's review of the BWON Compliance Review and Verification Report, by no later than ninety (90) Days after receipt of Tesoro's submission of the BWON Compliance Review and Verification Report required by Paragraph 13.c above, EPA may select up to twenty (20) additional waste streams at the Anacortes Refinery for sampling for benzene concentration. Tesoro will conduct the required sampling and submit the results to EPA and NWCAA within ninety (90) Days of receipt of EPA's request ("Phase Two sampling"). Tesoro will use the results of this Phase Two sampling to reevaluate the TAB and the uncontrolled benzene quantity and to amend the BWON Compliance Review and Verification Report, as needed. To the extent that EPA requires Tesoro to sample a waste stream as part of the Phase Two sampling that Tesoro chose to sample as part of the Phase One Review and Verification process, Tesoro may average the results of the two sampling events. If Phase Two sampling is required by EPA, Tesoro will submit to EPA and NWCAA for comment, an Amended BWON Compliance Review and Verification Report within one-hundred twenty (120) Days following the date of the completion of the required Phase Two sampling. This Amended BWON Compliance Review and Verification Report will supersede and replace the originally-submitted BWON Compliance Review and Verification Report and will be considered the Final BWON Compliance Review and Verification Report. If Phase Two sampling is not required by EPA, the originally-submitted BWON Compliance Review and Verification Report will constitute the Final BWON Compliance Review and Verification Report.

e. Amended TAB Reports. If the results of the Final BWON Compliance Review and Verification Report indicate that the Anacortes Refinery's most recently-filed TAB report pursuant to 40 C.F.R. § 61.357(a)(1) does not satisfy the requirements of NESHAP Subpart FF, then Tesoro's Final BWON Compliance Review and Verification Report will be deemed an amended TAB report for purposes of NESHAP Subpart FF reporting to EPA.

f. Implementation of Actions Necessary to Correct Non-Compliance. Tesoro shall correct any non-compliance with the 2 Mg Compliance Option identified in the Final BWON Compliance Review and Verification Report as follows. If the results of the Final BWON Compliance Review and Verification Report indicate that Tesoro's Anacortes Refinery is not in compliance with NESHAP Subpart FF, then Tesoro will submit to EPA and NWCAA for comment, by no later than one-hundred twenty (120) Days after submission of the Final BWON Compliance Review and Verification Report, a plan that identifies with specificity the compliance strategy and schedule that Tesoro will implement to ensure that the Anacortes Refinery complies with NESHAP Subpart FF as soon as practicable, including, as an alternative to the 2 Mg Compliance Option, adopting the 6 BQ option set forth in 40 C.F.R. § 61.342(e).

g. Implementation of Actions Necessary to Correct Non-Compliance: Certification of Compliance. By no later than thirty (30) Days after completion of the implementation of all actions, if any, required pursuant to Paragraph 13.f above to come into compliance with NESHAP Subpart FF, Tesoro will submit its certification and a report to EPA and NWCAA that the Anacortes Refinery complies with NESHAP Subpart FF.

B. Kapolei Refinery

14. Except as expressly set forth elsewhere in this Consent Decree, the terms used in this Section V.B, shall have the meaning given to those terms in this Paragraph, or, if not defined in this Consent Decree, as defined in the Clean Air Act and the regulations promulgated thereunder.

a. "Flue Gas Recirculation" or "FGR" shall mean extraction of a portion of the flue gas downstream of the furnace exit and reintroducing it into the combustion air stream to reduce NOx emissions.

b. "Fuel Oil" shall mean any liquid fossil fuel with sulfur content of greater than 0.05% by weight.

c. "Kapolei Refinery Catalytic Reformer Unit Heaters" or "Kapolei CRU Heaters" shall mean the following Kapolei Covered Heaters: CRU Charge Heater H501, CRU Interheater H502, CRU Interheater H503, and CRU Interheater H504.

d. "Kapolei Refinery Covered Heater or Boiler" or "Kapolei Covered Heater or Boiler" shall mean each of the following twelve heaters or boilers at the Kapolei Refinery as referred to in the initial or current Kapolei Refinery Title V/Covered Source Permit: (i) Vacuum Distillation Unit Charge Heater, ID No. H175 ("Vacuum Unit Charge Heater H175"); (ii) Catalytic Reformer Unit Charge Heater, ID No. H501 ("CRU Charge Heater H501"); (iii) Catalytic Reformer Unit Interheater, ID No. H502 ("CRU Interheater H502"); (iv) Catalytic Reformer Unit Interheater, ID No. H503 ("CRU Interheater H503"); (v) Catalytic Reformer Unit Interheater, ID No. H504 ("CRU Interheater H504"); (vi) Distillate Hydrocracker Unit Second Stage Charge Heater, ID No. H601 ("Hydrocracker 2nd Stage Charge Heater H601"); (vii) Distillate Hydrocracker Unit Fractionator Inlet Heater, ID No. H602 ("Hydrocracker Fractionator Inlet Heater H602"); (viii) Distillate Hydrocracker Unit First Stage Charge Heater, ID No. H603 ("Hydrocracker 1st Stage Charge Heater H603"); (ix) Asphalt Waste Gas Incinerator, ID No. H802 ("Asphalt Waste Gas Incinerator H802"); (x) Visbreaker Unit Heater, ID No. H901 ("Visbreaker Heater H901"); (xi) Hydrogen Generation Unit Reformer Furnace, ID No. H2001 ("Hydrogen Reformer Furnace H2001"); and (xii) Package Boiler, ID No. SG 1103 ("Package Boiler SG1103"). Collectively, these twelve heaters or boilers shall be referred to as the "Kapolei Refinery Covered Heaters and Boilers" or "Kapolei Covered Heaters and Boilers."

e. "Kapolei Refinery Sulfur Recovery Plant" or "Kapolei SRP" shall mean the SRP at the Kapolei Refinery and includes, but is not limited to SRU 2 (BR1371), SRU 2 Sulfur Pit, SRU 3 (BR1381), SRU 3 Sulfur Pit, Tail Gas Unit (BR1393), Tail Gas Incinerator H1353, and Tail Gas Incinerator H1391. The Kapolei SRP has a capacity greater than 20 long tons per day.

NOx Emissions Reductions from the Kapolei Refinery Covered Heaters and Boilers

15. Kapolei Refinery Covered Heaters and Boilers NOx Control Technologies and Emission Limits. For each Kapolei Covered Heater or Boiler listed in the following table, Par shall: (i) install the corresponding control technology on (or permanently shut down) the indicated heater or boiler by no later than the Kapolei Covered Heater's or Boiler's corresponding compliance date specified in the table; (ii) maintain and continuously operate such control technology on and after the Kapolei Covered Heater's or Boiler's corresponding compliance date specified in the table; and (iii) comply with the Kapolei Covered Heater's or Boiler's corresponding NOx emission limits by no later than the corresponding compliance date specified in the table below. For the Long-Term NOx Emission Limit (365-day rolling average), the first complete 365-day rolling average shall be calculated on the corresponding compliance date specified in the table below, based on monitoring data from such compliance date and the 364 Days prior to such compliance date.

KAPOLEI COVERED HEATER OR BOILER	**RATED CAPACITY (MMBtu/hr)**	**CONTROL TECHNOLOGY**	**SHORT-TERM NOx EMISSION LIMIT**	**LONG-TERM NOx EMISSION LIMIT**	**COMPLIANCE DATES**
Vacuum Unit Charge Heater H175	86	ULNB and convert from co-fired to gas-fired only	50.0 ppmvd @ 0% O_2 (3-hour block average)	Not Applicable	January 1, 2018
CRU Charge Heater H501	80.4	FGR	When not firing with liquid fuel, Interim Short-Term CRU NOx Emission Limit of 130.0 ppmvd @ 0% O_2 (30-day rolling average) Proposed and Final Short-Term CRU NOx Emission Limits to be established pursuant to Paragraph 15.d below	Proposed and Final Long-Term CRU NOx Emission Limits to be established pursuant to Paragraph 15.d below	For installation and operation of FGR and CEMS and for Interim Short-Term CRU NOx Emission Limit: January 1, 2018 Compliance dates for the Proposed and Final Short-Term and Long-Term CRU NOx Emission Limits to be established pursuant to Paragraph 15.d below
CRU Interheater H502	74	FGR			
CRU Interheater H503	36.3	FGR			
CRU Interheater H504	18.4	FGR			

KAPOLEI COVERED HEATER OR BOILER	RATED CAPACITY (MMBtu/hr)	CONTROL TECHNOLOGY	SHORT-TERM NOx EMISSION LIMIT	LONG-TERM NOx EMISSION LIMIT	COMPLIANCE DATES
Hydrocracker 2nd Stage Charge Heater H601	40	ULNB	40.0 ppmvd @ 0% O_2 (3-hour block average)	Not Applicable	By the earliest occurrence of either (i) 90 Days after the first Scheduled Turnaround of the hydrocracker plant after the Date of Lodging; or (ii) by January 1, 2018
Hydrocracker Fractionator Inlet Heater H602	77	ULNB	50.0 ppmvd @ 0% O_2 (3-hour block average)		
Hydrocracker 1st Stage Charge Heater H603	76	ULNB	40.0 ppmvd @ 0% O_2 (3-hour block average)		
Asphalt Waste Gas Incinerator H802	26.9	Permanent Shutdown pursuant to Paragraph 15.c	Not Applicable	Not Applicable	October 1, 2015
Visbreaker Heater H901	75	ULNB	40.0 ppmvd @ 0% O_2 (3-hour block average)	Not Applicable	January 1, 2017
Hydrogen Reformer Furnace H2001	172.8	ULNB	60.0 ppmvd @ 0% O_2 (30-day rolling average)	50.0 ppmvd @ 0% O_2 (365-day rolling average)	By the earliest occurrence of either (i) 90 Days after the first Scheduled Turnaround of the hydrogen plant after the Date of Lodging (455 Days after such Scheduled Turnaround for the Long-Term NOx Emission Limit only); or (ii) by January 1, 2018 (January 1, 2019, for the Long-Term NOx Emission Limit only)

KAPOLEI COVERED HEATER OR BOILER	RATED CAPACITY (MMBtu/hr)	CONTROL TECHNOLOGY	SHORT-TERM NOx EMISSION LIMIT	LONG-TERM NOx EMISSION LIMIT	COMPLIANCE DATES
Package Boiler SG1103	126	ULNB, FGR, convert from co-fired to gas-fired only, and reduce design firing rate from 126 to 98 MMBtu/hr (high heating value)	35.0 ppmvd @ 0% O_2 (3-hour block average) when the main fuel valve is open and SG1103 is firing at or more than 25 MMBtu/hr; and 70.0 ppmvd @ 0% O_2 (3-hour block average) when the main valve is open and SG1103 is firing less than 25 MMBtu/hr	Not Applicable	January 1, 2017

a. Rated Capacities. The rated capacities listed in the preceding table in this Paragraph 15 are the rated capacities as of the Date of Lodging and are included solely for the purpose of identifying each Kapolei Covered Heater or Boiler listed in the table.

b. Startup, Shutdown, or Malfunction. NOx emissions during periods of Startup, Shutdown, or Malfunction of the Hydrogen Reformer Furnace H2001 or a Kapolei CRU Heater, or Malfunction of the associated NOx control equipment, if any, shall not be used in determining compliance with the following corresponding limits provided that during such periods Par, to the extent practicable, maintains and operates the Hydrogen Reformer Furnace H2001 or the Kapolei CRU Heater, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions: (i) the Hydrogen Reformer Furnace H2001 30-day rolling average Short-Term NOx Emission Limit; or (ii) if and only if there is a concurrent and corresponding Long-Term NOx Emission Limit, the Proposed or Final Short-Term CRU NOx Emission Limit. All other emission limits set forth in this Paragraph 15 (including, but not limited to, the Interim Short-Term CRU NOx Emission Limit) for Kapolei Refinery Covered Heaters and Boilers shall apply at all times.

c. Permanent Shutdown of the Asphalt Waste Gas Incinerator H802. By no later than October 1, 2015, Par shall provide a report to EPA and Hawaii DOH with a written certification that: (i) the Asphalt Waste Gas Incinerator H802 is permanently shut down; (ii) the Asphalt Waste Gas Incinerator H802 is no longer included in any currently applicable EPA or Hawaii DOH permits; and (iii) all emissions of air pollutants associated with the Asphalt Waste Gas Incinerator H802 are no longer included as part of any Kapolei Refinery emissions inventory.

d. NOx Emission Limits for the Kapolei CRU Heaters.

i. Interim Short-Term CRU NOx Emission Limit. By no later than the compliance date specified in the table in this Paragraph 15 for the Kapolei CRU Heaters Interim Short-Term NOx Emission Limit, when not firing with liquid fuel and when the air preheater is operating, Par shall comply with the Interim Short-Term CRU NOx Emission Limit until either: (i) Par proposes more stringent Final Short-Term and Long-Term CRU NOx Emission Limits pursuant to Paragraph 15.d.vi below; or (ii) EPA establishes Final Short-Term and Long-Term CRU NOx Emission Limits pursuant to Paragraph 15.d.vii below.

ii. Final Short-Term and Long-Term CRU NOx Emission Limits. For the Kapolei CRU Heaters, Par shall comply with Final Short-Term and Long-Term CRU NOx Emission Limits established during a Demonstration Period pursuant to Paragraph 15.d.iii-vii.

iii. FGR Optimization Study. By no later than January 1, 2018, Par shall commence a FGR Optimization Study for the Kapolei CRU Heaters pursuant to this Paragraph, which shall be completed by no later than April 1, 2018 ("FGR Optimization Study"). The goal of the FGR Optimization Study shall be to determine the optimal performance of the FGR that the Kapolei CRU Heaters can be operated at to minimize NOx emissions. During the FGR Optimization Study period, Par shall provide both EPA and Hawaii DOH, on a monthly basis and by electronic mail, data specified in (a) through (j) below obtained as part of the FGR Optimization Study. By no later than sixty (60) Days after completing the FGR Optimization Study, Par shall report to EPA and Hawaii DOH the results of the FGR Optimization Study. The report shall include, at a minimum, the following information on an hourly average basis:

(a) Firing rate (in MMBtu/hr);

(b) Flue Gas Recirculation rate (in scfm);

(c) Recirculated gas temperature (in degrees Fahrenheit);

(d) Recirculated gas O_2;

(e) Stack gas O_2;

(f) Stack gas temperature (in degrees Fahrenheit);

(g) NOx ppmvd at 0% O_2;

(h) Type of fuel and amount of refinery fuel gas or liquid fuel burned;

(i) Mode of operation for forced draft or natural draft; and

(j) Flue gas flow rate.

As part of the report on the FGR Optimization Study required by this Paragraph, Par shall propose to EPA and Hawaii DOH the range of recirculation rates at which the Kapolei CRU Heaters shall operate during an eighteen (18) month Demonstration Period that will follow submittal of the FGR Optimization Study report. The proposed Flue Gas Recirculation rates, impact on flame stability, and O_2 levels may also give consideration to the unique operating constraints that may affect the ability of the Kapolei CRU Heaters to continuously operate at a given recirculation rate.

iv. Demonstration Period. By no later than September 1, 2018, Par shall commence and by no later than March 1, 2020, Par shall complete an eighteen (18) month demonstration of FGR in order to establish final NOx emission limits for the Kapolei CRU Heaters ("Demonstration Period"). During the Demonstration Period, Par shall operate the Kapolei CRU Heaters and the FGR in a manner that minimizes NOx emissions to the extent practicable and without interfering with conversion or processing rates. During the Demonstration Period, Par shall provide both EPA and Hawaii DOH, on a monthly basis and by electronic mail, data specified in (a) through (j) of Paragraph 15.d.iii above obtained as part of the Demonstration Period.

v. Demonstration Report. Par shall report the results of the Demonstration Period to EPA and Hawaii DOH by no later than sixty (60) Days after completion of the Demonstration Period ("Demonstration Report"). The Demonstration Report shall include, at a minimum, the NOx and O_2 CEMS data recorded during the Demonstration Period and all process and control device data listed in Paragraph 15.d.iii above on an hourly average basis for the Demonstration Period. Par shall submit any additional available data that EPA and Hawaii DOH determine is needed to evaluate the demonstration.

vi. Proposed Final CRU NOx Emission Limits. In the Demonstration Report, Par shall submit concentration-based (ppmvd) Proposed Final Short-Term and Long-Term CRU NOx Emission Limits (each corrected to 0% O_2) and corresponding rolling averaging times (i.e., 3-hour, 12-hour, or 24-hour for short-term rolling averages and 365-day for long-term rolling averages), including, but not limited to, short-term and long-term limits and averaging times that apply (i) when no liquid fuel is burned in any of the Kapolei CRU Heaters and when the air preheater is operating, and (ii) when liquid fuel is burned in any of the Kapolei CRU Heaters and/or when the air preheater is not operating. Par shall comply with the Proposed Final Short-Term and Long-Term CRU NOx Emission Limits beginning immediately upon submission of the Demonstration Report until Par is required to comply with Final Short-Term and Long-Term CRU NOx Emission Limits established by EPA, after an opportunity for consultation with Hawaii DOH, pursuant to Paragraph 15.d.vii below.

vii. Final NOx Emission Limits for the Kapolei CRU Heaters. EPA, after an opportunity for consultation with Hawaii DOH, will use the data collected about the Kapolei CRU Heaters during the Demonstration Period, as well as all other available and relevant information, to establish Final Short-Term and Long-Term CRU NOx Emission Limits that shall apply to the Kapolei CRU Heaters.

(a) EPA will establish concentration-based (ppmvd) Final Short-Term and Long-Term CRU NOx Emission Limits (each corrected to 0% O_2) and corresponding rolling averaging times (i.e., 3-hour, 12-hour, or 24-hour for short-term rolling averages and 365-day for long-term rolling averages), including, but not limited to, short-term and long-term limits and averaging times that apply:

(1) when no liquid fuel is burned in any of the Kapolei CRU Heaters and when the air preheater is operating; and

(2) when liquid fuel is burned in any of the Kapolei CRU Heaters and/or when the air preheater is not operating.

(b) EPA will determine these limits based on:

(1) the level of performance during the baseline, Optimization, and Demonstration Period;

(2) a reasonable certainty of compliance; and

(3) any other available and relevant information.

(c) EPA will notify Par of its determination of the Final Short-Term and Long-Term CRU NOx Emission Limits that shall apply to the Kapolei CRU Heaters. Par shall immediately (or within sixty (60) Days, if EPA's final NOx emission limits are more stringent than Par's proposed NOx emission limits) operate the Kapolei CRU Heaters so as to comply with the EPA-established Final Short-Term and Long-Term CRU NOx Emission Limits. If Par disputes the EPA-determined Final Short-Term and Long-Term CRU NOx emission limits, Par shall invoke dispute resolution provisions of this Consent Decree by no later than thirty (30) Days after EPA's determination of the Final Short-Term and Long-Term CRU NOx Emission Limits. During the period of dispute resolution, Par shall continue to comply with the Proposed Final Short-Term and Long-Term CRU NOx Emission Limits that Par proposed pursuant to Paragraph 15.d.vi above.

16. Demonstrating Compliance with Kapolei Refinery Covered Heaters and Boilers NOx Emission Limits.

a. CEMS Requirements. Beginning no later than the corresponding compliance dates in the table in Paragraph 15 above, Par shall use NOx and O_2 CEMS at each of the following Kapolei Covered Heaters and Boilers to monitor performance and to report compliance with the terms and conditions of Paragraphs 15-16 of this Consent Decree: CRU Charge Heater H501, CRU Interheater H502, CRU Interheater H503, CRU Interheater H504, and Hydrogen Reformer Furnace H2001. A single NOx and O_2 CEMS may be used for the Kapolei CRU Heaters so long as the Kapolei CRU Heaters share and exclusively use a common stack. The NOx and O_2 CEMS shall be used to demonstrate compliance with the NOx emission limits specified in the table in Paragraph 15 above. Par shall make CEMS data available to EPA or Hawaii DOH upon request. Par shall install, certify, calibrate, maintain, and operate all

CEMS required by this Paragraph in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to COMS) and Part 60, Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B.

b. Annual Performance Tests. Beginning no later than the corresponding compliance dates in the table in Paragraph 15 above and once every calendar year thereafter, Par shall conduct a NOx performance test under representative operating conditions for each of the following Kapolei Covered Heaters and Boilers to test and report compliance with the terms and conditions of Paragraphs 15-16 of this Consent Decree: Vacuum Unit Charge Heater H175, Hydrocracker 2nd Stage Charge Heater H601, Hydrocracker Fractionator Inlet Heater H602, Hydrocracker 1st Stage Charge Heater H603, Visbreaker Heater H901, and Package Boiler SG1103. Par shall comply with the performance test protocols established by EPA Method 7E in conjunction with either EPA Method 19 or EPA Methods 1, 2, 3, 3A, and 4, or an EPA-approved alternative test method. No more than ninety (90) Days after each test, Par shall submit the performance test report to Hawaii DOH and shall make performance test data and test results, including, but not limited to, mass emission rates, available to EPA or Hawaii DOH upon request.

SO_2 Emissions Reductions from the Combustion Units at the Kapolei Refinery

17. Reducing or Eliminating Fuel Oil Burning.

a. Limit on Sulfur Content of Fuel Oil Burned. Beginning no later than October 1, 2015, Par shall not burn Fuel Oil with a sulfur content greater than 0.5 percent by weight (determined daily on a 30-day rolling average basis) in any Combustion Unit at the Kapolei Refinery.

i. Monitoring. At least five Days per week, Par shall monitor the sulfur content of all fuel oil burned in any Combustion Unit at the Kapolei Refinery in accordance with American Society for Testing and Materials D129, D2622, D4294, or D5453. Samples shall be taken from the pump/circulation loop of Tank 1103, which is the only source of fuel oil delivered to the Combustion Units that burn Fuel Oil at the Kapolei Refinery.

ii. Reporting and Recordkeeping. Par shall record the quantity and sulfur content of all Fuel Oil burned in any Combustion Unit at the Kapolei Refinery, and shall include this data with the semi-annual report submitted in accordance with Section X of this Consent Decree.

b. Study to Minimize or Eliminate Fuel Oil Burning.

i. One year prior to seeking Termination under Section XXI for all of its remaining obligations under this Consent Decree, Par shall conduct a study on the minimization or elimination of Fuel Oil burning at the Kapolei Refinery ("Fuel Oil Study"). Par shall complete the Fuel Oil Study within four (4) months of commencement of the Fuel Oil Study. By

no later than sixty (60) Days after the completion of the Fuel Oil Study, Par shall submit to EPA and Hawaii DOH a report on the results of the Fuel Oil Study. The Fuel Oil Study report shall include all of the following:

(a) A detailed and comprehensive evaluation of the availability of natural gas and the availability of synthetic natural gas for use at the Kapolei Refinery in place of Fuel Oil burning;

(b) A proposed volumetric limit on or the proposed elimination of Fuel Oil burning at the Kapolei Refinery based on the lowest feasible volume of Fuel Oil burning needed to operate the Kapolei Refinery, given the availability of natural gas or synthetic natural gas; and

(c) If Par concludes that it is not feasible to eliminate all Fuel Oil burning at the Kapolei Refinery, then an estimated cost associated with Par's proposed volumetric limit on Fuel Oil burning and the estimated cost associated with eliminating all Fuel Oil burning at the Kapolei Refinery.

ii. After an opportunity to review the Fuel Oil Study report, EPA may request, in writing, any other information EPA deems necessary to evaluate Par's report. If EPA requests additional information, Par shall provide such information to EPA and Hawaii DOH within thirty (30) Days or such other period as agreed upon by EPA and Par.

iii. EPA shall, after consultation with Hawaii DOH, approve or disapprove, in writing, Par's proposed volumetric limit on, or proposed elimination of, Fuel Oil burning at the Kapolei Refinery pursuant to Section XVI (Review, Approval, and Comment on Deliverables). If EPA disapproves Par's proposal, EPA will establish an alternative volumetric limit on or require the elimination of Fuel Oil burning at the Kapolei Refinery.

iv. Par shall comply with its proposed volumetric limit on or proposed elimination of Fuel Oil burning at the Kapolei Refinery upon submission of its Fuel Oil Study report and until it is required to comply with the EPA-approved or EPA-established volumetric limit on, or elimination of, Fuel Oil burning at the Kapolei Refinery pursuant to Paragraph 17.b.iii above.

v. Within thirty (30) Days of receipt of the written notice of EPA's response to the Fuel Oil Study Report pursuant to Section XVI (Review, Approval, and Comment on Deliverables), Par shall be subject to the EPA-approved or EPA-established volumetric limit on, or elimination of, Fuel Oil burning at the Kapolei Refinery in accordance with the EPA-approved or EPA-established time-frames. If Par disagrees with the EPA-established volumetric limit on, or elimination of, Fuel Oil burning at the Kapolei Refinery, Par shall invoke dispute resolution, pursuant to Section XV of this Consent Decree, within the same thirty (30) Day period or such other period as agreed upon by EPA and Par.

18. NSPS Applicability to Specific Kapolei Refinery Fuel Gas Combustion Devices.

a. Beginning no later than October 1, 2015, Crude Heater No. 1 (Title V/Covered Source Permit ID No. H101A), Stabilizer Heater No. 1 (Title V/Covered Source Permit ID No. H102A), and Stabilizer Heater No. 2 (Title V/Covered Source Permit ID No. H102B) at the Kapolei Refinery shall be "affected facilities" as that term is used in 40 C.F.R. Part 60, Subparts A and J, and shall be subject to and comply with the requirements of 40 C.F.R. Part 60, Subparts A and J, for SO_2 applicable to FGCDs. H_2S CMS(s) for these three FGCDs shall comply with (i) the applicable monitoring requirements of 40 C.F.R. Part 60, Subparts A and J (or, if applicable, Subparts A and Ja); and (ii) Part 60, Appendix F. Par shall make CMS data available to EPA or Hawaii DOH upon request. Entry of this Consent Decree and compliance with the relevant monitoring requirements of this Consent Decree for Crude Heater No. 1 (Title V/Covered Source Permit ID No. H101A), Stabilizer Heater No. 1 (Title V/Covered Source Permit ID No. H102A), and Stabilizer Heater No. 2 (Title V/Covered Source Permit ID No. H102B) shall satisfy the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a).

b. By no later than October 1, 2015, Par shall provide a report to EPA and Hawaii DOH with a written certification that all non-flare FGCDs at the Kapolei Refinery (i) are "affected facilities" as that term is used in 40 C.F.R. Part 60, Subparts A and J (or, if applicable, Subparts A and Ja); and (ii) are subject to the requirements of 40 C.F.R. Part 60, Subparts A and J (or, if applicable, Subparts A and Ja), for SO_2 applicable to FGCDs.

SO_2 Emissions Reductions from the Kapolei Refinery Sulfur Recovery Plant

19. Long-Term Kapolei SRP SO_2 Emission Limit. Beginning no later than October 1, 2016, Par shall comply with a long-term Kapolei SRP SO_2 emission limit of 180 ppmvd SO_2 @ 0% O_2 (365-day rolling average) ("Long-Term Kapolei SRP SO_2 Emission Limit"), with the first complete 365-day rolling average calculated on October 1, 2016, based on monitoring data (obtained from the CEMS on Tail Gas Incinerator H1391) from October 1, 2016, and the 364 Days prior to October 1, 2016. Par shall comply with the Long-Term Kapolei SRP SO_2 Emission Limit at each and every process train or release point or comply with a flow weighted average of the limit for all release points from the Kapolei SRP. The Long-Term Kapolei SRP SO_2 Emission Limit shall apply at all times when the Kapolei SRP is operating (i.e., when there is Acid Gas feed to the Kapolei SRP).

20. Demonstrating Compliance with Long-Term Kapolei SRP SO_2 Emission Limit. Beginning no later than October 3, 2015, Par shall use SO_2, O_2, and flow CEMS on Tail Gas Incinerator H1391 to monitor performance of the Kapolei SRP and to report compliance with the terms and conditions of Paragraph 19 above. Beginning no later than October 1, 2016, Par shall use SO_2, O_2, and flow CEMS to monitor performance of the Kapolei SRP at all release points and to report compliance with the terms and conditions of Paragraph 19 above. CEMS shall be used to demonstrate compliance with the SO_2 emission limit established in Paragraph 19 above. Par shall make CEMS data available to EPA or Hawaii DOH upon request. Par shall install, certify, calibrate, maintain, and operate all CEMS required by this Paragraph in accordance with

the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to COMS) and Part 60, Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B.

21. NSPS Applicability to Kapolei SRP. Beginning no later than October 1, 2016, the Kapolei SRP shall be an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and Ja, and shall be subject to and comply with the requirements of 40 C.F.R. Part 60, Subparts A and Ja, for SO_2 applicable to sulfur recovery plants (including, but not limited to, the requirements to install, certify, calibrate, maintain, and operate SO_2 and O_2 CEMS on Tail Gas Incinerator H1353 and Tail Gas Incinerator H1391). Entry of this Consent Decree and compliance with the relevant monitoring requirements of this Consent Decree for the Kapolei SRP shall satisfy the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a).

CEMS/CMS Downtime Minimization, O&M, and Corrective Action

22. Certification of Installation, Upgrade, or Replacement of Kapolei SRP CEMS and Non-Flare FGCD CMS. By no later than January 1, 2017, Par shall provide a report to EPA and Hawaii DOH with a written certification that: (i) all Kapolei SRP CEMS have been installed, upgraded, or replaced to meet the requirements of 40 C.F.R. Part 60, Subparts A and Ja; and (ii) all non-flare FGCD CMS have been installed, upgraded, or replaced to meet the applicable requirements of 40 C.F.R. Part 60, Subparts A and J (or, if applicable, Subparts A and Ja).

23. CEMS/CMS O&M Plan. By no later than July 1, 2017, Par shall develop and submit for EPA and Hawaii DOH review and comment, as provided in Paragraph 27 below, a comprehensive CEMS/CMS Operation and Maintenance Plan ("CEMS/CMS O&M Plan" or "Plan") for the Kapolei Refinery that is designed to enhance the performance of CEMS/CMS components, improve CEMS/CMS accuracy and stability, and minimize periods of CEMS/CMS Downtime. This CEMS/CMS O&M Plan shall include at a minimum each of the elements identified in Paragraphs 24 through 26 below. By no later than July 1, 2018, Par shall submit for EPA and Hawaii DOH review and comment, as provided in Paragraph 27 below, a revision to the CEMS/CMS O&M Plan to account for the new NOx CEMS installed pursuant to Paragraph 16.a above.

24. CEMS Operations and Maintenance Training. Par shall provide regular training for all individuals (Par employees and contractors) involved in CEMS/CMS operations and maintenance to maintain necessary levels of monitoring competency. All newly-hired individuals (Par employees and contractors) involved in CEMS/CMS operations and maintenance shall be trained prior to undertaking any CEMS/CMS-related responsibilities. The CEMS/CMS O&M Plan shall additionally ensure that all individuals involved in CEMS/CMS operations and maintenance have access to and are familiar with the CEMS/CMS O&M Plan.

25. CEMS Testing and Calibration. Par shall certify, calibrate, maintain, and operate all CEMS/CMS in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS/CMS (excluding those provisions applicable only to COMS) and 40 C.F.R. Part 60,

Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B. These requirements shall be included in the CEMS/CMS O&M Plan.

26. Preventative Maintenance and Repair, and Quality Assurance/Quality Control ("QA/QC"). The Kapolei Refinery's CEMS/CMS O&M Plan shall include the following:

a. A CEMS/CMS preventative maintenance program to provide for a regularly scheduled set of activities designed to prevent problems before they occur. Such activities and procedures may be based initially on the CEMS/CMS vendor's recommendations. Routine preventative maintenance procedures shall be updated periodically to include such procedures as may be necessary or appropriate based on experience with each CEMS/CMS.

b. A CEMS/CMS QA/QC program to include provisions for assessing and maintaining the quality of continuous emission monitoring data, including regular (e.g., daily, weekly, monthly) routine internal (and, as needed, external) maintenance and operation checks designed to maintain or improve data quality and minimize CEMS/CMS Downtime. Internal checks include, but are not limited to, CEMS/CMS inspections, periodic calibrations, routine maintenance, and measures to assess the quality of CEMS/CMS data (i.e., accuracy and precision). External checks include, but are not limited to, independent third-party CEMS/CMS audits, third-party sampling and analysis for accuracy and precision, or other assessments to ensure continuous and accurate CEMS/CMS operations.

c. A CEMS/CMS repair program to ensure the timely repair of CEMS/CMS to address both routine maintenance and repair and non-routine maintenance and repair. Par shall maintain a spare parts inventory adequate to meet the normal operating and CEMS/CMS preventative maintenance requirements. Par shall establish procedures for acquisition of parts on an emergency basis (e.g., vendor availability on a next-day basis). An individual at the Kapolei Refinery shall be designated for overall responsibility for maintaining the adequacy of the spare parts inventory. The on-site spare parts inventory may be based on the vendor's recommendations and shall be modified on an as-needed basis.

27. EPA Review and Comment on CEMS/CMS O&M Plan.

a. EPA may provide written comments on the CEMS/CMS O&M Plan submitted by Par, in whole or in part, or EPA may decline to comment, as provided by Section XVI of this Decree (Review, Approval, and Comment on Deliverables).

b. Upon the latter of expiration of sixty (60) Days from the date of Par's submission of the CEMS/CMS O&M Plan, or upon completion of any dispute resolution process under Section XV of this Consent Decree regarding the CEMS/CMS O&M Plan, Par shall implement the CEMS/CMS O&M Plan in accordance with the requirements and schedule within the Plan, or as otherwise agreed by the Parties or ordered by the Court in dispute resolution (if applicable).

28. CEMS/CMS Root Cause Failure Analysis. For any CEMS/CMS having a Downtime greater than 5% of the total operating time for each of two consecutive Calendar Quarters, no later than ninety (90) Days following the end of the second Calendar Quarter triggering this

requirement, Par shall conduct a CEMS/CMS Root Cause Failure Analysis and develop a downtime corrective action plan ("Downtime Corrective Action Plan") to promptly address the findings of the CEMS/CMS Root Cause Failure Analysis. Solely for the purpose of conducting a CEMS/CMS Root Cause Failure Analysis under this Paragraph 28, Downtime for the Kapolei SRP CEMS on each Tail Gas Incinerator (i.e., H1353 and H1391) will be quantified independently. The CEMS/CMS Root Cause Failure Analysis shall include the following elements, at a minimum:

a. An identification and detailed analysis setting forth the root cause(s) of the CEMS/CMS Downtime;

b. The steps, if any, taken to limit the duration of the CEMS/CMS Downtime; and

c. An analysis of the measures reasonably available to prevent the root cause(s) of the CEMS/CMS Downtime from recurring. This analysis shall include an evaluation of possible design, operational, and maintenance measures. For any CEMS/CMS for which a CEMS/CMS Root Cause Failure Analysis is required twice within 12 consecutive Calendar Quarters, Par shall retain an independent third party to evaluate Par's assessment of CEMS/CMS Downtime cause(s), which may include recommendations for additional corrective actions or modification to Par's CEMS/CMS O&M Plan.

29. The findings of the CEMS/CMS Root Cause Failure Analysis and Downtime Corrective Action Plan, including a schedule for implementation, shall be submitted to EPA and Hawaii DOH in a written report included with the first semi-annual report required by Section X of this Consent Decree following completion of the CEMS/CMS Root Cause Failure Analysis.

30. Corrective Action related to the CEMS/CMS Root Cause Failure Analysis and Downtime Corrective Action Plan. The Downtime Corrective Action Plan shall require Par to undertake, as expeditiously as reasonably possible, such reasonably available corrective actions as are necessary to correct the cause of the CEMS/CMS Downtime and to prevent a recurrence of the root cause(s) identified in the CEMS/CMS Root Cause Failure Analysis. The Downtime Corrective Action Plan shall include a description of any corrective actions already completed or, if not complete, a schedule for their implementation including proposed commencement and completion dates.

a. After a review of a CEMS/CMS Root Cause Failure Analysis and Downtime Corrective Action Plan, EPA may notify Par in writing of: (i) any deficiencies in the corrective actions listed in the findings; or (ii) any objections to the schedules of implementation of the corrective actions and explain the basis for EPA's objections.

i. If Par has not yet commenced implementation of the Downtime Corrective Action Plan, Par shall implement an alternative or revised corrective action or implementation schedule based on EPA's comments.

ii. If a corrective action that EPA has identified as deficient has already commenced or is already completed, then Par is not obligated to implement the corrective action

identified by EPA. However, Par shall be on notice that EPA considers such corrective action deficient and not acceptable for remedying any subsequent, similar root cause(s) of any future CEMS/CMS Downtime.

b. If EPA and Par cannot agree on the appropriate corrective action(s) or implementation schedule(s), if any, to be taken in response to a CEMS/CMS Root Cause Failure Analysis, either party may invoke dispute resolution pursuant to Section XV of this Consent Decree.

Requirements for Certain Tanks at the Kapolei Refinery

31. Tanks 106, 107, 110, 202, 204, 405, 510, 611, and 3526. By no later than October 1, 2015, Par shall provide a report to EPA and Hawaii DOH with a written certification that (i) Tanks 106, 107, 110, 202, 204, 405, 510, 611, and 3526 at the Kapolei Refinery are in compliance with the applicable requirements of NESHAP Subparts A and CC, including, but not limited to, 40 C.F.R. §§ 63.646 and 63.647; and (ii) Tanks 107, 110, 611, and 3526 at the Kapolei Refinery are in compliance with the applicable requirements of NSPS Subparts A and Kb, including, but not limited to, 40 C.F.R. § 60.112b.

C. Kenai Refinery

32. Additional Definitions. Except as expressly set forth elsewhere in this Consent Decree, the terms used in this Section V.C shall have the meaning given to those terms in this Paragraph, or, if not defined in this Consent Decree, as defined in the Clean Air Act and the regulations promulgated thereunder.

a. 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.

b. "AOP" or "Kenai Refinery AOP" shall mean the Title V Permit issued by ADEC for the Kenai Refinery.

c. "Kenai SRU Flare" shall mean the emission unit labeled SRU Flare in Table A of the Kenai Refinery AOP.

d. "Kenai Main Refinery Flare" shall mean the emission unit labeled J-801 in Table A of the Kenai Refinery AOP.

e. "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.

33. H_2S Monitoring for the Kenai Main Refinery Flare and Kenai Refinery Fuel Gas System. By July 1, 2015, Tesoro shall comply with the following requirements:

a. Tesoro shall comply with the applicable NSPS Subpart A and NSPS Subpart J requirements, 40 C.F.R. § 60.1-19 and § 60.100-109, at the Kenai Refinery Fuel Gas System.

b. Tesoro shall upgrade the H_2S or Total Sulfur ("TS") CMS at the Kenai Refinery for the Kenai Main Refinery Flare and the Kenai Refinery Fuel Gas System ("Upgraded CMS").

i. The TS CMS monitor (AI-8716) for the Main Refinery Flare shall be capable of satisfying the span value requirements set forth in 40 C.F.R. § 60.107a(e)(1)(i).

ii. The H_2S CMS monitor (AI-7408) for the Kenai Refinery Fuel Gas System shall be capable of recording a range up to 3,000 ppm H_2S.

c. Tesoro shall install and continuously operate the Upgraded CMS monitors in accordance with the applicable requirements of the Kenai Refinery AOP and 40 C.F.R. § 60.13(e).

34. NSPS Subpart QQQ Compliance.

a. Tesoro shall comply with the applicable NSPS Subpart QQQ requirements, 40 C.F.R. §§ 60.690-699, at the Kenai Refinery.

b. By no later than January 1, 2014, Tesoro shall install an above ground storage tank or tanks sufficient to replace the capacity of the API canals (emission unit ID 110) at the Kenai Refinery.

c. The storage tank(s) shall meet the applicable requirements of 40 C.F.R. Part 60, Subpart QQQ for oil-water separators.

35. Subpart KKKK Compliance. Tesoro shall comply with the applicable NSPS Subpart KKKK requirements, 40 C.F.R. §§ 60.4300-4420, at the Kenai Refinery.

36. NESHAP Subpart UUU Compliance. Tesoro shall comply with the applicable NESHAP Subpart UUU requirements, 40 C.F.R. §§ 63.1560-1579, at the Kenai Refinery.

37. Ambient SO_2 Monitoring Requirements.

a. Acid Gas Flaring Event Reporting. Beginning on January 1, 2013, by no later than thirty (30) Days after the end of a month during which an Acid Gas Flaring Event ends, Tesoro shall submit to EPA and ADEC a report that sets forth the following:

i. The date and time that the Acid Gas Flaring Event started and ended. To the extent that the Acid Gas Flaring Event involved multiple releases within a 24-hour period or within subsequent, contiguous, non-overlapping 24-hour periods, Tesoro will set forth the starting and ending dates and times of each release;

ii. An estimate of the quantity of SO_2 that was emitted during the Acid Gas Flaring Event, and the calculations or data analyzed or used to determine the quantity;

iii. The steps, if any, Tesoro took to limit the duration and/or quantity of SO_2 emissions associated with the Acid Gas Flaring Event;

iv. An analysis that sets forth the root cause and all contributing causes of the Acid Gas Flaring Event, to the extent determinable;

v. A statement on whether Tesoro claims that the Acid Gas Flaring Event was caused by *force majeure* and the basis for that claim;

vi. A statement on the number of Acid Gas Flaring Events in the preceding 12-month period, including any Acid Gas Flaring Events that have been claimed as attributable to *force majeure*;

vii. An analysis of the measures, if any, that are available to reduce the likelihood of a recurrence of an Acid Gas Flaring Event resulting from the same root cause or contributing causes in the future;

viii. To the extent that analysis and investigation of the estimated quantity of SO_2 released and the causes and/or possible corrective actions still are underway on the due date of the report, a statement of the anticipated date by which a follow-up report fully conforming to the requirements of this Paragraph will be submitted; and

ix. To the extent that completion of the implementation of corrective action(s), if any, is not finalized at the time of the submission of the report required under this Paragraph, then, by no later than thirty (30) Days after completion of the corrective action(s), Tesoro will submit a report identifying the corrective action(s) taken and the dates of commencement and completion of those actions.

b. No later than twelve (12) months from the last Day of the month when an SO_2 Monitor Trigger Event ends, Tesoro will install, operate, and maintain an ambient SO_2 monitoring system including meteorological monitoring equipment at the Kenai Refinery in

accordance with the requirements in Paragraphs 37.c-i below. If EPA concludes that an SO_2 Monitor Trigger Event has occurred, it will notify Tesoro in writing within a reasonable time.

c. SO_2 Monitoring Equipment. The ambient SO_2 monitoring system required by Paragraph 37.b above shall measure the concentrations of SO_2 in air in accordance with the EPA federal reference test method or the EPA equivalent reference test method requirements specified in 40 C.F.R. Part 53. Concentrations of SO_2 will be continuously measured and reported in accordance with PSD monitoring requirements outlined in 40 C.F.R. Part 58, and the most recent version of EPA Quality Assurance ("QA") Handbook for Air Pollution Measurement Systems, Volume II (available at http://www.epa.gov/ttn/amtic/qalist.html). Within ninety (90) Days of an SO_2 Monitor Trigger Event, Tesoro shall provide EPA and ADEC with a monitoring plan that includes, at a minimum, an identification of the locations of the meteorological station and the monitoring station and how those sites meet this Consent Decree's requirements and a proposed Quality Assurance Project Plan ("QAPP") that describes the Quality Assurance/Quality Control procedures, specifications, and other technical activities to be implemented to ensure that the results of the monitoring program meet project specifications and data availability requirements of this Consent Decree. The monitoring plan is subject to EPA approval in consultation with ADEC in accordance with Section XVI of this Consent Decree (Review, Approval, and Comment on Deliverables).

d. Meteorological Monitoring Equipment. The SO_2 monitoring system required by Paragraph 37.b above shall include meteorological monitoring equipment/sensors that shall meet or exceed PSD performance specifications as outlined in the most recent version of EPA document QA Handbook for Air Pollution Measurement Systems, Volume IV: Meteorological Measurements Version 2.0. Specific meteorological parameters will be continuously monitored and recorded to obtain data representative of prevailing meteorological conditions for the Kenai Refinery area. The data set produced shall be adequate to correlate prevailing conditions with pollutant measurements and transport.

i. Continuously measured meteorological parameters shall include hourly-averaged (scalar or vector) measurements of horizontal wind speed and wind direction, the standard deviation of the horizontal wind direction (sigma theta), air temperature and relative humidity. Wind speed and direction shall be measured at a height of approximately 10 meters. Temperature shall be measured at both a height of 2 meters and 10 meters (for determining delta temperature). Relative humidity, solar radiation and barometric pressure shall be measured at a height of 2 meters.

ii. Wind direction and sigma theta measurement data shall be compiled and reported as hourly block averages in degrees (^{o}), rounded to the nearest whole degree. Wind speed data measurement data shall be compiled and reported as hourly block averages in meters per second (m/s) rounded to the nearest tenth of a m/s.

iii. Air temperature measurement data will be compiled and reported as hourly block averages in degrees Fahrenheit (^{o} F) or Celsius (^{o} C), rounded to the nearest tenth of a degree.

iv. Relative humidity measurement data will be compiled and reported as hourly block averages in percent, rounded to the nearest whole percent.

e. Quality Assurance/Quality Control ("QA/QC"). In accordance with Section XVI (Review, Approval, and Comment on Deliverables), Tesoro shall, no later than ninety (90) Days after the SO_2 Monitor Triggering Event, and prior to commencing operation of the monitor, develop and submit to EPA and ADEC for approval by EPA in consultation with ADEC a QAPP that describes the make and model of the monitor to be used, Quality Assurance/Quality Control procedures, specifications, and other technical activities to be implemented to ensure that the results of the monitoring meets project specifications. Tesoro shall, at a minimum, incorporate into their QAPP the QC checks and QC criteria specified in the SO_2 Validation Template located in Appendix D of the EPA document QA Handbook for Air Pollution Measurement Systems, Volume II. Tesoro shall ensure that all data collected by the monitor is verified and validated on a monthly basis or more frequently. The verification/validation process for a given month's data shall be completed by no later than the end of the month following the month within which the data were collected and shall follow the procedures described in the approved QAPP. EPA or ADEC may request data or a demonstration from Tesoro at any time that the monitoring equipment is functioning as contemplated in the approved QAPP.

f. Monitor Station. All monitoring equipment (except the meteorological equipment and support tower) shall be installed and operated inside a temperature controlled equipment shelter. The temperature within this shelter shall be continuously monitored and recorded to a data acquisition system ("DAS" or "data logger") with an averaging time of no greater than 1 hour. The climate control system for the monitoring shelter shall be capable of maintaining a stable temperature within the range of 15° C to 30° C or per manufacturer specifications, and shall meet 24-hour standard deviation criteria as specified in the EPA QA Handbook for Air Pollution Measurement Systems, Volume II.

g. Monitor Location. The SO_2 ambient monitor shall be located at the existing monitoring station site (referred to as "UTAMP1") located to the southwest of the Kenai Refinery. The following siting criteria based on 40 C.F.R. Part 58 Appendix E requirements shall be considered, unless otherwise approved by EPA in consultation with ADEC:

i. Probe or sampler inlet should be 2 to 5 meters above ground and have unrestricted airflow 270 degrees around the sample inlet probe. The Kenai SRU Flare shall be within this 270 degree arc of unrestricted airflow.

ii. Probe or sampler inlet shall be >20 meters from the drip line of any tree(s).

iii. The SO_2 sampler inlet shall be >1 meter away from supporting structures, walls and parapets.

iv. The distance from a sampler probe inlet to an obstacle, such as a building, should be at least twice the height the obstacle protrudes above the sampler, probe, or monitoring path.

v. All probes and samplers should be away from minor sources, such as incineration flues, to avoid undue influences from minor sources. The separation distance is dependent on the height of the minor source's emission point (such as a flue), the type of fuel or waste burned, and the quality of the fuel.

h. Monitor Operation. Tesoro shall operate and maintain the SO_2 monitor described herein in accordance with manufacturers' recommendations for a period of five (5) years after an SO_2 Monitor Trigger Event and installation has occurred. Nothing in this Paragraph shall preclude the use of any other, additional ambient monitoring equipment and/or monitoring of any other, additional pollutants around the Kenai Refinery. The requirements of this Paragraph 37 shall cease to apply if the Kenai Refinery becomes subject to an enforceable requirement to conduct equivalent SO_2 monitoring as a result of a newly promulgated SIP or any other federal or state legal requirement applicable to the Kenai Refinery. In the event Tesoro believes such a requirement exists, it may request a Certificate of Completion under Section XXI of this Consent Decree (Termination). Upon issuance of such Certification of Completion, the requirements of this Paragraph 37 shall cease.

i. SO_2 Monitor Data Reporting.

i. Tesoro shall retain all data recorded by the SO_2 monitor pursuant to this Paragraph 37 in accordance with the record retention provisions of this Consent Decree, and shall make all data recorded by the monitor available to EPA or ADEC within thirty (30) Days of a written request.

ii. Tesoro shall submit to EPA and ADEC in report form all quality reviewed raw data from the SO_2 monitor and the meteorological sensors on a semi-annual basis pursuant to Section X (Reporting and Recordkeeping). For all missing or invalidated data points, Tesoro shall provide qualifying remarks which provide an explanation as to why the data is not present.

iii. Tesoro shall also submit to EPA and ADEC an event report for any period when: (i) any 1-hour SO_2 concentration equals or exceeds 75 ppb; (ii) any 3-hour SO_2 concentration equals or exceeds 500 ppb; or (iii) any 24-hour SO_2 concentration equals or exceeds 140 ppb. Tesoro shall submit its event report to EPA and ADEC by no later than fourteen (14) Days after any event meeting the criteria set out in this Paragraph.

iv. These notification and reporting requirements shall not supersede any other applicable notification or reporting requirements that apply to releases pursuant to Tesoro's permits or other legal obligations.

38. Kenai Refinery Title V Compliance.

a. Tesoro shall comply with AOP conditions identified in the following table at the Kenai Refinery (or future succeeding AOP condition(s) as applicable):

Permit Number AQ0035TVP02 Rev. 4 (Issue Date: October 15, 2012, Revision Date: August 6, 2015 Expiration Date: Oct. 15, 2017) Condition Number	**Source of Underlying Obligation**
10.2	1/18/97 & 10/1/2004 SIP Requirements found at 18 AAC 50.055(d)(3)(A)
10.6, 35.3 & 35.4	Construction Permit No. 9923-AC010 Rev.1, Exhibits C & D(6), 12/31/02
20.1-20.2	Construction Permit No. 9923-AC010 Rev.1, Exhibits B(A), C & D(5), 12/31/02
16	Construction Permit No. 9923-AC010 Rev.1 Exhibits B (G), 12/31/02
23	Construction/Operating Permit No. 9323-AA008 (amended), Condition 22 and Exhibit C, 11/18/96
137	1/18/97 & 10/1/2004 SIP requirements found at 18 AAC 50.205
140.1	1/18/97 SIP requirements found at 18 AAC 50.240(c)

b. Title V Compliance Audit.

i. Tesoro shall implement a third-party compliance auditing program at the Kenai Refinery that will consist of at least two cycles of auditing and correction.

ii. The third-party auditor shall be an entity with demonstrated experience and expertise in evaluating compliance with applicable Clean Air Act requirements, and shall not share any common ownership or management responsibilities with the Settling Defendants or their subsidiaries or affiliates.

iii. The objective of the auditing program will be to determine compliance with the requirements identified in the Kenai Refinery AOP excluding the Kenai Refinery's LDAR obligations.

iv. The scope of the audit shall be broad enough to enable the third-party auditor to identify and address applicable requirements under the Clean Air Act that are not identified in the facility's AOP.

v. Tesoro shall initiate the first cycle of the compliance audit by retaining a third-party auditor to perform the audit by no later than December 1, 2016. The audit shall review compliance with any of the facility's applicable requirements under the Clean Air Act during the one year period immediately preceding the beginning of the onsite audit. The audit report shall be submitted to the EPA and ADEC no later than July 1, 2017 ("AOP Compliance Audit Report").

vi. Tesoro shall initiate the second cycle of the compliance audit by retaining a third party to perform an audit no later than October 1, 2020, and no earlier than July 1, 2017. The second cycle of the compliance audit shall identify any non-compliance with any of the Kenai Refinery's applicable requirements under the Clean Air Act during the two-year period preceding the date of the beginning of the second onsite audit. The AOP Compliance Audit Report shall be submitted to the EPA no later than 18 months after initiating the second cycle of the compliance audit.

vii. Tesoro shall provide supporting documentation used in the preparation of the audit report upon written request by the EPA and/or ADEC.

viii. Tesoro shall include in each AOP Compliance Audit Report at least the following information:

(a) An identification of each AOP requirement covered by the compliance audit;

(b) Identification of any applicable requirements that were not included in the AOP at the time of the audit;

(c) Description of the compliance status with respect to each applicable requirement; and

(d) If non-compliance was identified, a description of the root cause of each non-compliant condition, to the extent determinable, as well as what actions were taken or are being taken to achieve compliance with each applicable requirement as soon as practicable.

D. Mandan Refinery

39. Stack Test Requirements for Mandan Refinery FCCU. By no later than July 1, 2016, Tesoro shall conduct annual PM stack testing using three test runs of at least one hour in length as set forth in 40 C.F.R. § 63.1571(b)(2) to demonstrate compliance with 40 C.F.R. § 63.1564.

40. Tesoro shall operate the scrubber and the wet electrostatic precipitator at the Mandan Refinery according to manufacturer's specifications and good engineering practices.

41. CMS Downtime Minimization, O&M, and Corrective Action.

a. CMS Operation and Maintenance Plan. By no later than July 1, 2016, Tesoro shall develop and submit for EPA comment, a comprehensive CMS Operation and Maintenance Plan ("CMS O&M Plan" or "Plan") for the Mandan Refinery that is designed to enhance the performance of CMS components, improve CMS accuracy and stability, and minimize periods of CMS Downtime. This CMS O&M Plan shall include, at a minimum, each of the elements identified in Paragraph 41.a.i through 41.a.iv. below.

i. CMS Operations and Maintenance Training. The CMS O&M Plan shall provide for regular training for all individuals (Tesoro employees and contractors) involved in CMS operations and maintenance to maintain necessary levels of monitoring competency. All newly-hired individuals (Tesoro employees and contractors) involved in CMS operations and maintenance shall be trained prior to undertaking any CMS-related responsibilities. The CMS O&M Plan shall additionally ensure that all individuals involved in CMS operations and maintenance have access to and are familiar with the CMS O&M Plan.

ii. CMS Testing and Calibration. Tesoro shall certify, calibrate, maintain, and operate all CMS in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CMS (excluding those provisions applicable only to COMS) and 40 C.F.R. Part 60, Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B. These requirements shall be included in the CMS O&M Plan.

iii. Preventative Maintenance and Repair, and Quality Assurance/Quality Control ("QA/QC"). The CMS O&M Plan shall include the following:

(a) A CMS preventative maintenance program to provide for a regularly scheduled set of activities designed to prevent problems before they occur. Such activities and procedures may be based initially on the CMS vendor's recommendations. Routine preventative maintenance procedures shall be updated periodically to include such procedures as may be necessary or appropriate based on experience with each CMS.

(b) A CMS QA/QC program to include provisions for assessing and maintaining the quality of continuous emission monitoring data, including regular (e.g., daily, weekly, monthly) routine internal (and, as needed, external) maintenance and operation checks designed to maintain or improve data quality and minimize CMS Downtime. Internal checks include, but are not limited to, CMS inspections, periodic calibrations, routine maintenance and measures to assess the quality of CMS data (i.e., accuracy and precision). External checks include, but are not limited to, independent third-party CMS audits, third-party sampling and analysis for accuracy and precision, or other assessments to ensure continuous and accurate CMS operations.

iv. A CMS repair program to ensure the timely repair of CMS to address both routine maintenance and repair and non-routine maintenance and repair. Tesoro shall maintain a spare parts inventory adequate to meet the normal operating and CMS preventative maintenance requirements. Tesoro shall establish procedures for acquisition of parts on an emergency basis (e.g., vendor availability on a next-day basis). An individual at the Mandan Refinery shall be designated for overall responsibility for maintaining the adequacy of the spare parts inventory. The on-site spare parts inventory may be based on the vendor's recommendations and shall be modified on an as-needed basis.

b. EPA Review and Comment on CMS O&M Plan. EPA may provide written comments on the CMS O&M Plan submitted by Tesoro, in whole or in part, or EPA may decline to comment, as provided by Section XVI (Review, Approval, and Comment on Deliverables).

c. Upon the latter of expiration of sixty (60) Days from the date of Tesoro's submission of the CMS O&M Plan, or if Tesoro invokes dispute resolution, upon completion of any dispute resolution process under Section XV of this Consent Decree regarding the CMS O&M Plan, Tesoro shall implement the CMS O&M Plan in accordance with the requirements and schedule within the Plan or as otherwise agreed by the Parties or ordered by the Court in dispute resolution (if applicable).

d. CMS Root Cause Failure Analysis. For any CMS having a Downtime greater than 5% of the total time for each of two consecutive Calendar Quarters, no later than ninety (90) Days following the end of the second Calendar Quarter triggering this requirement, Tesoro shall conduct a CMS Root Cause Failure Analysis and develop a downtime corrective action plan ("Downtime Corrective Action Plan") to promptly address the findings of the CMS Root Cause Failure Analysis and submit this plan to EPA for comment. The CMS Root Cause Failure Analysis shall include the following elements, at a minimum:

i. An identification and detailed analysis setting forth the root cause(s) of the CMS Downtime;

ii. The steps, if any, taken to limit the duration of the CMS Downtime; and

iii. An analysis of the measures reasonably available to prevent the root cause(s) of the CMS Downtime from recurring. This analysis shall include an evaluation of possible design, operational, and maintenance measures. For any CMS for which a CMS Root Cause Failure Analysis is required twice within 12 consecutive Calendar Quarters, Tesoro shall retain an independent third party to evaluate Tesoro's assessment of CMS Downtime cause(s), which may include recommendations for additional corrective actions or modification to Tesoro's CMS O&M Plan.

e. Corrective Action. The Downtime Corrective Action Plan shall require Tesoro to undertake as expeditiously as reasonably possible such reasonably available corrective actions as are necessary to correct the cause of the CMS Downtime and to prevent a recurrence of the root cause(s) identified in the CMS Root Cause Failure Analysis. The Downtime Corrective Action Plan shall include a description of any corrective actions already completed or, if not complete, a schedule for their implementation including proposed commencement and completion dates.

f. After a review of a CMS Root Cause Failure Analysis and Downtime Corrective Action Plan, EPA may notify Tesoro in writing of: (i) any deficiencies in the corrective actions listed in the findings; and/or (ii) any objections to the schedules of implementation of the corrective actions and explain the basis for EPA's objections.

i. If Tesoro has not yet commenced implementation of the Downtime Corrective Action Plan, Tesoro shall implement an alternative or revised corrective action or implementation schedule based on EPA's comments.

ii. If a corrective action that EPA has identified as deficient has already commenced or is already completed, then Tesoro is not obligated to implement the corrective action identified by EPA. However, Tesoro shall be on notice that EPA considers such corrective action deficient and not acceptable for remedying any subsequent, similar root cause(s) of any future CMS Downtime.

iii. If EPA and Tesoro cannot agree on the appropriate corrective action(s) or implementation schedule(s), if any, to be taken in response to a CMS Root Cause Failure Analysis, either party may invoke the dispute resolution pursuant to Section XV of this Consent Decree.

E. Martinez Refinery

42. Additional Definitions. Except as expressly set forth elsewhere in this Consent Decree, the terms used in this Section V.E shall have the meaning given to those terms in this Paragraph, or, if not defined in this Consent Decree, as defined in the Clean Air Act and the regulations promulgated thereunder.

a. "Acid Gas" or "AG" for purposes of this Section V.E shall mean any gas that contains H_2S and is generated at the Martinez Refinery by the regeneration of an amine scrubber solution.

b. "Acid Gas Flaring" shall mean the combustion of Acid Gas or Sour Water Stripper Gas in an AG Flaring Device. Nothing in this definition shall be construed to modify, limit, or affect EPA's authority to regulate the flaring of gases that do not fall within the definitions contained in this Consent Decree of Acid Gas or Sour Water Stripper Gas.

c. "AG Flaring Device" shall mean any device at the Martinez Refinery that is used for the purpose of combusting Acid Gas or Sour Water Stripper Gas, except facilities in which gases are combusted to produce elemental sulfur, sulfuric acid, or ammonium thiosulfate.

NO_x Emissions Reductions from the Martinez Refinery FCCU

43. Interim and Final Martinez FCCU NOx Emission Limits.

a. Interim Limits. Beginning no later than October 1, 2015, Tesoro shall comply with the following interim emission limits at the Martinez FCCU: (i) a short-term FCCU NOx emission limit of 175.1 ppmvd NOx @ 0% O_2 (24-hour average) ("Interim Short-Term Martinez FCCU NOx Emission Limit"); and (ii) a long-term FCCU NOx emission limit of 52.5 ppmvd NOx @ 0% O_2 (365-day rolling average) ("Interim Long-Term Martinez FCCU NOx Emission Limit"). For the Interim Long-Term Martinez FCCU NOx Emission Limit, the first complete 365-day rolling average shall be calculated on October 1, 2015, based on monitoring data (obtained from CEMS certified as compliant with either EPA or BAAQMD CEMS monitoring requirements) from October 1, 2015, and the 364 Days prior to October 1, 2015.

b. Final Limits. Tesoro shall comply with the following final emission limits at the Martinez FCCU: (i) beginning no later than July 1, 2017, a short-term Martinez FCCU NOx emission limit of 40 ppmvd NOx @ 0% O_2 (7-day rolling average) ("Final Short-Term Martinez FCCU NOx Emission Limit"); and (ii) beginning no later than July 1, 2018, a long-term Martinez FCCU NOx emission limit of 20 ppmvd NOx @ 0% O_2 (365-day rolling average) ("Final Long-Term Martinez FCCU NOx Emission Limit"). For the Final Long-Term Martinez FCCU NOx Emission Limit, the first complete 365-day rolling average shall be calculated on July 1, 2018, based on monitoring data from July 1, 2018, and the 364 Days prior to July 1, 2018.

c. Startup, Shutdown, or Malfunction. NOx emissions during periods of Startup, Shutdown, or Malfunction of the Martinez FCCU or Malfunction of the associated NOx control equipment, if any, shall not be used in determining compliance with the Interim or Final Short-Term Martinez FCCU NOx Emission Limits (i.e., 24-hour average or 7-day rolling average) required by this Paragraph, provided that during such periods Tesoro, to the extent practicable, maintains and operates the Martinez FCCU, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. The Interim and Final Long-Term Martinez NOx Emission Limits shall apply at all times.

d. Martinez FCCU CO Boiler. Compliance with the NOx emission limits established pursuant to this Paragraph 43 shall be determined by measuring the emissions from the Martinez FCCU CO Boiler exit stack (as opposed to measuring the gases exiting the Martinez FCCU Catalyst Regenerator prior to the gases entering the Martinez FCCU CO Boiler).

e. Exception to the NOx Emission Limits at Martinez FCCU CO Boiler Stack. The Interim and Final Short-Term and Long-Term Martinez FCCU NOx Emission Limits shall not apply at the Martinez FCCU CO Boiler exit stack when the Martinez FCCU CO Boiler is operating and firing only refinery fuel gas (i.e., not processing gases from the Martinez FCCU Catalyst Regenerator).

44. Demonstrating Compliance with Martinez FCCU NOx Emission Limits. Beginning no later than October 1, 2015, Tesoro shall use NOx and O_2 CEMS to monitor performance of the Martinez FCCU and to report compliance with the terms and conditions of this Section V.E. CEMS shall be used to demonstrate compliance with the NOx emission limits established pursuant to this Section V.E. Tesoro shall make CEMS data available to EPA upon request. Tesoro shall install, certify, calibrate, maintain, and operate all CEMS required by this Paragraph in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to COMS) and Part 60, Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B. With respect to 40 C.F.R. Part 60 Appendix F, in lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, Tesoro shall conduct either a RAA or a RATA on each CEMS at least once every three (3) years. Tesoro shall also conduct CGAs each Calendar Quarter during which a RAA or a RATA is not performed. Tesoro may conduct a FAT in lieu of the required RAA or CGA.

CO Emissions Reductions from the Martinez Refinery FCCU

45. Martinez FCCU CO Emission Limit. Beginning no later than October 1, 2015, Tesoro shall comply with the following emission limit at the Martinez FCCU: a long-term Martinez FCCU CO emission limit of 180 ppmvd CO @ 0% O_2 (365-day rolling average) ("Long-Term Martinez FCCU CO Emission Limit"). For the Long-Term Martinez FCCU CO Emission Limit, the first complete 365-day rolling average shall be calculated on October 1, 2015, based on monitoring data from October 1, 2015, and the 364 Days prior to October 1, 2015. The Long-Term Martinez FCCU CO Emission Limit shall apply at all times.

46. Demonstrating Compliance with Martinez FCCU CO Emission Limit. Beginning no later than October 1, 2015, Tesoro shall use CO CEMS to monitor performance of the Martinez FCCU and to report compliance with the terms and conditions of this Section V.E. CEMS shall be used to demonstrate compliance with the CO emission limit established in this Section V.E. Tesoro shall make CEMS data available to EPA upon request. Tesoro shall install, certify, calibrate, maintain, and operate all CEMS required by this Paragraph in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to COMS) and Part 60, Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B. With respect to 40 C.F.R. Part 60 Appendix F, in lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, Tesoro shall conduct either a RAA or a RATA on each CEMS at least once every three (3) years. Tesoro shall also conduct CGAs each Calendar Quarter during which a RAA or a RATA is not performed. Tesoro may conduct a FAT in lieu of the required RAA or CGA.

SO_2 Emissions Reductions from the Martinez Refinery Sulfur Recovery Plant

47. Sulfur Pit Emissions. Beginning no later than January 1, 2016, Tesoro shall re-route any Martinez SRP Sulfur Pit emissions such that all Sulfur Pit emissions to the atmosphere are either: (i) eliminated; (ii) included as part of the Martinez SRP's emissions subject to the NSPS Subpart J SO_2 limit; or (iii) included as part of the Martinez SAP's emissions subject to the limits in Paragraphs 52 and 54 of this Consent Decree.

48. Good Operation and Maintenance. Beginning no later than December 31, 2005, Tesoro shall comply with the Martinez Refinery's Preventive Maintenance and Operation Plan ("PMO Plan") at all times. If Tesoro makes changes to the PMO Plan related to minimizing Acid Gas Flaring or SO_2 emissions, such changes shall be summarized and reported to EPA on an annual basis.

VOC, H_2S, and PM Emissions Reductions from the Martinez Refinery Delayed Coker

49. Control of VOC, H_2S, and PM Emissions from the Delayed Coker.

a. From October 1, 2015, through December 31, 2018, Tesoro shall not commence Coke Drum Venting until the Coke Drum Overhead Pressure is 2.0 psig or less prior to closing the Coke Drum overhead valve to the blowdown quench tower.

b. Beginning no later than January 1, 2019, Tesoro shall not commence Coke Drum Venting until the Coke Drum Overhead Pressure is 2.0 psig or less prior to venting to the atmosphere.

50. Delayed Coker Quench Water Operating Practices. Beginning no later than October 1, 2015, Tesoro shall comply with all the following operating limits:

a. Tesoro shall use only the following for the Quench Water Make-Up:

i. Water that is fresh (i.e., water brought into the Martinez Refinery that has not been in contact with process water or process wastewater);

ii. Non-contact cooling water blowdown;

iii. Water that has been stripped in a sour water stripper;

iv. Water from other refinery sources where the water has a TOC concentration of less than 745 ppm and a total sulfide concentration of less than 35 ppm; or

v. Some combination of water from Paragraph 50.a.i to 50.a.iv above.

b. Tesoro shall not feed or dispose of any materials with a TOC concentration of 745 ppm or greater into any Coke Drum during the quench cycle.

c. Quench Water Fill Time shall be at least five (5) hours per cycle.

51. Control of PM Emissions from the Coke Pit/Pad Area. By no later than October 1, 2015, the Coke Pit/Pad Area shall have walls on all four sides that are at least 30 feet in height above the ground level of the Coke Pit/Pad Area's pad. A portion of the east side of the Coke Pit/Pad Area shall consist of the Delayed Coker structure. The south side of the Coke Pit/Pad Area shall have a wall cutout that leads to the Delayed Coker settling basin. Sections of the north wall of the Coke Pit/Pad Area can be removed to allow access. The requirements in this Paragraph are in addition to the coke handling requirements already contained in the Martinez Refinery's Title V permit, including an enclosed coke conveyance system, enclosed coke storage facilities, vehicle wash-off, and other measures to control fugitive PM.

SO_2 Emissions Reductions from the Martinez Refinery Sulfuric Acid Plant

52. Martinez SAP SO_2 Emission Limits.

a. Limits. Tesoro shall comply with the following SO_2 emission limits at the Martinez SAP (expressed as pounds of SO_2 emitted per ton of 100% Sulfuric Acid Produced ("lbs SO_2/ton H_2SO_4")): (i) beginning no later than January 1, 2016, Tesoro shall comply with a short-term SAP emission limit of 1.85 lbs SO_2/ton H_2SO_4 (3-hour rolling average) ("Short-Term SAP SO_2 Emission Limit"); and (ii) beginning no later than January 1, 2017, Tesoro shall comply with a long-term SAP emission limit of 1.7 lbs SO_2/ton H_2SO_4 (365-day rolling average)

("Long-Term SAP SO_2 Emission Limit"). For the Long-Term SAP SO_2 Emission Limit, the first complete 365-day rolling average shall be calculated on January 1, 2017, based on monitoring data from January 1, 2017, and the 364 Days prior to January 1, 2017.

b. Startup, Shutdown, or Malfunction. SO_2 emissions during periods of Malfunction, SAP Startup, or SAP Shutdown of the Martinez SAP or Malfunction of the associated SO_2 control equipment, if any, shall not be used in determining compliance with the Short-Term SAP SO_2 Emission Limit set forth in Paragraph 52.a above, provided that during such periods Tesoro, to the extent practicable, maintains and operates the Martinez SAP, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. The Long-Term SAP SO_2 Emission Limit set forth in Paragraph 52.a above shall apply at all times.

53. Demonstrating Compliance with the Martinez SAP SO_2 Emission Limits. Beginning no later than January 1, 2016, to monitor performance of the Martinez SAP, and to demonstrate and report compliance with the Short-Term and Long-Term SAP SO_2 Emission Limits, Tesoro shall: (i) use 100% sulfuric acid production meters, a SO_2 CEMS on the final stack, and a flow rate monitor on the final stack of the Martinez SAP; and (ii) implement the Martinez SAP Monitoring Plan, which is attached hereto as Appendix A-1. The Martinez SAP Monitoring Plan describes how Tesoro shall monitor compliance with the Short-Term and Long-Term SAP SO_2 Emission Limits, including the methodology that Tesoro shall use to demonstrate compliance in the event of SO_2 CEMS Downtime lasting longer than twenty-four (24) hours. Tesoro shall make CEMS data available to EPA upon request. Tesoro shall install, certify, calibrate, maintain, and operate all CEMS required by this Paragraph in accordance with the provisions of the SAP Monitoring Plan. For the Long-Term SAP SO_2 Emission Limit, Tesoro shall demonstrate compliance each Day in the manner specified in the Martinez SAP Monitoring Plan.

54. NSPS Applicability to the Martinez SAP.

a. Beginning no later than January 1, 2016, the Martinez SAP shall be an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and H, and shall be subject to and comply with the applicable requirements of 40 C.F.R. Part 60, Subparts A and H. Entry of this Consent Decree and compliance with the relevant monitoring and performance testing requirements of this Consent Decree for the Martinez SAP shall satisfy the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance testing requirement of 40 C.F.R. § 60.8(a).

b. SO_2, Acid Mist, and Opacity Emission Limits. Beginning no later than January 1, 2016, the Martinez SAP shall comply with the SO_2, Acid Mist, and Opacity emission limits of 40 C.F.R. §§ 60.82 and 60.83. Compliance with the SO_2 and Acid Mist emission limits shall be demonstrated using the performance tests required by Paragraph 55 below. The SO_2 and Acid Mist performance tests required by Paragraph 55 below may be undertaken at the same time. At Tesoro's election, a COMS may be used for monitoring compliance with the Opacity limit found at 40 C.F.R. § 60.83(a)(2).

55. Performance Testing.

a. SO_2 Emission Limits. By no later than January 1, 2016, Tesoro shall complete a performance test at the Martinez SAP measuring the SO_2 emission rate in accordance with the applicable requirements of 40 C.F.R. Part 60, Appendix A, Reference Test Method 8, and Part 60, Appendix B, Performance Specification 2 or an alternative EPA-approved method. This test shall consist of at least three (3) reference method test runs; however, if this test is also to serve as the SO_2 CEMS RATA required under Performance Specification 2, then this test shall consist of at least nine (9) reference method test runs. Tesoro shall collect accurate measurements of 100% Sulfuric Acid Produced during each test run and shall include in the test protocol all measurements to be taken during the test to ensure accurate measurements of 100% Sulfuric Acid Produced during each test run.

b. Acid Mist Limit. By no later than January 1, 2016, Tesoro shall complete a performance test at the Martinez SAP measuring the Acid Mist emission rate in accordance with the applicable requirements of 40 C.F.R. Part 60, Appendix A, Reference Test Method 8, or an alternative EPA-approved method. This performance test shall be used to demonstrate compliance with the Acid Mist emission limit of 40 C.F.R. § 60.83(a)(1). Tesoro shall collect accurate measurements of 100% Sulfuric Acid Produced during each test run and shall include in the test protocol all measurements to be taken during the test to ensure accurate measurements of 100% Sulfuric Acid Produced during each test run.

c. Opacity Limit. By no later than January 1, 2016, Tesoro shall complete a performance test at the Martinez SAP measuring Opacity in accordance with the applicable requirements of 40 C.F.R. § 60.11 and Part 60, Appendix A, Reference Test Method 9, or an alternative EPA-approved method. This performance test shall be used to demonstrate compliance with the Opacity limit of 40 C.F.R. § 60.83(a)(2).

d. Advance Notification. By no later than thirty (30) Days before any performance test required by this Paragraph is conducted or such other period agreed upon by EPA and Tesoro, Tesoro shall provide notice to EPA of its intent to conduct such testing. This notification shall include the schedule date of the test(s), an emission test protocol, a description of the planned operating rate and operating conditions, and the procedures that will be used to measure 100% Sulfuric Acid Produced. If EPA requires any adjustment of the testing protocol or operating conditions, Tesoro shall either (i) make such adjustments and conduct the performance test in conformity with EPA's requirements; or (ii) submit the issue(s) for dispute resolution under Section XV of this Consent Decree.

e. Report of Results. By no later than sixty (60) Days after conducting a performance test required under this Paragraph or such other period agreed upon by EPA and Tesoro, Tesoro shall submit to EPA a report documenting the results of the performance tests.

56. Operation and Maintenance Plan.

a. By no later than January 1, 2016, Tesoro shall prepare and submit to EPA an Operation and Maintenance Plan ("O&M Plan") for the Martinez SAP. The O&M Plan shall

describe the operating and maintenance procedures necessary to: (i) minimize the frequency of SAP Shutdowns (thereby reducing the number of SAP Startups); and (ii) maintain and operate the Martinez SAP, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

b. EPA may provide written comments on the O&M Plan submitted by Tesoro, in whole or in part, or EPA may decline to comment, as provided by Section XVI of this Decree (Review, Approval, and Comment on Deliverables).

c. By no later than April 1, 2016, Tesoro shall implement the O&M Plan, provided that the O&M Plan need not include elements that specifically respond to EPA's comments or recommendations until the process for responding to or disputing such comments or recommendations has been completed in accordance with Section XVI (Review, Approval, and Comment on Deliverables). All other elements of the O&M Plan shall be implemented.

2005 Consent Decree Requirements Applicable to the Martinez Refinery

57. Appendix A-2 to this Consent Decree contains those requirements from the 2005 Martinez Consent Decree applicable to the Martinez Refinery that are being incorporated into this Consent Decree.

58. Tesoro shall comply with all requirements set forth in Appendix A-2 until the requirements therein are terminated pursuant to Section XXI (Termination).

F. SLC Refinery

59. [Reserved]

60. NOx Emissions Reductions from the SLC FCCU.

a. By January 1, 2018, Tesoro shall install a non-regenerative wet gas scrubber and LoTOx System or equivalent on the SLC FCCU.

b. Final NOx Emission Limits. By no later than January 1, 2018, Tesoro shall comply with the following NOx limits at the SLC FCCU: (i) 10 ppmvd NOx @ 0% O_2 (365-day rolling average) ("Long-Term SLC FCCU NOx Limit"); and (ii) 20 ppmvd NOx @ 0% O_2 (7-day rolling average) ("Short-Term SLC FCCU NOx Limit"). For the Long-Term SLC FCCU NOx Limit, the first complete 365-day rolling average shall be calculated on January 1, 2019, based on monitoring data from January 1, 2019, and the 364 Days prior to January 1, 2019.

c. Startup, Shutdown and Malfunction. NOx emissions during periods of Startup, Shutdown, or Malfunction of the SLC FCCU, or Malfunction of the associated NOx control equipment, if any, shall not be used in determining compliance with the Short-Term SLC FCCU NOx Limit established in Paragraph 60.b above provided that during such periods Tesoro, to the extent practicable, maintains and operates the SLC FCCU, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for

minimizing emissions. The Long-Term SLC FCCU NOx Limit established in Paragraph 60.b above shall apply at all times.

d. Demonstrating Compliance with FCCU NOx Emission Limits. By no later than January 1, 2018, Tesoro shall use NOx and O_2 CEMS to monitor performance of the SLC FCCU and to report compliance with the terms and conditions of this Consent Decree. CEMS shall be used to demonstrate compliance with the Short-Term and Long-Term SLC FCCU NOx Emission Limits established pursuant to Paragraph 60.b above. Tesoro shall make CEMS data available to EPA within thirty (30) Days of a written request. Tesoro shall install, certify, calibrate, maintain, and operate all CEMS at the SLC FCCU required by this Paragraph in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to COMS) and Part 60 Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60 Appendix B.

61. SO_2 Reductions from the SLC FCCU.

a. Final SO_2 Emission Limits at the SLC FCCU. By no later than January 1, 2018, Tesoro shall comply with the following SO_2 limits at the SLC FCCU: (i) 10 ppmvd SO_2 @ 0% O_2 (365-day rolling average) ("Long-Term SLC FCCU SO_2 Emission Limit"); and (ii) 18 ppmvd SO_2 @ 0% O_2 (7-day rolling average) ("Short-Term SLC FCCU SO_2 Emission Limit"). For the Long-Term SLC FCCU SO_2 Limit, the first complete 365-day rolling average shall be calculated on January 1, 2019, based on monitoring data from January 1, 2019, and the 364 Days prior to January 1, 2019.

b. Startup, Shutdown or Malfunction. SO_2 emissions during periods of Startup, Shutdown, or Malfunction of the SLC FCCU, or Malfunction of the associated SO_2 control equipment, if any, shall not be used in determining compliance with the Short-Term SLC FCCU SO_2 Emission Limit established in Paragraph 61.a above, provided that during such periods Tesoro, to the extent practicable, maintains and operates the SLC FCCU, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. The Long-Term SLC FCCU SO_2 Emission Limit established in Paragraph 61.a above, shall apply at all times.

c. Demonstrating Compliance with FCCU SO2 Emission Limits. By no later than January 1, 2018, Tesoro shall use an SO_2 and O_2 CEMS to monitor the performance of the SLC FCCU and to report compliance with the terms and conditions of this Consent Decree. Tesoro shall make CEMS data available to EPA within thirty (30) Days of a written request. Tesoro shall install, certify, calibrate, maintain, and operate all CEMS at the SLC FCCU required by this Paragraph in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to COMS) and Part 60 Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60 Appendix B19.

62. CO Emissions from the SLC FCCU.

a. Final CO Emission Limit at the SLC FCCU. Beginning on October 1, 2015, Tesoro shall comply with the following CO limits at the SLC FCCU: (i) a short-term FCCU CO

emission limit of 500 ppmvd CO @ 0% O_2 (one-hour block average) ("Short-Term FCCU CO Emission Limit"); and (ii) a long-term FCCU CO emission limit of 100 ppmvd CO @ 0% O_2 (365-day rolling average) ("Long-Term FCCU CO Emission Limit"). For the Long-Term SLC FCCU CO Emission Limit, the first complete 365-day rolling average shall be calculated on October 1, 2015, based on monitoring data from October 1, 2015 and the 364 Days prior to October 1, 2015.

b. Startup, Shutdown or Malfunction. CO emissions during periods of Startup, Shutdown, or Malfunction of the SLC FCCU, or Malfunction of the associated CO control equipment, if any, shall not be used in determining compliance with the Short-Term SLC FCCU CO Emission Limit established in Paragraph 62.a above, provided that during such periods Tesoro, to the extent practicable, maintains and operates the SLC FCCU, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. The Long-Term SLC FCCU CO Emission Limit established in Paragraph 62.a above shall apply at all times.

c. Demonstrating Compliance with FCCU CO Emission Limits. By October 1, 2015, Tesoro shall use a CO and O_2 CEMS to monitor the performance of the SLC FCCU and to report compliance with the terms and conditions of this Consent Decree. Tesoro shall make CEMS data available to EPA within thirty (30) Days of a written request. Tesoro shall install, certify, calibrate, maintain, and operate all CEMS at the SLC FCCU required by this Paragraph in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to COMS) and Part 60 Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60 Appendix B.

63. NSPS Applicability to the SLC FCCU.

a. The SLC FCCU Catalyst Regenerator is an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and J for PM, SO_2, and CO. On and after October 1, 2015, until January 1, 2018, the SLC FCCU Catalyst Regenerator shall continue to be subject to and shall comply with 40 C.F.R. Part 60, Subparts A and J for SO_2.

b. Beginning on October 1, 2015, the SLC FCCU shall become an "affected facility" as that term is used in 40 C.F.R. Part 60, Subpart Ja for PM and CO in lieu of Subpart J. Beginning on January 1, 2018, the SLC FCCU shall become an "affected facility" as that term is used in 40 C.F.R. Part 60, Subpart Ja for NOx, and Subpart Ja for SO_2 in lieu of Subpart J. On and after January 1, 2018, Tesoro shall comply with all applicable requirements in 40 C.F.R. Part 60, Subpart Ja at the SLC FCCU.

c. Entry of this Consent Decree and compliance with the relevant monitoring requirements of this Consent Decree for the SLC FCCU shall satisfy the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a).

VI. AFFIRMATIVE RELIEF APPLICABLE TO ALL COVERED REFINERIES

A. Enhanced Leak Detection and Repair ("ELDAR Program")

General LDAR Provisions

64. Definitions. The terms used in this Section VI.A (ELDAR Program) shall have the meanings as set forth below. Any other terms shall have the meaning given to those terms in the Clean Air Act and the regulations promulgated thereunder.

a. "Covered Equipment" shall mean all pumps and valves (excluding pressure relief devices and check valves), in light liquid or gas/vapor service in all Covered Process Units.

b. "Covered Process Unit" shall mean any process unit that is, or under the terms of this Consent Decree becomes, subject to the equipment leak provisions of 40 C.F.R. Part 60, Subpart GGGa or 40 C.F.R. Part 63, Subpart CC.

c. "Equipment" shall mean any equipment as defined in 40 C.F.R. § 60.591a.

d. "Maintenance Shutdown" shall mean a Shutdown of a Covered Process Unit that lasts longer than 30 Days.

e. "Process Unit Shutdown" means a work practice or operational procedure that stops production from a process unit or part of a process unit during which it is technically feasible to clear process material from a process unit, or part of a process unit, consistent with safety constraints, and during which repairs can be accomplished. The following are not considered Process Unit Shutdowns: (i) an unscheduled work practice or operational procedure that stops production from a process unit or part of a process unit for less than 24 hours; (ii) an unscheduled work practice or operational procedure that would stop production from a process unit or part of a process unit for a shorter period of time than would be required to clear the process unit or part of the process unit of materials and start up the unit, and would result in greater emissions than delay of repair of leaking components until the next scheduled Process Unit Shutdown; and (iii) the use of spare equipment and technically feasible bypassing of equipment without stopping production.

65. NSPS & Covered Process Units Applicability. No later than October 1, 2016, all process units as defined by 40 C.F.R. Part 60 Subpart GGGa at each Covered Refinery shall be an "affected facility" for purposes of that standard. Once Subpart GGGa applies to a process unit pursuant to this Consent Decree, then the requirements of Subpart GGG shall no longer apply prospectively to that unit. The dates that various process units become "affected facilities" under Subpart GGGa and "Covered Process Units" as defined in Paragraph 64.b above shall be in accordance with the following intervals:

a. 30 percent of the process units to be completed at each Covered Refinery by no later than April 1, 2016;

b. 60 percent of the process units to be completed at each Covered Refinery by no later than July 1, 2016; and

c. 100 percent of the process units to be completed at each Covered Refinery by no later than October 1, 2016.

For purposes of this Consent Decree only, "Covered Process Unit" also includes petroleum refining process units (as defined by 40 C.F.R. § 63.641) and process units (as defined by 40 C.F.R. § 60.591a). "Covered Process Units" subject to this ELDAR Program by virtue of this provision will be addressed under the schedule set forth above.

66. The requirements in this Section VI.A of this Consent Decree shall not apply to compressors at the Covered Refineries.

67. Initial monitoring of valves subject to 40 C.F.R. Part 60, Subpart GGGa shall be completed as of the date each particular process unit becomes an affected facility under Paragraph 65 above. In implementing initial monitoring of valves under this provision, a monitoring event already completed under existing regulatory or Consent Decree requirements may be used as a consecutive monthly monitoring event.

68. Beginning on the date that any particular process unit becomes an "affected facility" as set forth in Paragraph 65 above, it shall be subject to and comply with the requirements of Subpart GGGa and this ELDAR Program.

69. Entry of this Consent Decree satisfies the notification and testing requirements that are triggered by initial applicability of 40 C.F.R. Part 60, Subparts A and GGGa: 40 C.F.R 60.7, 60.8, 60.18.

70. The two consecutive months of monitoring that Tesoro previously conducted for purposes of 40 C.F.R. Part 60, Subpart GGGa satisfies the requirement to conduct monitoring of those components for two consecutive months following the initial applicability of 40 C.F.R. Part 60, Subpart GGGa for the following units:

Refinery	**Covered Process Unit**	**Month Completed**
Anacortes	BenSat/Reformate Splitter	January 2012
	Crude Railcar Offloading Facility	October 2012
	Clean Fuels and Diesel Hydrotreaters	June 2015
	Vacuum Flasher	June 2015
	Crude Unit	June 2015
	Selective Hydrogenation Unit	Nov. 2015
	Amine Treating Unit (ATU) 2	Nov. 2015
	Flare	Dec. 2015
	Truck Rack	Dec. 2015

Refinery	Covered Process Unit	Month Completed
Kenai	Crude Unit	April 2011
	DIB Unit	December 2014
	Vacuum Unit	
	PRIP Unit	March 2014
	Hydrogen Unit	February 2014
	Diesel Desulfurization Unit	February 2015
	LPG Unit	April 2015
	Hydrocracker Unit	May 2015
Mandan	Ultraformer Unit	July 2013
	Crude Unit	
	Poly Unit	
	Power Station	
	Gasoline Hydrotreating Unit	August 2013
	Diesel Desulfurization Unit	
	Alkylation Unit	
	Racks Unit	November 2013
	Vapor Recovery Unit	June 2014
	Fluid Catalytic Cracking Unit	March 2015
	Merox Unit	March 2015
	Oil Movements (Including Tank Farm)	March 2015
	Sulfur Recovery Unit	March 2015
Salt Lake City	Gasoline Hydrotreating Unit	June 2009
	BenSat Unit	June 2012
	Co-generation Unit	March 2014
	Sulfur Recovery Unit	
	Virgin Naphtha Stabilizer	
	Fluid Catalytic Cracking Unit	December 2013
	Vapor Recovery Unit	November 2013
	Alkylation Unit	
	Distillate Desulfurization Unit	
	Butane Loading Rack	July 2014
	Polymerization Unit	
	Transport Loading Rack	August 2014
	Crude Unit (N2C)	September 2014
	Ultra Former	
	Tank Farm	October 2014
	Remote Tank Farm	December 2014

Between the Date of Lodging and the Date of Entry for this Consent Decree, Settling Defendants can provide notice of additional units which have satisfied the two consecutive months of monitoring under 40 C.F.R. Part 60, Subpart GGGa (and therefore the two consecutive months of monitoring required by this Consent Decree) by providing written notice to the United States and Applicable State Co-Plaintiffs.

71. Nothing in this Consent Decree shall relieve Settling Defendants of their independent obligation to comply with the requirements of any other federal, state or local LDAR regulation that may be applicable to equipment at each Covered Refinery.

72. Enhanced Leak Detection and Repair. Settling Defendants shall implement and comply with the requirements of the ELDAR Program for all Covered Equipment at each Covered Refinery by the dates specified herein and shall continue to comply with all ELDAR Program requirements until Termination. The requirements of this ELDAR Program are in addition to, and not in lieu of, the requirements of any federal, state or local LDAR regulation that may be applicable to a piece of Covered Equipment. If there is a conflict between a federal, state or local LDAR regulation and this ELDAR Program, Settling Defendants shall follow whichever regulation is more stringent.

73. Exceptions/Limitations for Martinez Refinery. Settling Defendants shall comply with the ELDAR Program set forth in this Section VI.A at the Martinez Refinery except for the following requirements:

a. Leak Detection and Repairs for Valves and Pumps (Paragraphs 87-96 below).

b. Monitoring Frequency and Methods (Paragraphs 83-85 below), except Settling Defendants shall comply with Paragraph 86 below (Calibration of LDAR Monitoring Equipment).

c. Valve Replacement/Improvement Program (Paragraphs 98-102 below).

d. However, in lieu of the above excepted ELDAR Program, Settling Defendants shall comply with all applicable BAAQMD requirements and 40 C.F.R. Part 60, Subpart GGGa requirements. If BAAQMD requirements and Subpart GGGa requirements differ, Settling Defendants shall comply with the more stringent requirement.

Facility-Wide LDAR Program and Training at Each Covered Refinery

74. Written LDAR Program. By no later than January 1, 2016, Settling Defendants shall develop a written facility-wide LDAR Program for each Covered Refinery that describes: (i) the facility-wide LDAR program for that Covered Refinery (*e.g.*, applicability of regulations to process units and/or specific Equipment; leak definitions; monitoring frequencies); (ii) a tracking program (*e.g.*, "Management of Change") that ensures that new pieces of Equipment added to that Covered Refinery for any reason are integrated into the LDAR program and that pieces of Equipment that are taken out of service are removed from the LDAR program; (iii) the roles and

responsibilities of all employee and contractor personnel assigned to LDAR functions at that Covered Refinery; (iv) the basis for the Settling Defendant's determination that the number of personnel dedicated to LDAR functions is sufficient to satisfy the requirements of the LDAR program; and (v) how the Covered Refinery plans to implement this ELDAR Program. Beginning on October 1, 2016, Settling Defendants shall review this document on an annual basis and update it as needed by no later than December 31 of each year, after completion of the initial written facility-wide LDAR Program.

75. Training. Settling Defendants shall implement the following training programs:

a. By no later than April 1, 2016, for any employee newly-assigned to LDAR responsibilities, Settling Defendants shall require that each such employee satisfactorily complete LDAR training prior to beginning any LDAR work;

b. By no later than April 1, 2016, for all the Covered Refineries' employees assigned specific LDAR responsibilities as a primary job function, such as monitoring technicians, database users, Quality Assurance ("QA")/Quality Control ("QC") personnel and the LDAR Coordinator, Settling Defendants shall provide and require completion of initial training before the employee begins LDAR responsibilities and annual LDAR refresher training thereafter;

c. By no later than April 1, 2016, for all employee operations and maintenance personnel, who have duties relevant to LDAR, such as operators and mechanics performing valve repacking and designated unit supervisors reviewing DOR work, Settling Defendants shall provide and require completion of an initial training program that includes instruction on aspects of LDAR that are relevant to the person's duties. Refresher training for these personnel shall be performed every three years; and

d. If contract employees are performing LDAR work, Settling Defendants shall maintain copies of all training records, as required under this Paragraph, for the contract employees.

LDAR Audits at Each Covered Refinery.

76. LDAR Audits. Settling Defendants shall conduct a third-party or internal LDAR audit at each Covered Refinery every other year pursuant to the requirements of Paragraphs 77 through 82 below.

77. Third-Party Audits. Settling Defendants shall retain a third party with experience in conducting LDAR audits to conduct the initial LDAR audit under this Consent Decree at each Covered Refinery. Third parties shall be utilized at least every four years for any subsequent required audits until Termination of this Consent Decree. To perform the third-party LDAR audit, Settling Defendants shall select a different company than its regular LDAR contractor with expertise in LDAR program requirements. For the Anacortes, Kapolei, and Kenai Refineries, the first third-party LDAR Audit Commencement Date shall be no later than October 1, 2016. For each subsequent third-party LDAR audit, the LDAR Audit Completion Date shall occur within

the same Calendar Quarter that the first LDAR Audit Completion Date occurred. For the Martinez, Mandan, and Salt Lake City Refineries, the LDAR audits shall follow the schedule set forth below.

Refinery	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Martinez	4th Quarter		4th Quarter		4th Quarter	
Mandan	3rd or 4th Quarter		3rd or 4th Quarter		3rd or 4th Quarter	
Salt Lake City		3rd Quarter		3rd Quarter		3rd Quarter

Subsequent audits shall occur within the same Calendar Quarter as the previous audits on a biennial basis until Termination of this Consent Decree pursuant to Section XXI (Termination).

78. Internal LDAR Audits. In years in which Settling Defendants are not required to retain a third-party auditor, Settling Defendants may conduct an LDAR audit internally by using its own personnel, provided that the personnel Settling Defendants use are not employed at the Covered Refinery to be audited but rather are employed at another refinery owned or operated by a Settling Defendant that at the time of the audit uses Certified Low-Leaking Valve and/or Certified Low-Leaking Valve Packing Technology. All such internal LDAR audits shall be conducted by personnel familiar with regulatory LDAR requirements and this ELDAR Program. At its discretion, Settling Defendants may use a third-party auditor in lieu of conducting these internal LDAR audits.

79. Each LDAR audit shall include, but not be limited to, reviewing compliance with all applicable regulations including valves and pumps in heavy liquid service, reviewing and/or verifying the same items that are required to be reviewed and/or verified in Paragraph 105 of this Consent Decree, and performing the following activities for Covered Equipment:

a. Calculating a Comparative Monitoring Audit Leak Percentage. Covered Equipment shall be monitored to calculate a leak percentage for each Covered Process Unit broken down by Covered Equipment type (*i.e.*, valves and pumps). The monitoring that takes place during each LDAR audit shall be called "comparative monitoring" and the leak percentages derived from the comparative monitoring shall be called the "Comparative Monitoring Audit Leak Percentage." Until Termination of this Consent Decree pursuant to Section XXI, Settling Defendants shall conduct a comparative monitoring audit pursuant to this Paragraph during each LDAR audit. Each Covered Process Unit at a Covered Refinery that is not the subject of the current audit shall have a comparative monitoring audit at least once before a previously-audited Covered Process Unit is audited again.

b. Calculating the Historic Average Leak Percentage from Prior Periodic Monitoring Events. For the Covered Process Unit that is audited, the historic average leak percentage from prior monitoring events, broken down by Covered Equipment type (*i.e.*, valves and pumps) shall be calculated. The following number of complete monitoring periods immediately preceding the comparative monitoring audit shall be used for this purpose:

valves-4 periods if valves are on quarterly cycle or 2 periods if valves are on an annual cycle; and pumps-12 periods.

c. Calculating the Comparative Monitoring Leak Ratio. For the Covered Process Unit that is audited, the ratio of the Comparative Monitoring Audit Leak Percentage from Paragraph 79.a above to the historic average leak percentage from Paragraph 79.b above shall be calculated ("Comparative Monitoring Leak Ratio"). If a calculated ratio yields an infinite result, Settling Defendants shall assume one leaking piece of Covered Equipment was found in the process unit through its routine monitoring during the 12-month period before the audit, and the ratio shall be recalculated.

d. In addition to these items, LDAR audits after the first audit shall include reviewing each Covered Refinery's compliance with this ELDAR Program.

80. When More Frequent Periodic Monitoring is Required. If a Comparative Monitoring Audit Leak Percentage calculated pursuant to Paragraph 79.a above triggers a more frequent monitoring schedule under any applicable federal, state, or local law or regulation than the frequencies listed in Paragraphs 83-84 of this Consent Decree for the equipment type in that Covered Process Unit, Settling Defendants shall monitor the affected type of Covered Equipment at the greater frequency unless and until less frequent monitoring is again allowed under the specific federal, state, or local law or regulation.

81. Corrective Action Plan ("CAP").

a. Requirements of a CAP. By no later than thirty (30) Days after each LDAR Audit Completion Date, Settling Defendants shall develop a preliminary CAP if the results of an LDAR audit identify any deficiencies or if the Comparative Monitoring Leak Ratio calculated pursuant to Paragraph 79.c above is 3.0 or higher and a Comparative Monitoring Audit Leak Percentage calculated pursuant to Paragraph 79.a above is 0.5% or higher. The CAP shall describe the actions that Settling Defendants shall take to correct the deficiencies and/or the systemic causes of a Comparative Monitoring Leak Ratio that is 3.0 or higher. The CAP also shall include a schedule by which those actions shall be undertaken. Settling Defendants shall complete each corrective action as expeditiously as possible with the goal of completing each action within ninety (90) Days after the LDAR Audit Completion Date. If any action is not completed or is not expected to be completed within ninety (90) Days after the LDAR Audit Completion Date, Settling Defendants shall explain the reasons in the final CAP to be submitted under Paragraph 81.b below, together with a proposed schedule for completion of the action(s) as expeditiously as practicable.

b. Submissions of the CAP to EPA. By no later than one hundred and twenty (120) Days after the LDAR Audit Completion Date, Settling Defendants shall submit the final CAP to EPA for approval, together with a certification of the completion of corrective action(s). For any corrective action(s) requiring more than ninety (90) Days to complete, Settling Defendants shall include an explanation together with a proposed schedule for completion as expeditiously as practicable.

c. Approval/Disapproval of All or Parts of a CAP.

i. Unless within sixty (60) Days after receipt of the CAP, EPA disapproves all or part of a CAP's proposed actions and/or schedules, the CAP shall be deemed approved.

ii. By no later than sixty (60) Days after receipt of a Settling Defendant's CAP, EPA may disapprove any or all aspects of the CAP. Each item that is not specifically disapproved in writing shall be deemed approved. Except for good cause, EPA may not disapprove any action within the CAP that already has been completed. Within forty-five (45) Days of receipt of any disapproval from EPA, the submitting Settling Defendant shall submit a revised CAP that addresses the deficiencies that EPA identified that Settling Defendant shall implement the revised CAP either pursuant to the schedule that EPA proposed, or, if EPA did not so specify, as expeditiously as practicable.

iii. A dispute arising with respect to any aspect of a CAP shall be resolved in accordance with the dispute resolution provisions of this Decree set forth in Section XV.

82. Certification of Compliance. Within 180 Days after the initial LDAR Audit Completion Date, each Settling Defendant shall submit a certification to EPA and the Applicable State Co-Plaintiff that certifies, to the best of the certifier's knowledge and belief after reasonable inquiry, that: (i) the Covered Refinery is in compliance with all applicable LDAR regulations; (ii) Settling Defendant has completed all corrective actions, if applicable, or is in the process of completing all corrective actions pursuant to a CAP; and (iii) all Equipment at the Covered Refinery that is regulated under any federal, state, or local leak detection program has been identified and included in each Covered Refinery's LDAR program. To the extent that a Settling Defendant cannot make the certification in all respects, it shall specifically identify any deviations from items (i)–(iii).

Monitoring Frequency and Methods

83. For all Covered Equipment, Settling Defendants shall comply with the monitoring frequency for valves as required by 40 C.F.R. § 60.482-7a, except as provided in 40 C.F.R. § 60.482-1a, and for pumps as required by 40 C.F.R. § 60.482-2a.

84. Alternative Standards for Valves – Skip Period Leak Detection and Repair. Settling Defendants may elect to comply with the skip period monitoring requirements set forth in 40C.F.R. § 60.483-2a, if applicable.

85. Method 21.

a. Except as provided in Paragraph 85.b below, for all Covered Equipment, Settling Defendants shall comply with Method 21 in performing LDAR monitoring, using a Toxic Vapor Analyzer 1000B Flame Ionization Detector, or equivalent equipment attached to a data logger, or equivalent equipment, which directly electronically records the Screening Value detected at each piece of Covered Equipment, the date and time that each Screening Value is taken, and the identification numbers of the monitoring instrument and technician. Settling Defendants shall

transfer this monitoring data to an electronic database on at least a weekly basis for recordkeeping purposes. Notwithstanding the foregoing, Settling Defendants may use paper logs where necessary or more feasible (e.g., small rounds, re-monitoring, or when data loggers are not available or broken). Any manually recorded monitoring data shall be transferred to the electronic database within seven (7) Days of monitoring.

b. Alternative Work Practice.

i. From October 1, 2015, Settling Defendants may utilize the Alternative Work Practice as defined at 40 C.F.R. § 60.18(g) (the "AWP") for monitoring Equipment that meets the "difficult to monitor" criteria set out at 40 C.F.R. § 60.482-7a(h)(1).

ii. No sooner than October 1, 2018, Settling Defendants may submit to EPA pursuant to Section XVI (Review, Approval, and Comment on Deliverables) a request for review and approval of an AWP for LDAR monitoring of all Covered Equipment. Such request shall include a protocol that, at a minimum, addresses the following operational criteria: (i) calibration procedures; (ii) Startup (i.e., warming-up the Optical Gas Imaging ("OGI") Instrument)/Shutdown procedures; (iii) video recording and storage; (iv) site-specific impact of weather conditions (e.g., wind speed, temperature, and visibility); (v) maintenance of the OGI Instrument; (vi) certification of personnel to use the OGI Instrument; (vii) minimum number of hours of field use by certified personnel prior to certified personnel performing compliance monitoring; and (viii) identified process unit(s) where certified personnel may monitor with an OGI instrument. If such request is approved by EPA, Settling Defendants may utilize the AWP for monitoring all Covered Equipment.

86. Calibration of LDAR Monitoring Equipment. Except as provided below, before each monitoring shift or before monitoring equipment is restarted during a monitoring shift, Settling Defendants shall calibrate LDAR monitoring equipment as required by Subpart GGGa in accordance with 40 C.F.R. Part 60, EPA Reference Test Method 21, prior to each time LDAR monitoring equipment is used to monitor Covered Process Units. Settling Defendants shall conduct calibration drift assessment rechecks of the LDAR monitoring equipment at the end of each monitoring shift and prior to each time LDAR monitoring equipment is turned off during each monitoring shift, except when LDAR monitoring equipment is unable to function such that the calibration drift assessment recheck cannot be performed before the LDAR monitoring equipment turns off. Settling Defendants are not required to conduct a calibration drift assessment re-check during the same monitoring shift in the event of a "flame-out" of the instrument if the instrument can be promptly re-ignited. The calibration drift assessment shall be conducted using calibration gas as provided in 40 C.F.R. § 60.485a(b)(1) with a concentration approximately equal to the applicable internal leak definition. If any calibration drift assessment after the initial calibration shows a negative drift of more than 10% from the previous calibration, Settling Defendants shall re-monitor all components as required by 40 C.F.R. § 60.485a. Settling Defendants shall retain all calibration records for at least one year, or as otherwise required by any federal, state or local law, whichever is most stringent.

Leak Detection and Repairs for Valves and Pumps

87. Leak Definition for Valves and Pumps. Settling Defendants shall utilize the following leak definitions in Paragraphs 87.a and 87.b below for valves and pumps in light liquid and/or gas/vapor service in Covered Process Units, unless other permit(s), regulations, or laws require the use of lower leak definitions.

a. Leak Definition for Valves. Settling Defendants shall utilize a leak definition of 500 ppm VOCs for all of the valves in Covered Process Units.

b. Leak Definition for Pumps. Settling Defendants shall utilize a leak definition of 2,000 ppm VOCs for all of the pumps in Covered Process Units.

88. For each leak detected at or above the leak definition for valves in Covered Process Units, Settling Defendants shall perform repairs in accordance with Paragraphs 90-96 of this Consent Decree.

89. For each leak detected at or above the leak definition for pumps in Covered Process Units, Settling Defendants shall perform repairs in accordance with Paragraphs 91-92 and 95-96 of this Consent Decree.

90. Settling Defendants shall make an attempt at repair on any valve in a Covered Process Unit that has a reading greater than 100 ppm of VOCs, excluding control valves and other valves that LDAR personnel are not authorized to repair.

91. For each leak subject to Paragraph 87 of this Consent Decree, by no later than five (5) Days after detecting a leak, Settling Defendants shall perform a first attempt at repair. By no later than fifteen (15) Days after detection, Settling Defendants shall perform a final attempt at repair or may place the valve or pump on the Delay of Repair list provided that Settling Defendants has complied with 40 C.F.R. Part 60, Subpart GGGa and with the requirements of Paragraph 97 of this Consent Decree.

92. For each attempt at repair as set forth in Paragraphs 88-91 above, Settling Defendants shall perform Repair Verification Monitoring. After Repair Verification Monitoring for an attempt performed under Paragraph 90 above, no further action is necessary, unless the provisions of Paragraph 99.e below (Chronically Leaking valves) apply or unless the re-monitored leak rate is greater than the applicable leak definition.

93. Drill-and-Tap Repairs. Except as otherwise provided for in Paragraph 94 for leaking valves in Covered Process Units (other than control valves), when other repair attempts have failed to reduce emissions below the applicable leak definition and a Settling Defendant is not able to remove the leaking valve from service, that Settling Defendant shall attempt at least one drill-and-tap repair (with a second injection of sealant if the first injection is unsuccessful at repairing the leak) as set forth below before placing the valve on the DOR list. Prior to October 1, 2015, each Covered Refinery shall select one of the following two compliance options for drill-and-tap repairs. Each Covered Refinery may change the selection between Paragraphs 93.a

and 93.b below no more than once every four years but may not change options prior to October 1, 2017. If under Paragraph 79 above, a Comparative Monitoring Audit Leak Percentage calculated pursuant to Paragraph 79.a triggers a more frequent monitoring schedule under any applicable federal, state, or local law or regulation than the frequencies listed in Paragraphs 83-84 of this Consent Decree for the equipment type in that Covered Process Unit, then the selection shall automatically change from option in Paragraph 93.a below to the option in Paragraph 93.b below.

a. If a Settling Defendant is performing skip period monitoring on any process units at a Covered Refinery pursuant to Paragraph 84 above, then for valves in Covered Process Units (other than control valves) leaking at a rate of 500 ppm or greater that cannot otherwise be repaired, that Settling Defendant shall use drill-and-tap before placing the valve on the DOR list.

b. If a Settling Defendant is not performing skip period monitoring on any process units at a Covered Refinery pursuant to Paragraph 84 above, then for valves in Covered Process Units (other than control valves) leaking at a rate of 1,000 ppm or greater that cannot otherwise be repaired, that Settling Defendant shall use drill-and-tap before placing the valve on the DOR list.

c. If a drill-and-tap attempt can reasonably be completed within the fifteen-day repair period set forth in Paragraph 91 above, the Covered Refinery shall complete the drill-and-tap attempt in that time period. If a drill-and-tap attempt cannot reasonably occur within the fifteen-day repair period (i.e., if the Covered Refinery's drill-and-tap contractor is not local and must mobilize to the Refinery), the Settling Defendant provisionally may place the valve on the DOR list pending attempting the drill-and-tap repair as expeditiously as practical. In no event (other than as provided in Paragraph 94 below) may Settling Defendant take more than thirty (30) Days from the initial monitoring to attempt a drill-and-tap repair. If drill-and-tap is successful, the valve shall be removed from the provisional DOR list.

94. Drill-and-tap is not required when there is a major safety, mechanical, product quality, or environmental issue with repairing the valve using the drill-and-tap method, in which case, Settling Defendants shall document the reason(s) why any drill-and-tap attempt was not performed prior to placing any valve on the DOR list.

95. For each leak in a Covered Process Unit, Settling Defendants shall record the following information: the date of all repair attempts; the repair methods used during each repair attempt; the date, time and Screening Values for all re-monitoring events; and, if relevant, the information required under Paragraph 97 below for Covered Equipment placed on the DOR list.

96. Nothing in Paragraphs 88-95 of this Consent Decree is intended to prevent Settling Defendants from taking a leaking piece of Covered Equipment out of service; provided however, that prior to placing the leaking piece of Covered Equipment back in service, Settling Defendants shall repair the leak or shall comply with the requirements of Paragraph 97 of this Consent Decree (Delay of Repair) to place the piece of Covered Equipment on the DOR list.

Delay of Repair

97. Settling Defendants shall require the following for Covered Equipment placed on the DOR list:

a. Sign-off from the plant manager, a Settling Defendant official responsible for environmental management and compliance, a Settling Defendant official responsible for plant engineering, an operations manager, or an area supervisor that the piece of Covered Equipment is technically infeasible to repair without a Process Unit Shutdown;

b. Periodic monitoring, at the frequency required for other pieces of Covered Equipment of that type in the process unit, of the Covered Equipment placed on the DOR list;

c. No more than 0.10% of all valves in all Covered Process Units may be on the DOR list at any one time. If a valve is: (i) isolated and taken out of VOC and/or HAP service at the same time it is placed on the DOR list and is repacked with Certified Low-Leaking Valve Packing Technology or is replaced with Certified Low-Leaking Valves before it is placed back into VOC and/or HAP service; or (ii) scheduled to be repacked with Certified Low-Leaking Valve Packing Technology or replaced with Certified Low-Leaking Valves at the next Maintenance Shutdown, such valve shall not be included in computing the applicable percentage limitation of valves that may be on the DOR list at any one time; and

d. Covered Equipment may be removed from the DOR list if it is monitored at the frequency required for other pieces of Covered Equipment of that type in the process unit for two successive monitoring periods without detecting a leak greater than the leak definition as set forth in Paragraph 87 above for that type of Covered Equipment.

Valve Replacement/Improvement Program

98. Settling Defendants shall implement the program set forth in Paragraphs 99-102 below to replace and/or improve the emissions performance of the valves in each Covered Process Unit.

99. Valves.

a. By no later than October 1, 2015, Settling Defendants shall implement modified purchasing procedures that evaluate the availability of valves and valve packing for Covered Equipment that meet the requirements for a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology at the time that the valves and/or valve packing is acquired.

b. Except as provided in Paragraph 100 below, by no later than October 1, 2016, Settling Defendants shall install valve packing material that meets the requirements for Certified Low-Leaking Valve Packing Technology whenever repacking any valve in gas/vapor or light liquid VOC service in a Covered Process Unit.

c. Settling Defendants shall ensure that each new valve in gas/vapor or light liquid VOC service that it purchases for use in any Covered Process Unit either is a Certified Low-Leaking Valve or is fitted with Certified Low-Leaking Valve Packing Technology.

d. By no later than October 1, 2016, Settling Defendants shall ensure that each new valve in gas/vapor or light liquid VOC service that it installs in any Covered Process Unit either is a Certified Low-Leaking Valve or is fitted with Certified Low-Leaking Valve Packing Technology.

e. Replacing or Repacking Chronically Leaking Valves (Existing Valves that have Screening Values At or Above 5,000 ppm). Except as provided in Paragraph 100 below, for each Chronically Leaking valve in a Covered Process Unit, Settling Defendants shall replace or repack the existing Chronically Leaking valve in the Covered Process Unit with a Certified Low-Leaking Valve or with Certified Low-Leaking Valve Packing Technology. Settling Defendants shall undertake this replacement or repacking by no later than thirty (30) Days after the monitoring event that triggers the replacement or repacking requirement, unless the replacement or repacking requires a Process Unit Shutdown. If the replacement or repacking requires a Process Unit Shutdown, Settling Defendants shall undertake the replacement or repacking during the Maintenance Shutdown that follows the monitoring event that triggers the requirement to replace or repack the valve. If a Settling Defendant completes the replacement or repacking within thirty (30) Days of detecting the leak, that Settling Defendant shall not be required to comply with Paragraph 93 of this Consent Decree. If a Settling Defendant does not complete the replacement or repacking within thirty (30) Days, or if, at the time of the leak detection, that Settling Defendant reasonably can anticipate that it might not be able to complete the replacement or repacking within thirty (30) Days, that Settling Defendant shall comply with all applicable requirements of Paragraph 93 of this Consent Decree.

100. Commercial Unavailability of a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology.

a. Settling Defendants shall not be required to utilize a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology to replace or repack a valve if a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology is commercially unavailable in accordance with the provisions in Appendix B ("Commercial Unavailability"). Prior to claiming this Commercial Unavailability exemption, Settling Defendants shall contact a reasonable number of vendors of valves and obtain a written representation or equivalent documentation from each vendor that the particular valve that Settling Defendants need is commercially unavailable either as a Certified Low-Leaking Valve or with Certified Low-Leaking Valve Packing Technology. In the Compliance Status Reports due under Paragraph 108 of this Consent Decree, Settling Defendants shall: (i) identify each valve which could not comply with the requirement to replace or repack the valve with a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology; (ii) identify the vendors contacted to determine the unavailability of such a Valve or Packing Technology; and (iii) include the written representations or documentation secured from each vendor regarding the unavailability.

b. Ongoing Assessment of Availability. Settling Defendants may use a prior determination of Commercial Unavailability of a valve or valve packing pursuant to this Paragraph and Appendix B for a subsequent Commercial Unavailability claim for the same valve or valve packing (or valve or valve packing in the same or similar service), provided that the previous determination was completed within the preceding twelve (12) month period. After one year, Settling Defendants shall conduct a new assessment of the availability of a valve or valve packing meeting Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology requirements.

101. Records of Certified Low-Leaking Valves and Certified Low-Leaking Valve Packing Technology. Prior to installing any Certified Low-Leaking Valves or Certified Low-Leaking Valve Packing Technology, Settling Defendants shall secure from each manufacturer documentation that demonstrates that the proposed valve or packing technology meets the definition of "Certified Low-Leaking Valve" and/or "Certified Low-Leaking Valve Packing Technology." Settling Defendants shall retain that documentation for the duration of this Consent Decree and make it available upon request.

102. Valve Replacement/Improvement Report. In each Compliance Status Report due under Paragraph 108 of this Consent Decree, Settling Defendants shall include a separate section in the Report that: (i) describes the actions taken to comply with Paragraphs 98-101 above, including identifying each valve that was replaced or upgraded; and (ii) identifies the schedule for any future replacements or upgrades.

Tracking Program or Management of Change

103. For each Management of Change process or analysis or other tracking program, Settling Defendants shall ensure that each piece of Equipment added to any Covered Refinery or removed from any Covered Refinery for any reason is evaluated to determine if it is or was subject to ELDAR Program requirements and that such pieces of Equipment are integrated into or removed from the ELDAR Program.

Quality Assurance ("QA")/Quality Control ("QC")

104. Daily Certification by Monitoring Technicians. Commencing no later than October 1, 2015, on each Day that monitoring occurs, at the end of such monitoring Day to the extent practical, but in no case later than the next Working Day for the monitoring technician, Settling Defendants shall ensure that each monitoring technician certifies that the data collected represents the monitoring performed for that Day by requiring the monitoring technician to sign a form that includes the following certification:

> On [insert date], I reviewed the monitoring data that I collected on [insert date] and to the best of my knowledge and belief, the data accurately represents the monitoring I performed.

In lieu of a form for each technician for each Day of monitoring, a log sheet may be created that includes the certification that the monitoring technicians would date and sign each Day that the technician collects data.

105. Commencing no later than January 1, 2016, during each Calendar Quarter, at unannounced times, an LDAR-trained employee or contractor of a Settling Defendant, who does not serve as an LDAR monitoring technician on a routine basis, shall undertake the following:

a. Process unit walk-throughs as may be necessary to assure that all Covered Process Units are reviewed at least once per year, conduct spot checks of Covered Equipment to verify that the Equipment checked is included in the LDAR database and is properly tagged;

b. Review the LDAR database to:

i. verify that Covered Equipment was monitored at the appropriate frequency;

ii. verify that proper documentation and sign-offs have been recorded for all Equipment placed on the DOR list;

iii. ensure that repairs have been performed within the required timeframe;

iv. review monitoring data and Equipment counts (e.g., number of pieces of Covered Equipment monitored per Day) for feasibility and unusual trends; and

v. verify that proper calibration records and monitoring instrument maintenance information are stored and maintained;

c. Conduct spot checks of LDAR program records to verify that those records are maintained as required in Paragraph 107 below; and

d. Observe each LDAR monitoring technician in the field to ensure monitoring is being conducted as required.

106. Settling Defendants shall correct any deficiencies detected or observed as soon as practicable. Settling Defendants shall maintain a log that: (i) records the date and time that the reviews, verifications, and observations required by Paragraph 105 above were undertaken; and (ii) describes the nature and timing of any corrective actions taken.

Recordkeeping and Reporting

107. Settling Defendants shall keep all records, including copies of all LDAR audits, to document compliance with the requirements of this ELDAR Program in accordance with Section X (Reporting and Recordkeeping) of this Consent Decree. All monitoring data, leak repair data, training records, and audits shall be retained for five (5) years, except for the calibration records (including calibration drift assessments) which shall be retained for one (1) year. Upon request by EPA or an Applicable State Co-Plaintiff, Settling Defendants shall

make all such documents available to EPA and shall provide, in their original electronic format, all LDAR monitoring data generated during the life of this Consent Decree.

108. Compliance Status Reports. On the dates and for the time periods set forth in Paragraph 109 of this Consent Decree, Settling Defendants shall submit a compliance status report regarding compliance with this ELDAR Program. The compliance status report shall include the following information:

a. The number of personnel assigned to LDAR functions at each Covered Refinery and the percentage of time each person dedicated to performing his/her LDAR functions;

b. An identification and description of any non-compliance with the ELDAR Program;

c. An identification of any problems encountered in complying with the requirements of the ELDAR Program;

d. The information required in Paragraph 100 of this Consent Decree;

e. A description of any LDAR training required in accordance with Paragraph 75 of this Consent Decree;

f. Any deviations identified in the QA/QC performed under Paragraphs 104-105 above as well as any corrective actions taken under Paragraph 106 above;

g. A summary of LDAR audit results including specifically identifying all deficiencies; and

h. The status of all actions under any CAP that was submitted pursuant to Paragraph 81 above during the reporting period.

109. Due Dates. The first compliance status report shall be due on September 1, 2016. Until Termination, the Settling Defendants shall submit subsequent compliance status reports on each March 1 and September 1 for the preceding six month period. The initial report shall cover the period between October 1, 2015 and June 30, 2016. Subsequent semi-annual compliance status reports shall cover the time period from January 1 through June 30 of each year (submitted by September 1 of each year) and the period of July 1 through December 31 of each year (submitted by March 1 of each year).

110. Each compliance status report submitted under Paragraph 108 shall be certified as set forth in Paragraph 173 below.

B. Requirements for Control of Flaring Events

Definitions

111. Definitions. The following terms used in this Section VI.B of this Consent Decree shall be defined, solely for the purposes of this Section VI.B of this Consent Decree and the reports and documents submitted pursuant thereto, as follows:

a. "Malfunction" solely for the purposes of this Section VI.B (Requirements for Control of Flaring Events) 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." In any action under Section XV of this Consent Decree (Dispute Resolution) involving this definition, Settling Defendants shall have the burden of proving all of the following factors:

i. The excess emissions were caused by a sudden, unavoidable breakdown of technology, beyond the control of the Settling Defendant;

ii. The excess emissions (a) did not stem from any activity or event that could have been foreseen and avoided, or planned for, and (b) could not have been avoided by better operation and maintenance practices;

iii. To the maximum extent practicable the air pollution control equipment or processes were maintained and operated in a manner consistent with good practice for minimizing emissions;

iv. Repairs were made in an expeditious fashion when the operator knew or should have known that applicable emission limitations were being exceeded. Off-shift labor and overtime must have been utilized, to the extent practicable, to ensure that such repairs were made as expeditiously as practicable;

v. The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

vi. All possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

vii. All emission monitoring systems were kept in operation if at all possible;

viii. The Settling Defendant's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs, or other relevant evidence; and

ix. The Settling Defendant properly and promptly notified the appropriate regulatory authority.

b. "Flaring Process Unit" means the equipment assembled and connected by pipes or ducts to process raw and/or intermediate materials and to manufacture an intended product. A Flaring Process Unit includes any associated storage vessels. For the purpose of this Section VI.B Flaring Process Unit includes, but is not limited to petroleum refining process units as defined by 40 C.F.R. § 63.641.

112. Covered Flares Subject to the Requirements Set Forth in Paragraphs 113 through 153 below. Appendix C -2.1 sets forth which requirements of Paragraphs 113 through 153 below apply to which Covered Flares and the dates by which Settling Defendants shall comply with such requirements.

Interim Measures for Flare Combustion Efficiency and Vent and Waste Gas Minimization at the Covered Flares

113. Interim Combustion Efficiency Measures. Settling Defendants shall implement the following Interim Combustion Efficiency Measures at each Covered Flare as set forth in Appendix C - 2.1 until such Covered Flare complies with the requirements of Paragraph 139.

a. By no later than the applicable date(s) in Appendix C - 2.1, based on the monitoring systems and instrumentation existing at each Covered Flare as of the Date of Entry, Settling Defendants shall complete the installation of a system that depicts, on each Covered Flare's control panel, a visual image of the *S/VG* ratio of each Covered Flare.

b. By no later than the applicable date(s) in Appendix C - 2.1, for all operators and supervisors with responsibility and/or oversight for the operation of each Covered Flare as set forth in Appendix C - 2.1, Settling Defendants shall complete training on steam control for each Covered Flare. Such training shall include describing and identifying the existing monitoring and instrumentation systems, how to manually adjust the Total Steam Mass Flow Rate so as to optimize Combustion Efficiency and minimize oversteaming, and how to target the *S/VG* ratio at the lowest possible value to just avoid Smoke Emissions.

c. By no later than the applicable date(s) in Appendix C - 2.1, based on the visual readout at the control panel for each Covered Flare and other applicable operating information, Settling Defendants shall operate each Covered Flare to minimize the *S/VG* ratio to the extent practical with the existing monitoring and instrumentation systems.

114. Evaluating and Upgrading or Replacing, as Necessary, Meters Measuring Sweep Gas and Purge Gas Volumetric Flow Rates. By no later than the applicable date(s) in Appendix C - 2.1, Settling Defendants shall complete an evaluation of all meters that measure the flow of Sweep Gas and Purge Gas to each Covered Flare and shall upgrade or replace, as necessary, each such meter in order to ensure an acceptable level of control over flow. If the implementation of any such upgrade or replacement takes longer than the applicable date(s) in Appendix C - 2.1, Settling Defendants shall complete the implementation as soon as practicable and shall provide a schedule for such completion in the first semi-annual report under Section X (Reporting and Recordkeeping) of this Consent Decree that is due after the applicable date(s) in Appendix

C - 2.1. Under no circumstances may Settling Defendants implement any such measure later than the date set forth in Appendix C - 2.1 for installing Flare monitoring systems pursuant to Paragraph 117 below for the affected unit that first occurs after the applicable date(s) in Appendix C - 2.1.

115. Minimizing Sweep and Purge Gas Flow Rates Based on Survey Findings. Prior to the applicable date(s) in Appendix C - 2.1, Settling Defendants shall complete a survey of the amount of Sweep Gas and Purge Gas introduced to each Covered Flare. Based on the results of the survey, by no later than the applicable date(s) in Appendix C - 2.1, Settling Defendants shall complete the implementation of all measures necessary to minimize the amount of Sweep Gas and Purge Gas being directed to each Covered Flare. If the implementation of any such measure takes longer than the applicable date(s) in Appendix C - 2.1, Settling Defendants shall complete the implementation as soon as practicable and shall provide a schedule for such completion in the first semi-annual report under Section X (Reporting and Recordkeeping) of this Decree that is due after the applicable date(s) in Appendix C - 2.1. Under no circumstances may Settling Defendants implement any such measure later than the Scheduled Turnaround for the affected unit that first occurs after the applicable date(s) in Appendix C - 2.1.

116. Minimizing Leaking Pressure Relief Valves. By no later than one year after the applicable date(s) in Appendix C - 2.1, Settling Defendants shall conduct and complete a survey ("Initial PRV Leak Survey") of the large, high-pressure hydrocarbon pressure relief valves ("PRVs") that discharge to a Covered Flare; the PRVs are identified in Appendix C - 2.2. The Initial PRV Leak Survey shall include but not be limited to acoustic monitoring. During the first Scheduled Turnaround that occurs after eighteen months following completion of the Initial PRV Leak Survey of any unit that houses any PRV listed in Appendix C - 2.2, Settling Defendants shall repair or replace each leaking PRV in that unit. For all other hydrocarbon PRVs directed to a Covered Flare (that is, all those that are not identified in Appendix C - 2.2) that are tied into Flare headers and subheaders, Settling Defendants shall conduct acoustic monitoring pursuant to a plan and schedule that Settling Defendants shall include in the Initial Flare Management Plan due under Paragraph 127 below.

Instrumentation and Monitoring Systems for Covered Flares

117. Installation and Operation of Flare Monitoring Systems at Each Covered Refinery. By no later than the applicable date for each Covered Flare as set forth in Appendix C - 2.1, Settling Defendants shall have completed the installation and commenced the operation of the instrumentation, controls and monitoring systems set forth in this Paragraph 117. The Settling Defendants shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the Vent Gas Volumetric Flow Rate in each Covered Flare header or headers that feed the Flare as well as any Supplemental Gas used. Different flow monitoring methods may be used to measure different gaseous streams that make up the Vent Gas provided that the flow rates of all gas streams that contribute to the Vent Gas are determined. If Assist Air or Assist Steam is used, the Settling Defendants shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the volumetric flow rate of Assist Air and/or Assist Steam used with each Covered

Flare. If Premix Assist Air and Perimeter Assist Air are both used, Settling Defendants shall install, operate, calibrate, and maintain a monitoring system capable of separately measuring, calculating, and recording the volumetric flow rate of Premix Assist Air and Perimeter Assist Air used with the Flare. Continuously monitoring fan speed or power and using fan curves is an acceptable method for continuously monitoring Assist Air flow rates.

a. Each Covered Flare's flow rate monitoring systems must be able to correct for the temperature and pressure of the system and output parameters in Standard Conditions.

b. Mass flow monitors may be used for determining volumetric flow rate of the Vent Gas provided the molecular weight of the Vent Gas is determined using compositional analysis as specified in Paragraph 118 below so that the mass flow rate can be converted to volumetric flow at Standard Conditions using Equation 6 in Appendix C - 1.2.

c. Mass flow monitors may be used for determining volumetric flow rate of Assist Air or Assist Steam. Use Equation 6 in Appendix C - 1.2 to convert mass flow rates to volumetric flow rates. Use a molecular weight of 18 pounds per pound-mole for Assist Steam and use a molecular weight of 29 pounds per pound-mole for Assist Air.

d. Continuous pressure/temperature monitoring system(s) and appropriate engineering calculations may be used in lieu of a continuous volumetric flow monitoring system provided the molecular weight of the gas is known. For Assist Steam, use a molecular weight of 18 pounds per pound-mole. For Assist Air, use a molecular weight of 29 pounds per pound-mole. For Vent Gas, molecular weight must be determined using compositional analysis as specified in Paragraph 118 below.

118. Vent Gas Composition Monitoring. Settling Defendants shall determine the concentration of individual components in the Vent Gas using either the methods provided in Paragraphs 118.a or b below, to assess compliance with the operating limits in Paragraph 139 below and, if applicable, Paragraphs 135.d and 145 below. Alternatively, Settling Defendants may elect to directly monitor the Net Heating Value of the Vent Gas following the methods provided in Paragraph 118.c below, and, if desired, may directly measure the hydrogen concentration in the Vent Gas following the methods provided in Paragraph 118.d below. Settling Defendants may elect to use different monitoring methods for different gaseous streams that make up the Vent Gas provided the composition or Net Heating Value of all gas streams that contribute to the Vent Gas are determined.

a. Net Heating Value by Gas Chromatograph. Except as provided in Paragraphs 118.e and f below, Settling Defendants shall install, operate, calibrate, and maintain a monitoring system capable of continuously measuring (i.e., at least once every 15-minutes), calculating, and recording the individual component concentrations present in the Vent Gas.

b. Grab Sampling System. Except as provided in Paragraphs 118.e and f below, Settling Defendants shall install, operate, and maintain a grab sampling system capable of collecting an evacuated canister sample for subsequent compositional analysis at least once every eight hours. Subsequent compositional analysis of the samples must be performed according to

Method 18 of 40 C.F.R. Part 60, Appendix A-6, ASTM D6420-99 (Reapproved 2010), ASTM D1945-03 (Reapproved 2010), ASTM D1945-14 or ASTM UOP539-12 .

c. Net Heating Value By Calorimeter. Except as provided in Paragraphs 118.e and f below, Settling Defendants shall install, operate, calibrate, and maintain a calorimeter capable of continuously measuring, calculating, and recording NHV_{vg} at Standard Conditions. When installed, the Net Heating Value calorimeter shall meet or exceed the applicable specifications and Calibration Standards and Quality Assurance requirements set forth in Appendix C - 1.10.

d. Hydrogen Concentration Monitoring. If a Settling Defendant uses a continuous Net Heating Value calorimeter according to Paragraph 118.c above, that Settling Defendant may, at its discretion, install, operate, calibrate, and maintain a monitoring system capable of continuously measuring, calculating, and recording the hydrogen concentration in the Vent Gas.

e. Monitoring Not Required for Pipeline Quality Natural Gas. Direct compositional monitoring or Vent Gas Net Heating Value calorimeter is not required for purchased ("pipeline quality") natural gas streams. The Net Heating Value of purchased natural gas streams may be determined using annual or more frequent grab sampling at any one representative location. Alternatively, the Net Heating Value of any purchased natural gas stream can be assumed to be 920 BTU/scf.

f. For purposes of this Consent Decree only, Settling Defendants may also assume a constant molecular weight and composition that have been demonstrated for the Sweep Gas, Purge Gas, or Supplemental Gas that is representative of the molecular weight and composition of natural gas, Fuel Gas or other appropriate gas supplied at each Covered Flare.

119. Video Camera. This instrument shall record, in digital format, whether a flame or Smoke Emissions are present at each Covered Flare as set forth in Appendix C - 2.1. It is not a violation of this Consent Decree, however, if Flare video equipment cannot discern the Flare Combustion Zone and/or any Smoke Emissions at a Covered Flare subject to these provisions due to weather conditions such as fog or snow, provided that recordings are created and retained in accordance with this Consent Decree.

120. Instrumentation and Monitoring Systems: Optional Equipment for any Covered Flare. At their option, Settling Defendants may elect to install (if not already installed) and continuously measure the flow, in scfm or pounds per hour (if the instrument automatically converts flow from scfm to lb/hr), of all Pilot Gas to a Covered Flare. Settling Defendants may utilize the data generated by this system as part of the calculation of the Net Heating Value of the Combustion Zone Gas.

121. Instrumentation and Monitoring Systems: Specifications. For the Covered Flares set forth in Appendix C - 2.1, the applicable instrumentation and monitoring systems identified in Paragraphs 114, 117-119, and 122, and 144 of this Consent Decree shall meet or exceed the equipment and instrumentation technical specifications and quality assurance/quality control requirements set forth in Appendix C - 1.10.

122. The instrumentation and monitoring systems identified in Paragraphs 114, 117-119 and 144 of this Consent Decree shall be able to produce and record data measurements and calculations for each parameter at the following time intervals as applicable to the equipment installed:

Instrumentation and Monitoring System	**Recording and Averaging Times**
Vent Gas Flow; Vent Gas Average Molecular Weight; Total Steam Flow; Pilot Gas Flow (if installed)	Measure continuously and record 15-minute Block Averages.
Video Camera	Record at a rate of no less than 4 frames per minute.
Net Heating Value by Gas Chromatograph	Complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute Block Average Period.
Net Heating Value by Calorimeter	Measure continuously and record 15- minute Block Averages.

Nothing in this Paragraph shall prohibit Settling Defendants from setting up process control logic that uses different averaging times from those in this table provided that the recording and averaging times in this table are available and used for determining compliance with this Consent Decree.

123. Instrumentation and Monitoring Systems: Operation and Maintenance. Settling Defendants shall operate each of the instruments and monitoring systems required in Paragraphs Paragraphs 114, 117-119, and 122, and 144 of this Consent Decree on a continuous basis when the associated Covered Flare is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas, except for the following periods:

a. Malfunction of a monitoring system, for a monitoring system needed to meet the requirement(s);

b. Repairs associated with monitoring system malfunctions, for a monitoring system needed to meet the requirement(s);

c. Required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments).

d. Quality Assurance/Quality Control Activities.

Provided however, that in no event shall the excepted activities in Paragraphs 123.a-123.c above for any instrument exceed 5% of the time that the Covered Flare is In Operation and Capable of

Receiving Sweep, Supplemental, and/or Waste Gas in any six month period. The calculation of instrument downtime shall be made in accordance with 40 C.F.R. § 60.13(h)(2) and Paragraph VIII of Appendix C - 1.10. If the excepted activities in Paragraphs 123.a-123.c above exceed 5% of the time that the Covered Flare is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas in any six month period, EPA and/or the Applicable State Co-Plaintiff shall be entitled to seek stipulated penalties under Paragraph 188 of Section XII (Stipulated Penalties) and Settling Defendants shall be entitled to assert that the period of instrumentation and monitoring system downtime was justified under the circumstances. Nothing in this Paragraph is intended to prevent Settling Defendants from claiming a *force majeure* defense to any period of instrumentation and/or monitoring system downtime. Nothing in this Paragraph supersedes or replaces the monitoring requirements, including operation, maintenance, and quality assurance/quality control requirements, of 40 C.F.R. Part 60, Subpart Ja. All such requirements shall apply in accordance with the terms set forth in 40 C.F.R. Part 60, Subpart Ja.

Determining Whether a Covered Flare that has a Liquid Seal is Not Receiving Potentially Recoverable Gas

124. For a Covered Flare at which all of the following conditions are met, then the Covered Flare is not receiving Potentially Recoverable Gas flow:

a. For the liquid seal drum associated with the respective Covered Flare, the pressure difference between the inlet pressure and the outlet pressure is less than the liquid seal pressure as set by the static head of liquid between the opening of the dip tube in the drum and the level-setting weir in the drum; and

b. For the liquid seal drum associated with the respective Covered Flare, the liquid level in the drum is at the level of the weir.

125. As an alternative to Paragraph 124 for a Covered Flare which does not have a weir, the Covered Flare is not considered to be receiving a Potentially Recoverable Gas flow if the Vent Gas flow meter indicates a flow rate of less than 0.2 feet/second based on a 15-minute Block Average.

126. Until June 30, 2017, the spent air vent from the Tesoro Mandan Refinery's Merox Unit regenerator vessel shall not be considered Potentially Recoverable Gas. This gas stream shall be directed away from being combusted in a Flare and sent to a different location (e.g. heater or boiler) by June 30, 2017; provided however, that the Mandan Refinery can send the gas stream from the spent air vent from the Merox Unit to the Flare Gas Recovery System bypass after June 30, 2017, when the relevant heater or boiler is not operating (e.g., Fuel Gas valves to the heater or boiler close on a fuel-gas trip).

Vent and Waste Gas Minimization for Covered Flares

127. Initial Flare Management Plan ("Initial FMP"). By no later than the applicable date in Appendix C - 2.1 for Covered Flares subject to this requirement as set forth in Appendix C - 2.1, Settling Defendants shall submit to EPA and the Applicable State Co-Plaintiff an Initial Flare Management Plan for each Covered Refinery which incorporates its Covered Flares that discusses and evaluates flaring prevention measures ("Prevention Measures"), as required in Paragraph 127(j) below, both Refinery-wide and on a Flare-specific basis. The Initial FMP shall include but not be limited to:

a. A listing of all refinery Flaring Process Units, ancillary equipment, and Fuel Gas Systems connected to the Flare for each Covered Flare.

b. An assessment of whether discharges to Covered Flares from these Flaring Process Units, ancillary equipment and Fuel Gas Systems can be minimized or prevented during periods of Startup, Shutdown, or emergency releases. The Flare minimization assessment must (at a minimum) consider the items in Paragraphs 127.b.i-iii below. The assessment must provide clear rationale in terms of costs (capital and annual operating), natural gas offset credits (if applicable), technical feasibility, secondary environmental impacts and safety considerations for the selected minimization alternative(s) or a statement, with justifications, that flow reduction could not be achieved. Based upon the assessment, Settling Defendants shall identify the minimization alternatives that they have implemented by the due date of the Flare Management Plan and shall include a schedule for the prompt implementation of any selected measures that cannot reasonably be completed as of that date.

i. Modification in Startup and Shutdown procedures to reduce the quantity of process gas discharge to the Flare.

ii. Plan and schedule for conducting acoustic monitoring on all hydrocarbon PRVs directed to a Covered Flare that are not identified in Appendix C - 2.2, as required by Paragraph 116 above.

iii. Installation of a FGRS, or, for facilities that are Fuel Gas rich, a FGRS and a co-generation unit or combined heat and power unit.

c. A description of each Covered Flare containing the following information:

i. A general description of the Covered Flare, including whether it is a ground Flare or elevated (including height), the type of assist system (*e.g.*, air, steam, pressure, non-assisted), whether the Flare is used on a routine basis or if it is only used during periods of Startup, Shutdown or emergency release, and whether the Flare is equipped with a FGRS.

ii. The smokeless capacity of the Covered Flare based on design conditions. Note: a single value must be provided for the smokeless capacity of the Flare.

iii. The maximum Vent Gas flow rate (hydraulic load capacity).

iv. The maximum Supplemental Gas flow rate.

v. For Covered Flares that receive Assist Steam, the Minimum Total Steam Rate and the maximum Total Steam rate.

vi. For Covered Flares that receive Assist Air, an indication of whether the fan/blower is single speed, multi-fixed speed (e.g., high, medium, and low speeds), or variable speeds. For fans/blowers with fixed speeds, provide the estimated Assist Air flow rate at each fixed speed. For variable speeds, provide the design fan curve (e.g., air flow rate as a function of power input).

vii. Simple process flow diagram showing the locations of the Covered Flare following components of the Flare: Flare tip (date installed, manufacturer, nominal and effective tip diameter, tip drawing); knockout or surge drum(s) or pot(s) (including dimensions and design capacities); Flare header(s) and subheader(s); assist system; and ignition system.

d. Description and simple process flow diagram showing all gas lines (including Waste Gas, Purge Gas or Sweep Gas (as applicable), Supplemental Gas) that are associated with the Covered Flare. For Purge, Sweep, and Supplemental Gas, identify the type of gas used. Designate which lines are exempt from composition or Net Heating Value monitoring and why (*e.g.*, natural gas, gas streams that have been demonstrated to have consistent composition, Pilot Gas). Designate which lines are monitored and identify on the process flow diagram the location and type of each monitor. Designate the pressure relief devices that are vented to the Flare.

e. For each flow rate, gas composition, Net Heating Value calorimeter or hydrogen concentration monitor identified in Paragraph 127.d above, provide a detailed description of the manufacturer's specifications, including, but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance and quality assurance procedures.

f. For each pressure relief valve vented to the Covered Flare identified in Paragraphs 127.d above, provide a detailed description of each pressure release valve, including type of relief device (rupture disc, valve type) diameter of the relief valve, set pressure of the relief valve and listing of the Prevention Measures implemented. This information may be maintained in an electronic database on-site and does not need to be submitted as part of the Flare Management Plan unless requested to do so by EPA and the Applicable State Co-Plaintiff.

g. Procedures to minimize or eliminate discharges to the Flare during the planned Startup and Shutdown of the refinery Flaring Process Units and ancillary equipment that are connected to the Covered Flare, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the submission of the Flare Management Plan.

h. Waste Gas Characterization and Mapping. Settling Defendants shall assess the Waste Gas being disposed of at each Covered Flare subject to this requirement as set forth in Appendix C - 2.1 and determine its characteristics as follows:

i. Volumetric (in scfd) Flow Rate. Settling Defendants shall identify the volumetric flow of Waste Gas, in scfm on a 30-day Rolling Average vented to each Covered Flare subject to this requirement as set forth in Appendix C - 2.1 between December 1, 2015, and November 30, 2016. To the extent that, for any particular Covered Flare, Settling Defendants have instrumentation capable of measuring the volumetric flow rate of hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or steam in the Waste Gas, Settling Defendants may break down the volumetric flow as between: (i) all Waste Gas flows excluding hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam); and (ii) hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam) flows in the Waste Gas. Settling Defendants may use either an engineering evaluation or measurements from monitoring or a combination to determine flow rate. In determining flow rate, flows during all periods (including but not limited to normal operations and periods of Startup, Shutdown, Malfunction, process upsets, relief valve leakages, power losses due to an interruptible power service agreement, and emergencies arising from events within the boundaries of each of the Covered Refineries), except those described in the next sentence, shall be included. Flows that could not be prevented through reasonable planning and are caused by a natural disaster, act of war or terrorism, or External Power Loss are the only flows that shall be excluded from the calculation of flow rate. Settling Defendants shall specifically describe the date, time, and nature of the event that results in the exclusion of any flows from the calculation.

ii. Baseload Waste Gas Flow Rates. Settling Defendants shall utilize flow rate data to determine the Baseload Waste Gas Flow Rate, in scfd, to each Covered Flare subject to this requirement as set forth in Appendix C - 2.1. The Baseload Waste Gas Flow Rate shall not include flows during periods of Startup, Shutdown, and Malfunction. The Baseload Waste Gas Flow Rate shall be based on the period between December 1, 2015, and November 30, 2016.

iii. Identification of Constituent Gases. For each Covered Flare subject to this requirement as set forth in Appendix C - 2.1, Settling Defendants shall use best efforts to identify the constituent gases within the Waste Gas and the typical range of constituent concentrations during baseload conditions. Settling Defendants may use either an engineering evaluation or measurements from monitoring or a combination to determine Waste Gas constituents.

iv. Waste Gas Mapping. Using instrumentation, isotopic tracing, and/or engineering calculations, Settling Defendants shall identify and estimate the flow from each Flaring Process Unit Flare header to the main Flare header(s) for each Covered Flare subject to this requirement as set forth in Appendix C - 2.1. Using that information and all other available information, Settling Defendants shall complete an identification of each Waste Gas tie-in to the main Flare header(s) and Flaring Process Unit Flare header(s), as applicable, consistent with Appendix C - 1.11. Temporary connections to a Flare's header(s) and/or subheader(s) are not required to be included in the mapping.

i. Taking a Covered Flare out of Service. Settling Defendants shall identify any Covered Flare that it intends to take out of service, including the date for completion of the decommissioning. Taking a Covered Flare "out of service" means physically removing piping in

the Flare header or physically isolating the piping with a welded blind so as to eliminate direct piping to the Covered Flare.

j. Prevention Measures. Settling Defendants shall describe and evaluate all Prevention Measures, including a schedule for the expeditious implementation and commencement of operation of all Prevention Measures, to address the following:

i. Flaring that has occurred or may reasonably be expected to occur during planned maintenance activities, including Startup and Shutdown. The evaluation shall include a review of flaring that has occurred during these activities in the past three years and shall consider the feasibility of performing these activities without flaring.

ii. Flaring that may reasonably be expected to occur due to issues of gas quantity and quality. The evaluation shall include an audit of the flare gas recovery capacity of each Covered Flare subject to this requirement as set forth in Appendix C - 2.1, the capacity including internal piping systems and the amine treating capacity available for Waste Gases including any limitations associated with the amine treating of Waste Gases for use as fuel. The evaluation shall consider the feasibility of reducing flaring through the recovery, treatment, and use of the Waste Gas.

iii. Flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. The evaluation shall consider the adequacy of existing maintenance schedules and protocols for such equipment. A failure is "recurrent" if it occurs more than twice during any five year period as a result of the same root cause.

128. Updated Flare Management Plans. On the date specified in Appendix C - 2.1 and annually thereafter, Settling Defendants shall submit to EPA and the Applicable State Co-Plaintiff an Updated FMP, which shall update for the preceding calendar year, if and as necessary, the information required in Paragraphs 127.a-127.j and shall also include the following:

a. Reductions Based on Root Cause Analysis. Settling Defendants shall review all of the Root Cause Analysis reports prepared pursuant to 40 C.F.R. Part 60, Subpart Ja or this Consent Decree to determine if reductions in addition to the reductions achieved through any corrective action can be realized; and

b. Revised Schedule. To the extent that Settling Defendants propose to extend any schedule set forth in the Initial FMP, Settling Defendants shall do so only with good cause.

129. Implementation and Enforceability of Flare Management Plans.

a. Implementation. By no later than the dates specified in a FMP, Settling Defendants shall implement the actions described therein. If (i) no implementation date and/or (ii) no completion date for actions that do not require ongoing implementation (such as the

installation of a piece of an equipment) is (are) set forth in the FMP, the implementation and/or completion date shall be deemed the date of the submission of the FMP.

b. Enforceability. The terms of each FMP (including Initial, First Updated, and Subsequent Updated FMPs) submitted under this Section are specifically enforceable.

Flare Gas Recovery Systems for Covered Flares Limitations on Flaring

130. Flare Gas Recovery Systems: Capacity and Start-Up Dates. By no later than the applicable dates in Appendix C - 2.1 for each Covered Refinery, Settling Defendants shall complete installation and commence operation of the following Flare Gas Recovery Systems at each Covered Refinery:

Covered Refinery	**Minimum No. of Compressors**	**Minimum Capacity of each Compressor (kscfh)**	**Minimum FGRS Operating Design Capacity (kscfh)**
Anacortes	2 (both new)	60	120
Kapolei	2 (one existing, one new)	30 and 40	70
Kenai	2 (both new)	40	80
Mandan	2 (both new)	30	60
Martinez Unit 19/ DCU	2 (both existing)	166.7	333.4
Martinez 50U	2 (both existing)	3 and 132.5	135.5
Salt Lake City	2 (both new)	30	60

131. Flare Gas Recovery Systems: Operation.

a. General. Settling Defendants shall operate each FGRS in a manner to minimize Waste Gas to the respective Covered Flares subject to this requirement as set forth in Appendix C - 2.1 while ensuring safe refinery operations. Settling Defendants also shall operate each FGRS consistent with good engineering and maintenance practices and in accordance with its design and the manufacturer's specifications.

b. Requirements Related to Compressors Being Available for Operation and/or In Operation. By no later than the applicable dates listed in Appendix C - 2.1, Settling Defendants shall comply with the following requirements when Potentially Recoverable Gas is being generated:

i. FGRS at the Anacortes Refinery, Martinez Refinery Unit 19/DCU, Martinez Refinery 50U, Mandan Refinery, Kenai Refinery, and Salt Lake City Refinery. For each FGRS at the Anacortes Refinery, Martinez Refinery Unit 19/DCU, Martinez Refinery 50U, Mandan Refinery, Kenai Refinery, and Salt Lake City Refinery, Tesoro shall have one

Compressor Available for Operation and/or In Operation 98% of the time and two Compressors Available for Operation and/or In Operation 95% of the time.

ii. FGRS at the Kapolei Refinery. For the Kapolei Refinery FGRS, Par shall have one Compressor Available for Operation and/or In Operation 98% of the time and two Compressors Available for Operation and/or In Operation 95% of the time.

iii. Period to Be Used for Computing Percentage of Time. For purposes of calculating compliance with the 95% and the 98% of time that a Compressor or group of Compressors shall be Available for Operation and/or In Operation, as required by this Paragraph, the period to be used shall be an 8760-hour Rolling Sum, rolled hourly, using only hours when Potentially Recoverable Gas was generated during all or part of the hour but excluding hours for flows that could not have been prevented through reasonable planning and were in anticipation of or caused by a natural disaster, act of war or terrorism, or External Power Loss. When no Potentially Recoverable Gas was generated during an entire hour, then that hour shall not be used in computing the 8760-hour Rolling Sum.

iv. Periods of maintenance on and subsequent restart of the equipment within the FGRS that is shared by all Compressors (for example, the liquid seal, the knock-out drum, valves), such that the entire FGRS shall be shut down in order to undertake the maintenance may be included in the amount of time that a Compressor is Available for Operation; provided however, that these periods shall not exceed 1,344 hours in a five-year Rolling Sum Period, rolled daily. Settling Defendants shall use best efforts to schedule these maintenance activities during a Scheduled Turnaround of the Flaring Process Units venting to the Covered Flare. To the extent it is not practicable to undertake these maintenance activities during a Scheduled Turnaround, Settling Defendants shall use best efforts to minimize the generation of Waste Gas during such periods.

Limitations on Flaring

132. Limitations on Flaring: Initial Limit.

a. Settling Defendants shall comply with the following limitations on flaring of Waste Gas at all of the Covered Flares subject to this requirement as set forth in Appendix C - 2.1 at each Covered Refinery by the applicable dates in Appendix C - 2.1.

Covered Refinery	**30-day rolling avg., rolled daily (scfd)**	**365-day rolling avg., rolled daily (scfd)**
Anacortes	662,670	441,780
Kapolei	293,861	195,787
Kenai	231,354	154,236
Mandan	313,139	208,759
Martinez	1,516,353	1,010,902
Salt Lake City	271,505	181,003

The Rolling Average Period shall include only the prior 30 Days or 365 Days, as applicable, when any Covered Flare was In Operation. Each exceedance of the 30-day Rolling Average limit or each exceedance of the 365-day Rolling Average limit shall constitute one Day of violation. An exceedance of either or both of the limits shall not prohibit ongoing refinery operations.

b. The limitations set forth in Paragraph 132.a above were calculated using the equations set forth in Paragraphs 133.a.i and 133.a.ii below. Appendix C - 2.4 sets forth the actual calculation. Each Covered Refinery's crude capacity used in the calculation was taken from the "Total Operable" atmospheric crude oil distillation capacity, in barrels per Calendar Day, found in Part 5, Code 401, of the Form EIA-820 that Settling Defendants submitted to the U.S. Energy Information Administration ("EIA") for EIA's report dated June 25, 2014. A copy of that Form is included in Appendix C - 2.4. The "*Refinery Complexity*" and "*Industry Avg Complexity*" were calculated pursuant to the methodology set forth in Appendix C - 1.14.

133. Limitations on Flaring: Requesting an Increase in the Limit.

a. Once per calendar year, Settling Defendant(s) may submit a request to EPA to increase the limitations on flaring set forth in Paragraph 132.a above. Settling Defendant(s) may request an increase in the limit(s) and EPA will approve such an increase, only if: (i) the request is based on changes in crude capacity and/or complexity that were not reflected in the EIA reports as of the Date of Lodging; (ii) the changes are or will be permitted by the Applicable Permitting Authority; and (iii) the changes in crude capacity and/or complexity result in new limit(s) that are at least 20% higher than the limits set forth in Paragraph 132.a above. In any such request, Settling Defendant(s) shall propose (a) new limit(s) (hereafter referred to as "New Limit(s) Based on Projections") based upon the following equations:

i. For each Covered Refinery, the Refinery-wide, 30-day Rolling Average limit:

$$\text{Refinery Flaring} \leq 750{,}000 \text{ scfd} \times \frac{\textit{Refinery Crude Cap.}}{100{,}000 \text{ bpd}} \times \frac{\textit{Refinery Complexity}}{\textit{Industry Avg Complexity}}$$

ii. For each Covered Refinery, the Refinery-wide, 365-day Rolling Average limit:

$$\text{Refinery Flaring} \leq 500{,}000 \text{ scfd} \times \frac{\textit{Refinery Crude Cap.}}{100{,}000 \text{ bpd}} \times \frac{\textit{Refinery Complexity}}{\textit{Industry Avg Complexity}}$$

Nothing in this Paragraph or Consent Decree shall be construed to relieve Settling Defendants of an obligation to evaluate, under applicable PSD and NNSR requirements, an increase in a Refinery-Wide limit on flaring.

b. For purposes of Paragraphs 133.a.i and 133.a.ii above, the following shall apply:

i. The items in italics are variables that will change over time.

ii. Each Refinery Crude Capacity shall be determined as follows:

(a) If the modification does not affect the crude capacity, the Atmospheric Crude Oil Distillation Capacity, in barrels per Day, that the Covered Refinery reported under "Total Operable" capacity on Part 5, Code 401, of the Applicable Form EIA-820; the definition of "Applicable Form EIA-820" is defined in the "Definitions" section of Appendix C - 1.14 and included as Attachment 2 to Appendix C - 1.14; to the extent that the "Parts" or "Codes" on form EIA-820 change 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 its report dated June 25, 2014 (see Attachment 2 to Appendix C - 2.4) will be used; or

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

iii. Each Covered Refinery's Complexity shall be calculated in accordance with Equation 1 of Appendix C - 1.14. Settling Defendants shall certify the accuracy of the projected crude capacity and/or Flaring Process Unit capacities used to support the calculations.

iv. The Industry Average Complexity shall be calculated in accordance with Equation 2 of Appendix C - 1.14.

c. EPA Response to Request. EPA shall evaluate any request under Paragraph 133.a on the basis of consistency with Paragraphs 133.a and 133.b above.

d. The New Limit(s) Based on Projections shall take effect, if ever, beginning on the later of the date that EPA approves the request or a dispute is resolved in Settling Defendant(s) favor or the date(s) specified in the modification permit(s).

e. In the event that Settling Defendant(s) amend, modify or withdraw the air permit application(s) that is/are the basis for the New Limit(s) Based on Projections requested pursuant to Paragraph 133.a in a manner that affects the limit(s) calculation(s), Settling Defendant(s) shall, within fifteen (15) Days of amending, modifying, or withdrawing its air permit application(s), revise or withdraw its request under Paragraph 133.a above.

f. Consequences of a Mistake in Projected Capacities.

i. By no later than ninety (90) Days after the Startup of the permitted modifications, Settling Defendants shall determine whether the projected "Refinery Crude Capacity" or the projected capacities for new or modified units that Settling Defendants relied upon pursuant to Paragraphs 133.b.ii and/or 133.b.iii above, respectively, were or are different from the actual capacities that Settling Defendants have reported or will report to the EIA or the

Oil & Gas Journal after the Startup of the permitted modification. If there are differences, Settling Defendant(s) shall re-calculate the flaring limitation(s) using the actual capacities that Settling Defendant(s) have reported or will report to the EIA or the Oil & Gas Journal (hereafter referred to as "New Limit(s) Based on Actuals").

ii. If the New Limit(s) Based on Actuals that Settling Defendant(s) calculate under Paragraph 133.f.i above is/are greater than the New Limit(s) Based on Projections that Settling Defendants calculated under Paragraph 133.a above, then no further action shall be required. If Settling Defendant(s) elect to take no action, then the New Limits(s) Based on Projections shall remain in effect. Settling Defendant(s), however, may elect to submit for EPA approval, a revised, recalculated New Limit(s) Based on Actuals to EPA. After submission to EPA, Settling Defendant(s) shall secure EPA's approval of the New Limit(s) Based on Actuals before they become effective.

iii. If the New Limit(s) Based on Actuals that Settling Defendant(s) calculate under Paragraph 133.f.i above is/are less than the New Limit(s) Based on Projections that Settling Defendants calculated under Paragraph 133.a above, then by no later than ninety (90) Days after the Startup of the permitted modifications, Settling Defendant(s) shall: (i) commence complying with the New Limit(s) Based on Actuals; and (ii) submit the revised, recalculated New Limit(s) Based on Actuals to EPA. After submission to EPA, Settling Defendant(s) shall consult with EPA about the New Limit(s) Based on Actuals.

iv. Stipulated Penalties. If Paragraph 133.f.iii above applies, then by no later than ninety (90) Days after the Startup of the permitted modifications, the New Limit(s) Based on Actuals identified in the submission to EPA under Paragraph 133.f.iii.(ii) above shall apply and form the basis for determining compliance for purposes of the stipulated penalty provisions of Paragraph 188.c of Section XII (Stipulated Penalties). If EPA disapproves the New Limit(s) Based on Actuals, the New Limit(s) Based on Actuals shall continue to apply for purposes of stipulated penalties until such time as other limitation(s) either is/are agreed upon between EPA and Settling Defendant(s) or a dispute is resolved that sets forth revised limitation(s).

134. Meaning and Calculation of "Waste Gas" Flow for Purposes of the Limitation on Flaring. For purposes of the meaning and calculation of "Waste Gas" flow in the limitations on flaring in Paragraphs 132 and 133 above and any revised limitations on flaring developed pursuant to Paragraph 133 above, the following shall apply:

a. To the extent that Settling Defendants have instrumentation capable of measuring the volumetric flow rate of hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam) in the Waste Gas, the contribution of all measured flows of any of these elements/compounds may be excluded from the Waste Gas flow rate calculation.

b. Waste Gas flows during all periods (including but not limited to normal operations and periods of Startup, Shutdown, Malfunction, process upsets, relief valve leakages, power losses due to an interruptible power service agreement, and emergencies arising from events within the boundaries of the Covered Refinery) shall be included. Waste Gas flows that

could not be prevented through reasonable planning and are caused by a natural disaster, act of war or terrorism, or External Power Loss may be excluded from the calculation of flow rate.

Except for hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam) contributions to the flow rate that are excluded by virtue of instrumentation measuring these flows, Settling Defendants shall submit a description in the semi-annual report to EPA pursuant to Section X (Reporting and Recordkeeping) that specifically identifies the event that resulted in the exclusion. Settling Defendants shall describe the following: the date(s) and duration(s) of the flows caused by the event; the estimated VOC and SO_2 emissions during the event; whether flows from the event are anticipated to persist after the notice, and if so, for how long; and the measures taken or to be taken to prevent or minimize the flows, including, for future anticipated flow, the schedule by which those measures will be implemented.

Flare Combustion Efficiency Requirements for Covered Flares

135. Emission Standards and Work Practices Applicable to Each Covered Flare. By no later than the applicable dates in Appendix C - 2.1, Settling Defendants shall comply with the following combustion efficiency requirements at each Covered Flare subject to this requirement as set forth in Appendix C - 2.1:

a. Operation During Waste Gas Venting. Settling Defendants shall operate each Covered Flare subject to this requirement as set forth in Appendix C - 2.1 at all times when Waste Gas may be vented to it.

b. No Visible Emissions.

i. Settling Defendant shall specify the smokeless design capacity of each Covered Flare and operate with no Visible Emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours, when the Vent Gas flow rate is less than the smokeless design capacity of the Flare. Settling Defendants shall monitor for Visible Emissions from the Flare as specified in Paragraph 135.b.ii below.

ii. Settling Defendants shall monitor Visible Emissions when the Flare is In Operation. An initial Visible Emissions demonstration must be conducted using an observation period of 2 hours using Method 22 at 40 C.F.R. Part 60, Appendix A-7. Subsequent Visible Emissions observations must be conducted using either the methods in Paragraph 135.b.ii(a) below, alternatively, the methods in Paragraph 135.b.ii(b) below. Settling Defendants must record and report any instances where Visible Emissions are observed for more than 5 minutes during any 2 consecutive hours, including the date and time of the 2 hour period and an estimate of the cumulative number of minutes in the 2 hour period for which emissions were visible.

(a) At least once per Day, Settling Defendants shall conduct Visible Emissions observations using an observation period of 5 minutes using Method 22 at 40 C.F.R. Part 60, Appendix A-7. If at any time a Settling Defendant sees Visible Emissions, even if the minimum required daily Visible Emissions monitoring has already been performed, the Settling Defendant shall immediately begin an observation period of 5 minutes using Method 22 at

40 C.F.R. Part 60, Appendix A-7. If Visible Emissions are observed for more than one continuous minute during any 5-minute observation period, the observation period using Method 22 at 40 C.F.R. Part 60, Appendix A-7 must be extended to 2 hours or until 5-minutes of no Visible Emissions are observed.

(b) Use a video surveillance camera to continuously record (at least one frame every 15 seconds with time and date stamps) images of the Flare flame and a reasonable distance above the Flare flame at an angle suitable for Visual Emissions observations. Settling Defendants must provide real-time video surveillance camera output to the control room or other continuously manned location where the camera images may be viewed at any time.

c. Flame Presence.

i. Pilot Flame Presence. Settling Defendants shall operate each Covered Flare with a pilot flame present when the Flare is In Operation. Each 15-minute block during which there is at least one minute where no pilot flame is present when Vent Gas is routed to the Flare is a deviation of the standard. Deviations in different 15-minute blocks from the same event are considered separate deviations. Settling Defendants shall monitor for the presence of a pilot flame as specified in Paragraph 135.c.ii below.

ii. Pilot Flame Monitoring. Settling Defendants shall continuously monitor the presence of the pilot flame(s) using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot flame(s) is present.

d. Flare Tip Velocity.

i. For each Covered Flare, Settling Defendants shall comply with either Paragraph 135.d.i.(a) or 135.d.i.(b) below, provided the appropriate monitoring systems are in place, whenever the Vent Gas flow rate is less than the smokeless design capacity of the Flare.

(a) Except as provided in Paragraph 135.d.i.(b) below, the actual Flare Tip Velocity (V_{tip}) must be less than 60 feet per second. Settling Defendants shall monitor V_{tip} using the procedures specified in Paragraph 135.d.ii below.

(b) V_{tip} must be less than 400 feet per second and also less than the maximum allowed Flare Tip Velocity (V_{max}) as calculated according to Equation 5 in Appendix C - 1.2. Settling Defendants shall monitor V_{tip} using the procedures specified in Paragraphs 135.d.ii below and monitor gas composition and determine NHV_{vg} using the procedures specified in Paragraph 118 above and Equation 1 and 2 in Appendix C - 1.3.

ii. Calculation Methods for Cumulative Flow Rates and Determining Compliance with V_{tip} Operating Limits. Settling Defendants shall determine V_{tip} on a 15-minute Block Average basis according to the following requirements:

(a) Settling Defendants shall use design and engineering principles and the guidance in Appendix C - 1.6 to determine the Unobstructed Cross Sectional Area of the

Flare Tip. The Unobstructed Cross Sectional Area of the Flare Tip is the total tip area that Vent Gas can pass through. This area does not include any stability tabs, stability rings, and Upper Steam or air tubes because Vent Gas does not exit through them.

(b) Settling Defendants shall determine the cumulative volumetric flow of Vent Gas for each 15-minute Block Average Period using the data from the continuous flow monitoring system required in Paragraph 117 according to the following requirements as applicable.

(1) Use set 15-minute time periods starting at 12 midnight to 12:15 a.m., 12:15 a.m. to 12:30 a.m. and so on concluding at 11:45 p.m. to midnight when calculating 15-minute Block Average flow volumes.

(2) If continuous pressure/temperature monitoring system(s) and engineering calculations are used as allowed under Paragraph 117.d above, the Settling Defendants shall, at a minimum, determine the 15-minute Block Average temperature and pressure from the monitoring system and use those values to perform the engineering calculations to determine the cumulative flow over the 15-minute Block Average Period. Alternatively, the Settling Defendants may divide the 15-minute Block Average Period into equal duration subperiods (e.g., three 5-minute periods) and determine the average temperature and pressure for each subperiod, perform engineering calculations to determine the flow for each subperiod, then add the volumetric flows for the subperiods to determine the cumulative volumetric flow of Vent Gas for the 15-minute Block Average Period.

(c) The 15-minute Block Average V_{tip} shall be calculated using Equation 7 in Appendix C - 1.2.

(d) If Settling Defendants choose to comply with Paragraph 135.d.ii.(b) above, Settling Defendants shall also determine the NHVvg using Equations 1 and 2 in Appendix C - 1.3 and calculate V_{max} using Equation 5 in Appendix C - 1.2 in order to compare V_{tip} to V_{max} on a 15-minute Block Average basis.

e. Monitoring According to Applicable Provisions. Settling Defendants shall comply with all applicable Subparts of 40 C.F.R. Parts 60, 61, or 63, that state how a particular Covered Flare shall be monitored.

f. Good Air Pollution Control Practices. At all times, including during periods of Startup, Shutdown, and/or Malfunction, Settling Defendants shall implement good air pollution control practices to minimize emissions from each Covered Flare subject to this requirement as set forth in Appendix C - 2.1; provided however, that Settling Defendants shall not be in violation of this requirement for any practice that this Consent Decree requires Settling Defendants to implement after the Date of Entry for the period between the Date of Lodging and the implementation date or compliance date (whichever is applicable) for the particular practice.

136. Revisions to 40 C.F.R. §§ 60.18(b)-(f) and/or 63.11(b). To the extent that, from the Date of Lodging of this Consent Decree until its Termination pursuant to Section XXI, revisions

to 40 C.F.R. §§ 60.18(b)-(f) and/or 63.11(b) are final and effective (whether they are codified in Part 60 Subpart A, Part 63 or elsewhere) and are inconsistent with any of the requirements of Paragraphs 135 above, the Settling Defendants shall comply only with the final, effective requirements. As used in this Paragraph, "inconsistent" means that compliance with both provisions is not possible.

137. Work Practice Standards for each Covered Flare. By no later than the applicable date in Appendix C - 2.1, for all Covered Flares utilizing the instrumentation and controls required to be installed pursuant to Paragraphs 114, 117-119, and 122, above and Paragraph 144 below, as provided in Appendix C - 2.1, Settling Defendants shall install and operate on each such Covered Flare an Automatic Control System that shall automate the control of the Supplemental Gas flow rate to the respective Covered Flare as set forth in Appendix C - 2.1.

138. Operation According to Design. By no later than the applicable date(s) set forth in Appendix C - 2.1, for all Covered Flares, Settling Defendants shall operate and maintain each Covered Flare in accordance with its design, except if, and only to the extent that, operation and maintenance of the Covered Flare in conformance with its design conflicts with compliance with one or more of the requirements of this Section. The requirements of this Paragraph shall not apply to the extent necessary to achieve personnel and process safety or prevent equipment damage.

139. Net Heating Value Standards for each Covered Flare.

a. By no later than the applicable date in Appendix C - 2.1, for all Covered Flares, Settling Defendants shall operate each Covered Flare subject to this requirement to maintain the Net Heating Value of Combustion Zone Gas (NHV_{cz}) at or above 270 British thermal units per standard cubic feet (BTU/scf) determined on a 15-minute Block Average Period basis. Settling Defendants shall monitor and calculate NHV_{cz} as specified in Paragraphs 139 b.i and b.ii below.

b. Calculation Methods for Determining Combustion Zone Net Heating Value. Settling Defendants shall determine the Net Heating Value of the Combustion Zone Gas (NHV_{cz}) as specified in Paragraphs 139.b.i and 139.b.ii below, as applicable.

i. Except as specified in Paragraph 139.b.ii, 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 in Appendix C - 1.3. For periods when there is neither Assist Steam flow nor Premix Assist Air flow, $NHV_{cz} = NHV_{vg}$.

ii. Settling Defendants that use the feed-forward calculation methodology in Appendix C - 1.3 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 to the Flare must determine the 15-minute Block Average NHV_{cz} utilizing Equation 4 in Appendix C - 1.3.

140. 96.5% Combustion Efficiency. By no later than the applicable date in Appendix C - 2.1, Settling Defendants shall operate all Covered Flares subject to this requirement as set

forth in Appendix C - 2.1, with a minimum of a 96.5% Combustion Efficiency at all times when Waste Gases are vented to each Covered Flare. To demonstrate continuous compliance with the applicable Combustion Efficiency requirement, Settling Defendants shall operate each Covered Flare subject to this Paragraph as set forth in Appendix C - 2.1 within the range of relevant operating parameters set forth in Paragraphs 139 above and 145 below.

141. Inapplicability of Paragraphs 139, 140 and 145.

a. The requirements of Paragraphs 139, 140 and 145 are not applicable to any Covered Flare when the only gases being vented to the Covered Flare is/are Pilot Gas and/or Purge Gas. Pilot Gas and Purge Gas will be considered to be the only gases being vented to those Flares if the following conditions are satisfied for the liquid seal drum that is part of the FGRS associated with the respective Covered Flare:

i. For the liquid seal drum associated with respective Covered Flare, the pressure difference between the inlet pressure and outlet pressure is less than the liquid seal pressure as set by the static head of liquid between the opening of the dip tube in the drum and the level-setting weir in the drum;

ii. For the liquid seal drum associated with the respective Covered Flare, the liquid level in the drum is at the level of the weir; and

iii. Downstream of the seal drum associated with the respective Covered Flare there is no flow of Supplemental Gas directed to the Covered Flare.

b. As an alternative to Paragraph 141.a above, for a Covered Flare which does not have a weir, Pilot Gas and Purge Gas will be considered to be the only gases being vented to those Flares if the Vent Gas flow meter indicates a flow rate of less than 0.2 feet/second based on a 15-minute Block Average.

142. Recordkeeping: Timing and Substance. Settling Defendants shall comply with the following recordkeeping requirements:

a. By no later than the applicable date in Appendix C - 2.1 for all Covered Flares subject to this requirement as set forth in Appendix C - 2.1, Settling Defendants shall calculate and record, in accordance with the recording and averaging times required in Paragraph 122 above, each of the following parameters:

i. NHV_{cz} (in BTU/scf);

ii. *S/VG* (in lbs steam/lbs Vent Gas), Total Steam Mass Flow Rate (in lb/hr), Vent Gas Mass Rates (in scfm and lb/hour) for periods when the Covered Flare is subject to the requirements of Paragraph 113; and

iii. NHV_{vg} (in BTU/scf).

Covered Flares are only required to calculate and record the parameters specified in Paragraph 142.a.i-iii above if applicable as specified in Appendix C - 2.1.

b. By no later than the applicable dates in Appendix C - 2.1, all Covered Flares subject to this requirement as set forth in Appendix C - 2.1, commencing if and when the downtime of any instrumentation and monitoring system subject to Paragraph 123 above exceeds 5% of the time that the Covered Flare is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas in any six month period for the Covered Flare that is being monitored by the respective instrument, Settling Defendants shall record the duration of the deviation, an explanation of the cause(s) of the deviation, and a description of the corrective action(s) that Settling Defendants took.

c. At any time that Settling Defendants deviate from the standards in Paragraphs 135, 139-140 above and 145 below, after the effective date of those standards, Settling Defendants shall record the duration of the deviation, an explanation of the cause(s) of the deviation, and a description of the corrective action(s) that Settling Defendants performed.

d. Output of the monitoring device used to detect the presence of a Pilot Flame as required in Paragraph 135.c.

e. Records of daily Visible Emissions observations or video surveillance images required in Paragraph 135.b.i.

i. If Visible Emissions observations are performed using Method 22 at 40 C.F.R. Part 60, Appendix A-7, the record must identify whether the Visible Emissions observation was performed, the results of each observation, total duration of observed Visible Emissions, and whether it was a 5-minute or 2-hour observation. If the Settling Defendants perform Visible Emissions observations more than one time during a Day, the record must also identify the date and time of day each Visible Emissions observation was performed.

ii. If video surveillance camera is used, the record must include all video surveillance images recorded, with time and date stamp.

iii. For each 2 hour period for which Visible Emissions are observed for more than 5 minutes in 2 consecutive hours, the record must include the date and time of the 2 hour period and an estimate of the cumulative number of minutes in the 2 hour period for which emissions were visible.

f. The 15-minute Block Average cumulative flows for Vent Gas and, if applicable, Total Steam, Perimeter Assist Air, and Premix Assist Air specified to be monitored under Paragraph 117, along with the date and time interval for the 15-minute Block Average Period.

g. The Vent Gas compositions specified to be monitored under Paragraph 118 above.

h. Each 15-minute Block Average operating parameter calculated following the methods specified in Paragraph 135.d.ii and Appendix C - 1.3, as applicable.

i. All periods during which operating values are outside of the applicable operating limits specified in Paragraphs 135.d and 139.a above and Paragraph 145 below.

j. All periods during which the Settling Defendants do not perform Flare monitoring according to the procedures in Paragraphs 117, 118-119, 122, and 135.b and c above.

k. Records of when the flow of Vent Gas exceeds the smokeless capacity of the Flare, including start and stop time and dates of the flaring event.

l. Recordkeeping: Document Retention. For purposes of this Consent Decree, and except with respect to the data produced by video cameras required pursuant to Paragraph 119 above, Settling Defendants shall retain all records created pursuant to this Consent Decree, including the raw data values, in accordance with Section X (Reporting and Recordkeeping) and shall make any such documents available to EPA and the Applicable State Co-Plaintiff upon request. Settling Defendants shall retain the data recorded by the Video Cameras required pursuant to Paragraph 119 above for six months.

143. Portable Flares.

a. Applicability. The provisions of this Paragraph shall apply to Portable Flares.

b. Distinction Between Planned and Unplanned Outages of Covered Flares. For purposes of this Paragraph, a "planned" outage shall mean an outage of a Covered Flare that is scheduled 30 Days or more in advance of the outage. An "unplanned" outage is an outage of a Covered Flare that either is scheduled less than 30 Days in advance or is unscheduled.

c. 504 Hours or Less. For any planned or unplanned outage of a Covered Flare that Settling Defendants know or reasonably anticipate will result in 504 hours or less of downtime on a 1095-day Rolling Sum Period, rolled daily, Settling Defendants shall make good faith efforts to ensure that the Portable Flare that replaces the Covered Flare complies with all of the requirements of this Consent Decree that are applicable to the Covered Flare that the Portable Flare replaces.

d. More than 504 Hours.

i. Planned. For any planned outage of a Covered Flare that Settling Defendants know or reasonably can anticipate will last 504 hours or more on a 1095-day Rolling Sum Period, rolled daily, Settling Defendants shall ensure that the Portable Flare complies with all of the requirements of this Consent Decree related to the Covered Flare that it replaces as of the date that the Portable Flare is In Operation and Capable of Receiving Waste, Supplemental, and/or Sweep Gas.

ii. Unplanned. For any unplanned outage of a Covered Flare that, in advance of the outage, Settling Defendants cannot reasonably anticipate will last longer than 504 hours, Settling Defendants shall ensure that the Portable Flare complies with all of the requirements of this Consent Decree related to the Covered Flare that it replaces by no later than 30 Days after the date that Settling Defendants know or reasonably should have known that the outage will last 504 hours or more.

e. Recordkeeping. Settling Defendants shall keep records sufficient to document compliance with the requirements of this Paragraph any time it uses a Portable Flare.

Requirements for Air-Assisted Flares

144. Additional Air-Assisted Flare Requirements: Instrumentation and Monitoring Systems. Tesoro shall undertake the following measures for Air-Assisted Flares.

a. By no later than the applicable dates in Appendix C - 2.1, install a flow meter in order to determine the Vent Gas Volumetric Flow Rate to Air-Assisted Flares. The air flow rate shall be determined from the fan speeds or measured on the Assist Air blowers;

b. By no later than the applicable dates in Appendix C - 2.1, continue to operate a Variable Speed Motor on the Air-Assisted Flares' Assist Air blowers; and

c. By no later than the applicable dates in Appendix C - 2.1, install a control system at the Kenai Refinery that will automate the control of the Variable Speed Motor on the Air-Assisted Flares' Assist Air blowers to enable Tesoro to comply with the standard set forth in Paragraph 145 below.

145. Dilution Operating Limits for Flares with Perimeter Assist Air. By no later than the applicable dates in Appendix C - 2.1, for each Covered Flare actively receiving Perimeter Assist Air, Settling Defendants shall operate the Covered Flare to maintain the Net Heating Value Dilution Parameter (NHV_{dil}) at or above 22 British Thermal Units per square foot (BTU/ft^2) determined on a 15-minute Block Average basis. The Settling Defendants shall monitor and calculate the NHV_{dil} as specified in Appendix C - 1.3.

146. Kenai Passive FTIR Testing. By no later than September 30, 2015, Tesoro shall commence Passive FTIR testing on the Kenai Refinery Air-Assisted Flare. By no later than sixty (60) Days prior to the testing, Tesoro shall submit an Emissions and Flare Combustion Efficiency Test Protocol in accordance with the general requirements in Appendix C - 2.3. Tesoro shall complete the testing on the Kenai Refinery Air-Assisted Flare within sixty (60) Days of commencing testing.

147. Kenai Passive FTIR Report. By no later than four (4) months after completing the testing required in Paragraph 146 above, Tesoro shall submit a report to EPA for approval that sets forth the following:

a. The detailed results of the testing that include minute by minute electronic data in Excel format for all measurements and process data and is consistent with the requirements of Appendix C - 2.5 that are relevant to the Kenai Refinery Air-Assisted Flare;

b. A detailed description of the extent to which the $\dot{m}$air-asst/$\dot{m}$air-stoich-vg affects Combustion Efficiency; and

c. A detailed description of the range of the $\dot{m}$air-asst/$\dot{m}$air-stoich-vg, indicative of 96.5% Combustion Efficiency or as high an efficiency as reliably obtainable, for the Kenai Refinery Air Assist Flare, taking into consideration variability in Vent Gas Mass Flow Rate and composition.

Alternative Means of Emission Limitation

148. Settling Defendants may follow the procedures in 40 CFR §63.670(r) to apply for alternative means of emission limitation or compliance demonstration. Any alternative means of emission limitation or compliance demonstration shall only affect the requirements of Paragraphs 117, 118, 135, 139, 140, and 145 above.

Resolution of Inconsistencies between Consent Decree and MACT Requirements

149. To the extent that, from the Date of Lodging of this Consent Decree until its Termination pursuant to Section XXI, revisions to Refinery MACT standards in 40 C.F.R. Part 63, Subparts UUU and CC are final and effective and are inconsistent with any of the requirements for this Section VI.B (Requirements for Control of Flaring Events), Tesoro shall comply only with the final, effective regulatory requirements. As used in this Paragraph, "inconsistent" means that compliance with both provisions is not possible.

Exception for Monitoring System Downtime

150. A failure to comply with the work practices or standards in Paragraphs 135, 137, 139 and 145 above shall not constitute a violation of such work practice or standard if the non-compliance results from downtime of monitoring systems due to the following:

a. Malfunction of a monitoring system, for a monitoring system needed to meet the requirement(s);

b. Repairs associated with monitoring system malfunctions, for a monitoring system needed to meet the requirement(s);

c. Required monitoring system quality assurance or quality control activities (including, as applicable, calibration checks and required zero and span adjustments); or

d. Quality Assurance/Quality Control activities on a monitoring system needed to meet the requirement.

Provided, however, that this exception shall no longer be applicable if the activities in Paragraphs 150.a-150.d above exceed 5% of time that the Covered Flare is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas in any six month period for any instrument. The calculation of monitoring system downtime shall be made in accordance with 40 C.F.R. § 60.13(h)(2) and Paragraph VIII of Appendix C - 1.10.

NSPS Subparts A and Ja Applicability for Flares

151. NSPS Subparts A and Ja. As further set forth in Appendix C - 2.1, each Covered Flare shall be an "affected facility" within the meaning of Subparts A and Ja of 40 C.F.R. Part 60, and shall comply with all of the requirements of Subparts A and Ja on and after November 11, 2015. After November 11, 2015, Subpart J shall not apply to Covered Flares.

Reporting Requirements

152. Monitoring System Downtime and Emissions Exceedances. On and after the date of applicability of any work practice or standard, Settling Defendants shall provide a summary of the following, for each Covered Flare subject to this requirement as set forth in Appendix C - 2.1 (hours shall be rounded to the nearest tenth) in their semi-annual reports submitted pursuant to Section X (Reporting and Recordkeeping):

a. The total number of hours of downtime of each monitoring instrument/equipment required pursuant to Paragraphs 117-119, 121-122 below (and, if applicable, Paragraph 144 above), expressed as both an absolute number and a percentage of time each Covered Flare that the instrument/equipment monitors is available for operation;

b. If the total number of hours of downtime of any monitoring instrument/equipment required pursuant to Paragraphs 117-119, 121-122 below (and, if applicable, Paragraph 144 above), exceeds 5% of the time that the Covered Flare is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas in any six month period an identification of the periods of downtime by date, time, cause (including Malfunction or maintenance), and, if the cause is asserted to be a Malfunction, the corrective action taken;

c. Inapplicability of Emissions Standards. The total number of hours expressed as both an absolute number of hours and a percentage of time each Covered Flare was In Operation in which the requirements of Paragraphs 139-140 above were not applicable because the only gas or gases being vented was/were Pilot Gas and/or Purge Gas; for purposes of Paragraphs 152.d and 152.e below, all remaining hours shall be termed "Hours of Applicability";

d. Exceedances of Standards. During the Hours of Applicability, the total number of hours of exceedances of each of the standards in Paragraphs 139 (and, if applicable, Paragraphs 145) above, expressed as both an absolute number of hours and a percentage of time each Covered Flare was In Operation; provided however, that if the exceedance of these standards was less than 5% of the time that the Covered Flare is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas in any six month period, the report shall so note;

i. Records of the output of the monitoring device used to detect the presence of a Pilot Flame as required in Paragraph 135.c for each 15-minute block.

ii. Visible Emission records of the date and time of the 2 hour period and an estimate of the cumulative number of minutes in the 2 hour period for which emissions were visible for each period of 2 consecutive hours during which Visible Emissions exceed a total of 5 minutes.

iii. The 15-minute Block Average Periods for which the applicable operating limits specified in Paragraphs 135.d, 139 (and, if applicable, Paragraphs 144-145) are not met. Indicate the date and time for the period, the Net Heating Value and/or Flare Tip Velocity operating parameter(s) determined following the methods in Appendix C - 1.2 and Appendix C - 1.3 as applicable.

e. Flaring Flow Rate Limitations Exceedances.

i. For any Waste Gas flows that are excluded from the calculation of flow rate because they are asserted to be based on one or more of the excludible events identified in Paragraph 134 above, the information required in Paragraph 134 above;

ii. An identification of each Day in which the limitations on flaring set forth in Paragraph 132 (or 133, if applicable) above were exceeded;

iii. The cause of the exceedance;

iv. If the cause is asserted to be a Malfunction, description of the Malfunction and any corrective actions taken;

v. A quantification of the total flow and a calculation of the percent over the standard in Paragraph 132 (or 133, if applicable) above.

153. Emissions Data. In the semi-annual report that is required to be submitted by Paragraph 170 of Section X of this Consent Decree by September 1 of each year, Settling Defendants shall provide, for each Covered Flare subject to this requirement as set forth in Appendix C - 2.1, for the prior calendar year, the amount of emissions of the following compounds (in tons per year): VOCs, SO_2, H_2S, CO_2, methane, and ethane.

VII. SURVIVAL OF CONSENT DECREE REQUIREMENTS

154. Obtaining Permits for Consent Decree Requirements That Are Effective Upon Date of Entry. Except as set forth below, by no later than 180 Days after the Date of Entry, Settling Defendants shall submit applications to the Applicable Permitting Authority for each Covered Refinery to incorporate the requirements listed in Paragraph 158.a and b below that are required by this Consent Decree and that are effective on or before the Date of Entry into federally enforceable minor or major New Source Review ("NSR") permits or other permits (other than Title V Permits) that are federally enforceable. Settling Defendants shall file any applications

necessary to incorporate the requirements of those permits into the Title V Permit for the relevant Covered Refinery prior to the next Title V Permit modification or renewal occurring after the issuance of those permits.

155. Obtaining Permits For Consent Decree Requirements That Become Effective After Date of Entry. Except as set forth below, as soon as practicable, but in no event later than 180 Days after the effective date or establishment of any requirement listed in Paragraph 158 below that is required by this Consent Decree other than those effective as of the Date of Entry, Settling Defendants shall submit applications to the Applicable Permitting Authority to incorporate those requirements into federally enforceable minor or major NSR permits, or other permits (other than Title V Permits) which are federally enforceable. Settling Defendants shall file any applications necessary to incorporate the requirements of those permits into the Title V Permit for the relevant Covered Refinery prior to the next Title V Permit modification or renewal occurring after the issuance of those permits.

156. Mechanism for Title V Incorporation. The Parties agree that the incorporation of any emission limits or other standards into the Title V Permit for each Covered Refinery as required by Paragraph155 above shall be in accordance with the applicable state or local Title V rules.

157. Construction Permits. Settling Defendants agree to obtain all required, federally enforceable permits for the construction of the pollution control technology and/or the installation of equipment necessary to implement the requirements of this Consent Decree.

158. Obligations that Shall Survive Consent Decree Termination. The requirements imposed by the following provisions of this Consent Decree shall survive Termination of this Consent Decree under Section XXI:

a. Emission Limits and Standards. The following Consent Decree requirements shall constitute emission limits and standards that shall survive Termination of this Consent Decree:

Covered Refinery	**Emission Limit or Standard**	**Consent Decree Paragraph Numbers**
Anacortes		
	Heater F201 NSPS Subpart J requirements for H_2S, if applicable.	¶ 12
Kapolei		
	Heater and Boiler Limits	¶ 15
	SRP Limit	¶ 19
Mandan	Operation of Scrubber and Wet Electostatic Precipitator	¶ 40

Covered Refinery	Emission Limit or Standard	Consent Decree Paragraph Numbers
Martinez		
	FCCU/CO Boiler: Final CO Limit	¶ 45
	FCCU/CO Boiler: Final NOx Limits	¶ 43.b, c, d, e
	SAP Limits	¶ 52
	Sulfur Pit Requirements	¶ 47
	Final Limits that Carried Over from 2005 Martinez Consent Decree in Appendix A-2.	Appendix A-2
SLC		
	FCCU Limits	¶¶ 60-62
	SLC NOx Limit for F-1 UltraFormer Environmental Mitigation Project	Appendix D

b. Certain Other Requirements.

i. Flares and Control of Flaring Events at Covered Refineries. The following Consent Decree requirements shall constitute emission limits and standards that shall survive Termination of this Consent Decree to the extent such requirements are applicable to a Covered Flare under Appendix C - 2.1:

Requirement	Paragraph Numbers
Instrumentation and Monitoring Systems for Covered Flares Except Optional Equipment	¶114, 117-119, 121-123
Flare Gas Recovery Systems	¶¶ 130-131
Flaring Limits	¶¶ 132-134
Flare Emission Standards and Work Practices	¶ 135
Work Practice Standards	¶ 137
Operation According to Design	¶ 138
Net Heating Value Standards	¶ 139
96.5% Combustion Efficiency	¶ 140
Inapplicability	¶ 141
Recordkeeping	¶ 142
Portable Flares	¶ 143
Air Assist Flare Requirements	¶¶ 144-145
Exceptions for Instrument Downtimes	¶ 150
Applicability Determinations for Flares	¶ 151

ii. All Monitoring Requirements at Covered Refineries.

Refinery	Monitoring Requirements
Kapolei	¶¶ 16-17, 20, 22
Kenai	¶ 33
Martinez	¶¶ 44, 46, 53 (including SAP Monitoring Plan attached as Appendix A-1)
SLC	¶¶ 60.d, 61.c, 62.c

iii. ELDAR NSPS GGGa Applicability at Covered Refineries Pursuant to Paragraph 65 (upon completion of NSPS GGGa applicability phase-in under Paragraph 65) of this Consent Decree.

iv. All of Section VIII (Emission Credit Generation).

v. Other Specific-Facility Consent Decree Requirements.

Covered Refinery	Requirement	Consent Decree Paragraph Numbers
Anacortes		
	Heater NSPS Applicability	¶ 12
Kapolei		
	All Applicability Determinations	¶¶ 18, 21
	Fuel Oil Burning Restrictions	¶ 17
	Heater and Boiler Control Technologies	¶ 15
Martinez		
	Delayed Coker Requirements	¶¶ 49-51
	SAP Applicability Determinations (NSPS A & H)	¶ 54
	Any Carry Over Applicability Determinations from Prior CD (except Monitoring Plans).	Appendix A-2
SLC		
	Ja Applicability for FCCU	¶ 63

c. Agreement Required for Changes to Surviving Requirements. In the event a Settling Defendant should ever seek to delete or modify a requirement surviving Termination by virtue of Paragraph 158.a and b above, such requirements shall not be deleted or modified unless EPA and the Applicable State Co-Plaintiff shall have first agreed in writing to the deletion or modification.

VIII. EMISSION CREDIT GENERATION

159. Prohibition. Settling Defendants shall neither generate nor use any CD Emissions Reductions: as netting reductions; as emissions offsets; to apply for, obtain, trade, or sell any emission reduction credits; or in determining whether a project would result in a significant net emissions increase in any PSD, major non-attainment, and/or minor NSR permit or permit proceeding. Baseline actual emissions during any 24-month period selected by Settling Defendants shall be adjusted downward to exclude any portion of the baseline emissions that would have been eliminated as CD Emissions Reductions had Settling Defendants been complying with this Consent Decree during that 24-month period. Any plant-wide applicability limits ("PALs") as that term is defined in 40 C.F.R. § 52.21(b) that apply to emissions units covered by this Consent Decree shall be adjusted downward to exclude any portion of the baseline emissions used in establishing such limit(s) that would have been eliminated as CD Emissions Reductions had Settling Defendants been complying with this Consent Decree during such baseline period.

160. Additional Prohibition. Even if the Waste Gas minimization requirements of Paragraphs 127-129 of Section VI.B (Control of Flaring Events) result in emissions lower than the allowable level under the flaring limitations in Paragraphs 132-133 of Section VI.B such reductions shall be considered CD Emissions Reductions and shall be subject to the general prohibition set forth in Paragraph 159 above.

161. Outside the Scope of Prohibition. Nothing in this Section VIII (Emission Credit Generation) is intended to prohibit Settling Defendants from seeking to:

a. Use or generate emission reductions from emissions units that are covered by this Consent Decree to the extent that the proposed emission reductions represent the difference between CD Emissions Reductions and more stringent limits that Settling Defendants may elect to accept for those emissions units in a permitting process, except as provided in Paragraphs 160-161 above;

b. Use or generate emission reductions from emissions units that are not subject to an emission limitation or control requirement pursuant to this Consent Decree; and

c. Use CD Emissions Reductions for compliance with any rules or regulations designed to address regional haze or the non-attainment status of any area (excluding PSD and non-attainment NSR rules, but including, for example, RACT rules) that apply to the facility; provided, however, that Settling Defendants shall not be allowed to trade or sell any CD Emissions Reductions.

IX. ENVIRONMENTAL MITIGATION PROJECTS

162. Tesoro shall implement the Environmental Mitigation Projects ("Projects") as set forth in Paragraphs 163 through 169 below and in Appendix D of this Consent Decree in compliance with the schedules for such Projects and the other terms of this Consent Decree.

163. The Projects to be performed by Tesoro shall be for the purpose of beneficially restoring and/or mitigating the environments allegedly damaged by the operation of Tesoro's refineries.

164. Tesoro shall maintain, and present to EPA and the Applicable State Co-Plaintiff upon request, all documents to substantiate the Project Dollars expended and work completed to implement the Projects described in Appendix D, and shall provide these documents to EPA within thirty (30) Days of a request for the documents.

165. All plans and reports prepared by Tesoro pursuant to the requirements of this Section of this Consent Decree and required to be submitted to EPA shall be publicly available from Tesoro without charge.

166. Tesoro certifies the truth and accuracy of the following:

a. that Tesoro is not otherwise required by law to perform the Projects on the schedule set forth in this Consent Decree;

b. that Tesoro is unaware of any other person who is required by law to perform the Projects, and that Tesoro shall not use any Project, or portion thereof, to satisfy any obligations that it may have under other applicable requirements of law; and

c. that for each Project, Tesoro had not otherwise planned to perform the Project generally described in Appendix D, and that Tesoro is unaware of any other person who is planned to perform the same Project.

167. If Tesoro elects (where such an election is allowed) to undertake a Project by contributing funds to another person or instrumentality that will carry out the Project in lieu of Tesoro, but not including Tesoro's agents or contractors, that person or instrumentality shall, in writing: (a) identify its legal authority for accepting such funding; and (b) identify its legal authority to conduct the Project for which Tesoro contributes the funds. Regardless of whether Tesoro elects (where such election is allowed) to undertake a Project by itself or to do so by contributing funds to another person or instrumentality that will carry out the Project, Tesoro acknowledges that it will receive credit for the expenditure of such funds as Project Dollars only if Tesoro demonstrates that the funds have been actually spent by either Tesoro or by the person or instrumentality receiving them, and that such expenditures met all requirements of this Consent Decree.

168. Tesoro shall comply with the reporting requirements described in Section X (Reporting and Recordkeeping) of this Consent Decree and in Appendix D.

169. The purpose of the Projects is to remediate prior emissions that United States and/or the State Co-Plaintiffs contend were in violation of the Clean Air Act. The Projects are not in lieu of penalties.

X. REPORTING AND RECORDKEEPING

170. Settling Defendants shall submit to EPA and the Applicable State Co-Plaintiff a semi-annual report for each Covered Refinery at which that Settling Defendant is responsible for compliance with this Consent Decree pursuant to Paragraph 6 above on each March 1 and September 1 until Termination. The initial semi-annual report shall be due by September 1, 2016 and shall cover the time period between October 1, 2015, and June 30, 2016. Subsequent semi-annual reports shall cover the time period from January 1 through June 30 of each year (submitted by September 1 of each of the following years) and the period of July 1 through December 31 of each year (submitted by March 1 of each of the following years). Each report shall contain for the period covered by the report:

a. A summary of the emissions data for each Covered Refinery that is specifically required by the reporting requirements of this Consent Decree;

b. A description of any problems anticipated with respect to meeting the requirements of this Consent Decree at each Covered Refinery;

c. A description of the implementation activity for the Environmental Mitigation Projects set forth in Section IX (Environmental Mitigation Projects);

d. A summary of Tesoro's actions implemented and expenditures (cumulative and in the current reporting period) made to implement the Environmental Mitigation Projects required pursuant to Section IX (Environmental Mitigation Projects);

e. Any additional matters that the Settling Defendants believe should be brought to the attention of EPA and State Co-Plaintiffs; and

f. Any additional items required by any other Paragraph of this Consent Decree to be submitted with a semi-annual report.

171. Within sixty (60) Days following the completion of each Environmental Mitigation Project required under Section IX (Environmental Mitigation Projects) of this Consent Decree (including any applicable periods of demonstration or testing), Tesoro shall submit to the United States and the Applicable State Co-Plaintiff a report that documents:

a. The date that the Mitigation Project was completed;

b. The results achieved by implementing the Mitigation Project, including the emission reductions or other environmental benefits expected to be realized;

c. The methodology and any calculations used in the derivation of such expected benefits, reductions, or mitigation;

d. The Project Dollars expended by Tesoro in implementing the Mitigation Project; and

e. Certification by an authorized representative that the Mitigation Project has been completed in full satisfaction of the requirements of the Consent Decree and Appendix D.

172. Emissions Data. In the semi-annual report required by Paragraph 170 above to be submitted by September 1 of each year, each Settling Defendant shall provide the following emissions data for each Covered Refinery for which that Settling Defendant is responsible for compliance with this Consent Decree pursuant to Paragraph 6 above, for the prior calendar year:

a. NOx emissions in tons per year from the Kapolei Refinery Covered Heaters and Boilers;

b. SO_2 emissions in tons per year from the Kapolei SRP;

c. SO_2 emissions in tons per year from Acid Gas Flaring from the Kenai SRU Flare;

d. NOx, SO_2, CO, and PM emissions in tons per year from the Martinez Refinery FCCU;

e. VOCs, H_2S, PM, and methane in tons per year from the Martinez Refinery Delayed Coker;

f. SO_2 and Acid Mist emissions in tons per year from the Martinez SAP;

g. NOx, SO_2, CO, and PM emissions in tons per year from the SLC Refinery FCCU;

h. VOCs, SO_2, H_2S, CO_2, methane, and ethane emissions in tons per year from each Covered Flare as set forth in Appendix C - 2.1; and

i. For each of the estimates or calculations in Paragraphs 172.a through 172.h above, the basis for the emissions estimate or calculation (i.e., stack tests, CEMS, emission factor, etc.).

To the extent that the required emissions summary data are available in other reports generated by Settling Defendants, such other reports can be attached or the appropriate information can be extracted from such other reports and attached to the report to satisfy the requirement.

173. Certification. Each semi-annual report shall be certified by either the person responsible for environmental management and compliance at the applicable Covered Refinery, or by a person responsible for overseeing implementation of this Consent Decree at the applicable Covered Refinery. The certification shall state:

> I certify under penalty of law that this information was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, the information

submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

174. Except where other time periods are specifically noted, Settling Defendants shall retain all records required to be maintained in accordance with this Consent Decree for a period of no less than five (5) years or until Termination, whichever is longer, unless applicable regulations require the record to be maintained longer, in which case Settling Defendants shall comply with those regulations. Settling Defendants shall provide such records to EPA or the Applicable State Co-Plaintiff upon request.

XI. CIVIL PENALTIES

175. In satisfaction of the civil claims asserted by the United States and State Co-Plaintiffs in the Complaint filed in this matter, within thirty (30) Days of the Date of Entry of this Consent Decree, Tesoro shall pay civil penalties totaling $10,450,000.00 as follows: (i) $8,050,000 plus Interest accruing from September 30, 2015, to the United States; (ii) $1,300,000 plus Interest accruing from September 30, 2015, to the State of Alaska; (iii) $850,000 plus Interest accruing from September 30, 2015, to the State of Hawaii; and (iv) $250,000 plus Interest accruing from September 30, 2015, to the Northwest Clean Air Agency.

176. Payment of the civil penalty to the United States shall be made by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing DOJ Case Number 90-5-2-1-09512/1 and the civil action case name and case number of this action in the Western District of Texas. The costs of such EFT shall be the responsibility of Tesoro. Payment shall be made in accordance with instructions provided to Tesoro by the Financial Litigation Unit of the U.S. Attorney's Office for the Western District of Texas. Any funds received after 5:00 p.m. (EST) shall be credited on the next Working Day. Tesoro shall provide notice of payment, referencing DOJ Case Number 90-5-2-1-09512/1 and the civil action case name and case number to the Department of Justice and to EPA.

177. State Payment Instructions.

a. State of Alaska. Tesoro shall pay the civil penalty owed pursuant to Paragraph 175 above to the State of Alaska by delivering a cashier's check payable to "State of Alaska" to:

Accounting Staff
The ADEC Division of Air Quality
Administrative Support Section
555 Cordova Street
Anchorage, AK 99501

The payment shall be accompanied by a cover letter that includes the following information: State of Alaska Operating Permit and Enforcement Tracking Number: AQ0035TVP02, CATS ID 2007-0049.

b. State of Hawaii. Tesoro shall pay the civil penalty owed pursuant to Paragraph 175 above to the State of Hawaii by delivering a certified check made payable to "State of Hawaii" to:

Clean Air Branch
Environmental Management Division
Hawaii Department of Health
P.O. Box 3378
Honolulu, HI 96801-3378

The payment shall be accompanied by a cover letter that includes the following information: the case caption and civil action number and that the case concerns the Kapolei Refinery.

c. Northwest Clean Air Agency. Tesoro shall pay the civil penalty owed pursuant to Paragraph 175 above to the Northwest Clean Air Agency by delivering a check made payable to " Northwest Clean Air Agency" to:

Director
Northwest Clean Air Agency
1600 South Second Street
Mount Vernon, WA 98273

The payment shall be accompanied by a cover letter that includes the following information: the case caption and civil action number and that the case concerns the Anacortes Refinery.

178. The civil penalty set forth in this Section XI is a penalty within the meaning of Section 162(f) of the Internal Revenue Code, 26 U.S.C. § 162(f). Tesoro shall not treat these penalty payments as tax deductible for purposes of federal, state, or local law.

179. Upon the Date of Entry of this Consent Decree, this Consent Decree shall constitute an enforceable judgment for purposes of post-judgment collection in accordance with Federal Rule of Civil Procedure 69, the Federal Debt Collection Procedure Act, 28 U.S.C. §§ 3001-3308, and other applicable federal authority. The United States and the State Co-Plaintiffs shall be deemed judgment creditors for purposes of collecting any unpaid amounts of the civil and stipulated penalties and Interest.

XII. STIPULATED PENALTIES

180. Stipulated penalties shall be paid to the United States and to the Applicable State Co-Plaintiffs for each failure by Settling Defendants to comply with the terms of this Consent Decree as provided herein at any Covered Refinery where the Settling Defendant is responsible for compliance under Paragraph 6 above. Where more than one Settling Defendant is responsible for compliance with respect to a Covered Refinery, asset, and/or equipment that it owns or operates at a Covered Refinery, there shall be only one stipulated penalty assessed per violation against the Settling Defendants responsible for compliance for which they shall be

jointly and severally liable. Stipulated penalties shall be calculated in the amounts specified in this Section XII.

181. For those provisions where a stipulated penalty of either a fixed amount or 1.2 times the economic benefit of delayed compliance is available, the decision of which alternative to seek shall rest exclusively within the discretion of the United States, after consultation with the Applicable State Co-Plaintiff. In no event shall any assessed stipulated penalty exceed $37,500 per Day for any individual violation of this Consent Decree.

182. Demand for Stipulated Penalties. Subject to Section XV (Dispute Resolution) or any order of the Court, the applicable Settling Defendants shall pay stipulated penalties upon written demand by the United States and/or Applicable State Co-Plaintiff by no later than sixty (60) Days after a Settling Defendant receives such demand. Demand from one Plaintiff shall be deemed to be a demand from all applicable Plaintiffs, but the Plaintiffs will consult with each other prior to making a demand. A demand for the payment of stipulated penalties shall identify the particular violation(s) to which the stipulated penalty relates, the stipulated penalty amount that the United States or the Applicable State Co-Plaintiff is demanding for each violation (as can be best estimated), the calculation method underlying the demand, and the grounds upon which the demand is based.

183. Payment of Stipulated Penalties. Any stipulated penalty demand shall identify to which Plaintiff(s) payment shall be made. In the event both the United States and an Applicable State Co-Plaintiff make a written demand for stipulated penalties for the same violation of this Consent Decree, then the stipulated penalties shall be apportioned between the United States and the Applicable State Co-Plaintiff, 50% to each. Stipulated penalties owing to the United States of under $10,000 shall be paid by check and made payable to "U.S. Department of Justice," referencing DOJ Number 90-5-2-1-09512/1, and delivered to the U.S. Attorney's Office in the Western District of Texas. Stipulated penalties owing to the United States of $10,000 or more and stipulated penalties owing to any State Co-Plaintiff shall be paid in the manner set forth in Section XI (Civil Penalties).

184. Disputes over Stipulated Penalties.

a. By no later than sixty (60) Days after receiving a demand for stipulated penalties, Settling Defendant(s) may dispute liability for any or all stipulated penalties demanded by invoking the dispute resolution procedures of Section XV of this Decree (Dispute Resolution).

b. In the event of a dispute over stipulated penalties, stipulated penalties shall cease accruing on the later of either:

i. the date that, during dispute resolution under Section XV, the United States and Settling Defendant(s) agree upon; or

ii. the date that Settling Defendant(s) files a motion with the Court under Paragraph 202 below;

c. Provided however, that in order for stipulated penalties to cease accruing pursuant to either this Paragraph 184.b.i or ii above, Settling Defendant(s) shall place the disputed amount in an interest-bearing commercial escrow account. If the dispute thereafter is resolved in Settling Defendant(s)'s favor, the escrowed amount plus accrued Interest shall be returned to Settling Defendant(s); otherwise, the United States shall be entitled to the amount determined by the Court to be due, plus Interest that has accrued on such amount in the escrow account.

185. Accrual of Stipulated Penalties.

a. Subject to the provisions of Paragraphs 184 above and 185.b below, stipulated penalties will begin to accrue on the Day after performance is due or the Day a violation occurs, whichever is applicable, and will continue to accrue until performance is satisfactorily completed or until the violation ceases. Stipulated penalties shall accrue simultaneously for separate violations of this Consent Decree. Except where stipulated penalties are placed in in interest-bearing account pursuant to Paragraph 184.c above, Interest on stipulated penalties shall begin to accrue on the 61st Day after a Settling Defendant's receipt of a demand for stipulated penalties by a Plaintiff.

b. Accrual of Stipulated Penalties During Dispute Resolution. Stipulated penalties shall continue to accrue as provided in Paragraph 185.a above during any dispute resolution, but need not be paid until the following:

i. If the dispute is resolved by agreement or by a decision of EPA that is not appealed to the Court, Settling Defendant(s) shall pay accrued penalties determined to be owing, together with Interest, to the United States and the Applicable State Co-Plaintiff within thirty (30) Days of the effective date of the agreement or the receipt of EPA's decision or order.

ii. If the dispute is appealed to the Court and the United States prevails in whole or in part, Settling Defendant(s) shall pay all accrued penalties determined by the Court to be owing, together with Interest, within sixty (60) Days of receiving the Court's final decision or order, except as provided in Paragraph 185.c below.

iii. If any Party appeals the District Court's decision, Settling Defendant(s) shall pay all accrued penalties determined to be owing, together with Interest, within fifteen (15) Days of receiving the final judgment.

c. Stipulated penalties shall not accrue with respect to any submission under Section XVI (Review, Approval, and Comment on Deliverables) that EPA contends is deficient during the period, if any, beginning on the 91st Day after EPA receipt of such submission until the date that the EPA notifies the Settling Defendant(s) responsible for compliance at a Covered Refinery pursuant to Paragraph 6 above of any deficiency.

186. Waiver of Payment. The United States may, in its unreviewable discretion, reduce or waive payment of stipulated penalties otherwise due to it under this Consent Decree.

187. Failure to Pay Civil Penalty. If Settling Defendant(s) fails to pay any portion of the Civil Penalties required to be paid under Section XI of this Consent Decree (Civil Penalties) when due, Settling Defendant(s) shall pay a stipulated penalty of $15,000 per Day for each Day that the payment is late. Late payment of the civil penalty and any accrued stipulated penalties shall be made in accordance with Paragraphs 176-177 above.

188. Failure to Meet all Other Consent Decree Obligations. Settling Defendants shall be liable for stipulated penalties to the United States and/or the Applicable State Co-Plaintiff for violations of this Consent Decree at any Covered Refinery where the Settling Defendant is responsible for compliance under Paragraph 6 above unless excused under Section XIV of this Consent Decree (Force Majeure).

a. Violations of Refinery-Specific Requirements Except Those Pertaining to ELDAR or Covered Flares.

i. Anacortes Refinery. Tesoro Refining & Marketing Company LLC and/or, if applicable under Paragraph 6 of this Consent Decree, Tesoro Logistics L.P. shall be liable for the following stipulated penalties for violations of the requirements of Section V.A of this Consent Decree:

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(a) Violation of Paragraph 12. Failure to comply with the requirements of Part 60 Subparts A and J at Heater F-201 as required by Paragraph 12.	Days 1-30:	$500
	Days 31-60:	$1000
	Days 61 and beyond:	$2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(b) Violation of Paragraph 13. Requirements for Benzene Waste NESHAP. Failure to complete the Phase One Review and Verification process pursuant to Paragraph 13.b and c, and if necessary the Phase Two sampling and Amended TAB as required by Paragraph 13.d and e.	Per Month	$5000

Consent Decree Violation	Period of Delay or Non-Compliance or Other Measure as Indicated	Penalty Per Violation Per Day or Other Time Period or Measure as Indicated
(c) Violation of Paragraph 13.f and g. Failure to perform any corrective action as required by Paragraphs 13.f and g.	Days 1-30:	$1250
	Days 31-60:	$3000
	Days 61 and beyond:	$5000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

ii. Kapolei Refinery. Par shall be liable for the following stipulated penalties for violations of the requirements of Section V.B of this Consent Decree:

Consent Decree Violation	Period of Delay or Non-Compliance or Other Measure as Indicated	Penalty Per Violation Per Day or Other Time Period or Measure as Indicated
(a) Violation of Paragraph 15. Failure to install required NOx emissions reductions control technologies for any Kapolei Covered Heater or Boiler as required by Paragraph 15.	Days 1–30:	$1500
	Days 31–60:	$2000
	Days 61 and beyond:	$3000.
(b) Violation of Paragraph 15. Failure to maintain and operate required NOx emissions reductions control technologies for any Kapolei Covered Heater or Boiler as required by Paragraph 15.	Days 1-30:	$500 per Covered Heater or Boiler per Day
	Days 31-60:	$1000 per Covered Heater or Boiler per Day
	Days 61 and beyond:	$2000 per Covered Heater or Boiler per Day, or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(c) Violation of Paragraph 15. Failure to comply with any Short-Term or Long-Term NO_x Emission Limit established in Paragraph 15.	Days 1-30:	$500 per Covered Heater or Boiler per Day
	Days 31-60:	$1000 per Covered Heater or Boiler per Day
	Days 61 and beyond:	$2000 per Covered Heater or Boiler per Day, or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(d) Violation of Paragraph 15.d.iii. Failure to perform the FGR Optimization Study Report as required by Paragraph 15.d.iii.	Days 1-30:	$1000
	Days 31-60:	$1500
	Days 61 and beyond:	$2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(e) Violation of Paragraph 15.d.iv. Failure to perform the FGR demonstration as required by Paragraph 15.d.iv.	Days 1-30:	$1000
	Days 31-60:	$1500
	Days 61 and beyond:	$2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(f) Violation of Paragraph 15.d.iii-v. Failure to submit the monthly data, FGR Optimization Study, or Demonstration Report as required by Paragraph 15.d.iii-v.	Days 1-30:	$1000
	Days 31-60:	$1500
	Days 61 and beyond:	$2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(g) Violation of Paragraph 16.a. Failure to install, certify, calibrate, maintain, and/or operate a NO_x and/or O_2 CEMS on a Kapolei Covered Heater or Boiler as required by Paragraph 16.a.	Days 1-30:	$500 per unit per Day
	Days 31-60:	$1000 per unit per Day
	Days 61 and beyond:	$2000 per unit per Day or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(h) Violation of Paragraph 16.b. Failure to comply with the performance testing or reporting at a Kapolei Covered Heater or Boiler as required by Paragraph 16.b.	Days 1-30:	$200 per Day per test per Covered Heater or Boiler
	Days 31-60:	$500 per Day per test per Covered Heater or Boiler
	Days 61 and beyond:	$1000 per Day per test per Covered Heater or Boiler, or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(i) Violation of Paragraph 17. Failure to comply with any limitation on Fuel Oil as required by Paragraph 17.	Days 1-30:	$1250 per Combustion Unit per Day
	Days 31 and beyond:	$4000 per Combustion Unit per Day, or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(j) Violation of Paragraph 17. Failure to comply with the monitoring, reporting, or recordkeeping requirements of Paragraph 17.	Days 1-30:	$500
	Days 31-60:	$1000
	Days 61 and beyond:	$2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(k) Violation of Paragraph 17.b. Failure to conduct a study on the minimization or elimination of Fuel Oil burning as required by Paragraph 17.b.	Days 1-30:	$1000
	Days 31-60:	$1500
	Days 61 and beyond:	$2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(l) Violation of Paragraph 18.a. Failure to comply with any applicable requirement (including any monitoring requirement) of 40 C.F.R. Part 60, Subparts A or J (or, if applicable, Subparts A or Ja) at a FGCD as required by Paragraph 18.a.	Days 1-30:	$500 per FGCD per Day
	Days 31-60:	$1000 per FGCD per Day
	Days 61 and beyond:	$2000 per FGCD per Day or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(m) Violation of Paragraph 18.b. Failure to provide the non-flare FGCD report required by Paragraph 18.b.	Days 1-30:	$500
	Days 31-60:	$1500
	Days 61 and beyond:	$2000.
(n) Violation of Paragraph 19. Failure to comply with the Long-Term Kapolei SRP SO_2 Emission Limit established in Paragraph 19.	Days 1-30:	$500
	Days 31-60:	$1000
	Days 61and beyond:	$2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(o) Violation of Paragraph 20. Failure to install, certify, calibrate, maintain, and /or operate a Kapolei SRP SO_2, O_2, and/or flow CEMS as required by Paragraph 20.	Days 1-30:	$500 per emission release point per Day
	Days 31-60:	$1000 per emission release point per Day
	Days 61 and beyond:	$2000 per emission release point per Day or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(p) Violation of Paragraph 21. Failure to comply with any requirement of 40 C.F.R. Part 60, Subparts A and Ja for the Kapolei SRP as required by Paragraph 21.	Days 1-30:	$1000 per emission release point (or per SRP if applying a flow rate weighted average) per Day
	Days 31-60:	$2000 per emission release point (or per SRP if applying a flow rate weighted average) per Day
	Days 61 and beyond:	$3000 per emission release point (or per SRP if applying a flow rate weighted average) per Day or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(q) Violation of Paragraph 22. Failure to provide the Kapolei SRP CEMS/non-flare FGCD CMS report as required by Paragraph 22.	Days 1-30:	$500
	Days 31-60:	$1500
	Days 61 and beyond:	$2000.
(r) Violation of Paragraph 23. Failure to develop, submit, or implement CEMS/CMS O&M Plan as required by Paragraph 23.	Days 1-30:	$200
	Days 31-60:	$500
	Days 61 and beyond:	$1000.
(s) Violation of Paragraph 24. Failure to develop or implement the CEMS/CMS O&M training programs required by Paragraph 24.	Days 1-30:	$300
	Days 31-60:	$400
	Days 61 and beyond:	$500.
(t) Violation of Paragraph 25. Failure to certify, calibrate, maintain, and/or operate any CEMS/CMS as required by Paragraph 25 or the CEMS/CMS O&M Plan developed and implemented pursuant to Paragraph 23.	Days 1-30:	$200
	Days 31-60:	$500
	Days 61 and beyond:	$1000.

Consent Decree Violation	Period of Delay or Non-Compliance or Other Measure as Indicated	Penalty Per Violation Per Day or Other Time Period or Measure as Indicated
(u) Violation of Paragraph 26. Failure to develop or implement a Preventive Maintenance, Repair, or QA/QC program as required by Paragraph 26.	Days 1-30:	$500
	Days 31-60:	$1500
	Days 61 and beyond:	$2000.
(v) Violation of Paragraph 28. Failure to conduct a CEMS/CMS Root Cause Failure Analysis as required by Paragraph 28.	$5000 per month, per analysis.	
(w) Violation of Paragraph 30. Failure to implement any corrective action as required by Paragraph 30.	Days 1-15:	$500
	Days 16 -30:	$750
	Days 31 and beyond:	$1000, not to exceed $200,000 per occurrence.
(x) Violation of Paragraph 31. Failure to provide the tank report as required by Paragraph 31.	Days 1-30:	$500
	Days 31-60:	$1500
	Days 61 and beyond:	$2000.

iii. Kenai Refinery. Tesoro Alaska Company LLC and/or, if applicable under Paragraph 6 of this Consent Decree, Tesoro Logistics L.P., shall be liable for the following stipulated penalties for violations of the requirements of Section V.C of this Consent Decree:

Consent Decree Violation	Period of Delay or Non-Compliance or Other Measure as Indicated	Penalty Per Violation Per Day or Other Time Period or Measure as Indicated
(a) Violation of Paragraph 33. Failure to comply with any of the Upgraded CMS requirements in Paragraph 33.	$3500 per Day.	
(b) Violation of Paragraph 37. Failure to install, operate and maintain an ambient SO_2 monitoring system as required by Paragraph 37. Violations of Paragraphs 37.a and 37.i are addressed in (c) and (d) below.	$3500 per Day.	
(c) Violation of Paragraph 37.a. Failure to submit Acid Gas Flaring Event reports as required by Paragraph 37.a.	Days 1–30:	$500
	Days 31-60:	$1000
	Days 61 and beyond:	$2000.

Consent Decree Violation	Period of Delay or Non-Compliance or Other Measure as Indicated	Penalty Per Violation Per Day or Other Time Period or Measure as Indicated
(d) Violation of Paragraph 37.i. Failure to submit SO_2 monitoring data as required by Paragraph 37.i.	Days 1-30:	$500
	Days 31-60:	$1000
	Day 61 and beyond:	$2000.
(e) Violation of Paragraph 38.b. Failure to implement a third-party compliance auditing program as required by Paragraph 38.b. Violations of Paragraphs 38.b.vii and 38.b.viii are addressed in (f) below.	$2500 per Day.	
(f) Violation of Paragraphs 38.b.vii or 38.b.viii. Failure to timely submit an AOP Compliance Audit Report as required by Paragraph 38.b.vii or 38.b.viii.	Days 1-30:	$500
	Days 31-60:	$1000
	Days 61 and beyond:	$2000.

iv. Mandan Refinery. Tesoro Refining & Marketing Company LLC and/or, if applicable under Paragraph 6 of this Consent Decree, Tesoro Logistics L.P., shall be liable for the following stipulated penalties for violations of the requirements of Section V.D of this Consent Decree.

Consent Decree Violation	Period of Delay or Non-Compliance or Other Measure as Indicated	Penalty Per Violation Per Day or Other Time Period or Measure as Indicated
(a) Violation of Paragraph 39. Failure to conduct stack test at the Mandan FCCU as required by Paragraph 39.	Days 1-30:	$500
	Days 31-60:	$1000
	Days 61 and beyond:	$2000.
(b) Violation of Paragraph 40. Failure to operate scrubber and wet electrostatic precipitator as required by Paragraph 40.	Days 1-30:	$500
	Days 31-60:	$1000
	Days 61 and beyond:	$2000.
(c) Violation of Paragraph 41.a. Failure to develop, submit, or implement the CMS O&M Plan required by Paragraph 41.a.	Days 1-30:	$200
	Days 31-60:	$500
	Days 61 and beyond:	$1000.

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(d) Violation of Paragraph 41.a.i. Failure to develop or implement CMS training programs required by Paragraph 41.a.i.	Days 1-30:	$300
	Days 31-60:	$400
	Days 61 and beyond:	$500.
(e) Violation of Paragraph 41.a.ii or the CMS O&M Plan. Failure to certify, calibrate, maintain, and/or operate any CMS as required by Paragraph 41.a.ii or the CMS O&M Plan.	Days 1-30:	$200
	Days 31-60:	$500
	Days 61 and beyond:	$1000.
(f) Violation of Paragraph 41.a.iii-iv and Paragraph 41.c. Failure to develop or implement a Preventive Maintenance, Repair, or QA/QC program as required by Paragraph 41.a.iii-iv and Paragraph 41.c.	Days 1-30:	$500
	Days 31-60:	$1500
	Days 61 and beyond:	$2000.
(g) Violation of Paragraph 41.d. Failure to conduct a CMS Root Cause Failure Analysis required by Paragraph 41.d.	$5000 per month, per analysis.	
(h) Violation of Paragraph 41.e. Failure to implement any corrective action as required by Paragraph 41.e.	Days 1 – 15:	$500
	Days 16 -30:	$750
	Days 31 and beyond:	$1000, not to exceed $200,000 per occurrence.

v. Martinez Refinery. Tesoro Refining & Marketing Company LLC and/or, if applicable under Paragraph 6 of this Consent Decree, Tesoro Logistics L.P., shall be liable for the following stipulated penalties for violations of the requirements of Section V.E of this Consent Decree.

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(a) Violation of Paragraph 43. Failure to comply with the Interim or Final Martinez Short-Term or Long-Term FCCU NO_X Emission Limit established in Paragraph 43.	$2500 per FCCU per Day on which the specified 7-day or 365-day rolling average exceeds the applicable limit.	
(b) Violation of Paragraph 44. Failure to install, certify, calibrate, maintain, and/or operate an FCCU NO_X and/or O_2 CEMS as required by Paragraph 44.	Days 1–30:	$500 per unit per Day
	Days 31–60:	$1000 per unit per Day
	Days 61 and beyond:	$2000 per unit per Day or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(c) Violation of Paragraph 45. Failure to comply with the Long-Term Martinez FCCU CO Emission Limit established in Paragraph 45.	$2,500 per FCCU per Day on which the specified 365-day rolling average exceeds the applicable limit.	
(d) Violation of Paragraph 46. Failure to install, certify, calibrate, maintain, and/or operate a CO CEMS at the Martinez FCCU as required by Paragraph 46.	Days 1-30:	$500 per unit per Day
	Days 31-60:	$1000 per unit per Day
	Days 61 and beyond:	$2000 per unit per Day, or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(e) Violation of Paragraph 47. Failure to comply with any Sulfur Pit emissions requirement in Paragraph 47.	Days 1-30:	$2000
	Days 31-60:	$3500
	Days 61 and beyond:	$5000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(f) Violation of Paragraph 48. Failure to comply with the Preventive Maintenance and Operation Plan as required by Paragraph 48.	Days 1-30:	$500
	Days 31-60:	$1500
	Days 61 and beyond:	$2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(g) Violation of Paragraph 49.a. Failure to comply with Delayed Coker pressure requirement in Paragraph 49.a.	Days 1-30:	$1000
	Days 31-60:	$2000
	Days 61 and beyond:	$3000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(h) Violation of Paragraph 49.b. Failure to comply with Delayed Coker pressure requirement in Paragraph 49.b.	Days 1-30:	$350
	Days 31-60:	$1500
	Days 61 and beyond:	$3000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(i) Violation of Paragraphs 50-51. Failure to comply with any Delayed Coker requirement in Paragraphs 50-51.	Days 1-30:	$1000
	Days 31-60:	$2000
	Days 61 and beyond:	$3000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(j) Violation of Paragraph 52.a. Failure to comply with the Short-Term SAP SO_2 Emission Limit established in Paragraph 52.a.	Percentage Over the Limit	Penalty per Violation
	1-50%	$250
	51-100%	$500
	Over 100%	$750
	No separate stipulated penalty will apply with respect to the limit on SO_2 emissions under 40 C.F.R. Part 60, Subpart H.	

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(k) Violation of Paragraph 52.a. Failure to comply with the Long-Term SAP SO_2 Emission Limit established in Paragraph 52.a.	Days 1-14:	$1000
	Days 15-30:	$1500
	Day 31 and beyond:	$2000
	No separate stipulated penalty will apply with respect to the limit on SO_2 emissions under 40 C.F.R. Part 60, Subpart H.	
(l) Violation of Paragraph 53 or Appendix A-1. Failure to install, certify, calibrate, maintain, and/or operate all CEMS as required by Paragraph 53 or the SAP Monitoring Plan, attached as Appendix A-1.	Days 1-30:	$500 per unit per Day
	Days 31-60:	$1000 per unit per Day
	Days 61 and beyond:	$2000 per unit per Day or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(m) Violation of Paragraph 53 or Appendix A-1. Failure to comply with any other provision in the SAP Monitoring Plan as required by Paragraph 53 or Appendix A-1 (except failure to install, certify, calibrate, maintain, and/or operate all CEMS will be addressed under Paragraph 188.a.v.(l) above).	Days 1-14:	$1500
	Days 15-30:	$2000
	Days 31 and beyond:	$2500.
(n) Violation of Paragraph 54.b. If Tesoro uses a COMS to comply with the Opacity limit, failure to certify, calibrate, maintain, and/or operate the COMS as required by 40 C.F.R. Part 60, Subpart A.	Days 1-30:	$500 per unit per Day
	Days 31-60:	$1000 per unit per Day
	Days 61 and beyond:	$2000 per unit per Day or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(o) Violation of Paragraph 54.b. Failure to comply with the Opacity emission limit as required by Paragraph 54.b and 40 C.F.R. Part 60, Subpart H.	$40 per six (6) minute average reading in excess of the limit, up to a maximum of $2000 per Day.	

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(p) Violation of Paragraph 54.b. Failure to comply with the Acid Mist emission limit, and/or, if using COMs, failure to comply with Opacity emissions limit as required by Paragraph 54.b and 40 C.F.R. Part 60, Subpart H.	**Percentage Over the Limit**	**Penalty per Violation**
	1-50%	$250
	51-100%	$500
	Over 100%	$750.
(q) Violation of Paragraph 55. Failure to comply with the performance testing, notification, or reporting as required by Paragraph 55.	Days 1-14:	$1000
	Days 15-30:	$1500
	Days 31 and beyond:	$2000.
(r) Violation of Paragraphs 56.a and 56.b. Failure to prepare and submit to EPA an O&M Plan as required by Paragraphs 56.a and 56.b.	Days 1-14:	$150
	Days 15-30:	$250
	Days 31 and beyond:	$500.
(s) Violation of Paragraph 56.c. Failure to comply with the O&M Plan as required by Paragraph 56.c.	Days 1-14:	$150
	Days 15-30:	$250
	Days 31 and beyond:	$500.
Violations of Appendix A-2 of this Consent Decree	**Period of Delay or Non-Compliance**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(t) Violation of Appendix A-2, Paragraph B.1. Failure to comply with the SO_2 emission limits for the Martinez FCCU exhaust gas as required by Appendix A-2, Paragraph B.1.	$750 for each Day in a Calendar Quarter on which the specified 7-day rolling average exceeds the applicable limit; $2500 for each Day in a Calendar Quarter on which the specified 365-day rolling average exceeds the applicable limit.	
(u) Violation of Appendix A-2, Paragraph B.1. Failure to comply with the HTO Plan required by Appendix A-2, Paragraph B.1 for operating the Martinez FCCU in the event of a hydrotreater outage.	Days 1-30:	$250
	Days 31-60:	$1000
	Days 61 and beyond:	$2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

Violations of Appendix A-2 of this Consent Decree	**Period of Delay or Non-Compliance**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(v) Violation of Appendix A-2, Paragraph B.2. Failure to comply with 40 C.F.R. Part 60, Subpart J emission limits as required by Appendix A-2, Paragraph B.2.	Days 1-30:	$2500 per emission point per Day
	Days 31 and beyond:	$5000 per emission point per Day or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(w) Violation of Appendix A-2, Paragraph C.4 or C.5. Failure to comply with the PM emission limit for the Martinez FCCU as required by Appendix A-2, Paragraph C.4 or C.5.	$3000 for each Day in a Calendar Quarter on which the Martinez FCCU exceeds the specified limit	
(x) Violation of Appendix A-2, Paragraph D.7 or D.8. Failure to comply with the CO emission limit for the Martinez FCCU as required by Appendix A-2, Paragraph D.7 or D.8.	$750 for each Day in a Calendar Quarter on which the specified one-hour average exceeds the applicable limit.	
(y) Violation of Appendix A-2, Section E. Failure to achieve the final emission reduction goals in accordance with Appendix A-2, Section E.	$200,000 per quarter.	
(z) Violation of Appendix A-2, Paragraph 13. Burning Fuel Oil in a manner inconsistent with the requirements of Appendix A-2, Paragraph 13.	Days 1-30:	$1750 per unit per Day
	Days 31 and beyond:	$5000 per unit per Day or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(aa) Violation of Appendix A-2, Paragraph 16. Failure to comply with the 40 C.F.R. Part 60, Subpart J emission limits required by Appendix A-2, Paragraph 16.	Days 1-30:	$1000 per unit per Day in a Calendar Quarter
	Days 31-60:	$2000 per unit per Day in a Calendar Quarter
	Days 61 and beyond:	$3000 per unit per Day in a Calendar Quarter or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

Violations of Appendix A-2 of this Consent Decree	**Period of Delay or Non-Compliance**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(bb) Violation of Appendix A-2, Section G. Each rolling 12-hour average of SO_2 emissions from the Martinez SRP in excess of the limitations of 40 C.F.R. § 60.104(a)(2)(i) that is not attributable to Startup, Shutdown, or Malfunction of the SRP, or that is not attributable to Malfunction of the associated Tail Gas treatment unit.	**Number of rolling 12-hour average exceedance**	**Penalty per rolling 12-hour average exceedances within a Day**
	1-12	$350
	13 and beyond	$750.
(cc) Violation of Appendix A-2, Paragraph 18. Operation of the Martinez SRP during scheduled maintenance of its associated Tail Gas treatment unit (except that this stipulated penalty shall not apply during periods in which Tesoro is engaged in the Shutdown of the Martinez SRP for, or Startup of the Martinez SRP following, scheduled maintenance of the SRP).	$25,000 per SRP per Day.	
(dd) Violation of Appendix A-2, Paragraph B.3, C.6, D.9, F.15, or G.17; or Section E. Failure to conduct any performance test; or to install, calibrate, and operate a CEMS or COMS.	Days 1-30:	$500
	Days 31-60:	$1,000
	Days 61 and beyond:	$2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

vi. SLC Refinery. Tesoro Refining & Marketing Company LLC, and/or, if applicable under Paragraph 6 of this Consent Decree, Tesoro Logistics L.P., shall be liable for the following stipulated penalties for violations of the requirements of Section V.F of this Consent Decree.

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(a) Violation of Paragraph 60.a. Failure to install a non regenerative wet gas scrubber and LoTOx System or equivalent on the FCCU as required by Paragraph 60.a.	$10,000 per Day.	

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
(b) Violation of Paragraph 60.b. Failure to comply with the Short-Term or Long-Term SLC FCCU NO_X Emissions Limit established in Paragraph 60.b.	$2500 per unit per Day on which the specified 7-day or 365-day rolling average exceeds the applicable limit.	
(c) Violation of Paragraph 60.d. Failure to install, certify, calibrate, maintain, and/or operate an FCCU NOx and/or O_2 CEMS as required by Paragraph 60.d.	Days 1-30:	$500
	Days 31-60	$1000
	Days 61 and beyond:	$2000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(d) Violation of Paragraph 61.a. Failure to comply with the Short-Term or Long-Term SLC FCCU SO_2 Emission Limit established in Paragraph 61.a.	$3000 per unit per Day on which the specified 7-day or 365-day average exceeds the applicable limit.	
(e) Violation of Paragraph 61.c. Failure to install, certify, calibrate, maintain, and/or operate an FCCU SO_2 and/or O_2 CEMS as required by Paragraph 61.c.	Days 1-30:	$500
	Days 31-60:	$1000
	Days 61 and beyond:	$2000, or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
(f) Violation of Paragraph 62.a. Failure to comply with the Short-Term or Long-Term SLC FCCU CO Emission Limit established in Paragraph 62.a.	$2,500 per unit per Day on which the specified one-hour block average or 365-day rolling average exceeds the applicable limit.	
(g) Violation of Paragraph 62.c. Failure to install, certify, calibrate, maintain, and/or operate an FCCU CO CEMS as required by Paragraph 62.c.	Days 1-30:	$500
	Days 31-60:	$1000
	Days 61 and beyond:	$2000, or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

b. Violations of ELDAR Program Requirements at Covered Process Units. The Settling Defendant(s) responsible for compliance at each Covered Refinery as specified in Paragraph 6 of this Consent Decree shall be liable for the following stipulated penalties for violations of the requirements of Section VI.A (ELDAR Program Requirements):

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
i. Violation of Paragraph 74. Failure to timely develop and complete a written facility-wide LDAR Program Plan, or to timely update the LDAR Program Plan as required by Paragraph 74.	Days 1-30:	$300 per Day per Refinery
	Days 31-60:	$400 per Day per Refinery
	Days 61 and beyond:	$500 per Day per Refinery.
ii. Violation of Paragraph 75. Failure to perform initial, refresher, or new personnel training as required by Paragraph 75.	$1000 per person, per month of non-compliance	
iii. Violation of Paragraphs 76-79. Failure to conduct an LDAR audit in accordance with schedule in Paragraphs 76-79.	Days 1-15:	$300
	Days 16-30:	$400
	Days 31 and beyond:	$500, not to exceed $100,000 per audit.
iv. Violation of Paragraph 77. Failure to use a third-party auditor, or to use a third-party auditor that is not experienced in LDAR audits as required by Paragraph 77.	$25,000 per audit.	
v. Violation of Paragraph 79. Failure to complete audit as required by Paragraph 79 or failure to substantially comply with the comparative monitoring requirements of Paragraph 79.	$50,000 per audit.	
vi. Violation of Paragraphs 79. Failure to comply with the requirements for LDAR Audits in Paragraphs 79.a-d, except for comparative monitoring.	$10,000 per missed requirement, not to exceed $100,000 per audit.	
vii. Violation of Paragraph 81 or Paragraph 82. Failure to timely develop and/or submit a Corrective Action Plan as required by Paragraph 81 or failure to timely submit a Certification of Compliance, as required by Paragraph 82.	Days 1-15:	$100
	Days 16-30:	$250
	Days 31 and beyond:	$500, not to exceed $100,000 per audit.

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
viii. Violation of Paragraph 81. Failure to implement corrective action within 90 Days after the LDAR Audit Completion Date, or pursuant to the approved schedule, as required by Paragraph 81.	Days 1 -15:	$500
	Days 16 -30:	$750
	Days 31 and beyond:	$1000, not to exceed $200,000 per audit.
ix. Violation of Paragraphs 83-84. Failure to comply with monitoring frequency requirements set forth in Paragraphs 83-84	$100 per component but not greater than $10,000 per month, per unit	
x. Violation of Paragraph 85. Failure to properly perform Method 21 (or the AWP, as applicable) as set forth in Paragraph 85, performing LDAR monitoring, as indicated by the leak percentage ratio calculated under Paragraph 79 of the ELDAR Program, but only if the auditor identifies a leak rate of at least 0.5% per component type in the process unit.	**Leak Percentage Ratio**	**Penalty per Covered Process Unit**
	3.0 or greater but less than 4.0	$15,000
	4.0 or greater but less than 5.0	$30,000
	5.0 or greater but less than 6.0	$45,000
	6.0 or greater	$60,000
xi. Violation of Paragraph 85. Failure to use a monitoring device that is attached to a data logger; failure, during each monitoring event, to directly electronically record the Screening Value, date, time, identification number of the monitoring equipment, or the identification of the technician, as required by Paragraph 85.	$100 per failure per piece of Covered Equipment, but not greater than $5,000 per unit per month.	
xii. Violation of Paragraph 85. Failure to transfer monitoring data to an electronic database on at least a weekly basis, as required by Paragraph 85.	$150 per Day for each Day that the transfer is late.	
xiii. Violation of Paragraphs 90- 91. Failure to timely perform a first attempt at repair as required by Paragraphs 90- 91. For purposes of this Paragraph 188.b.xiii the term "repair" includes the required Repair Verification Monitoring in Paragraph 92 after the first repair attempt (in which case the stipulated penalties of Paragraph 185.c.xv do not apply).	$150 per Day for each Day after deadline, not to exceed $1500 per leak.	

Consent Decree Violation	**Period of Delay or Non-Compliance or Other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
xiv. Violation of Paragraph 91. Failure to timely perform a final attempt at repair as required by Paragraph 91. For purposes of this Paragraph188.b.xiv, the term "repair" includes the required Repair Verification Monitoring in Paragraph 92 after the first repair attempt (in which case the stipulated penalties of Paragraph185188.b.xv do not apply).	Valves	$300 per Day per component not to exceed $37,500.
	Pumps	$1200 per Day per component not to exceed $150,000.
xv. Violation of Paragraph 92. Failure to timely perform Repair Verification Monitoring where the first attempt to repair was made within 5 Days and the final attempt to repair was made within 15 Days as required by Paragraph 92.	Valves	$150 per Day per component, not to exceed $18,750.
	Pumps	$600 per Day per component, not to exceed $75,000.
xvi. Violation of Paragraph 93. Failure to undertake drill-and-tap repairs as required by Paragraph 93.	Days 1-15:	$200 per Covered Process Unit
	Days 16-30:	$350 per Covered Process Unit
	Days 31 and beyond:	$500 per Covered Process Unit, not to exceed $37,500.
xvii. Violation of Paragraph 95. Failure to record the information required by Paragraph 95.	$100 per component, per item of missed information.	
xviii. Violation of Paragraph 97. Improperly placing a piece of Covered Equipment on the DOR list.	Valves	$300 per Day per component, not to exceed $75,000.
	Pumps	$1200 per Day per component, not to exceed $300,000.
xix. Violation of Paragraph 97.a. Failure of the relevant manager or official to sign-off on placing a piece of Covered Equipment on the DOR list as required by Paragraph 97.a.	$250 per piece of Covered Equipment.	
xx. Violation of Paragraph 97.c. Failure to comply with the 0.10% limit on valves that may be placed on the DOR list as required by Paragraph 97.c.	$5,000 per valve.	

Consent Decree Violation	Period of Delay or Non-Compliance or Other Measure as Indicated	Penalty Per Violation Per Day or Other Time Period or Measure as Indicated
xxi. Violation of Paragraph 99. Failure to install a Certified Low-Leaking Valve or to fit a valve with Certified Low-Leaking Valve Packing as required by Paragraph 99.	$1000 per valve required by Paragraph 99.a-d and $5000 per valve required by Paragraph 99.e.	
xxii. Violation of Paragraph 103. Failure to add a piece of Covered Equipment to the LDAR program as required by Paragraph 103.	$300 per piece of Covered Equipment (plus an amount, if any, due under Paragraph 188.c.x-xi for any missed monitoring for a component that should have been added to the LDAR program).	
xxiii. Violation of Paragraph 103. Failure to remove a piece of Covered Equipment from the LDAR program as required by Paragraph 103.	$150 per piece of Covered Equipment.	
xxiv. Violation of Paragraph 104. Failure of a monitoring technician to complete the certification as required by Paragraph 104.	$100 per failure, per technician.	
xxv. Violation of Paragraph 105. Failure to comply with QA/QC requirements in Paragraph 105.	$1000 per missed requirement, per year.	

c. Violations of Flaring Requirements at Covered Flares. The Settling Defendant(s) responsible for compliance at each Covered Refinery as specified in Paragraph 6 of this Consent Decree shall be liable for the following stipulated penalties for violations of the requirements of Section VI.B (Requirements for Control of Flaring Events).

Consent Decree Violation	Period of Delay or Non-Compliance or other Measure as Indicated	Penalty Per Violation Per Day or Other Time Period or Measure as Indicated
i. Violation of Paragraph 113. Failure to implement Interim Combustion Efficiency Measures as required by Paragraph 113.	Days 1-30:	$500 per Flare per Day
	Days 31-60:	$1500 per Flare per Day
	Days 61 and beyond:	$2500 per Flare per Day.
ii. Violation of Paragraphs 114-115. Failure to timely upgrade or replace, if necessary to ensure an acceptable level of control over flow, Sweep and Purge Gas flow meters that conform to the requirements of Paragraph 114 or failure to timely implement the measures necessary to minimize Sweep and Purge Gas flow as required by Paragraph 115.	Days 1-30:	$250 per Meter per Day
	Days 31-60:	$500 per Meter per Day
	Days 61 and beyond:	$1250 per Meter per Day.

Consent Decree Violation	**Period of Delay or Non-Compliance or other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
iii. Violation of Paragraph 116. Failure to timely complete the Initial PRV Leak Survey as required by Paragraph 116.	Days 1-30:	$250
	Days 31-60:	$500
	Days 61 and beyond:	$1250.
iv. Violation of Paragraph 116. Failure to timely repair each leaking PRV as required by Paragraph 116.	Days 1-30:	$500
	Days 31-60:	$700
	Days 61 and beyond:	$1000.
v. Violation of Paragraphs 117-119, 121-122 and 144. Failure to timely install the equipment and monitoring systems as required by Paragraphs 117-119, 121-122 and 144.	Days 1-30:	$750 per monitoring system per Day
	Days 31-60:	$1250 per monitoring system per Day
	Days 61 and beyond:	$2000 per monitoring system per Day or an amount equal to 1.2 times the economic benefit of delayed compliance.
vi. Violation of Paragraphs 117-119, 122 and 144. Failure to operate the monitoring instrument as required by Paragraphs 117-119, 122 and 144.	**Per monitoring instrument, number of Hours per Calendar Quarter of Downtime over 5% of the time that the Covered Flare is In Operation and Capable of Receiving Sweep, Supplemental, and/or Waste Gas in a six month period**	**Penalty per Hour per monitoring instrument:**
	0.25-100.0	$250
	100.25-200.0	$500
	Over 200.0	$1000
	For any monitoring system that serves as a dual purpose, this stipulated penalty applies per instrument only.	

Consent Decree Violation	**Period of Delay or Non-Compliance or other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
vii. Violation of Paragraph 121. Failure to comply with the equipment and instrumentation technical specifications and quality assurance/quality control specifications and requirements in Appendix C - 1.10.	**Type of Requirement**	**Penalty per Violation per day**
	Daily requirement	$100
	Quarterly requirement	$200
	Annual requirement	$300.
viii. Violation of Paragraphs 127-128. Failure to submit an Initial Flare Management Plan as required by Paragraph 127 and subsequent plans required by Paragraphs 127-128.	Days 1-30:	$500
	Days 31-60:	$750
	Days 61 and beyond:	$1000.
ix. Violation of Paragraph 130. Failure to timely install, in accordance with Paragraph 130 and Appendix 2.1, a Flare Gas Recovery System that conforms to the requirements of Paragraph 130.	Days 1-30:	$1250 per FGRS
	Days 31-60:	$3000 per FGRS
	Days 61 and beyond:	$5000 per FGRS or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.
x. Violation of Paragraphs 130-131. Failure to have the required number of Compressors at each FGRS Available for Operation and/or In Operation 98% of the time or failure to have the required number of Compressors at each FGRS Available for Operation and/or In Operation 95% of the time as required by Paragraphs 130-131.	$750 Per FGRS, per hour or fraction thereof – in a rolling 8760-hour period that a Compressor required to be Available for Operation is not Available for Operation.	
xi. Violation of Paragraph 132. Failure to comply with the refinery-wide, 30-day Rolling Average limit on Waste Gas flaring as required by Paragraph 132.	**Magnitude of Exceedance**	**Penalty per Refinery per Day**
	≤ 10%	$6250
	>10% to ≤ 20%	$12,500
	>20%	$18,750.

<table>
<tr><td>Consent Decree Violation</td><td colspan="2">Period of Delay or Non-Compliance or other Measure as Indicated</td><td>Penalty Per Violation Per Day or Other Time Period or Measure as Indicated</td></tr>
<tr><td rowspan="4">xii. Violation of Paragraph 132. Failure to comply with the refinery-wide 365-day Rolling Average limit on Waste Gas flaring as required by Paragraph 132.</td><td colspan="2">Magnitude of Exceedance</td><td>Penalty per Refinery per Day</td></tr>
<tr><td colspan="2">≤ 10%</td><td>$12,500</td></tr>
<tr><td colspan="2">>10% to ≤ 20%</td><td>$18,750</td></tr>
<tr><td colspan="2">>20%</td><td>$37,500.</td></tr>
<tr><td colspan="4">xiii. For any given Day, where a failure to comply with the 30-day and/or the 365-day Rolling Average limit on Waste Gas flaring required by Paragraph 132 (and potentially subject to the stipulated penalty provisions of Paragraph 188.c.xi-xii) is the result of a failure to have the requisite number of Compressors Available for Operation as required by Paragraphs 130-131 (and potentially subject to the stipulated penalty provision of Paragraph 188.c.x) only the stipulated penalty provision that results in the higher penalty shall be applicable for that Day (i.e., the stipulated penalties under Paragraphs 188.c.x, 188.c.xi and 188.c.xii shall not be assessed). Nothing in the previous sentence shall be construed to result in only one penalty being applicable on any given Day for violation of both the 30-day and the 365-day Rolling Average limits on Waste Gas flaring (i.e., for any given Day in which both the 30-day Rolling Average limits are violated, stipulated penalties under both Paragraphs (188.c.xi and 188.c.xii) may be assessed).</td></tr>
<tr><td>xiv. Violation of Paragraph 137.
Failure to comply with the Automatic Control System required by Paragraph 137.</td><td colspan="3">$500 per Flare per Day.</td></tr>
<tr><td rowspan="5">xv. Violation of Paragraph 139. Failure to comply with the Net Heating Value Standards in Paragraph 139.</td><td>On a per Covered Flare Basis, Hours of Non-compliance:</td><td colspan="2">Penalty per Covered Flare per Hour or Fraction thereof:</td></tr>
<tr><td>No. of hours: 0.25-100.0</td><td colspan="2">$150 per hour</td></tr>
<tr><td>No. of hours: 100.25-200.0</td><td colspan="2">$350 per hour</td></tr>
<tr><td>No. of hours: over 200</td><td colspan="2">$500 per hour.</td></tr>
<tr><td colspan="3">For purposes of calculating the number of hours of non-compliance with the NHVcz standard, all 15-minute periods of violation shall be added together to determine the total.
The period for calculating a stipulated penalty under this Subparagraph is different than the averaging period of the underlying requirement. For example, if Tesoro has six exceedances of a standard expressed as a 15-minute Block Average, then the stipulated penalty would be assessed on 1.5 hours of violation.</td></tr>
</table>

Consent Decree Violation	**Period of Delay or Non-Compliance or other Measure as Indicated**	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
xvi. Violation of Paragraphs 142, 143.e and 152-153. Failure to record and retain any information as required by Paragraphs 142, 143.e and 152-153.	$100 per Day.	
xvii. Violation of Paragraphs 143.d.i and ii. Failure to ensure that a Portable Flare that falls under the conditions of Paragraphs 143.d.i and ii complies with the requirements of those Paragraphs.	Days 1-7:	$1000
	Days 8-15:	$2000
	Days 16 and beyond:	$5000.
xviii. Violation of Paragraph 145. For Air Assisted Flares failure to comply with the NHV_{dil} Standard in Paragraph 145.	**On a per Covered Flare Basis, Hours of Non-compliance:**	**Penalty per Covered Flare per Hour or Fraction thereof:**
	No of hours: 0.166-100.0	$100 per hour
	No. of hours: 100.166-200.0	$200 per hour
	No. of hours: over 200	$300 per hour.
	The period for calculating a stipulated penalty under this Subparagraph is different than the averaging period of the underlying requirement. For example, if Tesoro has six exceedances of a standard expressed as a 15-minute Block Average Period, then the stipulated penalty would be assessed on 1.5 hours of violation.	
xix. Violation of Paragraph 146. Failure to timely conduct the testing set forth in Paragraph 146 in accordance with the protocol.	Days 1-30:	$250 per Flare test
	Days 31-60:	$500 per Flare test
	Days 61 and beyond:	$1000 per Flare test.
xx. Violation of Paragraphs 146-147. Failure to timely submit a test protocol that conforms to the requirements of this Consent Decree as required by Paragraph 146 or failure to timely submit a test report that conforms to the requirements of this Consent Decree as required by Paragraph 147.	Days 1-30:	$200
	Days 31-60:	$300
	Days 61 and beyond:	$400.

<table>
<tr><th>Consent Decree Violation</th><th>Period of Delay or Non-Compliance or other Measure as Indicated</th><th>Penalty Per Violation Per Day or Other Time Period or Measure as Indicated</th></tr>
<tr><td rowspan="5">xxi. Violation of Paragraph 151. Failure to comply with the NSPS Subpart A or Ja H_2S emission limit at an affected facility under Paragraph 151.</td><td>On a per Covered Flare Basis, Hours of Non-compliance:</td><td>Penalty per Covered Flare per Hour:</td></tr>
<tr><td>No of hours: 1-50</td><td>$50 per hour</td></tr>
<tr><td>No of hours: 51-100</td><td>$100 per hour</td></tr>
<tr><td>No of hours: over 100</td><td>$200 per hour</td></tr>
<tr><td colspan="2">For purposes of calculating the number of hours of non-compliance with the H_2S limit, all hours of violation shall be added together to determine the total. The averaging period for this standard is a 3-hour Rolling Average.

The period for calculating a stipulated penalty under this Subparagraph is different than the averaging period of the underlying requirement. For example, if Tesoro has an exceedance of a standard expressed as a 3-hour Rolling Average in 6 15-minute Block Periods, then the stipulated penalty would be assessed on 1.5 hours of violation.</td></tr>
</table>

189. Violation of Other Consent Decree Requirements. The Settling Defendant(s) responsible for compliance pursuant to Paragraph 6 of this Consent Decree shall be liable for the following stipulated penalties for the following other violations of this Consent Decree at the Covered Refineries:

Consent Decree Violation	Penalty Per Violation Per Day or Other Time Period or Measure as Indicated
Failure to submit a written report or deliverable (unless a more specific stipulated penalty applies in Paragraphs 187-188.a-c above).	Period of Delay or Non-Compliance Penalty per Day Days 1-30: $300 Days 31-60: $1000 Days 61 and beyond: $2000.
Violation of Paragraphs 154-157. Failure to submit an application to incorporate Consent Decree requirements into relevant local, state and/or federal permits as required by Paragraphs 154-157.	Period of Delay or Non-Compliance Penalty per Day Days 1-30: $500 Days 31-60: $1500 Days 61 and beyond: $3000.

Consent Decree Violation	**Penalty Per Violation Per Day or Other Time Period or Measure as Indicated**
Violation of Paragraphs 162-168. Failure to implement Mitigation Projects as required by Paragraphs 162-168 and Appendices D 1-3.	Period of Delay or Non-Compliance Penalty per Day Days 1-30: $500 Days 31-60: $1500 Days 61 and beyond: $3000.
Failure to comply with any other Consent Decree term, condition, or requirement that does not have a specific stipulated penalty set forth in this Paragraph or Paragraphs 187-188 above.	$200 per violation per Day.

190. No amount of the stipulated penalties paid by Settling Defendants shall be used to reduce its federal tax obligations.

191. The United States and the State Co-Plaintiffs reserve the right to pursue any other nonmonetary remedies to which they are legally entitled, including but not limited to, injunctive relief and mitigation, for Settling Defendants' violations of this Consent Decree. Where a violation of this Consent Decree is also a violation of the Clean Air Act, its regulations, or a federally-enforceable state law, regulation, or permit, subject to the provisions of Section XVII of this Consent Decree (Effect of Settlement/Reservation of Rights), the stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to the United States for Settling Defendants' violations of this Consent Decree or applicable law except that where a violation of this Consent Decree is also a violation of federal or state law, Settling Defendants shall be allowed a credit for any stipulated penalties paid against any statutory penalties imposed for such violation.

XIII. RIGHT OF ENTRY

192. Any authorized representative of EPA or the Applicable State Co-Plaintiff, upon presentation of credentials, shall have a right of entry upon the premises of the Covered Refineries at any reasonable time (and subject to any applicable health and safety or legal requirements) for the purpose of monitoring compliance with the provisions of this Consent Decree, including inspecting plant equipment and systems, and inspecting all records maintained by Settling Defendants required by this Consent Decree or that EPA or the Applicable State Co-Plaintiff have notified Settling Defendants are reasonably necessary to verify compliance with this Consent Decree. Except where other time periods specifically are noted, Settling Defendants shall retain such records for the period of this Consent Decree. Nothing in this Consent Decree shall limit the authority of EPA or the Applicable State Co-Plaintiff to conduct tests, inspections, or other activities under any statutory or regulatory provision.

XIV. FORCE MAJEURE

193. "*Force majeure*" for purpose of this Consent Decree, is defined as any event arising from causes beyond the control of a Settling Defendant, of any entity controlled by a Settling Defendant, or of a Settling Defendant's contractors, that delays or prevents the performance of any obligation under this Consent Decree despite Settling Defendant's best efforts to fulfill the obligation. The requirement that a Settling Defendant 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 Settling Defendant's financial inability to perform any obligation under this Consent Decree. 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 Settling Defendant 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 Settling Defendant.

194. If any event occurs or has occurred that may delay the performance of any obligation under this Consent Decree, whether or not caused by a *force majeure* event, each Settling Defendant responsible for compliance with that requirement pursuant to Paragraph 6 above shall provide notice orally or by electronic or facsimile transmission to EPA and the Applicable State Co-Plaintiff(s) within three (3) Working Days of when the Settling Defendant first knew that the event might cause a delay. Within ten (10) Working Days thereafter, the Settling Defendant shall provide in writing to EPA and the Applicable State Co-Plaintiff an explanation and description of the reasons for the delay; the anticipated duration of the delay; all actions taken or to be taken to prevent or minimize the delay; a schedule for implementation of any measures to be taken to prevent or mitigate the delay or the effect of the delay; the Settling Defendant's rationale for attributing such delay to a *force majeure* event if it intends to assert such a claim; and a statement as to whether, in the opinion of the Settling Defendant, such event may cause or contribute to an endangerment to public health, welfare, or the environment. The Settling Defendant shall include with any notice all appropriate documentation supporting the claim that the delay was attributable to a *force majeure*. Failure to comply with the above requirements shall preclude the Settling Defendant from asserting any claim of *force majeure* for that event for the period of time of such failure to comply, and for any additional delay caused by such failure. The Settling Defendant shall be deemed to know of any circumstance of which the Settling Defendant, any entity controlled by the Settling Defendant, or the Settling Defendant's contractors had actual or constructive notice.

195. If EPA, after a reasonable opportunity for review and comment by the Applicable State Co-Plaintiff, agrees that the delay or anticipated delay is attributable to a *force majeure* event, the time for performance of the obligations under this Consent Decree that are affected by the *force majeure* event shall be extended by EPA, after a reasonable opportunity for review and comment by the Applicable State Co-Plaintiff, for such time as is necessary to complete those obligations. An extension of the time for performance of the obligations affected by the *force majeure* event shall not, of itself, extend the time for performance of any other obligation. As

soon as practicable, EPA shall notify the Settling Defendant in writing of the length of the extension, if any, for performance of the obligations affected by the *force majeure* event.

196. If EPA, after a reasonable opportunity for review and comment by the Applicable State Co-Plaintiff, does not agree that the delay or anticipated delay has been or will be caused by a *force majeure* event, EPA shall notify the Settling Defendant in writing of its decision as soon as practicable.

197. If the Settling Defendant elects to invoke the dispute resolution procedures set forth in Section XV (Dispute Resolution) with respect to EPA's decision regarding a *force majeure* claim, it shall do so no later than fifteen (15) Working Days after receipt of EPA's notice pursuant to Paragraphs 195 or 196 above. In any such proceeding, the Settling Defendant shall have the burden of demonstrating by a preponderance of the evidence that the delay or anticipated delay has been or will be caused by a *force majeure* event, that the duration of the delay or the extension sought was or will be warranted under the circumstances, that best efforts were exercised to avoid and mitigate the effects of the delay, and that the Settling Defendant complied with the requirements of Paragraphs 194 above. If the Settling Defendant carries this burden, the delay at issue shall be deemed not to be a violation by the Settling Defendant of the affected obligation of this Consent Decree identified to EPA and the Court.

XV. DISPUTE RESOLUTION

198. Unless otherwise expressly provided for in this Consent Decree, the dispute resolution procedures of this Section shall be the exclusive mechanism to resolve disputes arising under or with respect to this Consent Decree.

199. Informal Dispute Resolution. Any dispute subject to dispute resolution under this Consent Decree shall first be the subject of informal negotiations. The dispute shall be considered to have arisen when the Settling Defendant responsible for compliance with a particular Consent Decree provision pursuant to Paragraph 6 above disputes a decision of the United States pertaining to that provision and sends the United States a written Notice of Dispute with a copy to the Applicable State Co-Plaintiff. Such Notice of Dispute shall state clearly the matter in dispute. The period of informal negotiations shall not exceed twenty (20) Working Days from the date the dispute arises, unless that period is modified by written agreement. If the Parties cannot resolve a dispute by informal negotiations, then the position advanced by the United States shall be considered binding unless, within forty-five (45) Working Days after the conclusion of the informal negotiation period, the Settling Defendant invokes formal dispute resolution procedures as set forth below.

200. Formal Dispute Resolution. A Settling Defendant shall invoke formal dispute resolution procedures, within the time period provided in the preceding Paragraph, by serving on the United States, with a copy to the Applicable State Co-Plaintiff, a written Statement of Position regarding the matter in dispute. The Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting the Settling Defendant's position and any supporting documentation relied upon by a Settling Defendant.

201. The United States shall serve its Statement of Position within forty-five (45) Working Days of receipt of the Settling Defendant's Statement of Position. The United States' Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting that position and any supporting documentation relied upon by the United States. The United States' Statement of Position shall be binding on the Settling Defendant unless it files a motion for judicial review of the dispute in accordance with the following Paragraph.

202. The Settling Defendant may seek judicial review of the dispute by filing with the Court and serving on the United States a motion requesting judicial resolution of the dispute. The motion shall be filed within twenty-one (21) Working Days of receipt of the United States' Statement of Position pursuant to the preceding Paragraph. The motion shall contain a written statement of Settling Defendant's position on the matter in dispute, including any supporting factual data, analysis, opinion, or documentation, and shall set forth the relief requested and any schedule within which the dispute shall be resolved for orderly implementation of this Consent Decree.

203. The United States shall respond to Settling Defendant's motion within the time period allowed by the Local Rules of this Court for responding to a dispositive motion. The Settling Defendant may file a reply memorandum, to the extent and within the time period permitted by the Local Rules for a dispositive motion.

204. Standard of Review.

a. Disputes Concerning Matters Accorded Record Review. Except as otherwise provided in this Consent Decree, in any dispute brought under Paragraph 202 above pertaining to a matter that involves EPA's exercise of discretion under this Consent Decree, the Settling Defendant shall have the burden of proof based on the administrative record (including the Parties' Statements of Position) and the applicable standard of review as set forth in the Administrative Procedure Act, 5 U.S.C. § 500 et seq.

b. Other Disputes. Except as otherwise provided in this Consent Decree, in any other dispute brought under Paragraph 202 above, the Settling Defendant shall bear the burden of demonstrating that its position complies with this Consent Decree.

205. The invocation of dispute resolution procedures under this Section shall not, by itself, extend, postpone, or affect in any way any obligation of the Settling Defendant under this Consent Decree, unless and until final resolution of the dispute so provides. Stipulated penalties with respect to the disputed matter shall continue to accrue from the first Day of non-compliance, but payment shall be stayed pending resolution of the dispute as provided in Paragraph 185.b above. If the Settling Defendant does not prevail on the disputed issue, subject to the Court's order, stipulated penalties shall be assessed and paid as provided in Section XII (Stipulated Penalties).

XVI. REVIEW, APPROVAL, AND COMMENT ON DELIVERABLES

206. Where any provision of this Consent Decree specifically requires the submission of a plan, notification, report, procedure, protocol, or other deliverable (hereinafter referred to as a "submission") by a Settling Defendant to be subject to EPA approval or subject to EPA comment, or where any provision of this Consent Decree specifically references this Section XVI, the submission shall be subject to the provisions of this Section.

207. For each submission, the Settling Defendant shall submit one copy of the submission to each EPA addressee listed in Section XIX (Notices) along with all accompanying data in hard-copy paper and one copy of the submission to EPA along with all accompanying data in a widely-recognized electronic format (such as .pdf or Microsoft® Excel).

208. Submissions Subject to EPA Approval.

a. Unless otherwise provided herein, for submissions subject to EPA approval, EPA may approve the submission or decline to approve it, in whole or in part, and may provide written comments.

b. Unless otherwise provided herein, if EPA disapproves a submission, in whole or in part, it shall state in writing the basis for such disapproval.

c. Unless otherwise provided herein, upon receiving EPA's written comments or written notice that EPA disapproves a submission, in whole or in part, the Settling Defendant shall have: (i) forty-five (45) Days to alter the submission consistent with EPA's written comments or notice of disapproval and provide the submission to EPA for final approval; or (ii) to invoke dispute resolution under Section XV of this Consent Decree.

d. If EPA fails to approve or disapprove a submission writing within ninety (90) Days of the submission, Settling Defendant may invoke dispute resolution under Section XV of this Consent Decree for EPA's failure to act on the submission.

209. Submissions Subject to EPA Comment.

a. Unless otherwise provided herein, for submissions under any provision of this Consent Decree that are subject to EPA comment, EPA may provide written comments on the submission, in whole or in part, or may decline to comment. If EPA provides written comments within ninety (90) Days of receiving a submission, the Settling Defendant shall within forty-five (45) Days of receiving such comments either: (i) alter and implement the submission consistent with EPA's written comments; or (ii) submit the matter for dispute resolution under Section XV (Dispute Resolution) of this Consent Decree.

b. Unless otherwise provided herein, after ninety (90) Days from the date of such submission, EPA may nonetheless thereafter provide written comments requiring changes to the submission which the Settling Defendant shall implement unless implementation of the written comments would be unduly burdensome given the degree to which the Settling Defendant has

proceeded with implementing the deliverable or otherwise unreasonable. If the Settling Defendant determines that implementation of the written comments is unduly burdensome or otherwise unreasonable, it shall invoke dispute resolution within sixty (60) Days of receiving EPA comments.

210. Implementation of Plans, Limits, or Other Measures Pursuant to Submissions Subject to EPA Comment or Approval. Unless otherwise provided for herein, upon receipt of EPA's final approval of a submission, or upon the expiration of ninety (90) Days from the date of a submission subject to comment or approval or upon completion of any dispute resolution process under Section XV of this Consent Decree regarding a submission, the Settling Defendant shall implement the submission in accordance with the requirements and schedule within the submission.

XVII. EFFECT OF SETTLEMENT/RESERVATION OF RIGHTS

211. Definitions. For purposes of this Section XVII (Effect of Settlement/Reservation of Rights), the following definitions apply:

a. "Benzene Waste NESHAP Requirements" shall mean the requirements imposed by the National Emission Standard for Benzene Waste Operations, 40 C.F.R. Part 61, Subpart FF, any applicable state, regional, or local regulations that implement, adopt, or incorporate the Benzene Waste NESHAP and any Title V Permit requirement that implements, adopts, or incorporates the provisions cited in this Paragraph.

b. "Hazardous Air Pollutants" or "HAPs" shall have the meaning set forth in 42 U.S.C. § 7412(b)(1).

c. "LDAR Requirements" shall mean 40 C.F.R. Part 60, Subparts GGG and GGGa, 40 C.F.R. Part 61, Subparts J and V; and 40 C.F.R. Part 63, Subpart CC; any applicable state or local regulation that implements, adopts, or incorporates the federal provisions cited in this Paragraph; and any Title V Permit requirement that implements, adopts, or incorporates the provisions cited in this Paragraph.

d. "NNSR Requirements" shall mean the Non-Attainment New Source Review requirements found in the following: 42 U.S.C. §§ 7502(c)(5), 7503(a)-(c); 40 C.F.R. Part 51, Appendix S, Part IV, Conditions 1-4; any applicable, federally approved and federally enforceable state or local regulation that implements, adopts, or incorporates the federal provisions cited in this Paragraph; any Title V Permit requirement that implements, adopts, or incorporates the federal, or federally approved state, provisions cited in this Paragraph; and any applicable state or local regulation that implements, adopts, or incorporates the federal provisions cited in this Paragraph. This definition of NNSR Requirements includes all minor NSR requirements incorporated in a SIP or federal implementation plan.

e. "PSD Requirements" shall mean the Prevention of Significant Deterioration requirements found in the following: 42 U.S.C. § 7475; 40 C.F.R. §§ 52.21(a)(2)(iii) and 52.21(j) - 52.21(r)(5); any applicable, federally approved and federally enforceable state or local

regulation that implements, adopts, or incorporates the federal provisions cited in this Paragraph; any Title V Permit requirement that implements, adopts, or incorporates the federal, or federally approved state, provisions cited in this Paragraph; and any applicable state or local regulation that implements, adopts, or incorporates the federal provisions cited in this Paragraph. This definition of PSD Requirements includes all minor NSR requirements incorporated in a SIP or federal implementation plan.

212. Entry of this Consent Decree shall resolve the civil claims of the United States and the State Co-Plaintiffs for the violations alleged in the Complaint and the specific provisions set forth in Paragraphs 213-221 below.

213. Resolution of Claims for Violations of Requirements at Covered Flares.

a. Violations of PSD and NNSR Requirements at Covered Flares. With respect to emissions of SO_2, VOCs, CO and H_2S from Covered Flares, entry of this Consent Decree shall resolve the civil claims of the United States and the State Co-Plaintiffs against Settling Defendants for violations of the PSD and NNSR Requirements at Covered Flares resulting from any construction or modification occurring prior to the Date of Lodging for the time periods set forth in the following table:

Covered Refinery	**Dates of Release**
Anacortes	Date of construction or modification through October 1, 2017.
Kapolei	Date of construction or modification through October 1, 2017.
Kenai	Date of construction or modification through October 1, 2017.
Mandan	Date of construction or modification through October 1, 2017.
Martinez	Date of construction or modification through October 1, 2017.
Salt Lake City	Date of construction or modification through October 1, 2017.

b. Resolution of Claims for Violations of Listed Regulations at the Covered Flares. With respect to emissions of the following pollutants at Covered Flares, entry of this Consent Decree shall resolve the civil claims of the United States and the State Co-Plaintiffs against Settling Defendants for violations of regulations listed below that commenced prior to the Date of Lodging, and any applicable state regulations that implement, adopt, or incorporate any of the listed regulations, from the date the claim accrued through the date indicated on the following table:

Pollutant	Regulation(s)	End Date of Release
SO_2 and H_2S	40 C.F.R. Part 60, Subparts A and J.	November 11, 2015.
SO_2 and H_2S	40 C.F.R. Part 60, Subpart Ja.	November 11, 2015.
VOCs and HAPs	BTU/scf Flared Gas Requirements: 40 C.F.R. § 60.18(c)(3)(ii); 40 C.F.R. § 63.11(b)(6(ii); 40 C.F.R. §§ 60.482-10(d), 60.482-10a(d), but only to the extent that these provisions require compliance with 40 C.F.R. §§ 60.18(c)(3)(ii); 40 C.F.R. §§ 60.592(a), 60.592a(a), but only to the extent that these provisions: (a) relate to Flares, and (b) require compliance with 40 C.F.R. § 60.18(c)(3)(ii); 40 C.F.R. § 63.643(a)(1), but only to the extent that this provision requires compliance with 40 C.F.R. § 63.11(b)(6)(ii); 40 C.F.R. § 63.648(a), but only to the extent that this provision: (1) relates to Flares; and (2) requires compliance with 40 C.F.R. § 60.18(c)(3)(ii); 40 C.F.R. § 61.349(a)(2)(iii), but only to the extent that this provision requires compliance with 40 C.F.R. § 60.18(c)(3(iii); 40 C.F.R. § 63.1566(a)(1)(i) and Table 15, but only to the extent that these provisions: (1) relate to Flares; and (2) require compliance with 40 C.F.R. § 63.11(b)(6)(ii); and 40 C.F.R. § 63.113(a)(1)(i), but only to the extent that this provision requires compliance with 40 C.F.R. § 63.11(b)(6)(ii).	Date of Lodging.

Pollutant	Regulation(s)	End Date of Release
VOCs and HAPs (continued)	General Flare Requirements: 40 C.F.R. § 60.18(c)(1) and 40 C.F.R. § 63.11(b)(4) (both relate to a prohibition on Visible Emissions); 40 C.F.R. § 60.18(c)(2) and 40 C.F.R. § 63.11(b)(5) (both relate to flame presence); 40 C.F.R. §§ 60.18(c)(4) and 40 C.F.R. 63.11(b)(7) (both relate to exit velocity requirements for Steam Assisted Flares); and 40 C.F.R. § 60.18(e) and 40 C.F.R. § 63.11(b)(3) (both relate to operation during emissions venting). Good Air Pollution Control Practice Requirements: 40 C.F.R. § 60.11(d); 40 C.F.R. § 61.12(c); 40 C.F.R. § 63.6(e)(1)(i); 40 C.F.R. Part 63, Subpart CC, Table 6, but only to the extent that Table 6 requires compliance with 40 C.F.R. § 63.6(e)(1)(i); and 40 C.F.R. Part 63, Subpart UUU, Table 44, but only to the extent that Table 44 requires compliance with 40 C.F.R. § 63.6(e)(1). Requirements Related to Monitoring, Operation, and Maintenance According to Flare Design: 40 C.F.R. § 60.18(d); 40 C.F.R. § 63.11(b)(1); 40 C.F.R. §§ 60.482-10(d), 60.482-10a(d), but only to the extent that these provisions require compliance with 40 C.F.R. § 60.18(d); 40 C.F.R. §§ 60.482-10(e), 60.482-10a(e), but only to the extent that these provisions relate to Flares; 40 C.F.R. §§ 60.592(a), 60.591a(a), but only to the extent that these provisions: (1) relate to Flares; and (2) require compliance with 40 C.F.R. § 60.18(d); 40 C.F.R. § 63.643(a)(1), but only to the extent that this provision requires compliance with 40 C.F.R. § 63.11(b)(1); 40 C.F.R. § 63.648(a), but only to the extent that this provision: (1) relates to Flares; and (2) requires compliance with 40 C.F.R. § 60.18(d); and 40 C.F.R. § 63.1566(a)(1)(i) and Table 15, but only to the extent that this provision: (1) relates to Flares; and (2) requires compliance with 40 C.F.R. § 63.11(b)(1).	Date of Lodging

c. Resolution of Post-Lodging Claims Under Listed Regulations at Covered Flares. With respect to emissions of VOCs and HAPs at Covered Flares, entry of this Consent Decree shall resolve the civil claims of the United States and State Co-Plaintiffs against Settling Defendants for violations of the regulations listed in Paragraph 213.c.i below through the dates indicated in Paragraph 213.c.ii below but only to the extent that these claims are based on Settling Defendants' use of too much steam in relation to Vent Gas flow:

i. Listed Regulations.

40 C.F.R. § 60.18(d);
40 C.F.R. § 63.11(b)(1);
40 C.F.R. §§ 60.482-10(d), 60.482-10a(d), but only to the extent that these provisions require compliance with 40 C.F.R. § 60.18(d); 40 C.F.R. §§ 60.482-10(e), 60.482-10a(e), but only to the extent that these provisions relate to Flares;
40 C.F.R. §§ 60.592(a), 60.591a(a), but only to the extent that these provisions: (1) relate to Flares; and (2) require compliance with 40 C.F.R. § 60.18(d);
40 C.F.R. § 63.643(a)(1), but only to the extent that this provision requires compliance with 40 C.F.R. § 63.11(b)(1);
40 C.F.R. § 63.648(a), but only to the extent that this provision: (1) relates to Flares; and (2) requires compliance with 40 C.F.R. § 60.18(d); and
40 C.F.R. § 63.1566(a)(1)(i) and Table 15, but only to the extent that this provision: (1) relates to Flares; and (2) requires compliance with 40 C.F.R. § 63.11(b)(1).

ii. Dates of Release.

Covered Refinery	**End Date of Release**
Anacortes	October 1, 2017.
Kapolei	October 1, 2017.
Kenai	October 1, 2017.
Mandan	October 1, 2017.
Martinez	October 1, 2017.
Salt Lake City	October 1, 2017.

214. Resolution of Claims for Violation of LDAR Requirements. Entry of this Consent Decree shall resolve the civil claims of the United States and the State Co-Plaintiffs against

Settling Defendants for violations of LDAR Requirements that occurred during the time period set forth in the table below for each Covered Process Unit at each Covered Refinery.

Refinery	**Dates of Release**
Anacortes	January 1, 2006 through the LDAR Audit Completion Date and related corrective actions as set forth in Paragraph 82 of this Consent Decree, provided that Settling Defendant identifies any such violation of LDAR Requirements in its summary of LDAR audit results in a Compliance Status Report required under Paragraph 108.g and corrects such violation as required by Paragraphs 81-82.
Kapolei	January 1, 2006 through the LDAR Audit Completion Date and related corrective actions as set forth in Paragraph 82 of this Consent Decree, provided that Settling Defendant identifies any such violation of LDAR Requirements in its summary of LDAR audit results in a Compliance Status Report required under Paragraph 108.g and corrects such violation as required by Paragraphs 81-82.
Kenai	January 1, 2006 through the LDAR Audit Completion Date and related corrective actions as set forth in Paragraph 82 of this Consent Decree, provided that Settling Defendant identifies any such violation of LDAR Requirements in its summary of LDAR audit results in a Compliance Status Report required under Paragraph 108.g and corrects such violation as required by Paragraphs 81-82.
Mandan	January 1, 2006 through the Date of Lodging.
Martinez	January 1, 2006 through the Date of Lodging.
Salt Lake City	January 1, 2006 through the Date of Lodging.

215. Resolution of Claims for Other Violations at the Anacortes Refinery.

a. With respect to emissions of the following pollutants from those process units at the Anacortes Refinery listed in the table below, entry of this Consent Decree shall resolve the civil claims of the United States and the Northwest Clean Air Agency against Tesoro Refining & Marketing Company LLC and Tesoro Logistics L.P. for violations of those regulations listed in the table below, and any applicable state regulations that implement, adopt, or incorporate any of the listed regulations, that occurred during the time period listed in the table below.

Process Unit	**Pollutant(s)**	**Regulations**	**Dates of Release**
Heater F-201	SO_2 (H_2S)	Combusting Fuel Gas containing H_2S in excess of 230 milligrams per dry standard cubic meter in violation of 40 C.F.R. § 60.104(a)(1).	January 1, 1981 through January 1, 2016.
Heater F-201	N/A	Failure to calibrate, maintain, operate CMS, NSPS A & J, 40 C.F.R. §§ 60.13(e) and 60.105(a).	January 1, 1981 through January 1, 2016.
Heater F-201	N/A	Failure to submit an initial notification and periodic reports as required by 40 C.F.R. §§ 60.7 and 60.107.	January 1, 1981 through January 1, 2016.

b. Entry of this Consent Decree shall resolve all civil liability of Tesoro Refining & Marketing Company LLC and Tesoro Logistics L.P. to the United States and Northwest Clean Air Agency for alleged violations of Benzene Waste NESHAP Requirements at the Anacortes Refinery that: (i) commenced and ceased prior to the Date of Entry; or (ii) are based on events identified in the BWON Compliance Review and Verification Report required under Paragraph 13.d above and are corrected pursuant to the requirements of Paragraph 13.f above.

216. Resolution of Claims for Other Violations at the Kapolei Refinery.

a. With respect to emissions of the following pollutants from those process units at the Kapolei Refinery listed in the table below, entry of this Consent Decree shall resolve the civil claims of the United States and the State of Hawaii against Par and Tesoro Logistics L.P. for violations of those regulations listed in the table below, and any applicable state regulations that implement, adopt, or incorporate any of the listed regulations, that occurred during the time period listed in the table below.

Process Unit	Pollutant(s)	Regulation	Dates of Release
Kapolei SRP	SO_2	Emissions containing SO_2 in excess of 250 ppmvd, NSPS Subpart J, 40 C.F.R. § 60.104(a)(2)(i).	November 1, 2007 through the Date of Lodging for Stack H1391; November 1, 2007 through October 1, 2016 for Stack H1353.
Kapolei SRP	N/A	Failure to calibrate, maintain, operate SO_2 CEMS, NSPS Subparts A & J, 40 C.F.R. §§ 60.13(e) and 60.105(a)(5).	July 1, 2006 through the Date of Lodging.
FGCDs except Covered Flares	N/A	Failure to calibrate, maintain, operate H_2S CMS, NSPS A & J, 40 C.F.R. §§ 60.13(e) and 60.105(a)(3)-(4).	March 1, 2006 through the Date of Lodging.
Tank 106	N/A	Failure to operate floating roof on liquid surface, NESHAP Subpart CC, 40 C.F.R. § 63.646(a).	January 1, 2007 through December 31, 2007.
Tank 107	N/A	Failure to operate floating roof on liquid surface, NSPS Subpart Kb, 40 C.F.R. § 60.112b(a)(2)(iii), and NESHAP Subpart CC, 40 C.F.R. § 63.640(n).	January 1, 2008 through June 30, 2008.
Tank 106	N/A	Failure to maintain automatic bleeder vents closed at all times when roof is floating, NESHAP Subpart CC, 40 C.F.R. § 63.646(f)(3).	September 1, 2008 through May 31, 2009.
Tank 611	N/A	Failure to maintain automatic bleeder vents closed at all times when roof is floating, NSPS Subpart Kb, 40 C.F.R. § 60.112b(a)(1)(v), and NESHAP Subpart CC, 40 C.F.R. §63.640(n).	June 1, 2007 through August 31, 2007.
Tank 3526	N/A	Failure to maintain automatic bleeder vents closed at all times when roof is floating, NSPS Subpart Kb, 40 C.F.R. § 60.112b(a)(2)(ii), and NESHAP Subpart CC, 40 C.F.R. § 63.647(a).	October 1, 2006 through February 28, 2007.
Tanks 202, 204, and 405	N/A	Failure to maintain automatic bleeder vents closed at all times when roof is floating, NESHAP Subpart CC, 40 C.F.R. § 63.646(f)(3).	January 1, 2010 through December 31, 2010.

Process Unit	Pollutant(s)	Regulation	Dates of Release
Tanks 107 and 110	N/A	Failure to maintain cover/lid on opening in floating roof in closed position, NSPS Subpart Kb, 40 C.F.R. § 60.112b(a)(2)(ii), NESHAP Subpart CC, 40 C.F.R. § 63.640(n), and, for Tank 110 only, § 63.647(a).	January 1, 2007 through December 31, 2008.
Tank 510	N/A	Failure to maintain cover/lid on opening in floating roof in closed position, NESHAP Subpart CC, 40 C.F.R. § 63.646(f)(1).	August 1, 2006 through July 31, 2007.

b. With respect to emissions of SO_2 and NOx at the Kapolei Refinery, entry of this Consent Decree shall resolve the civil claims of the United States and the State of Hawaii against Par and Tesoro Logistics L.P. for violations of the PSD Requirements occurring from January 1, 1986 through January 1, 2018, resulting from any construction or modification that both: (i) occurred between January 1, 1986, and December 31, 1991; and (ii) has as a documented purpose an increase of production capacity at the Kapolei Refinery.

217. Resolution of Claims for Other Violations at the Kenai Refinery. With respect to emissions of the following pollutants from those process units at the Kenai Refinery listed in the table below, entry of this Consent Decree shall resolve the civil claims of the United States and the State of Alaska against Tesoro Alaska Company LLC, and Tesoro Logistics L.P. for violations of those regulations listed in the table below, any applicable state regulations or permit conditions listed in the table below (or succeeding Kenai Refinery AOP condition(s) if applicable), that implement, adopt, or incorporate any of the listed regulations, that occurred during the time period listed in the table below.

Process Unit	Pollutant	Regulation	Dates of Release
SRU, DDU, and Heaters	N/A	Failure to comply with 40 C.F.R. § 60.7(a).	December 1, 2005 through March 31, 2007.
FGCDs except Covered Flares	N/A	Combustion of Fuel Gas containing H_2S in excess of 230 milligrams per dry standard cubic meter (mg/dscm) at 27 FGCDs in violation of NSPS Subpart J, 40 C.F.R. § 60.104(a)(1).	October 1, 2004 through Date of Lodging.
FGCDs except Covered Flares	N/A	Failure to calibrate, maintain, operate CMS, NSPS A & J, 40 C.F.R. §§ 60.13(e) and 60.105(a).	February 1, 2005 through July 31, 2009.
Stationary Gas Turbines	N/A	Failure to use approved ASTM test method for fuel analysis in violation of NSPS Subpart GG, 40 C.F.R. § 60.335.	July 1, 2003 through February 29, 2008.

Process Unit	Pollutant	Regulation	Dates of Release
Carbon Canisters and Closed Vent Systems	N/A	Failure to measure emissions from carbon canister controls using specified methods as required by NSPS Subpart QQQ, 40 C.F.R. §§ 60.696(b)(2) and 60.697(a).	February 1, 2006 through June 30, 2010.
Carbon Canisters and Closed Vent Systems	N/A	Failure to keep records as required by NSPS Subpart QQQ, 40 C.F.R. §§ 60.697(a) and (f).2 and AOP Condition 42.	April 1, 2006 through October 31, 2006.
Wastewater Tank 96	N/A	Failure to install secondary tank seals as required by NSPS Subpart QQQ, 40 C.F.R. § 60.693-2(a)(1).	April 1, 2002 through September 30, 2007.
Wastewater Tanks 04A, 04B, 96	N/A	Failure to inspect tanks semi-annually as required by NSPS Subpart QQQ, 40 C.F.R. § 60.693-2(a)(1)(iv)(5)(i).	July 1, 2003 through March 31, 2008.
API Canals	N/A	Failure to maintain roof openings closed at all times when not in use as required by NSPS Subpart QQQ, 40 C.F.R. § 60.693-2(a)(2).	June 1, 2009 through December 31, 2013.
API Canals	N/A	Failure to equip all tank access hatches with gaskets and latches as required by NSPS Subpart QQQ, 40 C.F.R. § 60.692-3(a)(3).	January 1, 2006 through December 31, 2013.
VU Drain System	N/A	Failure to use control device at all times when emissions from the VU drain system were vented to it, as required by 40 C.F.R. § 60.692-5(d).	October 5, 2010 through October 11, 2010.
SRU	SO_2	SRU emissions in excess of 250 ppmvd SO_2 at 0% excess air in violation of NESHAP Subpart UUU, 40 C.F.R. § 63.1568(a)(1) and Table 29.	January 1, 2005 through November 30, 2010.
SRU	N/A	Failure to install, calibrate, operate, and maintain a CEMS as required by NESHAP Subpart UUU, 40 C.F.R. § 63.1572 and Table 31.	April 1, 2005 through December 31, 2005.
SRU	N/A	Failure to submit Relative Accuracy Test Audit as required by NESHAP Subpart UUU Table 40, Item 4 and 40 C.F.R. Part 60 Performance Specification 2.	June 1, 2007 through June 30, 2007.
Heaters and Boilers and SRU Flare	SO_2	SO_2 sources burning gas in excess of the concentration of uncontrolled emissions that would result from burning gas containing 230 mg/dscm H_2S in violation of Title V Permit Condition 5.	June 1, 2005 through Date of Lodging.

Process Unit	Pollutant	Regulation	Dates of Release
SRU	N/A	Failure to include in semiannual Facility Operating Report a weekly mean sulfur dioxide concentration to nearest 5 ppm and the mean mass emission rate in lb/hr, and the semiannual standard deviation of the concentration as required by Title V Permit Condition 8.4(c).	August 1, 2005 through June 30, 2006.
6 heaters (Source ID numbers 6-11)	N/A	Exceedance of limit of percent of oxygen content in the exhaust gas from certain heaters and boilers in violation of Title V Permit Condition 9, Table 2 and Condition 10.1.	April 1, 2006 through November 30, 2010.
Surface Impoundment Air Stripper and Phillips / Marathon Air Stripper	BTX (benzene, toluene, xylene)	Failure to comply with BTX emissions limit from the Surface Impoundment Air Stripper of 0.24 mg/sec and Phillips/Marathon Air Stripper of 0.94 mg/sec as required by Title V Permit Condition 11.	July 1, 2005 through March 31, 2007.
Thermal Oxidation Unit and Phillips/Marathon Air Stripper	N/A	Failure to maintain minimum temperature of 1500 F in combustion chamber of Thermal Oxidation Unit or to shut down Phillips/Marathon Air Stripper or route exhaust gas elsewhere, as required by Title V Permit Condition 11.2.	August 1, 2006 through March 31, 2007.
Thermal Oxidation Unit and Phillips/Marathon Air Stripper	N/A	Failure to continuously monitor temperature in the combustion chamber of the Thermal Oxidation Unit on the Phillips/Marathon Air Stripper to ensure compliance with Title V Permit Condition 11.2a, as required by Condition 11.3.	August 1, 2006 through March 31, 2007.
Thermal Oxidation Unit and Phillips/Marathon Air Stripper	N/A	Failure to conduct monthly monitoring of BTX concentrations at the inlet for the Thermal Oxidation Unit on the Phillips/Marathon Air Stripper, as required by Title V Permit Condition 11.4.	May 1, 2009 through May 31, 2009.

Process Unit	Pollutant	Regulation	Dates of Release
Thermal Oxidation Unit and Phillips/Marathon Air Stripper	N/A	Failure to report non-compliance with Title V Permit Conditions, as required by Condition 11.7.	August 1, 2006 through August 31, 2006.
Air Strippers	N/A	Failure to maintain records of BTX emission monitoring from air strippers as required by the approved Quality Assurance Plan developed for the process monitoring requirements described in Title V Permit Conditions 7.2, 8, 10, 11, 34.2, and 36 in violation of Title V Permit Condition 12.	January 1, 2007 through February 28, 2007.
North and South Cummins Engines	N/A	Failure to record start and stop times and dates for North Cummins NHS6-1F (P-708A) and South Cummins NHS6-1F (P-708B) engines as required by Title V Permit Condition 15.1.	July 1, 2006 through January 31, 2008.
Stationary Gas Turbines	N/A	Failure to operate the GT-1400 and GT-1410 stationary gas turbines with a water injection rate of not less than 0.8 pounds of water per pound of fuel (whether natural gas, LPG or diesel) when sources operate at loads greater than 2.5 megawatts as required by Title V Permit Condition 34.2.	July 1, 2005 through December 31, 2006.
	N/A	Failure to certify all reports, compliance certifications, or other documents submitted to ADEC, as required by Title V Permit Condition 78.	January 1, 2006 through March 31, 2009.
	N/A	Failure to report unavoidable emergency, Malfunction, or non-routine repair that causes emissions in excess of a technology-based emission standard within two Working Days of the event; and all other excess emissions and permit deviations within 30 Days of the end of the month in which the emissions or deviation occurs as required by Title V Permit Condition 82.1.	January 1, 2005 through April 30, 2010.

218. Resolution of Claims for Other Violations at the Mandan Refinery. With respect to emissions of the following pollutants from those process units at the Mandan Refinery listed in the table below, entry of this Consent Decree shall resolve the civil claims of the United States against Tesoro Refining & Marketing Company LLC and Tesoro Logistics L.P. for violations of those regulations listed in the table below, and any applicable state regulations that implement, adopt, or incorporate any of the listed regulations, that occurred during the time period listed in the table below.

Process Unit	Pollutant	Regulation	Dates of Release
Mandan FCCU	PM	Exceedance of metal HAP emissions limit in 40 C.F.R. 63.1564(a)(1).	January 1, 2007 through Date of Lodging.
FGCDs except Flares	N/A	Failure to calibrate, maintain, operate H_2S CMS, NSPS A & J, 40 C.F.R. §§ 60.13(e) and 60.105(a).	July 1, 2009 through Date of Lodging.

219. Resolution of Claims for Other Violations at the Martinez Refinery.

a. With respect to emissions of the following pollutants from those process units at the Martinez Refinery listed in the table below, entry of this Consent Decree shall resolve the civil claims of the United States against Tesoro Refining & Marketing Company LLC and Tesoro Logistics L.P. for violations of those regulations listed in the table below, and any applicable state regulations that implement, adopt, or incorporate any of the listed regulations, that occurred during the time period listed in the table below.

Process Unit	Pollutant(s)	Regulation(s)	Dates of Release
Martinez FCCU	CO	Exceedance of 121.9 tons per year CO emissions limit in the Martinez Refinery Title V Permit (Condition 11433).	January 1, 2006 through October 1, 2015.
Martinez SAP	Acid Mist, Opacity, SO2	40 C.F.R. Part 60, Subparts A and H.	Date of pre-lodging construction, reconstruction, or modification through January 1, 2016.

b. Resolution of Claims for Violations of PSD and NNSR Requirements at the Martinez Refinery. With respect to emissions of the following pollutants from those process units at the Martinez Refinery listed in the table below, entry of this Consent Decree shall resolve the civil claims of the United States against Tesoro Refining & Marketing Company LLC and Tesoro Logistics L.P. for violations of the PSD and NNSR Requirements resulting from the constructions or modifications specified in the table below resulting in violations occurring during the time period set forth in the table below.

Process Unit	Pollutant	Construction or Modification	Dates of Release
Delayed Coker	H_2S	Construction of new delayed coker in 2006 in violation of PSD Requirements.	January 1, 2006 through October 1, 2015.
	POC	Construction of new delayed coker in 2006 in violation of NNSR Requirements.	
Martinez SAP	SO_2	Physical and/or operational changes that occurred at the Martinez SAP prior to the Date of Lodging in violation of PSD Requirements.	Date of pre-lodging construction or modification through January 1, 2016.

c. Resolution of Claims for Consent Decree Violations at the Martinez Refinery. Entry of this Consent Decree shall resolve the civil claims of the United States against Tesoro Refining & Marketing Company LLC and Tesoro Logistics L.P. for the following violations regarding the following pollutants and process units at the Martinez Refinery of the Consent Decree entered on November 23, 2005, in *United States, et al. v. Valero Refining Co., et al.*, Civil Action No. SA05CA0569 (W.D. Texas) through the dates indicated on the following table.

Process Unit	Pollutant	Alleged CD Violation	Dates of Release
Martinez SRP	SO_2	Failure to re-route Martinez SRP Sulfur Pit emissions to eliminate emissions or route to SRP and subject to NSPS Subpart J Limit as required by Paragraph 226 of the 2005 Martinez Consent Decree.	December 31, 2006 through January 1, 2016.
Martinez FCCU	NOx	Failure to comply with 365-day limit in Paragraph 35 of the 2005 Martinez Consent Decree.	November 30, 2007 through October 1, 2015.
Martinez FCCU	NOx	Failure to comply with 7-day limit in Paragraph 35 of the 2005 Martinez Consent Decree.	October 6, 2006 through October 1, 2015.

220. Resolution of Other Claims for Violations at the Salt Lake City Refinery.

a. With respect to emissions of the following pollutants from those process units at the Salt Lake City Refinery listed in the table below, entry of this Consent Decree shall resolve the civil claims of the United States against Tesoro Refining & Marketing Company LLC and Tesoro Logistics L.P. for violations of those regulations listed in the table below, and any applicable state regulations that implement, adopt, or incorporate any of the listed regulations, that occurred during the time period listed in the table below.

Process Unit	Pollutant(s)	Regulation(s)	Dates of Release
SLC FCCU	CO and PM	40 C.F.R. Part 60, Subparts A, J and Ja arising from any physical and/or operational changes that occurred prior to the Date of Lodging.	January 1, 2007 through the Date Compliance is required under Paragraphs 62-63 of this Consent Decree.
SLC FCCU	NOx and SO_2	40 C.F.R. Part 60 Subparts A, J and Ja arising from any physical and/or operational changes that occurred prior to the Date of Lodging.	January 1, 2007 through January 1, 2018.

b. With respect to emissions of the following pollutants from those process units at the Salt Lake City Refinery listed in the table below, entry of this Consent Decree shall resolve the civil claims of the United States against Tesoro Refining & Marketing Company LLC and Tesoro Logistics L.P. for violations occurring during the time period set forth in the table below of the PSD Requirements and NNSR Requirements resulting from the constructions or modifications specified in the table below.

Process Unit	Pollutant	Construction or Modification	Dates of Release
SLC FCCU	NOx and SO_2	2007 FCCU reliability project and turnaround.	January 1, 2007 through January 1, 2018.
SLC FCCU	CO	Spring 2013 maintenance and repair on CO boiler project.	January 1, 2013 through the Date Compliance is required under Paragraphs 62-63.

221. Resolution of Title V Claims. Entry of this Consent Decree shall resolve the civil claims of the United States and the State Co-Plaintiffs against Settling Defendants for the violations at the Covered Refineries of Sections 502(a), 503(c), and 504(a) of the CAA, 42 U.S.C. §§ 7661a(a), 7661b(c), 7661c(a), and of 40 C.F.R. §§ 70.1(b), 70.5(a) and (b), 70.6(a) and (c), and 70.7(b), that are based upon the violations resolved by Paragraphs 212-220 above for the same pollutants, projects, process units, and time frames set forth in those Paragraphs.

222. Reservation of Rights: Certain Resolution of Liability for Post Date of Lodging Violations in Paragraphs 212 to 221 Above Can be Rendered Void. Notwithstanding the resolutions of liability for violations after the Date of Lodging contained in Paragraphs 212-221 above, those resolutions of liability shall be rendered void if a Settling Defendant materially fails to comply with any of the obligations and requirements of:

Section V.A (Anacortes Refinery Requirements)

Section V.B (Kapolei Refinery Requirements)

Section V.E (Martinez Refinery Requirements)

Section V.F (SLC Refinery Requirements)

Section VI.A (Leak Detection and Repair (LDAR) Program Enhancements)

Section VI.B (Requirements for Control of Flaring Events)

Section VII (Survival of Consent Decree Requirements)

Section VIII (Emission Credit Generation)

a. To the extent that a material failure to comply with any of the obligations and requirements involves a particular Covered Refinery, the resolution of liability shall be rendered void only with respect to the related claims at that particular Covered Refinery.

b. The resolutions of liability for violations after the Date of Lodging in Paragraphs 212-221 above shall not be rendered void if Settling Defendants remedy such material failure as expeditiously as practicable and pay all stipulated penalties due as a result of such material failure.

223. The United States and State Co-Plaintiffs further reserve all legal and equitable remedies available to enforce the provisions of this Consent Decree. This Consent Decree shall not be construed to limit the rights of the United States or State Co-Plaintiffs to obtain penalties or injunctive relief under the CAA or regulations promulgated thereunder, or under other federal or state laws, regulations, or permit conditions, except as expressly specified in Paragraphs 212-221 above. The United States and State Co-Plaintiffs further reserve all legal and equitable remedies to address any imminent and substantial endangerment to the public health or welfare or the environment arising at, or posed by, Settling Defendants' Covered Refineries, whether related to the violations addressed in this Consent Decree or otherwise.

224. Prior NSPS Applicability Determinations. Nothing in this Consent Decree shall affect the status of any FCCU, FGCD, or Sulfur Recovery Plant currently subject to NSPS as previously determined by any federal, state, or local authority, or any applicable permit.

225. In any subsequent administrative or judicial proceeding initiated by the United States or State Co-Plaintiffs for injunctive relief, civil penalties, and/or other appropriate relief relating to the Covered Refineries for violations of PSD, NNSR, NSPS, NESHAP, LDAR, Title V, or state law requirements incorporating the foregoing federal requirements not identified in this Section:

a. Settling Defendants shall not assert, and may not maintain, any defense or claim based upon the principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, claim-splitting, or other defenses based upon any contention that the claims raised by the United States or State Co-Plaintiffs in the subsequent proceeding were or should have been brought in the instant case, except with respect to claims that have been specifically resolved pursuant to Paragraphs 212-221 above of this Section and for which the resolution of liability has not been voided pursuant to Paragraph 222.a above.

b. Except as set forth in Paragraph 225.a above, the United States and the State Co-Plaintiffs may not assert or maintain that this Consent Decree constitutes a waiver, or determination of, or otherwise obviates, any claim or defense by Settling Defendants whatsoever, or that this Consent Decree constitutes an acceptance by Settling Defendants of any interpretation or guidance issued by EPA related to the matters addressed in this Consent Decree.

226. This Consent Decree is not a permit, or a modification of any permit, under any federal, State, or local laws or regulations. Settling Defendants are responsible for achieving and maintaining complete compliance with all applicable federal, State, and local laws, regulations, and permits; and Settling Defendants' compliance with this Consent Decree shall be no defense to any action commenced pursuant to any such laws, regulations, or permits, except as set forth herein. The United States and the State Co-Plaintiffs do not, by their consent to the entry of this Consent Decree, warrant or aver in any manner that Settling Defendants' compliance with any aspect of this Consent Decree will result in compliance with provisions of the Act, 42 U.S.C. § 7401 *et seq.*, or with any other provisions of federal, State, or local laws, regulations, or permits.

227. Nothing in this Consent Decree shall be construed to limit or disqualify Settling Defendants, on the grounds that information was not discovered voluntarily, from seeking to apply EPA's Audit Policy to any violation or non-compliance that Settling Defendants discover during the course of any audit, investigation, or enhanced monitoring that Settling Defendants are required to undertake pursuant to this Consent Decree.

228. Imminent and Substantial Endangerment. Nothing in this Consent Decree shall be construed to limit the authority of the United States and Applicable State Co-Plaintiffs to undertake any action against any person to abate or correct conditions which may present an imminent and substantial endangerment to the public health, welfare, or the environment.

229. This Consent Decree does not limit or affect the rights of Settling Defendants, the United States, or State Co-Plaintiffs against any third parties that are not party to this Consent Decree, nor does it limit the rights of third parties that are not party to this Consent Decree against Settling Defendants, except as otherwise provided by law.

230. This Consent Decree shall not be construed to create rights in, or grant any cause of action to, any third party not party to this Consent Decree.

XVIII. GENERAL PROVISIONS

231. Other Laws. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Settling Defendants of their obligation to comply with all applicable federal, state, regional, and local laws, regulations, and permits, including but not limited to more stringent standards. In addition, nothing in this Consent Decree shall be construed to prohibit or prevent the United States or the State Co-Plaintiffs from developing, implementing, and enforcing more stringent standards subsequent to the Date of Lodging of this Consent Decree through rulemaking, the permit process, or as otherwise authorized or required under federal, state, regional, or local laws and regulations. Subject to Section XVII (Effect of

Settlement/Reservation of Rights), Section XII (Stipulated Penalties), and Paragraph 233 (Permit Violations) of this Consent Decree, nothing contained in this Consent Decree shall be construed to prevent or limit the rights of the United States or the State Co-Plaintiffs to seek or obtain other remedies or sanctions available under other federal, state, regional, or local statutes or regulations, by virtue of Settling Defendants' violations of this Consent Decree or of the statutes and regulations upon which this Consent Decree is based, or for Settling Defendants' violations of any applicable provision of law. This will include any right the United States or the State Co-Plaintiffs may have to invoke the authority of the Court to order Settling Defendants' compliance with this Consent Decree in a subsequent contempt action. The requirements of this Consent Decree do not exempt Settling Defendants from complying with any and all new or modified federal, state, regional, and/or local statutory or regulatory requirements that may require technology, equipment, monitoring, or other upgrades after the Date of Lodging of this Consent Decree.

232. Startup, Shutdown, and Malfunction. Notwithstanding the provisions of this Consent Decree regarding Startup, Shutdown, and Malfunction, this Consent Decree does not exempt Settling Defendants from the requirements of state laws and regulations or from the requirements of any permits or plan approvals issued to Settling Defendants, as these laws, regulations, permits, and/or plan approvals may apply to Startups, Shutdowns, and Malfunctions.

233. Permit Violations. Except as set forth in Section XVII (Effect of Settlement/Reservation of Rights) and subject to setoff for any Stipulated Penalties assessed under Section XII (Stipulated Penalties), nothing in this Consent Decree shall be construed to prevent or limit the right of the United States or the State Co-Plaintiffs to seek injunctive or monetary relief for violations of permits.

234. Failure of Compliance. The United States and the State Co-Plaintiffs do not, by their consent to the entry of this Consent Decree, warrant or aver in any manner that Settling Defendants' complete compliance with this Consent Decree will result in compliance with the provisions of the Clean Air Act, regulations promulgated thereunder or the corollary state and local statutes, regulations, or permits. Notwithstanding the review or approval by EPA or an Applicable State Co-Plaintiff of any plans, reports, policies, or procedures formulated pursuant to this Consent Decree, Settling Defendants shall remain solely responsible for compliance with the terms of this Consent Decree, all applicable permits, and all applicable federal, state, regional, and local laws and regulations, except as provided in Section XIV (Force Majeure).

235. Service of Process. Settling Defendants hereby agree to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable local rules of this Court, including but not limited to, service of a summons. The persons identified by Settling Defendants in Section XIX (Notices) are authorized to accept service of process with respect to all matters arising under or relating to this Consent Decree.

236. Pre-Entry Obligations. Obligations of Settling Defendants under this Consent Decree to perform duties scheduled to occur prior to the Date of Entry of this Consent Decree, shall be

legally enforceable only on and after the Date of Entry of this Consent Decree. Liability for stipulated penalties, if applicable, shall accrue for violation of such obligations and payment of such stipulated penalties may be demanded by the United States or the Applicable State Co-Plaintiff as provided in this Consent Decree, provided that the stipulated penalties that may have accrued between the Day compliance is due and the Date of Entry of this Consent Decree may not be collected unless and until this Consent Decree is entered by the Court.

237. Costs. Each Party to this action shall bear its own costs and attorneys' fees, except that the State Co-Plaintiffs shall be entitled to collect permit administration fees as authorized by state law for permits to be issued under this Consent Decree and Tesoro Alaska Company LLC shall pay ADEC under AS 46.03.760 for all of the administrative fees, legal fees, costs, and expenses incurred by the State of Alaska, including those of ADEC and the Alaska Department of Law ("ADOL"), in connection with the detection, investigation, attempted correction, and enforcement of the violations alleged above for the Kenai Refinery, including the preparation and implementation of this Consent Decree, and any future review by ADEC or ADOL of any proposed amendments, reports, notices, or submissions made pursuant to the provisions of this Consent Decree. The provisions of Section XV (Dispute Resolution) shall not apply to any administrative fees, costs, and expenses due under this Paragraph. Nothing in this Consent Decree diminishes Tesoro's right to appeal or request fee review under 18 AAC 15.190.

238. Public Documents. All information and documents submitted by Settling Defendants to EPA and the Applicable State Co-Plaintiffs pursuant to this Consent Decree shall be subject to public inspection in accordance with the respective statutes and regulations that are applicable to EPA and the Applicable State Co-Plaintiffs, unless subject to legal privileges or protection or identified and supported as trade secrets or business confidential in accordance with the respective state or federal statutes or regulations.

239. Public Notice and Comment. The Parties agree to this Consent Decree and agree that this Consent Decree may be entered upon compliance with the public notice procedures set forth at 28 C.F.R. § 50.7, and upon notice to this Court from the United States Department of Justice requesting entry of this Consent Decree. The United States and the Applicable State Co-Plaintiffs reserve the right to withdraw or withhold their consent to this Consent Decree if public comments disclose facts or considerations indicating that this Consent Decree is inappropriate, improper, or inadequate.

240. Opportunity for Comment by State Co-Plaintiffs. For all provisions of this Consent Decree that provide for EPA approval or comment, the Applicable State Co-Plaintiff is entitled to provide comments to EPA and to consult with EPA regarding the issue in question.

241. Paperwork Reduction Act. The information required to be maintained or submitted pursuant to this Consent Decree is not subject to the Paperwork Reduction Act of 1980, 44 U.S.C. §§ 3501 *et.seq*.

242. Effect of Shutdown. The permanent Shutdown of a unit and the surrender of all permits for that unit shall be deemed to satisfy all requirements of this Consent Decree

applicable to that unit on and after the later of: (i) the date of the Shutdown of the unit; or (ii) the date of the surrender of all permits. The permanent Shutdown of a Covered Refinery and the surrender of all air permits related to operation as a refinery for that Covered Refinery shall be deemed to satisfy all requirements of this Consent Decree applicable to that Covered Refinery.

243. Integration. This Consent Decree constitutes the final, complete, and exclusive agreement and understanding among the Parties with respect to the settlement embodied in the Decree and supersedes all prior agreements and understandings, whether oral or written, concerning the settlement embodied herein. No other document, nor any representation, inducement, agreement, understanding, or promise, constitutes any part of this Consent Decree or the settlement it represents, nor shall it be used in construing the terms of this Consent Decree.

244. Agreement to Request Termination of Relevant Portions of the 2005 Martinez Consent Decree and BP/Amoco Consent Decree. Tesoro and the United States agree that within sixty (60) Days of the Date of Entry, they shall file a motion requesting termination of the 2005 Martinez Consent Decree and the BP/Amoco Consent Decree as to Tesoro and its obligations for the Martinez Refinery, the SLC Refinery, and the Mandan Refinery.

XIX. NOTICES

245. Each report, study, notification, or other communications between Parties to this Consent Decree shall be submitted as specified in this Paragraph and Paragraphs 246-250 below. Where this Consent Decree requires that notices and submissions are to be made to the "United States" they shall be made to the U.S. Department of Justice, EPA Headquarters, and the EPA regional office(s) for the Covered Refinery or Refineries the submission concerns. Where this Consent Decree requires that notices and submissions are to be made to "EPA," Settling Defendants need not send copies to the U.S. Department of Justice. Where this Consent Decree requires that notices and submissions are to be made to an Applicable State Co-Plaintiff or Permitting Authority, they shall be submitted to the State Co-Plaintiff(s) and/or Permitting Authority for the jurisdiction(s) in which the Covered Refinery or Refineries are located.

246. Unless otherwise provided herein, notifications to or communications between the Parties shall be deemed submitted on the date they are postmarked and sent by U.S. Mail, postage pre-paid, or shipped by a delivery service with confirmation of delivery, except for notices under Section XIV (Force Majeure) and Section XV (Dispute Resolution) which shall be sent either by overnight mail or by certified or registered mail, return receipt requested.

247. If the date for submission of a report, study, notification, or other communication falls on a Saturday, Sunday, or legal holiday, the report, study, notification, or other communication shall be deemed timely if it is submitted the next Working Day.

248. Where an e-mail address is provided below, Settling Defendants may submit any reports, notifications, certifications, or other communications required by this Consent Decree electronically (other than submission of a permit application required by this Consent Decree, payment of penalties under Section XI or Section XII and notices under Sections XIV and XV) in lieu of submission by U.S. Mail. Electronic submissions shall be deemed submitted on the

date they are transmitted electronically. Any report, notification, certification, or other communication that cannot be submitted electronically shall be submitted in hard-copy as provided in this Section XIX.

249. Except as otherwise provided herein, all reports, notifications, certifications, or other communications required or allowed under this Consent Decree to be submitted or delivered to the United States, EPA, the State Co-Plaintiffs, and Settling Defendants shall be addressed as follows:

As to the United States:

The Department of Justice
Case No. DJ: 90-5-2-1-09512/1
Chief, Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, DC 20044-7611

Overnight Address
601 D. Street N.W.
Washington, D.C. 20004

EPA Headquarters
Director, Air Enforcement Division
Office of Civil Enforcement
U.S. Environmental Protection Agency
Mail Code 2242-A
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460-0001

And

Director, Air Enforcement Division
Office of Civil Enforcement
c/o Eastern Research Group, Inc.
14555 Avion Parkway, Suite 200
Chantilly, VA 20151-1124

and submitted electronically to:
refinerycd@erg.com
foley.patrick@epa.gov

EPA Regions

Region 8:

Director, Air and Toxics Technical Enforcement Program
Mail Code ENF-AT
U.S. Environmental Protection Agency Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

Region 9:

Manager, Air & TRI Section (ENF-2-1)
Enforcement Division
U.S. Environmental Protection Agency Region 9
75 Hawthorne Street
San Francisco, California 94105

and submitted electronically to:
mintz.tom@epa.gov

Region 10:

Manager, Air and RCRA Compliance Unit
Office of Compliance and Enforcement
Environmental Protection Agency Region 10
1200 Sixth Avenue, Suite 900
Mailcode OCE-101
Seattle, WA 98101

As to the State Co-Plaintiffs

The State of Alaska

Alaska Department of Environmental Conservation (Department)
Air Permits Program
610 University Ave.
Fairbanks, AK 99709-3643
ATTN: Compliance Technician.

The State of Hawaii

Clean Air Branch
Environmental Management Division
Hawaii Department of Health

(U.S. Mail Address)
P.O. Box 3378
Honolulu, HI 96801-3378

(Overnight Address)
919 Ala Moana Blvd.,
Room 203,
Honolulu, HI 96814

Northwest Clean Air Agency:

Director
Northwest Clean Air Agency
1600 South Second Street
Mount Vernon, WA 98273

As to Tesoro

Stoney K. Vining
Senior Counsel
Tesoro Companies, Inc.
19100 Ridgewood Parkway
San Antonio, Texas 78259
Stoney.K.Vining@TSOCorp.com

Douglas B. Price
Director, Environmental
Tesoro Companies, Inc.
19100 Ridgewood Parkway
San Antonio, Texas 78259
Douglas.B.Price@tsocorp.com

As to Tesoro Logistics L.P.

Stoney K. Vining
Senior Counsel
Tesoro Companies, Inc.
19100 Ridgewood Parkway
San Antonio, Texas 78259
Stoney.K.Vining@TSOCorp.com

Douglas B. Price
Director, Environmental
Tesoro Companies, Inc.

19100 Ridgewood Parkway
San Antonio, Texas 78259
Douglas.B.Price@tsocorp.com

As to Par

James Vaughan
Senior Vice President and General Counsel
Par Petroleum
One Memorial Plaza
800 Gessner Road
Suite 875
Houston, Texas 77024

Thomas Weber
Vice President
Par Hawaii Refining, LLC
91-325 Komohana Street
Kapolei, Hawaii 96707

Theodore K. Metrose
Par Hawaii Refining, LLC
91-325 Komohana Street
Kapolei, Hawaii 96707

250. Any Party may change either the notice recipient or the address for providing notices to it by serving all other parties with a notice setting forth such new notice recipient or address. In addition, the nature and frequency of reports required by this Consent Decree may be modified by mutual consent of the Parties. The consent of the United States to such modification shall be in the form of a written notification from EPA, but need not be filed with the Court to be effective.

XX. MODIFICATION

251. This Consent Decree contains the entire agreement of the Parties and shall not be modified by any prior oral or written agreement, representation, or understanding. Non-material modifications to this Consent Decree shall be effective when signed in writing by the United States, the Settling Defendants responsible for compliance at the Covered Refinery or Covered Refineries affected by the modification pursuant to Paragraph 6 above and the Applicable State Co-Plaintiff. The United States shall file non-material modifications with the Court on a periodic basis. For purposes of this Paragraph, non-material modifications include but are not limited to modifications to the frequency of reporting obligations and modifications to schedules that do not extend the date for compliance with emissions limitations following the installation of control equipment, provided that such changes are agreed upon in writing between the United States, Applicable State Co-Plaintiff and Settling Defendant pursuant to Paragraph 6 above. A

modification that does no more than incorporate new regulatory requirements, language, or citations is also a non-material modification. Material modifications to this Consent Decree shall be in writing, signed by the United States, the Applicable State Co-Plaintiff, and the Settling Defendants responsible for compliance at the Covered Refinery or Covered Refineries affected by the modification pursuant to Paragraph 6 above, and shall be effective upon approval by the Court.

252. In the event that the requirements of Clean Air Act or regulations promulgated thereunder are modified after the Date of Lodging, a Settling Defendant may submit to the United States and Applicable Co-Plaintiff for review and approval under Section XVI (Review, Approval, and Comment on Deliverables) a request for relief from its Consent Decree obligations or to modify its Consent Decree obligations to conform to the current statutory or regulatory requirements. Any modification of this Consent Decree proposed by a Settling Defendant and approved by the United States and Applicable State Co-Plaintiff shall be incorporated into and enforceable under this Consent Decree.

XXI. TERMINATION

253. Certification of Completion: Applicable Sections. Prior to moving for Termination under Paragraphs 257-259 below, the Settling Defendants responsible for compliance at each Covered Refinery pursuant to Paragraph 6 above may seek to certify completion of one or more of the following Sections of this Consent Decree applicable to that Refinery:

a. Section V.A (Anacortes Refinery Requirements)

b. Section V.B (Kapolei Refinery Requirements)

c. Section V.C (Kenai Refinery Requirements)

d. Section V.D (Mandan Refinery Requirements)

e. Section V.E (Martinez Refinery Requirements)

f. Section V.F (SLC Refinery Requirements)

g. Section VI.A (Leak Detection and Repair (LDAR) Program Enhancements)

h. Section VI.B (Requirements for Control of Flaring Events)

i. Section IX (Environmental Mitigation Projects)

254. Certification of Completion: Settling Defendants' Actions. If a Settling Defendant concludes that any of the Sections of this Consent Decree identified in Paragraph 253 above have been completed at a Covered Refinery, that Settling Defendant may submit a written report to EPA and the Applicable State Co-Plaintiffs describing the activities undertaken and certifying that the applicable Section(s) have been completed in full satisfaction of the requirements of this

incorporates the emission limits and standards set forth in Appendix A-2 (2005 Consent Decree Requirements Applicable to the Martinez Refinery), the United States and Tesoro shall jointly move the Court for Termination of the provisions in Appendix A-2 of this Consent Decree within sixty (60) Days, provided that Tesoro has paid any stipulated penalties demanded by the United States for any violations of Appendix A-2.

b. Termination of other Tesoro Obligations and Requirements Under this Consent Decree. The remaining requirements and obligations of this Consent Decree may be terminated as to Tesoro, Tesoro Logistics L.P., and the Tesoro Refineries, once Tesoro and Tesoro Logistics L.P. have completed and satisfied all of the following requirements of this Consent Decree at all Tesoro Refineries:

i. Installation and operation of control technology systems as specified in this Consent Decree at all Tesoro Refineries;

ii. Compliance with Section VI.A (ELDAR Program) for at least six years at each of the Tesoro Refineries;

iii. Compliance with all other provisions of this Consent Decree applicable to Tesoro Refineries contained in this Consent Decree, such compliance may be established for specific parts of this Consent Decree in accordance with Paragraphs 253-256 above;

iv. Payment of all penalties and other monetary obligations due under the terms of this Consent Decree;

v. Completion of the Environmental Mitigation Projects under Section IX;

vi. Application for and receipt of permits incorporating the requirements established for all Tesoro Refineries under this Consent Decree as required by Section VII;

vii. Operation of each Tesoro Refinery for at least one year of each unit in compliance with the emission limits established herein and certification of such compliance for each unit within the first progress report following the conclusion of the one-year compliance period; and

viii. Requirements set forth in Appendix A-2.

258. Termination of Par Obligations and Requirements Under this Consent Decree. The requirements and obligations of this Consent Decree may be terminated as to Par and the Kapolei Refinery once Par has completed and satisfied all of the following requirements of this Consent Decree at the Kapolei Refinery:

a. Installation and operation of control technology systems as specified in this Consent Decree;

b. Compliance with Section VI.A. (ELDAR Program) for at least six years;

c. Compliance with all other provisions contained in this Consent Decree at the Kapolei Refinery, such compliance may be established for specific parts of this Consent Decree in accordance with Paragraphs 253-256 above;

d. Payment of all penalties and other monetary obligations due under the terms of this Consent Decree;

e. Application for and receipt of permits incorporating the requirements for the Kapolei Refinery established under this Consent Decree as required by Section VII; and

f. Operation for at least one year of each unit in compliance with the emission limits established herein and certification of such compliance for each unit within the first progress report following the conclusion of the compliance period.

259. Termination: Procedure. At such time as Tesoro or Par believe that they have satisfied the requirements for Termination applicable to each set forth in Paragraphs 257-258 above respectively, Tesoro or Par shall certify such compliance and completion to the United States and the Applicable State Co-Plaintiffs in accordance with the certification language of Paragraph 254 above. Unless the United States or a State Co-Plaintiff objects in writing with specific reasons within one-hundred and twenty (120) Days of receipt of Tesoro's or Par's certification under this Paragraph, the Court may upon motion by Tesoro or Par order that the provisions of this Consent Decree pertaining to that Party be terminated. If the United States or a State Co-Plaintiff objects to the certification by Tesoro or Par, then the matter will be submitted to the Court for resolution under Section XV (Dispute Resolution). In such case, Tesoro or Par shall bear the burden of proving that this Consent Decree should be terminated.

XXII. SIGNATORIES

260. Each undersigned representative of Settling Defendants and the Assistant Attorney General for the Environment and Natural Resources Division of the Department of Justice certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind the Party he or she represents to this document.

261. This Consent Decree may be signed in counterparts, and its validity shall not be challenged on that basis.

XXIII. APPENDICES

262. The following appendices are attached to and part of this Consent Decree.

Appendix A: Martinez Refinery

A-1: SAP Monitoring Plan

A-2: 2005 CD Appendix

Appendix B: LDAR Commercial Unavailability Appendix

Appendix C: Flaring

C - 1.1: S-Drwgs

C - 1.2: Gen-Eqa

C - 1.3: NHV_{cz} and NHV_{dil}

C - 1.6: Tip-Area-Eq

C - 1.7: G-Drwg

C - 1.9: Gas Chromatograph-Compounds

C - 1.10: Tech-Specs

C - 1.11: Waste Gas Mapping

C - 1.14: Nelson Complexity Index

C - 1.15: Roll-Sum-Aver

C - 2.1: Covered Flares and Applicability Dates For Certain Consent Decree Requirements

C - 2.2: Large High Pressure Hydrocarbon Relief Vales

C - 2.3: Combustion Efficiency Test Protocol for Kenai Refinery Air Assisted Flare

C - 2.4: Refinery Specific Flare Cap Calculations

C - 2.5: Reports for Emissions and Flare Combustion Efficiency Testing

Appendix D: Mitigation Projects

D-1: Camera Project

D-2 School Bus Project

D-3 SLC Mitigation Project

XXIV. FINAL JUDGMENT

263. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment of the Court as to the United States, the State Co-Plaintiffs, and Settling Defendants.

_____
[_____]
UNITED STATES DISTRICT JUDGE
[_____] District of *[_____]*

THE UNITED STATES HEREBY CONSENTS TO ENTRY OF THE CONSENT DECREE IN UNITED STATES ET AL. v. TESORO ET AL., SUBJECT TO THE PUBLIC NOTICE REQUIREMENTS OF 28 C.F.R. § 50.7

FOR THE UNITED STATES OF AMERICA:

THE UNITED STATES DEPARTMENT OF JUSTICE

DATE: June 17 2016

[redacted]

JOHN C. CRUDEN
Assistant Attorney General
Environment & Natural Resources Division

DATE: June 22 2016

[redacted]

ELIZABETH L. LOEB
Senior Counsel
Environmental Enforcement Section
Environment & Natural Resources Division
P.O. Box 7611
Washington, D.C. 20044
Elizabeth.Loeb@usdoj.gov
(202) 616-8916

RICHARD L. DURBIN, JR.
United States Attorney

[redacted]

SUSAN STRAWN
Tex. Bar No. 19374330
Assistant United States Attorney
601 NW Loop 410, Ste 600
San Antonio, TX 78216
Tel. (210) 384-7388
Fax (210)384-7312
SStrawn@usa.doj.gov

THE ENVIRONMENTAL PROTECTION AGENCY OFFICE OF ENFORCEMENT AND COMPLIANCE ASSURANCE

DATE: 6/11/16

[redacted]

CYNTHIA GILES
Assistant Administrator
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

DATE: 6/10/16

[redacted]

SUSAN SHINKMAN
Director, Office of Civil Enforcement
United States Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

DATE: 6/9/2016

[redacted]

PHILLIP A. BROOKS
Director, Air Enforcement Division
Office of Civil Enforcement
United States Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

DATE: 6/9/16

[redacted]

MELANIE SHEPHERDSON
Assistant Regional Counsel
United States Environmental Protection Agency, Region 9
75 Hawthorne St.
San Francisco, CA 94105

THE ENVIRONMENTAL PROTECTION AGENCY

REGION 8:

DATE: 6/9/16

[redacted]

SUZANNE J. BOHAN
Assistant Regional Administrator
Office of Enforcement, Compliance and
Environmental Justice
United States Environmental Protection Agency
1595 Wynkoop Street
Denver, CO 80202

THE ENVIRONMENTAL PROTECTION AGENCY REGION 9:

DATE: 13 June 2016

[redacted]

ALEXIS STRAUSS
Acting Regional Administrator
United States Environmental Protection Agency, Region 9

Of Counsel:

THOMAS P. MINTZ
Assistant Regional Counsel
U.S. Environmental Protection Agency, Region 9
75 Hawthorne Street
San Francisco, California 94105

THE ENVIRONMENTAL PROTECTION AGENCY REGION 10:

DATE: 6-2-2016

[redacted]

ALLYN STERN
Regional Counsel
U.S. Environmental Protection Agency, Region 10

Of Counsel:

SHIRIN VENUS GALLAGHER
Assistant Regional Counsel
U.S. Environmental Protection Agency, Region 10
Office of Regional Counsel
1200 Sixth Avenue, Suite 900
Seattle, WA 98109
206-553-4194

THE STATE OF ALASKA HEREBY CONSENTS TO ENTRY OF THE CONSENT DECREE IN UNITED STATES ET AL. v. TESORO ET AL., SUBJECT TO THE PUBLIC NOTICE REQUIREMENTS OF 28 C.F.R. § 50.7

FOR THE STATE OF ALASKA

CRAIG W. RICHARDS
Attorney General
State of Alaska

DATE: 5/17/16

By: [redacted]
JENNIFER A. CURRIE (Alaska Bar No. 0609056)
Senior Assistant Attorney General
Department of Law
1031 West Fourth Avenue, Suite 200
Anchorage, Alaska 99501
Phone: (907) 269-5274

LARRY HARTIG
Commissioner
Alaska Department of Environmental Conservation

DATE: 4/25/16

By: [redacted]
DENISE KOCH
Director
Alaska Department of Environmental Conservation
Division of Air Quality
410 Willoughby Ave., Suite 303
PO Box 111800
Juneau, Alaska 99811-1800
Phone: (907) 465-5109

THE STATE OF HAWAII HEREBY CONSENTS TO ENTRY OF THE CONSENT DECREE IN UNITED STATES ET AL. v. TESORO ET AL., SUBJECT TO THE PUBLIC NOTICE REQUIREMENTS OF 28 C.F.R. § 50.7

FOR THE STATE OF HAWAII:

DOUGLAS S. CHIN (Hawaii Bar No. 6465)
Attorney General
State of Hawaii

DATE: 4-19-16

By: [redacted]
HEIDI M. RIAN (Hawaii Bar No. 3473)
WILLIAM F. COOPER (Hawaii Bar No. 4501)
Deputy Attorneys General
465 South King Street, Room 200
Honolulu, Hawaii 96813

Virginia Pressler, M.D.
Director
Hawaii Department of Health

DATE: 4-20-16

By: [redacted]
KEITH E. KAWAOKA, D. Env.
Deputy Director for Environmental Health
Environmental Health Administration
P.O. Box 3378
Honolulu, HI 96801-3378

THE NORTHWEST CLEAN AIR AGENCY HEREBY CONSENTS TO ENTRY OF THE CONSENT DECREE IN UNITED STATES ET AL. v. TESORO ET AL., SUBJECT TO THE PUBLIC NOTICE REQUIREMENTS OF 28 C.F.R. § 50.7

FOR THE NORTHWEST CLEAN AIR AGENCY:

DATE: 4/14/16

[redacted]

LAUGHLAN H. CLARK
WSBA #10996
Carmichael Clark, P.S.
1700 D Street
Bellingham, WA 98227
(360) 647-1500

DATE: 4/14/16

[redacted]

MARK ASMUNDSON
Executive Director
Northwest Clean Air Agency
1600 South Second Street
Mount Vernon, WA 98273
(360) 428-1617

TESORO ALASKA COMPANY LLC HEREBY CONSENTS TO ENTRY OF THE CONSENT DECREE IN UNITED STATES ET AL. V. TESORO,

FOR TESORO ALASKA COMPANY LLC:

DATE: May 9, 2016

[redacted]

GREGORY J. GOFF
Chairman of the Board of Managers and President
Tesoro Companies, Inc.
19100 Ridgewood Parkway
San Antonio, Texas 78259

TESORO LOGISTICS L.P. HEREBY CONSENTS TO ENTRY OF THE CONSENT DECREE IN UNITED STATES ET AL. V. TESORO.

FOR TESORO LOGISTICS, L.P.:

DATE: May 9, 2016

[redacted]

GREGORY J. GOFF
Chairman of the Board of Directors and Chief Executive Officer
Tesoro Companies, Inc.
19100 Ridgewood Parkway
San Antonio, Texas 78259

TESORO REFINING & MARKETING COMPANY LLC HEREBY CONSENTS TO ENTRY OF THE CONSENT DECREE IN UNITED STATES ET AL. V. TESORO,

FOR TESORO REFINING & MARKETING COMPANY LLC:

DATE: May 9, 2016

[redacted]

GREGORY J. GOFF
Chairman of the Board of Managers and President
Tesoro Companies, Inc.
19100 Ridgewood Parkway
San Antonio, Texas 78259

PAR HAWAII REFINING, LLC HEREBY CONSENTS TO ENTRY OF THE CONSENT DECREE IN UNITED STATES ET AL. v. TESORO ET AL:

DATE: 9 May 2016

[redacted]

JAMES MATTHEW VAUGHN
Senior Vice President and General Counsel
Par Pacific Holdings, Inc.
800 Gessner Road
Suite 875
Houston, TX 77024
832-916-3386

APPENDIX A

Appendix A-1

APPENDIX A-1

MARTINEZ SAP MONITORING PLAN

CEMS Plan for SO_2 Emissions for the Martinez Refinery Double Absorption SAP

Principle

This CEMS Plan is the mechanism for determining compliance with the Short-Term SAP SO_2 Emission Limit and the Long-Term SAP SO_2 Emission Limit in the Consent Decree for the Martinez SAP, as well as the SO_2 emission limit of 40 C.F.R. § 60.82. The methodology described in this CEMS Plan will provide a real-time indication of compliance with these SO_2 emission limits by determining the emission rate in terms of both pounds of SO_2 emitted per unit of time and pounds of SO_2 emitted per ton of 100% Sulfuric Acid Produced (lbs/ton). The system will utilize at least the following: appropriate meters to measure 100% sulfuric acid production, one analyzer to measure stack SO_2 concentration, and one stack volumetric flow rate analyzer. From these data, the emission rate, expressed as both pounds per unit of time and lbs/ton, will be directly calculated using Equations 1 and 2 below.

Equation 1:

$$M_{SO_2 Stack} = Q_{Stack} \cdot B \cdot \frac{64.058 \ {}^{lbs}/_{lb-mol}}{385.57 \ \frac{SCF}{lb-mol}}$$

Equation 2:

$$E_{lbs/ton} = \frac{M_{SO_2 Stack}}{P_{TonsH_2SO_4}} = \frac{Q_{Stack} \cdot B}{P_{TonsH_2SO_4}} \cdot 0.166 \ {}^{lbs}/_{SCF}$$

Where:

$P_{TonsH_2SO_4}$ = 100% Sulfuric Acid Produced, tons per unit of time

$M_{SO_2 Stack}$ = Mass SO_2 stack emission rate, lb per unit of time

Q_{Stack} = Volumetric flow rate of stack gas, dry standard cubic feet (DSCF) per unit of time

B = Stack SO_2 concentration, fraction (dry basis)

$E_{lbs/ton}$ = lb SO_2 per ton 100% Sulfuric Acid Produced

$64.058 \ {}^{lbs}/_{lb-mol}$ = Molecular weight of SO_2

$0.166 \ {}^{lbs}/_{SCF} = \frac{64.058 \ {}^{lbs}/_{lb-mol}}{385.57 \ \frac{SCF}{lb-mol}}$

$385.57 \ \frac{SCF}{lb-mol}$ = Volume of one lb-mole of gas at standard temperature and pressure (68˚F and 14.696 psia), cubic feet

The mass emission rate equation (Equation 1) calculates the SO_2 mass emission rate by multiplying the total stack gas flow rate by the stack SO_2 concentration. The lbs/ton equation (Equation 2) is the ratio of the SO_2 emission rate to the 100% Sulfuric Acid Produced rate.

Definitions

Terms used in this CEMS Plan that are defined in the Consent Decree shall have the meaning assigned to them therein.

"SAP Operating Periods" shall mean, for the purposes of this Martinez SAP Monitoring Plan, periods during which acid gas is being fed to the Martinez SAP. For the purpose of this definition, "acid gas" shall include, but not be limited to, spent acid from the alkylation plant, hydrogen sulfide from diethanolamine unit strippers, sulfuric acid from the Martinez SAP, or vent gas from the Martinez SRP Sulfur Pit(s).

Emissions and Production Monitoring

Tesoro will undertake the following monitoring procedures at the Martinez SAP:

- Emissions monitoring will be done using 100% sulfuric acid production meters, an SO_2 analyzer at the exit stack, and a stack flow rate analyzer. Except for any analyzer or meter malfunctions, associated repairs, and required quality assurance or control activities (including calibration checks and required zero and span adjustments, if required), Tesoro will conduct monitoring during all SAP Operating Periods and during Malfunction, SAP Startup, or SAP Shutdown.

- Once every five minutes, the analyzers and production meters will measure the stack SO_2 concentration (fraction, dry basis), 100% sulfuric acid production rate (tons per minute), and the volumetric flow rate (dry standard cubic feet per minute). These values will consist of the calculated average of all readings taken within each 5 minute block.

- During routine calibration checks, maintenance, and adjustments of any analyzers or meters, the last valid 5-minute average value will be used to fill in any data gaps that occur pending completion of the calibration checks, maintenance, and adjustments.

- If one or more analyzers or meters are not operating for a period of 24 hours or greater, data gaps in the array involving the non-operational analyzer(s) will be filled in as follows:

    - Exit stack gas will be sampled and analyzed for SO_2 at least once per 8-hour period, during all SAP Operating Periods. Sampling will be conducted by portable analyzer or other established method. The most recent sampling value will be substituted for the 96 five-minute readings that would otherwise have been taken if the analyzer had been operating normally.

- 100% sulfuric acid production rate will be estimated using engineering judgment.
- Stack volumetric flow rate will be estimated using engineering judgment.

- If one or more analyzers or meters are not operating for a period of less than 24 hours, one of the following must be done: (i) the requirements set forth for a 24-hour or greater period of downtime must be used to fill in the data gaps; or (ii) the data recorded for the last valid 5-minute average immediately preceding the affected analyzer's(s') stoppage must be used to fill in the data gap.

Emissions Calculations

Tesoro will make the following calculations at the Martinez SAP:

3-hour Rolling Average.

For purposes of calculating a 3-hour rolling average, the system will maintain an array of the 36 most recent measurements of each of the three monitored parameters. Every five minutes, the system will add the most recent readings to the array and exclude the oldest readings.

The 3-hour rolling average lbs/ton SO_2 emission rate (E_{3hravg}) will be calculated using Equation 3.

Equation 3:

$$E_{3hravg} = 0.166\,{}^{lbs}\!/_{SCF} \cdot \frac{\sum_{i=1}^{36} Q_{Stack\ i} \cdot B_i}{\sum_{i=1}^{36} P_{TonsH_2SO_4\ i}}$$

Where:

$P_{TonsH_2SO_4 i}$ = 100% Sulfuric Acid Produced (tons per minute) at measurement "*i*"

B_i = Stack SO_2 concentration, fraction (dry basis) at measurement "*i*"

$Q_{Stack\ i}$ = Stack volumetric flow rate, dry standard cubic feet per minute (DSCFM) at measurement "*i*"

$0.166\,{}^{lbs}\!/_{SCF} = \frac{64.058\,{}^{lbs}\!/_{lb-mol}}{385.57\,\frac{SCF}{lb-mol}}$

E_{3hravg} = 3-hour average lb SO_2 per ton 100% Sulfuric Acid Produced

365-Day Rolling Average.

For the purposes of calculating a 365-day rolling average, the system will maintain an array of all of the measurements of each of the three monitored parameters for 365 Days. Every day, the system will add the readings from that day to the array and exclude the readings from the oldest day.

The 365-day rolling average lbs/ton SO_2 emission rate ($E_{365-Day\ Avg}$) will be calculated using Equation 4.

Equation 4:

$$E_{365-Day\ Avg} = 0.166\ {}^{lbs}\!/_{SCF} \cdot \frac{\sum_{j=1}^{n} Q_{Stack\ j} \cdot B_j}{\sum_{j=1}^{n} P_{TonsH_2SO_4\ j}}$$

Where:

$P_{TonsH_2SO_4\ j}$ = 100% Sulfuric Acid Produced (tons per minute) at measurement "*j*"

B_j = Stack SO_2 concentration, fraction (dry basis) at measurement "*j*"

$Q_{Stack\ j}$ = Stack volumetric flow rate, dry standard cubic feet per minute (DSCFM) at measurement "*j*"

$0.166\ {}^{lbs}\!/_{SCF} = \frac{64.058\ {}^{lbs}\!/_{lb-mol}}{385.57\ \frac{SCF}{lb-mol}}$

n = the number of measurements taken at 5-minute intervals over the 365-day period

$E_{365-Day\ Avg}$ = 365-day rolling average lb SO_2 per ton 100% Sulfuric Acid Produced

Rounding of Numbers resulting from Calculations

Upon completion of the calculations, the final numbers shall be rounded as follows:

E_{3hravg}: Rounded to the nearest tenth.

$E_{365-Day\ Avg}$: Rounded to the nearest hundredth.

The number "5" shall be rounded up (*e.g.*, a short-term rate of 2.05011 shall be rounded to 2.1).

Rounding of Variables B, $P_{TonsH_2SO_4}$, and Q_{Stack}

Rounding of the variables identified as B, $P_{TonsH_2SO_4}$, and Q_{Stack} in the equations set forth in this CEMS Plan shall be done based on the accuracy of the measuring device as provided by the manufacturer of the device.

100% Sulfuric Acid Produced Calculation

The sulfuric acid produced from each product acid stream shall be calculated as follows:

100% Sulfuric Acid Produced (tons/min) = Flow (gal/min) * Density (lb/gal) * ton/2000 lb * on-line concentration

The production rate will also include an estimated amount of liquid that condenses from the Acid Mist in the Brinks Mist Eliminator Tank.

Compliance with Consent Decree SO_2 Limits

Short-Term SAP SO_2 Emission Limit

The Short-Term SAP SO_2 Emission Limit does not apply during periods of Malfunction, SAP Startup, or SAP Shutdown. During all times other than Malfunction, SAP Startup, or SAP Shutdown, Tesoro will be in compliance with the Consent Decree's Short-Term SAP SO_2 Emission Limit if E_{3hravg} does not exceed 1.85 lbs of SO_2 per ton of 100% Sulfuric Acid Produced. At Tesoro's option or upon written request from EPA, if Tesoro contends that emissions during a Malfunction(s) resulted in a calculated 3-hour rolling average emission rate(s) in excess of 1.85 lbs SO_2/ton H_2SO_4 after the period of the Malfunction(s) end(s), Tesoro shall recalculate E_{3hravg} to exclude measurements recorded during the period(s) of the claimed Malfunction(s).

NSPS SO_2 Limit

The SO_2 emission limit of 40 C.F.R. § 60.82 does not apply during periods of Malfunction, SAP Startup, or SAP Shutdown. During all times other than Malfunction, SAP Startup, or SAP Shutdown, Tesoro will be in compliance with this NSPS limit if E_{3hravg} does not exceed 4.0 lb of SO_2 per ton of 100% Sulfuric Acid Produced. At Tesoro's option or upon written request from EPA, if Tesoro contends that emissions during a Malfunction(s) resulted in a calculated 3-hour rolling average emission rate(s) in excess of 4.0 lbs SO_2/ton H_2SO_4 after the period of the Malfunction(s) end(s), Tesoro shall recalculate E_{3hravg} to exclude measurements recorded during the period(s) of the claimed Malfunction(s).

Long-Term SAP SO_2 Emission Limit

The Long-Term SAP SO_2 Emission Limit applies at all times, including, but not limited to, periods of Malfunction, SAP Startup, or SAP Shutdown. Tesoro will be in compliance with the Consent Decree's Long-Term SAP SO_2 Emission Limit if $E_{365-Day\ Avg}$ does not exceed 1.7 lbs of SO_2 per ton of 100% Sulfuric Acid Produced.

Changes to the CEMS Plan

Tesoro may make changes to this CEMS Plan if approved by EPA. Changes to this CEMS Plan shall be considered non-material modifications under Section XX (Modification) of the Consent Decree.

Recordkeeping and Reporting

In addition to any requirements in the Consent Decree or in 40 C.F.R. Part 60, Subparts A or H, Tesoro shall maintain records of the date, time, and duration that any one of the analyzers or meters required under this CEMS plan, as identified in Table 1, is not operating. Except for zero and span checks, in each semi-annual report required under Section X of the Decree, Tesoro specifically shall identify all periods of analyzer or meter Downtime during the reporting period and all data during the reporting period that is "substitute" data. "Substitute" data means data that is not generated contemporaneously by an analyzer or meter when gas flow stack (or duct) emissions are being measured, but rather is substituted for contemporaneous analyzer or meter measurements when an analyzer or meter is not operating. In addition, Tesoro shall specifically identify any substitute data that is inconsistent with the provisions of the "Emissions and Production Monitoring" section of this CEMS Plan.

Retention of All CEMS and Production Data, including Data during Malfunction, SAP Startup, or SAP Shutdown

Tesoro will retain all data generated by its SO_2 analyzer, sulfuric acid production meters, and stack flow analyzer, including all data generated during Malfunction, SAP Startup, or SAP Shutdown of the Martinez SAP in accordance with the requirements of Section X of the Consent Decree.

Analyzer Specifications

These analyzers or meters will meet the following specifications:

Table 1

Parameter	Location	Range
SO_2, mole fraction, dry basis	Stack	Dual range: Normal: 0 – 500 ppm SO_2 SSM: 0 – 3,600 ppm SO_2
100% H_2SO_4, tons/min	93% Acid Flow Meter: Outlet of the discharge pump from the cross flow stripper (V-12) 98% Acid Flow Meter: Outlet of the product cooler (E-16)	0 – 60 gallons per minute (gpm)
Volumetric flow rate, DSCFM	Stack	0 to 125% of the maximum expected volumetric flow rate

The stack SO_2 analyzer will meet all applicable requirements of 40 C.F.R. §§ 60.11 and 60.13; the applicable requirements of 40 C.F.R. Part 60, Appendix A; 40 C.F.R. Part 60, Appendix B, Performance Specification 2; and the Quality Assurance and Quality Control Procedures in 40 C.F.R. Part 60, Appendix F, Procedure 1.

- In lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3, and 5.1.4, Tesoro must conduct either a RAA or a RATA on the stack SO_2 analyzer at least once every three (3) years. Tesoro must also conduct a CGA each Calendar Quarter during which a RAA or a RATA is not performed. Tesoro may conduct a FAT, as defined in BAAQMD regulations or procedures, in lieu of the required RAA or CGA.

- The current stack SO_2 analyzer location is acceptable provided it meets the requirements of 40 C.F.R. Part 60, Appendix B, Performance Specification 2, § 8.1.1.

The sulfuric acid production meters will meet all manufacturer specifications.

The volumetric flow rate analyzer will meet 40 C.F.R. Part 60, Appendix B, Performance Specification 6 and the Quality Assurance and Quality Control Procedures in 40 C.F.R. Part 60, Appendix F, Procedure 1.

Compliance with the NSPS: 40 C.F.R. Part 60, Subparts A and H

In addition to the requirements in this CEMS Plan, Tesoro also will comply with all of the requirements of the 40 C.F.R. Part 60, Subparts A and H relating to monitoring provided that, pursuant to 40 C.F.R. § 60.13(i), this CEMS Plan will be an approved alternative to the following provisions of 40 C.F.R. Part 60, Subpart H:

- The requirement at 40 C.F.R. § 60.84(a) that the stack SO_2 analyzer have a span value of 1000 ppm. In lieu of this, Tesoro will utilize the span values specified in Table 1; and

- The procedures specified at 40 C.F.R. § 60.84(b) for converting monitoring data into the units of the applicable standard. In lieu of this, Tesoro will utilize the procedures specified in this CEMS Plan for calculating compliance with the SO_2 emission limit of 40 C.F.R. § 60.82.

Appendix A-2

APPENDIX A-2

2005 CONSENT DECREE REQUIREMENTS APPLICABLE TO THE MARTINEZ REFINERY

A. Additional Definitions

Except as expressly set forth elsewhere in this Consent Decree, the terms used in this Appendix A-2 shall have the meaning given to those terms in this Appendix or in Sections IV or V.E of this Consent Decree; or, if not defined in this Consent Decree, as defined in the Clean Air Act and the implementing regulations promulgated thereunder.

"Fuel Oil" shall mean fuel that is predominantly in the liquid phase at the point of combustion with a sulfur content of greater than 0.05% by weight. Fuel Oil does not include torch oil used to heat and/or maintain catalyst temperature during FCCU Startup or Shutdown.

"HHV" shall mean higher heating value.

"Hydrotreater" shall include any units that hydrotreat or otherwise desulfurize FCCU feedstocks.

"One-hour average" shall mean average hourly emission rate.

B. SO_2 Emissions Reductions from the Martinez Refinery FCCU

1. Martinez FCCU SO_2 Emission Limits.

a. Limits. Beginning no later than September 30, 2006, Tesoro shall comply with the following emission limits at the Martinez FCCU: (i) a short-term FCCU SO_2 emission limit of 50 ppmvd SO_2 @ 0% O_2 (7-day rolling average) ("Short-Term Martinez FCCU SO_2 Emission Limit"); and (ii) a long-term FCCU SO_2 emission limit of 25 ppmvd SO_2 @ 0% O_2 (365-day rolling average) ("Long-Term Martinez FCCU SO_2 Emission Limit").

b. Startup, Shutdown, or Malfunction. Beginning no later than October 4, 2010, Tesoro shall comply with an EPA-approved Hydrotreater Outage Plan ("HTO Plan") at all times, including periods of Startup, Shutdown, or Malfunction. Tesoro may make changes to the HTO Plan if approved by EPA.

i. SO_2 emissions during periods of Hydrotreater outages shall not be used in determining compliance with the Short-Term Martinez FCCU SO_2 Emission Limit (i.e., 7- day rolling average) required by this Paragraph, provided that during such periods (i) Tesoro is in compliance with the applicable HTO Plan; and (ii) Tesoro, to the extent practicable, maintains and operates the Martinez FCCU, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. In addition, in the event that Tesoro asserts that the basis for the Hydrotreater outage for which Tesoro seeks to secure relief from the Short-Term Martinez FCCU SO_2 Emission Limit is a shutdown (where no catalyst change out occurs) required by American Society of Mechanical

Engineers pressure vessel requirements or applicable state boiler requirements, Tesoro shall submit to EPA a report that identifies the relevant requirement and justifies Tesoro's decision to implement the shutdown during the selected time period.

2. NSPS Applicability to the Martinez FCCU. Beginning no later than September 30, 2006, the Martinez FCCU Catalyst Regenerator shall continue to be an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and J, and shall continue to be subject to and comply with the requirements of 40 C.F.R. Part 60, Subparts A and J, for SO_2 applicable to FCCU catalyst regenerators. SO_2 limits under this Paragraph B.2 shall not apply during periods of Startup, Shutdown, or Malfunction of the Martinez FCCU and Hydrotreater or Malfunction of the associated SO_2 control equipment, if any, provided that during such periods Tesoro, to the extent practicable, maintains and operates the Martinez FCCU, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. Entry of the 2005 Martinez Consent Decree and compliance with the relevant monitoring requirements of the 2005 Martinez Consent Decree for the FCCU catalyst regenerator satisfied the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a).

3. Demonstrating Compliance with Martinez FCCU SO_2 Emission Limits. Beginning no later than September 30, 2006, Tesoro shall use SO_2 and O_2 CEMS to monitor performance of the Martinez FCCU and to report compliance with the terms and conditions of this Section B. CEMS shall be used to demonstrate compliance with the SO_2 emission limits established pursuant to this Section B. Tesoro shall make CEMS data available to EPA upon request. Tesoro shall install, certify, calibrate, maintain, and operate all CEMS required by this Paragraph in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to COMS) and Part 60, Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B. With respect to 40 C.F.R. Part 60 Appendix F, in lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, Tesoro shall conduct either a RAA or a RATA on each CEMS at least once every three (3) years. Tesoro shall also conduct CGAs each Calendar Quarter during which a RAA or a RATA is not performed. Tesoro may conduct a FAT in lieu of the required RAA or CGA.

C. PM Emissions Reductions from the Martinez Refinery FCCU

4. Martinez FCCU PM Emission Limit.

a. Limit. Beginning no later than September 30, 2006, Tesoro shall comply with an emission limit at the Martinez FCCU of 1.0 pound of PM per 1,000 pounds of coke burned (front half only according to EPA Method 5B or 5F, as appropriate, set forth at 40 C.F.R. Part 60, Appendix A), measured as a one-hour average over three performance test runs ("Martinez FCCU PM Emission Limit").

b. Startup, Shutdown, or Malfunction. PM emissions during periods of Startup, Shutdown, or Malfunction of the Martinez FCCU or Malfunction of the associated PM control equipment, if any, shall not be used in determining compliance with the Martinez FCCU PM Emission Limit required by this Paragraph, provided that during such periods Tesoro, to the extent practicable, maintains and operates the Martinez FCCU, including associated air pollution

control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

5. NSPS Applicability to Martinez FCCU. Beginning no later than September 30, 2006, the Martinez FCCU Catalyst Regenerator shall continue to be an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and J, and shall continue to be subject to and comply with the requirements of 40 C.F.R. Part 60, Subparts A and J, for PM and opacity applicable to FCCU catalyst regenerators. PM and Opacity limits under this Paragraph C.5 shall not apply during periods of Startup, Shutdown, or Malfunction of the Martinez FCCU or Malfunction of the associated PM control equipment, if any, provided that during such periods Tesoro, to the extent practicable, maintains and operates the Martinez FCCU, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. Entry of the 2005 Martinez Consent Decree and compliance with the relevant monitoring requirements of the 2005 Martinez Consent Decree for the FCCU catalyst regenerator satisfied the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a).

6. Demonstrating Compliance with Martinez FCCU PM and Opacity Emission Limits.

a. PM Performance Tests. Any future performance testing performed by Tesoro to demonstrate compliance with the PM emission limits established by this Section C shall be conducted in accordance with EPA Method 5B or 5F, as appropriate, set forth at 40 C.F.R. Part 60, Appendix A.

b. COMS. Beginning no later than September 30, 2006, Tesoro shall use COMS or an approved alternative monitoring plan to monitor performance of the Martinez FCCU and to report compliance with the terms and conditions of this Section C. COMS shall be used to demonstrate compliance with the Opacity limits established pursuant to Paragraph C.5 of this Appendix. Tesoro shall make COMS data available to EPA upon request. Tesoro shall install, certify, calibrate, maintain, and operate all COMS required by this Paragraph in accordance with the provisions of 40 C.F.R. § 60.11, 60.13, and Part 60, Appendix A and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B.

D. CO Emissions Reductions from the Martinez Refinery FCCU

7. Martinez FCCU CO Emission Limit.

a. Limit. Beginning no later than September 30, 2006, Tesoro shall comply with the following emission limit at the Martinez FCCU: a short-term Martinez FCCU CO emission limit of 500 ppmvd CO @ 0% O_2 (one-hour block average) ("Short-Term Martinez FCCU CO Emission Limit").

b. Startup, Shutdown, or Malfunction. CO emissions during periods of Startup, Shutdown, or Malfunction of the Martinez FCCU or Malfunction of the associated CO control equipment, if any, shall not be used in determining compliance with the Short-Term Martinez FCCU CO Emission Limit (i.e., one-hour block average) required by this Paragraph, provided that during such periods Tesoro, to the extent practicable, maintains and operates the Martinez

FCCU, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

8. NSPS Applicability to Martinez FCCU. Beginning no later than September 30, 2006, the Martinez FCCU Catalyst Regenerator shall continue to be an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and J, and shall continue to be subject to and comply with the requirements of 40 C.F.R. Part 60, Subparts A and J, for CO applicable to FCCU catalyst regenerators. CO limits under this Paragraph D.8 shall not apply during periods of Startup, Shutdown, or Malfunction of the Martinez FCCU or Malfunction of the associated CO control equipment, if any, provided that during such periods Tesoro, to the extent practicable, maintains and operates the Martinez FCCU, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. Entry of the 2005 Martinez Consent Decree and compliance with the relevant monitoring requirements of the 2005 Martinez Consent Decree for the FCCU catalyst regenerator satisfied the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a).

9. Demonstrating Compliance with Martinez FCCU CO Emission Limits. Beginning no later than September 30, 2006, Tesoro shall use CO CEMS to monitor performance of the Martinez FCCU and to report compliance with the terms and conditions of this Section D. CEMS shall be used to demonstrate compliance with the CO emission limits established pursuant to this Section D. Tesoro shall make CEMS data available to EPA upon request. Tesoro shall install, certify, calibrate, maintain, and operate all CEMS required by this Paragraph in accordance with the provisions of 40 C.F.R. § 60.13 that are applicable to CEMS (excluding those provisions applicable only to COMS) and Part 60, Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B. With respect to 40 C.F.R. Part 60 Appendix F, in lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, Tesoro shall conduct either a RAA or a RATA on each CEMS at least once every three (3) years. Tesoro shall also conduct CGAs each Calendar Quarter during which a RAA or a RATA is not performed. Tesoro may conduct a FAT in lieu of the required RAA or CGA.

E. NOx Emissions Reductions from the Martinez Refinery Heaters and Boilers

10. Scope. For the purpose of this Section E, "Covered Heaters and Boilers" shall be defined to include all units at the Martinez Refinery that meet both of the following criteria:

a. Any stationary combustion unit used for the purpose of burning fossil fuel for the purpose of (i) producing power, steam, or heat by heat transfer; or (ii) heating a material for initiating or promoting a process or chemical reaction in which the material participates as a reactant or catalyst, but expressly excluding any turbine, internal combustion engine, duct burner, CO boiler, incinerator, or incinerator waste heat boiler; and

b. Any heaters and boilers with heat input capacity greater than 40 MMBtu/hr (HHV).

11. Martinez Refinery Heaters and Boilers NOx Emission Limit. Tesoro shall comply with Sections 9-10-301 or 9-10-308 of BAAQMD Regulation 9, Rule 10, as such provisions both relate to Covered Heaters and Boilers at the Martinez Refinery and establish NOx emission

standards for certain units, including the Covered Heaters and Boilers at the Martinez Refinery, based upon an emission level of 0.033 pounds NOx/MMBtu of Section 9-10-301 or the alternative total mass emission limit established pursuant to Section 9-10-308. If BAAQMD revises Sections 9-10-301 or 9-10-308, such revisions will become the applicable emission standard under this Paragraph provided that the refinery-wide NOx emission limit remains no less stringent than the 0.033 pounds NOx/MMBtu average emission rate limit of Section 9-10-301 or the alternative total mass emission limit established pursuant to Section 9-10-308. Compliance with these requirements shall be determined in accordance with BAAQMD's rules and regulations, including without limitation the interchangeable emission reduction credit provisions of BAAQMD Regulation 2, Rule 9.

12. Restriction on Use of Credits. Nothing in this Consent Decree is intended or shall be construed to limit the methods available to Tesoro under the BAAQMD rules and regulations for compliance with Sections 9-10-301 and 9-10-308 thereof; provided however, no credits generated under the BAAQMD rules and regulations may be traded or sold to another facility as provided in Paragraph 161.c of this Consent Decree. In the event that EPA, BAAQMD, the BAAQMD Hearing Board, or a court of competent jurisdiction should finally determine that this Consent Decree prohibits or limits the ability of Tesoro to generate, bank, or use interchangeable emission reduction credits, as defined in BAAQMD Regulation 2, Rule 9, from emission reductions at any emission unit at the Martinez Refinery, including without limitation the Covered Heaters and Boilers at the Martinez Refinery, then Tesoro may elect, upon written notice to EPA, to render null and void the provisions of this Section E. In the event that Tesoro provides written notice to EPA of such election pursuant to this Paragraph, the release from liability under Section XVII (Effect of Settlement/Reservation of Rights) of this Consent Decree applicable to NOx emissions from Covered Heaters and Boilers at the Martinez Refinery shall be rendered null and void. In lieu of providing such notice to EPA, Tesoro may propose and EPA may agree to allow Tesoro to implement such actions sufficient to satisfy the obligations of this Section E as if this Section E had remained in full force and effect not withstanding an adverse determination by EPA, BAAQMD, the BAAQMD Hearing Board, or a court of competent jurisdiction with respect to the Martinez Refinery. If such an agreement is reached, committed to writing, and signed by Tesoro and EPA, then the release from liability under Section XVII of this Consent Decree applicable to NOx emissions from Covered Heaters and Boilers at the Martinez Refinery shall not be rendered void under this Paragraph.

F. SO_2 Emissions Reductions from the Martinez Refinery Heaters and Boilers

13. Elimination of Fuel Oil Burning. Beginning no later than December 31, 2005, Tesoro shall not burn or combust Fuel Oil in any heater or boiler at the Martinez Refinery.

14. NSPS Applicability to Martinez Refinery Heaters and Boilers. Beginning no later than December 31, 2006, all of the heaters and boilers located at the Martinez Refinery (except FCCU Startup Heater and Furnaces F-8, F-9, F-12, and F-13) shall continue to be "affected facilities" as that term is used in 40 C.F.R. Part 60, Subparts A and J, and shall continue to be subject to and comply with the requirements of 40 C.F.R. Part 60, Subparts A and J, applicable to heaters and boilers. Beginning no later than December 31, 2010, FCCU Startup Heater and Furnaces F-8, F-9, F-12, and F-13 located at the Martinez Refinery shall continue to be "affected facilities" as that term is used in 40 C.F.R. Part 60, Subparts A and J, and shall continue to be subject to and

comply with the requirements of 40 C.F.R. Part 60, Subparts A and J, applicable to heaters and boilers. The limits under this Paragraph F.14 shall not apply during periods of Startup, Shutdown, or Malfunction of the heaters and boilers or Malfunction of the associated control equipment, if any, provided that during such periods Tesoro, to the extent practicable, maintains and operates the heaters and boilers, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. Entry of the 2005 Martinez Consent Decree and compliance with the relevant monitoring requirements of the 2005 Martinez Consent Decree for the heaters and boilers satisfied the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a).

15. Demonstrating Compliance with Martinez Refinery Heaters and Boilers SO_2 Emission Limit. Beginning no later than December 31, 2006, Tesoro shall use SO_2 and O_2 CEMS or an H_2S CMS to monitor performance of the Martinez Refinery heaters and boilers (except FCCU Startup Heater and Furnaces F-8, F-9, F-12, and F-13) and to report compliance with the terms and conditions of this Section F. Beginning no later than December 31, 2010, Tesoro shall use SO_2 and O_2 CEMS or an H_2S CMS to monitor performance of the Martinez Refinery FCCU Startup Heater and Furnaces F-8, F-9, F-12, and F-13 and to report compliance with the terms and conditions of this Section F. SO_2 CEMS or H_2S CMS shall be used respectively to demonstrate compliance with the SO_2 or H_2S emission limit established pursuant to this Section F. Tesoro shall make SO_2 CEMS or H_2S CMS data available to EPA upon request. Tesoro shall install, certify, calibrate, maintain, and operate all SO_2 CEMS or H_2S CMS required by this Paragraph in accordance with the respective provisions of 40 C.F.R. § 60.13 that are applicable to SO_2 CEMS or H_2S CMS (excluding those provisions applicable only to COMS) and Part 60, Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60, Appendix B. With respect to 40 C.F.R. Part 60 Appendix F, in lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, Tesoro shall conduct either a RAA or a RATA on each CEMS at least once every three (3) years. Tesoro shall also conduct CGAs each Calendar Quarter during which a RAA or a RATA is not performed. Tesoro may conduct a FAT in lieu of the required RAA or CGA.

G. SO_2 Emissions Reductions from the Martinez Refinery Sulfur Recovery Plant

16. NSPS Applicability to Martinez SRP. Beginning no later than December 31, 2006, the Martinez SRP shall continue to be an "affected facility" as that term is used in 40 C.F.R. Part 60, Subparts A and J, and shall continue to be subject to and comply with the requirements of 40 C.F.R. Part 60, Subparts A and J, for SO_2 applicable to sulfur recovery plants. Entry of the 2005 Martinez Consent Decree and compliance with the relevant monitoring requirements of the 2005 Martinez Consent Decree for the Martinez SRP satisfied the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a).

17. Emission Points. All emission points (stacks) to the atmosphere for tail gas emissions from the Martinez SRP will be monitored and reported upon in accordance with 40 C.F.R. §§ 60.7(c), 60.13, and 60.105. This requirement is not applicable to the following AG Flaring Devices: Ammonia Plant Flare, East Air Flare, West Air Flare, North Steam Flare, South Steam Flare, DCU Flare, and Emergency Flare.

18. Startup, Shutdown, or Malfunction. During the life of this Consent Decree and for the purpose of determining compliance with the SRP emission limits, Tesoro shall apply the "startup" and "shutdown" provisions set forth in NSPS Subpart A to the Martinez SRP but not to the independent startup or shutdown of its corresponding control device(s) (e.g., the tail gas unit). However, the malfunction exemption set forth in NSPS Subpart A shall apply to both the Martinez SRP and its control device(s) (e.g., the tail gas unit).

APPENDIX B

Appendix B

Process and Factors for "Commercial Unavailability" of Low-Leaking Valve or Packing Technology

Summary: This Appendix outlines a process to be followed and factors to be taken into consideration to establish that a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology is not "commercially available" pursuant to Paragraph 100 of the Consent Decree. Factors and procedures other than those identified in this Appendix may also be utilized to establish that a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology is not commercially available.

A. Factors. The following factors shall be taken in to account for determining the availability of safe and suitable Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technologies:

1. Valve type;
2. Valve service and operating conditions;
3. Type of refinery process equipment in which the valve is used;
4. Seal performance;
5. Service life;
6. Packing friction;
7. Temperature and pressure limitations; and
8. Retrofit applications (*e.g.*, re-piping or space limitations).

The following factors may also be relevant for consideration, depending on the process unit or equipment in use at the refinery:

9. Valve or valve packing specifications identified by the licensor of the process unit or equipment in use at the refinery (including components that are part of a design package by a specialty-equipment provider as part of a larger process unit); or

10. Valve or valve packing vendor or manufacturer recommendations for the relevant refinery unit and/or process unit components.

B. Process. The following procedure shall be followed for determining the availability of a Certified Low-Leaking Valve or Certified Valve Packing Technology:

1. The Settling Defendant must contact at least three vendors of valves and three vendors of valve packing technologies prior to asserting a claim that Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology is not commercially available.

   If fewer than three vendors of valve or valve packing technologies are contacted, the determination of whether such fewer number is reasonable for purposes of this Consent Decree shall be based on Factors 9. and/or 10. above, or on a demonstration

that fewer than three vendors offer valves or valve packing technologies for the service and operating conditions of the valve to be replaced, in consideration of Factors 1. through 8. above, as applicable.

2. The Settling Defendant shall obtain a written representation from each vendor contacted or equivalent documentation that the valve or valve packing does not meet the specifications for a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology.

3. The Settling Defendant shall prepare a written report fully explaining the basis for each claim that a valve or valve packing is not commercially available, to include all relevant documentation and other information supporting the claim. Such report shall also identify the commercially-available valve or packing technology that comes closest to meeting the requirements for a Certified Low-Leaking Valve or Certified Low-Leaking Valve Packing Technology that is selected and installed by the Settling Defendant pursuant to Paragraph 100 of the Consent Decree. Such report shall be included in the Compliance Status Report required by Paragraph 108 of the Consent Decree, for the period in which the valve or valve packing is replaced.

B. EPA Review of Claim of Commercial Unavailability. Upon discretionary review by EPA of any claim of Commercial Unavailability, if EPA disagrees that a valve or valve-packing technology is commercially unavailable, EPA shall notify the Settling Defendant in writing, specifying the valve or valve packing EPA believes to be commercially available and the basis for its availability for the service and operating conditions of the valve. Following receipt by the Settling Defendant of EPA's notice, the following shall apply:

1. The Settling Defendant is not required to retrofit the valve or valve packing for which the unavailability claim was asserted (unless otherwise required to do so pursuant to some other provision of this Consent Decree).

2. EPA's notification shall serve as notice to the Settling Defendant of EPA's intent that a future claim of Commercial Unavailability will not be accepted for a. the valve or valve packing that was the subject of the unavailability claim, or b. for a valve or valve packing in the same or similar service, taking into account the factors identified in this Appendix. If the Settling Defendant disagrees with EPA's notification, the Settling Defendant and EPA may informally discuss the basis for the claim of Commercial Unavailability. EPA may thereafter revise its notification, if necessary.

3. If the Settling Defendant makes a subsequent Commercial Unavailability claim for the same valve or valve packing (or valve or valve packing in the same or similar service) that was the subject of a prior unavailability claim which was not accepted by EPA, and such subsequent claim is also denied by EPA on the same basis as provided in EPA's prior notification, the Settling Defendant shall retrofit the valve or valve packing with the commercially available valve or valve packing technology at the next unit turnaround.

4. Any disputes concerning EPA's notification to the Settling Defendant of the commercial availability of a valve or valve packing technology in a particular application pursuant to Paragraph B.3 of this Appendix shall be addressed under the Dispute Resolution provisions in Section XV of this Consent Decree.

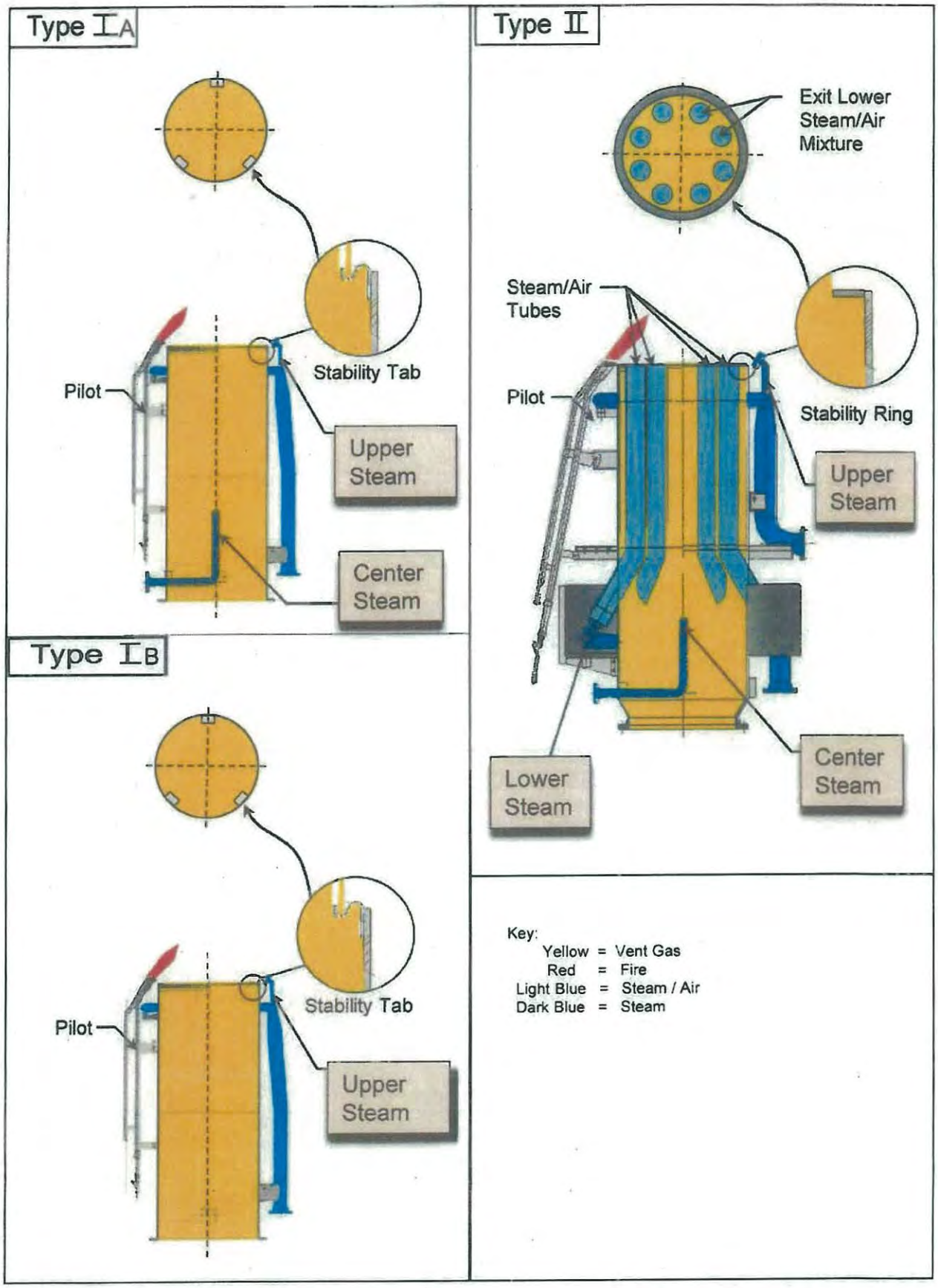
APPENDIX C

APPENDIX C INDEX

NUMBER	ABBREVIATION	DESCRIPTION
1.1	S-Drwgs	Drawings Illustrating Lower, Center, and Upper Steam Injection in Various Types of Flare Tips
1.2	Gen-Eq	General Equations
1.3	NHV_{cz} and NHV_{dil}	Calculating NHV_{cz} and NHV_{dil}
1.4	Intentionally left blank	Intentionally left blank
1.5	Intentionally left blank	Intentionally left blank
1.6	Tip-Area-Eq	Calculating the Unobstructed Cross Sectional Area of Various Types of Flare Tips
1.7	G-Drwg	Depiction of Gases Associated with Steam-Assisted Flares
1.8	Intentionally left blank	Intentionally left blank
1.9	Gas Chromatograph-Cmpnds	List of Compounds a Gas Chromatograph Must be Capable of Speciating
1.10	Tech-Specs	Equipment and Instrumentation Technical Specifications and Quality Assurance/Quality Control Requirements
1.11	Waste Gas Mapping	Waste Gas Mapping: Level Of Detail Needed To Show Headers And Flaring Process Unit Headers
1.12	Intentionally left blank	Intentionally left blank
1.13	Intentionally left blank	Intentionally left blank
1.14	Nelson Complexity Index	Determining Refinery-Specific and Industry-Average Complexity Through Use Of The Nelson Complexity Index
1.15	Roll-Sum-Aver	Calculating Rolling Sums and Rolling Averages
2.1	CD Requirement Applicability Dates	Covered Flares and Applicability Dates For Certain Consent Decree Requirements
2.2	PRV List	Large High Pressure Hydrocarbon Relief Valves
2.3	Kenai PFTIR Protocol	Combustion Efficiency Test Protocol for Kenai Air Assisted Flare
2.4	Flare Cap Calculations	Refinery Specific Flare Cap Calculations
2.5	Emission and CE Reports	Reports for Emissions and Flare Combustion Efficiency Testing

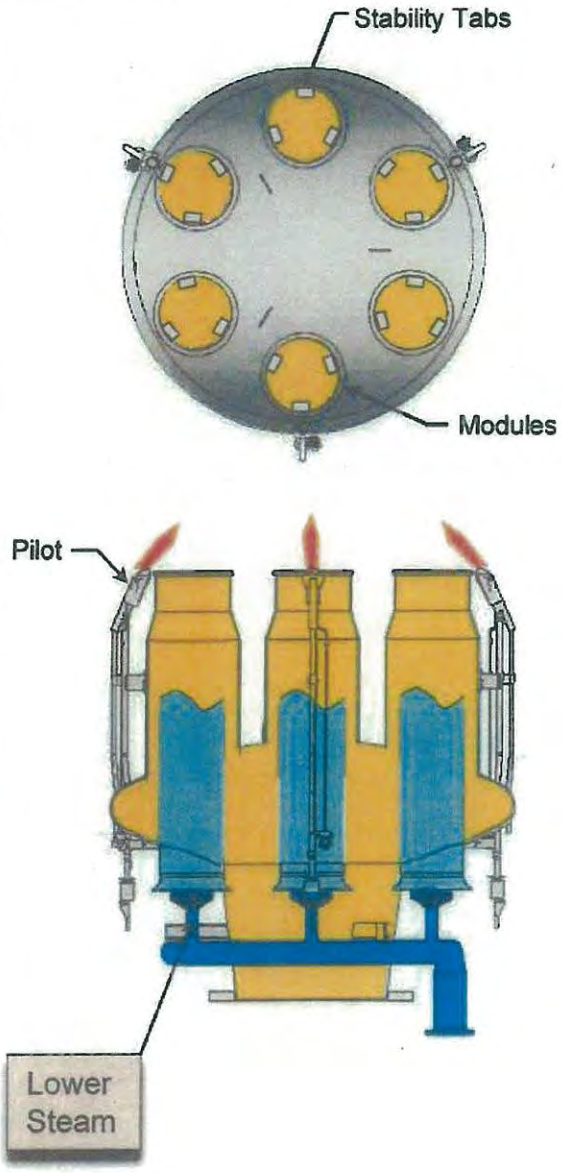
APPENDIX C-1.1

Appendix 1.1

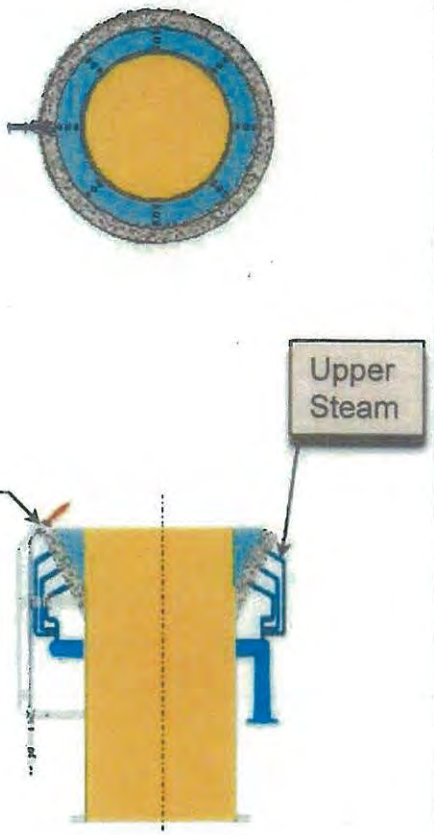

Type IA
Pilot
Stability Tab
Upper Steam
Center Steam
Type IB
Pilot
Stability Tab
Upper Steam
Type II
Exit Lower Steam/Air Mixture
Steam/Air Tubes
Pilot
Stability Ring
Upper Steam
Lower Steam
Center Steam
Key:
Yellow = Vent Gas
Red = Fire
Light Blue = Steam / Air
Dark Blue = Steam

Appendix 1.1

Type III



Type IV



Key:
Yellow = Vent Gas
Red = Fire
Light Blue = Steam / Air
Dark Blue = Steam

APPENDIX C-1.2

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 "$\dot{m}_s$":***

$$\dot{m}_s = Q_{s\text{-}rate} \times (18/385.3)$$

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 "$Q_{mass\text{-}rate}$":**

$$Q_{mass\text{-}rate} = Q_{vg} \times (MW_{vg}/385.3)$$

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}":***

$Log_{10}(V_{max}) = (NHV_{vg} + 1{,}212)/850$

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 C – 1.3, BTU/scf.
1,212	=	Constant.
850	=	Constant.

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

$Q_{vol} = (Q_{mass} \times 385.3)/MWt$

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

Equation 7: ***"15-Minute Block Average Tip Velocity" or "V_{tip}":***

$V_{tip} = Q_{cum}/(Area \times 900)$

where:

V_{tip}	=	Flare Tip Velocity, feet per second.
Q_{cum}	=	Cumulative volumetric flow over 15-minute Block Average Period, actual cubic feet.

Area	=	Unobstructed Cross Sectional Area of the Flare Tip, square feet.
900	=	Conversation factor, seconds per 15-minute Block Average

APPENDIX C-1.3

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

If compositional analysis data are collected as provided in Paragraphs 118.a and 118.b, the Settling Defendants shall determine the NHV_{vg} of a specific sample using the following equation.

$$NHV_{vg} = \sum_{i=1}^{n} (x_i \cdot NHV_i) \qquad \textit{Equation 1}$$

where:

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 Paragraph 118.c but a hydrogen concentration monitor is not used, the Settling Defendants 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 Paragraph 118.c and hydrogen concentration monitoring data are collected as provided in Paragraph 118.d, the Settling Defendants shall use the following equation to determine NHV_{vg} for each sample measured via the Net Heating Value calorimeter.

$$NHV_{vg} = NHV_{measured} + 938x_{H2}$$ ***Equation 2***

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 Paragraphs 118.a or 118.c and, if applicable, 118.d, the Settling Defendants may elect to determine the 15-minute Block Average NHV_{vg} using either the feed-forward or direct calculation methods below. The Settling Defendants 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 Settling Defendants 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 Settling Defendants intend to change the calculation method that applies to the Flare, the Settling Defendants 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 a.m. 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 Settling Defendants monitor 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 Paragraph 139.b.ii 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, $NHV_{cz} = NHV_{vg}$.

$$NHV_{cz} = \frac{Q_{vg} \times NHV_{vg}}{\left(Q_{vg} + Q_S + Q_{a,premix}\right)}$$ ***Equation 3***

where:

NHV_{cz} = Net Heating Value of Combustion Zone Gas, BTU/scf.

NHV_v = Net Heating Value of Vent Gas for the 15-minute Block Period, BTU/scf.

Q_v = 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.

$$NHV_{cz} = \frac{\left(Q_{vg} - Q_{NG2} + Q_{NG1}\right) \times NHV_{vg} + \left(Q_{NG2} - Q_{NG1}\right) \times NHV_{ng}}{\left(Q_{vg} + Q_S + Q_{a,premix}\right)}$$ ***Equation 4***

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 Paragraph 118.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 Settling Defendants 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.

$$NHV_{dil} = \frac{Q_{vg} \times Diam \times NHV_{vg}}{\left(Q_{vg} + Q_S + Q_{apremix} + Q_{aperimeter}\right)}$$ ***Equation 5***

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 Paragraph 135.b.ii.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.

Feed-Forward Calculation Method

Settling Defendants operating 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.

$$NHV_{dil} = \frac{\left[(Q_{vg} - Q_{NG2} + Q_{NG1}) \times NHV_{vg} + (Q_{NG2} - Q_{NG1}) \times NHV_{NG}\right] \times Diam}{\left(Q_{vg} + Q_S + Q_{a.premix} + Q_{a.perimester}\right)}$$ ***Equation 6***

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_{NG}	=	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 Paragraph 118.e, 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 Paragraph 135.d.ii.aand 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 Consent Decree, 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 C-1.4

(Intentionally Blank)

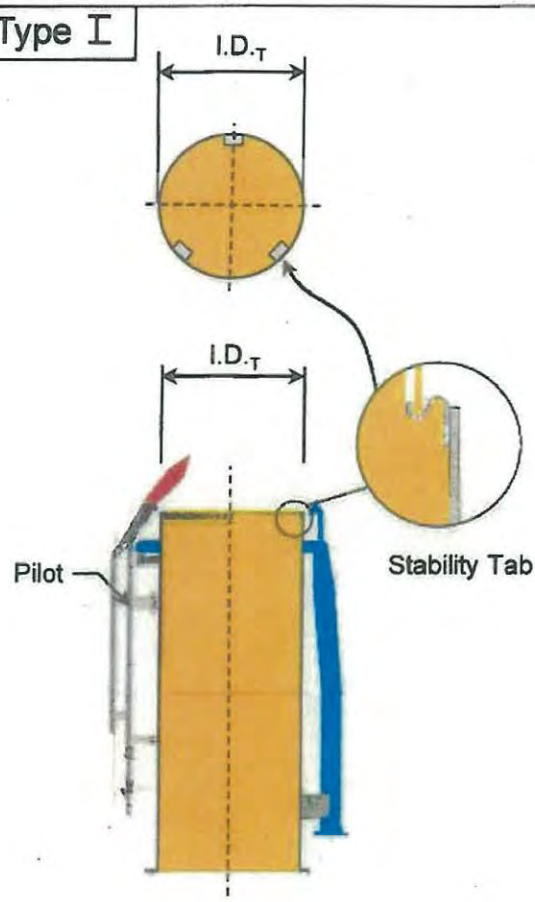
APPENDIX C-1.5

(Intentionally Blank)

APPENDIX C-1.6

APPENDIX 1.6

Type I



$A_{tip\text{-}unob} = \pi(I.D._T)^2/4 - (X_T * A_{ST})$

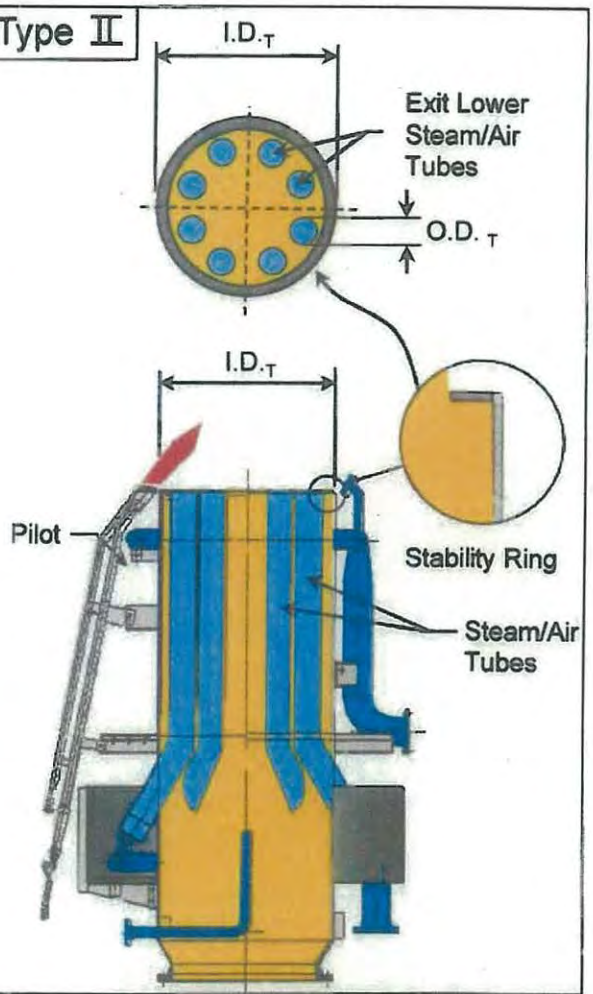
Where:
- $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip
- $I.D._T$ = Inside Diameter Flare Tip
- X_T = Number of Stability Tabs
- A_{ST} = Area of a Stability Tab

Example:
- $I.D._T$ = 41.5 inches
- X_T = 3
- A_{ST} = 3 Sq. inches

$A_{tip\text{-}unob} = \pi(41.5)^2/4 - (3 * 3)$

$A_{tip\text{-}unob}$ = 1344 Sq. inches

Type II



$A_{tip\text{-}unob} = \pi(I.D._T)^2/4 - A_{ST} - N_T * \pi * (O.D._T)^2/4$

Where:
- $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip
- $I.D._T$ = Inside Diameter Flare Tip
- A_{ST} = Area of Stability Ring
- $O.D._T$ = Outside Diameter of Steam/Air Tubes
- N_T = Number of Steam/Air Tubes

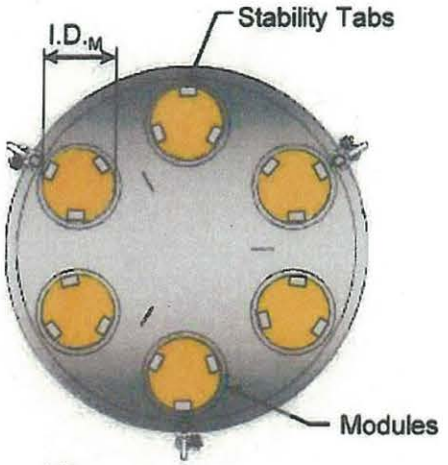
Example:
- $I.D._T$ = 47.5 inches
- A_{ST} = 100 Sq. inches
- $O.D._T$ = 6.5 inches
- N_T = 8

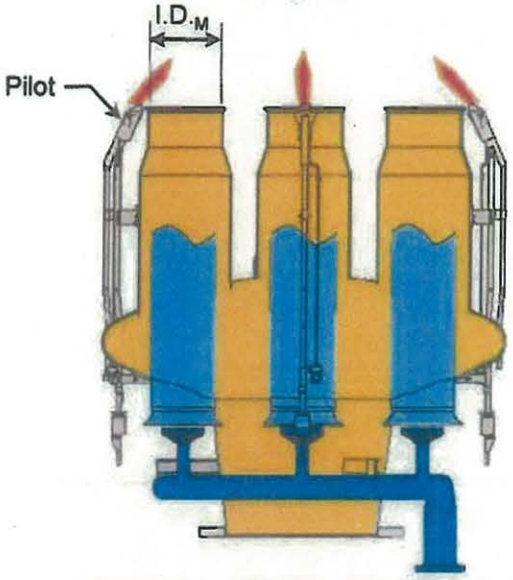
$A_{tip\text{-}unob} = \pi (47.5)^2/4 - 100 - 8 * \pi * (6.5)^2/4$

$A_{tip\text{-}unob}$ = 1322 Sq. inches

APPENDIX 1.6

Type III





$$A_{tip\text{-}unob} = N_M * (\pi * (I.D._M)^2/4 - X_T * A_{ST})$$

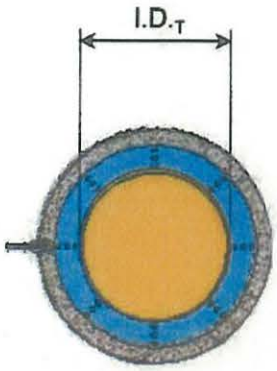
Where:
- $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip
- $I.D._M$ = Inside Diameter of One Tip Module
- N_M = Number of Modules
- X_T = Number of Stability Tabs per Module
- A_{ST} = Area of a Stability Tab

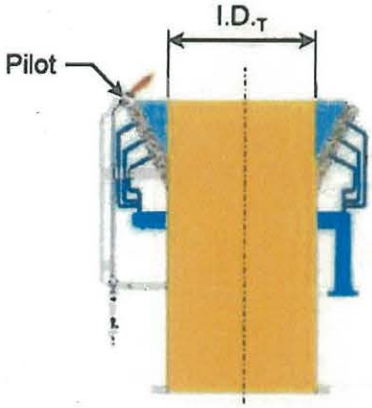
Example:
- $I.D._M$ = 17 inches
- N_M = 6 X_T = 3
- A_{ST} = 3 Sq. inches

$A_{tip\text{-}unob} = 6 * (\pi * (17)^2/4 - 3 * 3)$

$A_{tip\text{-}unob}$ = 1308 Sq. inches

Type IV





$$A_{tip\text{-}unob} = \pi (I.D._T)^2/4$$

Where:
- $A_{tip\text{-}unob}$ = Unobstructed Cross Sectional Area of Flare Tip
- $I.D._T$ = Inside Diameter of Flare Tip

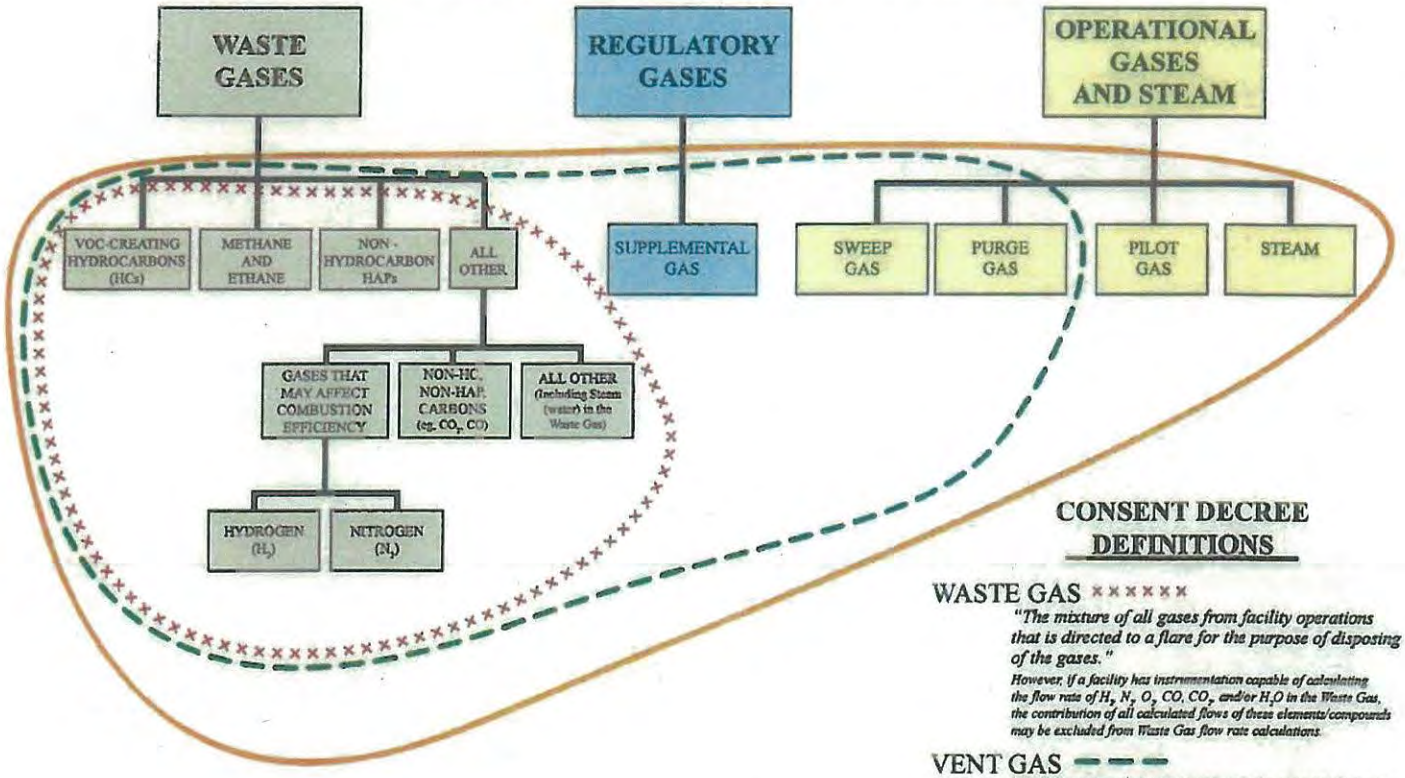
Example: $I.D._T$ = 41.5 inches

$A_{tip\text{-}unob} = \pi (41.5)^2/4$

$A_{tip\text{-}unob}$ = 1353 Sq. inches

APPENDIX C-1.7

DEPICTION OF GASES ASSOCIATED WITH STEAM-ASSISTED FLARES



CONSENT DECREE DEFINITIONS

WASTE GAS ××××××

"The mixture of all gases from facility operations that is directed to a flare for the purpose of disposing of the gases."

However, if a facility has instrumentation capable of calculating the flow rate of H_2, N_2, O_2, CO, CO_2, and/or H_2O in the Waste Gas, the contribution of all calculated flows of these elements/compounds may be excluded from Waste Gas flow rate calculations.

VENT GAS – – –

"The mixture of all gases found prior to the flare tip. This includes all Waste Gas, Supplemental Gas, Sweep Gas, and Purge Gas."

COMBUSTION ZONE GAS ———

"The mixture of all gases and steam found just after the flare tip. This includes all Vent Gas, Pilot Gas, and Total Steam."

APPENDIX 1.7

APPENDIX C-1.8

(Intentionally Blank)

APPENDIX C-1.9

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

Unless an alternative monitoring option is selected from Paragraph 118, 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 C-1.10

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 that must be installed by the date in Appendix 2.1:

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 1.9, except those listed as optional or if an alternative monitoring option is selected within Paragraph 118.

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.

A. 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 Paragraph 118, 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 Settling Defendants 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 Paragraph 123 and 150 of the Consent Decree, the time used for gas chromatograph calibration and validation activities required by Subparagraph V.B. of this 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. Net Heating Value Calorimeter

1. For purposes of calculating the 5% of instrument downtime allowed in any six month period pursuant to Paragraph 123 and 150 of the Consent Decree, the time used for NHV calorimeter calibration and validation activities required by Subparagraph V.B.1 of this 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 C-1.11

WASTE GAS MAPPING:
LEVEL OF DETAIL NEEDED TO SHOW HEADERS AND FLARING PROCESS UNIT HEADERS

Purpose:

Waste Gas mapping is required in order to identify the source(s) of Waste Gas entering each Covered Flare. Waste Gas mapping can be done using instrumentation, isotopic tracing, acoustic monitoring, and/or engineering estimates for all sources entering a Flare header (e.g. pump seal purges, sample station purges, compressor seal nitrogen purges, relief valve leakage, and other sources under normal operations). Appendix 1.11 outlines what needs to be included as the Waste Gas Mapping section within the Initial Flare Management Plan ("Initial FMP")

Waste Gas Mapping Criteria:

For purposes of Waste Gas mapping, a main header is defined as the last pipe segment prior to the Flare knock out drum. Flaring Process Unit headers are defined as pipes from inside the battery limits of each process unit that connect to the main header. For Flaring Process Unit headers that are greater than or equal to six (6) inches in diameter, flow ("Q") must be identified and quantified if it is technically feasible to do so. In addition, all sources feeding each Flaring Process Unit header must be identified and listed in a table, but not necessarily individually quantified. For Flaring Process Unit headers that are less than six (6) inches in diameter, sources must be identified, but they do not need to be quantified.

Waste Gas Mapping Submission Requirements:

For each Covered Flare, the following shall be included within the Waste Gas Mapping section of the Initial FMP:

1. Simplified schematic consistent with the example schematic included on the second page of this Appendix.

2. Table of all sources connected to each Flare main header and Flaring Process Unit header consistent with the Table included on the third page of this Appendix.

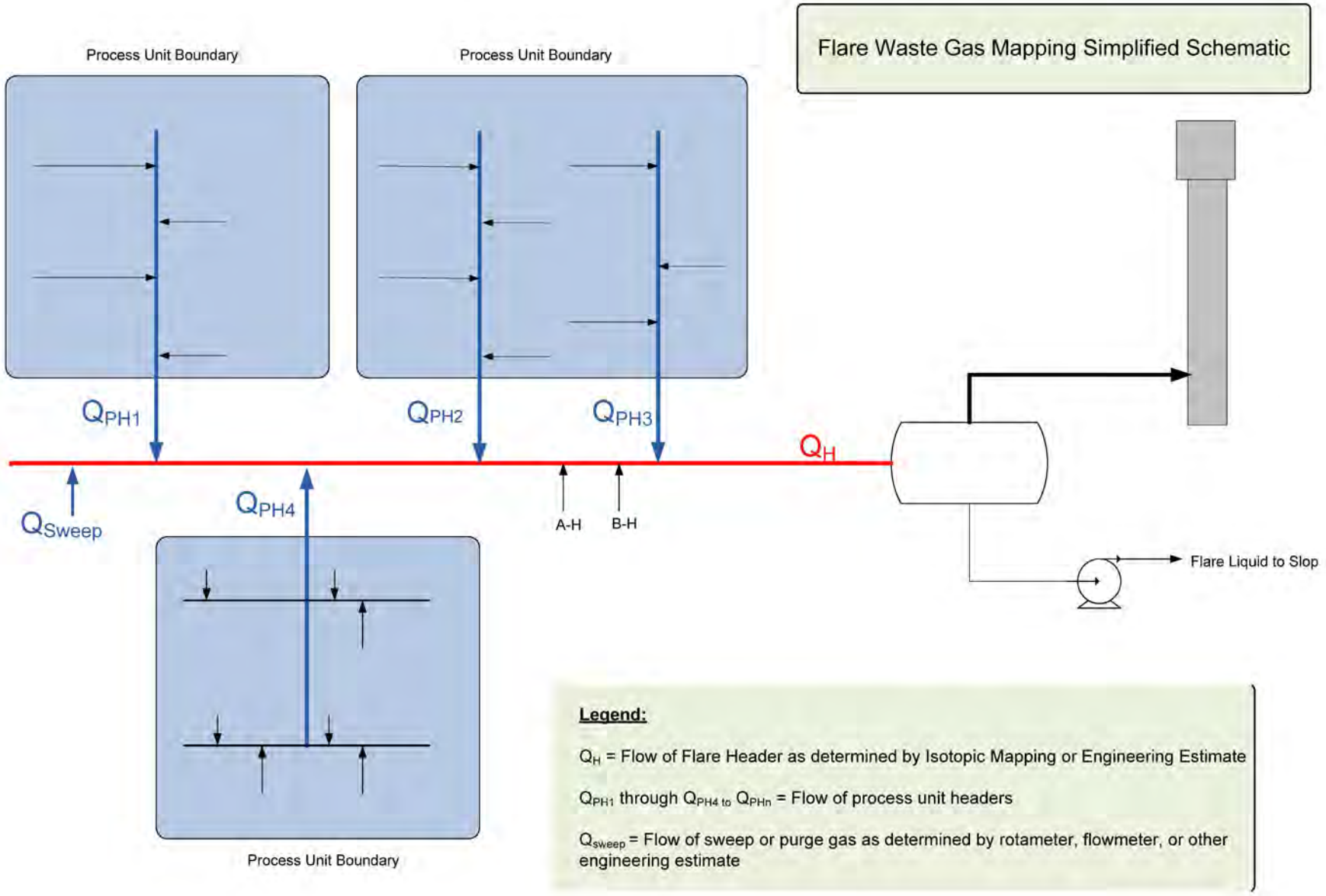

Flare Waste Gas Mapping Simplified Schematic
Process Unit Boundary
Process Unit Boundary
QPH1
QPH2
QPH3
QH
QSweep
QPH4
A-H
B-H
Flare Liquid to Slop
Process Unit Boundary
Legend:
QH = Flow of Flare Header as determined by Isotopic Mapping or Engineering Estimate
QPH1 through QPH4 to QPHn = Flow of process unit headers
Qsweep = Flow of sweep or purge gas as determined by rotameter, flowmeter, or other engineering estimate

Table 1: Example of Flare Source Description Table

Flaring Process Unit Header	Sources	Detailed Source Description
QPH1 (Ex: FCCU Gas Con Unit)	3 PSVs	PSV-14 on 110-D-5 Gas Con Absorber PSV-12 on 110-D-1 Amine Scrubber PSV-7 on 110-F-1 Batch Caustic Vessel
	2 Pump Seal Purges	110-G-1 LPG Pump 110-G-2 Rich Amine Pump
	1 Sample Station	110-S-1 LPG
	1 PSV	PSV 17 on 112-D-1 Main Column
	1 Pressure Control Valve	PCV 21 – Emergency Wet Gas Compressor
	1 PSV	PSV-21 on Flush Oil Drum
	1 Pump Seal Purge	110-G-23 Slurry Oil Pump
QPH2 (Ex: Gas Oil Treater)	Continue same as QPH1	Continue same as QPH1
QPH3	Continue same as QPH1	Continue same as QPH1
QPH4	Continue same as QPH1	Continue same as QPH1
A-H	1 PSVs	PSV-17 on 109-E-42 Slurry Heat Exchanger
B-H	2 Pump Seal Purges	110-G-3 Gas Oil Feed 110-G-4 Main Column Reflux

APPENDIX C-1.12

(Intentionally Blank)

APPENDIX C-1.13

(Intentionally Blank)

APPENDIX C-1.14

DETERMINING REFINERY-SPECIFIC AND INDUSTRY-AVERAGE COMPLEXITY THROUGH USE OF THE NELSON COMPLEXITY INDEX

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 EIA-820," is the Form EIA-820 that the refinery submitted prior to February 15, 2014, for its capacities as of January 1, 2014, (and not the Form EIA-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 report 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

$$Complexity = \sum_{n=1}^{i} \left(\frac{NCI_i \times CAP_i}{CAP_{Dist}} \right)$$

Where:

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

CAP_i = 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

the Refinery reported under "Total Operable" capacity on Part 5, Code 401[1] of the Applicable Form EIA-820; or

(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

$$Industry\_Average\_Complexity = \sum_{n=1}^{i} \left(\frac{NCI_i \times ICAP_i}{ICAP_{Dist}} \right)$$

Where:

NCI_i = 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
Sulfur Extraction	240.00

ATTACHMENT 1
TYPICAL FORM EIA-820

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&GJ 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 Intercil
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 Raffinerie Mediterranee 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	

WORLDWIDE REFINING Company and refinery location	Charge capacity, b/cd								Production capacity, b/cd									
	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
UNITED STATES																		
ALABAMA																		
Hunt Refining Co.—Tuscaloosa	72,000	15,000	[2]32,000	—	—	[1]7,200	15,000	[1]10,000	—	—	—	—	—	—	[a][1]8.0	500	120	14,000
						[3]16,000		[4]2,000							[4]8.0			
								[5]20,000										
								[8]10,000										
Shell Chemical Co.—Saraland	79,000	28,000	—	—	—	[1]22,500	[4]30,000	[1]25,000	—	—	—	[3]7,500	—	—	[6]6.0	—	20	—
								[9]18,000										
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	—	—	—	—	—	[11]4,500	—	—	—	—	4,500	—	[1]2.5	—	—	1,500
Delek US Holdings Inc.—El Dorado[B]	80,000	64,000	19,000	—	[1]42,000	[3]31,000	—	[1]25,000	[2]13,500	—	2,200	[3]14,000	—	—	[1]39	—	285	—
								[2]23,000							[4]22.0			
								[4]10,000										
								[5]54,000										
								[8]50,000										
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	—	—	—	[3]3,750	—	—	—	—	40	35,000
								[4]7,250										
								[5]13,500										
Chevron Corp.—El Segundo	269,000	161,000	[2]67,500	—	[1]65,000	[3]44,000	[1]46,000	[1]41,000	[1]30,000	—	—	[1]7,000	—	—	[a][1]69.3	4,064	775	—
								[2]13,000				[3]20,000						
								[4]33,000										
								[5]36,000										
								[6]13,000										
								[8]65,000										
Chevron Corp.—Richmond	257,000	110,000	—	—	[1]80,000	[1]69,000	[c][1]51,000	[1]58,000	[1]24,000	[1]3,700	—	[1]8,600	16,000	—	[1]150.0	—	600	—
							[c][3]35,000	[4]59,000				[3]28,000			[4]20.0			
							[c][4]65,000	[5]30,000										

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

WORLDWIDE REFINING Company and refinery location	Charge capacity, b/cd								Production capacity, b/cd									
	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
								[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								Production capacity, b/cd									
	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
								[12]33,000										
Valero Energy Corp.—Port Arthur	350,000	145,000	[2]100,000	—	[1]80,000	[3]53,000	c [1]60,000	[1]52,000	[2]20,000	—	—	—	—	—	[1]105.0	6,200	1,050	—
							[4]45,000	[2]30,000							[4]6.0			
								[4]30,000										
								[5]55,000										
								[8]65,000										
								[12]50,000										
Valero Energy Corp.—Sun-ray	170,000	53,200	—	—	[1]54,465	[1]18,500	c [2]29,500	[1]39,844	[1]9,500	—	—	[3]7,000	—	12,200	—	—	60	—
						[3]28,900		[2]22,000						32,700				
								[5]32,368										
								[12]3,400										
Valero Energy Corp.—Texas City	250,000	130,000	[1]50,000	—	[2]80,000	[3]14,500	—	[1]15,000	[2]12,000	—	—	[3]6,500	—	12,500	a [4]60.0	3,000	890	—
								[4]36,000										
								[5]52,000										
								[10]110,000										
								[12]50,000										
Valero Energy Corp.—Three Rivers	100,000	35,000	—	—	[1]24,500	[1]11,000	—	[1]23,000	[2]6,500	—	[1]18,000	—	3,200	—	[4]10.0	—	—	—
						[3]23,000		[4]11,000										
								[5]22,000										
								[8]20,000										
								[11]2,300										
Western Refining Inc.—El Paso	128,000	34,700	—	—	[1]28,000	[1]18,000	—	[1]18,300	[1]10,000	—	—	[1]2,500	—	—	—	—	20	4,800
								[4]8,200										
								[5]11,300										
WRB Refining LLC—Borger	143,000	76,000	[2]27,000	—	[1]50,000	[1]28,000	—	[1]37,000	[2]17,000	—	—	[1]16,000	—	—	[1]83.0	1,250	340	—
								[2]24,000				[3]27,000			[4]13.0			
								[5]27,000										
								[7]13,000										
								[8]70,000										
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	[2]2,500	—	—	[1]2,500	—	—	—	—	4	—
								[5]9,500				[3]1,700						
Chevron Corp.—Salt Lake City	50,000	25,600	[2]8,100	—	[1]17,800	[1]9,400	—	[1]7,300	[2]4,500	—	—	[1]1,000	—	—	—	281	56	—
								[5]10,200										
								[7]6,500										

WORLDWIDE REFINING Company and refinery location	Charge capacity, b/cd								Production capacity, b/cd									
	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
								[8]15,000										
HollyFrontier Corp.—Woods Cross	31,000	—	—	—	[1]8,900	[1]8,000	—	[1]12,000	[2]2,900	—	—	[3]3,000	—	—	—	—	10	—
								[4]3,000										
								[5]10,000										
Silver Eagle Refining Inc.—Woods Cross	6,250	6,000	—	—	—	[1]2,200	—	[5]2,200	—	—	—	—	—	—	—	—	—	1,200
								4,000										
Tesoro West Coast Co.—Salt Lake City	58,000	—	—	—	[1]23,000	[2]12,000	—	[1]12,000	[1]6,000	—	—	—	—	—	—	—	15	—
								[5]11,000										
Total	180,250	36,600	8,100	—	61,200	38,900	—	111,700	15,900	—	—	8,200	—	—	—	281	85	1,200
WASHINGTON																		
BP PLC*—Ferndale	222,300	106,400	[2]51,750	—	—	[1]58,500	[c 1]58,500	[1]47,700	—	—	—	[3]21,600	—	—	[1]92.5	3,250	245	—
								[2]18,900							[4]86.0			
								[3]20,700										
								[4]13,500										
								[5]53,460										
Phillips 66—Ferndale	101,000	48,200	—	—	[1]32,500	[2]16,600	—	[1]17,100	[2]9,200	—	—	[1]4,100	—	—	—	—	110	—
								[7]29,100										
								[12]19,900										
Shell Oil Products US—Anacortes	145,000	65,500	[2]23,000	—	[1]52,000	[1]33,000	—	[1]33,000	[1]12,050	[1]4,300	—	[2]7,000	—	—	[1]7.0	1,400	350	—
								[4]15,800										
								[5]44,400										
								[12]37,400										
Tesoro West Coast Co.—Anacortes	120,000	47,200	—	—	[1]44,800	[2]26,500	—	[1]36,000	[1]11,000	—	—	[1]3,400	—	—	—	—	48	1,000
								[5]18,500										
								[8]7,100										
TrailStone Group—Tacoma[c]	42,000	17,700	—	—	—	[1]5,650	—	[1]8,200	—	—	—	[3]3,000	—	—	—	—	—	10,000
								[5]6,600										
Total	630,300	285,000	74,750	—	129,300	140,250	58,500	427,360	32,250	4,300	—	39,100	—	—	185.5	4,650	753	11,000
WEST VIRGINIA																		
Ergon-West Virginia Inc.—Newell	23,000	9,700	—	—	—	[1]4,200	—	[1]7,000	—	—	—	[3]1,900	5,000	—	[1]4.1	—	1.0	—
								[5]9,000										
								[9]6,600										
Total	23,000	9,700	—	—	—	4,200	—	22,600	—	—	—	1,900	5,000	—	4.1	—	1	—
WISCONSIN																		
Calumet Specialty Products—Superior	45,000	19,500	—	—	[1]9,900	[1]7,200	—	[1]8,100	[2]1,350	—	—	[3]1,800	—	—	—	—	15	6,750
								7,020										

WORLDWIDE REFINING Company and refinery location	Charge capacity, b/cd								Production capacity, b/cd									
	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
Petroleos de Venezuela SA—Puerto de la Cruz	195,000	—	—	—	[1]13,600	—	—	—	[2]4,100	—	—	—	—	—	—	—	17	—
Petroleos de Venezuela SA—San Roque, Anzoategui	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**

APPENDIX C-1.15

ROLLING SUMS AND ROLLING AVERAGES

This Appendix describes how to calculate the standards, exceptions, and triggering events that are on a "Rolling Sum" or "Rolling Average" basis for the flaring requirements in the Consent Decree. Because the calculation of all Rolling Sums and Rolling Averages requires the calculation of Block Sums and Block Averages, respectively, those concepts are described as well. For Rolling Sums, the calculation—as the term "sum" implies—requires the use of addition. For Rolling Averages, the calculation—as the term "average" implies—requires the calculation of the arithmetic mean.

I. ROLLING SUMS

A. Definitions

2.2.1. "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.

> *Example 1.a. For an exception to instrument operation that applies during 5% downtime in any six month period, the exception is stated in terms of a "Block Sum"—5% downtime—but it is not explicitly defined as such. The defendant would add together the total number of hours in any six month period that an instrument was not operating and then compare that sum to the allowed Block Sum value to 5% of the total time in the six month period.*

2.2.2. "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.

> *Example 1.b. Using Example 1.a, the "Block Sum Period" is a calendar quarter.*

2.2.3. "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.

> *Example 2.a. A "365-day rolling sum, rolled daily," requires calculating daily Block Sums and then adding together the values for 365 Block Sums.*

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

> *Example 2.b. Using Example 2.a, the "Rolling Sum Period" is 365 Days.*

B. Relationship Between Block Sums and Rolling Sums

2.2.5. The calculation of a Block Sum is implicit or explicit in the calculation of all Rolling Sums.

> *Example 3. A "8760-hour rolling sum" without any further description requires the calculation of an hourly Block Sum and then the adding together of 8760 Block Sums.*

C. Time of Commencement of and Ability to Calculate Block Sums and Rolling Sums

2.2.6. Block Sums. A Block Sum commences with the first value that is recorded at the start of each Block Sum Period. A Block Sum cannot be calculated until after the last value in the Block Sum Period is recorded.

> *Example 4. For a Block Sum Period that is "daily," the calculation of the Block Sum commences with the value that is recorded starting at midnight each calendar day and ends with value that is recorded immediately prior to midnight of the next Day. For a Block Sum Period that is "hourly," the calculation of the Block Sum commences with the value that is recorded at the top of each hour and ends with value that is recorded immediately prior to the start of the next hour.*

2.2.7. Rolling Sums. A Rolling Sum commences with the first Block Sum that is calculated. A Rolling Sum cannot be calculated until the last Block Sum of the Rolling Sum Period is calculated.

> *Example 5. For a 365-day Rolling Sum, rolled daily, the Rolling Sum commences with the Block Sum that is calculated on the first Day of the Rolling Sum Period; however, the first Rolling Sum cannot be calculated until the first 365 Days are over (i.e., the 365-day Rolling Sum Period is completed).*

D. Standards, Exceptions and/or Triggering Events in this Consent Decree that Are on a "Rolling Sum" Basis

2.2.8. The following standards, exceptions, and/or triggering events are on a "rolling sum" basis in the Consent Decree. These standards, exceptions, and/or triggering events therefore require the calculation of Block Sums during Block Sum Periods in order to calculate Rolling Sums:

TABLE 1

Generic Description of Standards, Exceptions, and/or Triggering Events	Actual Standard, Exception, and/or Triggering Event in the CD	**Block Sum Period** (the "rolled by" period)	**Rolling Sum Period**
Percentage of Time Anacortes, Martinez 50U, Martinez 19/DCU, Mandan, Salt Lake City, Kapolei, and Kenai Compressors Are Available for Operation and/or In Operation	**95% of the time** (2 Compressors); **98% of the time** (1 Compressor) (¶¶ 131.b.i and 131.b.ii)	Hourly	8760 hours
Hours a Portable Flare is In Operation during outage(s) of a Covered Flare	**504 hours** (¶¶ 143.c and d)	Daily	1095 days

E. Calculating Rolling Sums for the Percentage of Time a Compressor is Available for Operation and/or In Operation

2.2.9. Calculate each Hourly Block Sum. Calculate the amount of time that a compressor is Available for Operation and/or In Operation ("A") during each hour (*i.e.*, during each Block Sum Period). Calculate the amount of time during each hour (*i.e.*, each Block Sum Period) that the standard is applicable and for which an exemption does not apply ("R"). Calculate each hourly Block Sum as A/R (which will be a percentage of time). If an exclusion applies during the entire hour, then that hour is not included in the Rolling Sum calculation.

2.2.10. Calculate the Rolling Sum for the First Rolling Sum Period. Add together the first 8760 hourly Block Sums. Use only the prior 8760 1-hour periods when at least some part of the hour was not covered by an exclusion.

2.2.11. Continue Calculating the Rolling Sum. Drop out the first Block Sum (*i.e.*, the first hour) in the first Rolling Sum Period and add in the 8761st Block Sum.

F. Calculating Rolling Sums for Exempted Hours of Maintenance on FGRS

2.2.12. Calculate each Daily Block Sum. Calculate the amount of time that a particular Compressor is shut down for exempted maintenance during each Day (*i.e.* during each Block Sum Period).

2.2.13. Calculate the Rolling Sum for the First Rolling Sum Period. Add together the first 1826 daily Block Sums ((5 years x 365 Days) + 1 leap year Day).

2.2.14. Continue Calculating the Rolling Sum. Drop out the first Block Sum (*i.e.*, the first Day) in the first Rolling Sum Period and add in the 1827th Block Sum.

G. Calculating Rolling Sums for the Number of Hours a Portable Flare Is In Operation During the Outage of a Covered Flare

2.2.15. Calculate each Daily Block Sum. Calculate the number of hours that the Portable Flare is In Operation during each Day (*i.e.* during each Block Sum Period).

2.2.16. Calculate the Rolling Sum for the First Rolling Sum Period. Add together the first 1095 daily Block Sums.

2.2.17. Continue Calculating the Rolling Sum. Drop out the first Block Sum (*i.e.*, the first Day) in the first Rolling Sum Period and add in the 1096th Block Sum.

II. ROLLING AVERAGES

A. Definitions

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

> *Example 6.a. For an exit velocity standard that is applicable on a one-hour Block Average, the arithmetic mean of all of the measurements during a one-hour period is calculated and compared to the standard.*

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

> *Example 6.b. Using Example 6.a, the "Block Average Period" is one-hour.*

2.2.20. "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.

Example 7.a. A "3-hour rolling average, rolling every 15 minutes" requires the calculation of 15-minute Block Averages and then the calculation of the arithmetic mean of 12 (i.e., 3 x 4) 15-minute Block Averages.

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

Example 7.b. Using Example 7.a, the "Rolling Average Period" is 3 hours.

B. Relationship Between Block Averages and Rolling Averages

2.2.22. The calculation of a Block Average is implicit or explicit in the calculation of all Rolling Averages.

Example 8. A "365-day rolling average" without any further description requires the calculation of daily Block Averages. A "1-hour rolling average, rolled every 5 minutes," requires the calculation of 5-minute Block Averages.

C. Time of Commencement of and Ability to Calculate Block Averages and Rolling Averages

2.2.23. Block Averages and Rolling Averages. The description set forth in Paragraphs 2.2.6 and 2.2.7 for time of commencement of and ability to calculate Block Sums and Rolling Sums applies equally to Block Averages and Rolling Averages.

Example 9. For "a 3-hour rolling average, rolled every 15 minutes," the calculation of the Block Average commences with the first value that is recorded starting at the top of each 15 minute period and ends with the last value that is recorded immediately prior to the start of the next 15 minute period. The Rolling Average commences with the first 15-minute Block Average that is calculated but the first Rolling Average cannot be calculated until all the first twelve Block Averages are calculated. ("Twelve" is the appropriate number of prior 15-minute Block Averages because there are four 15-minute Block Averages in one hour; therefore, there are twelve 15-minute Block Averages in three hours (4 x 3). The "3-hour rolling average, rolled every 15 minutes" would equal the arithmetic mean of twelve 15-minute Block Averages.)

D. Parameters in this Consent Decree that are on a "Rolling Average" Basis

1.2.24. The following parameters are on a "rolling average" basis in this Consent Decree. These parameters therefore require the calculation of Block Averages during Block Average Periods in order to calculate Rolling Averages:

TABLE 2

Generic Description of the Parameter	Standard in the CD	Block Average Period (the "rolled by" period)	Rolling Average Period
Waste Gas volumetric flow rate	30-day and 365-day limits	Daily	30 Days and 365 Days

E. When Measured values are "Zero" in a Block Average Period

2.2.25. If, during a Block Average Period, a parameter is measured to be zero, the number "0" is used for that measurement when determining the arithmetic mean of the values (*i.e.*, the Block Average) during the Block Average Period. If all of the measured values during a Block Average Period are zeros, the Block Average is the number "0." "0" *is* a value and "0" should be used in calculating the arithmetic mean. This is distinct from the circumstances identified in Paragraphs 2.2.26 and 2.2.27 below.

F. When One or More Measured Values Either May Be Excluded for Some Part of a Block Average Period and/or Do(es) Not Exist for Some Part of a Block Average Period.

2.2.26. If, for any reason, one or more value(s) of a parameter either: (i) may be excluded for some part of a Block Average Period and/or (ii) do(es) not exist for some part of a Block Average Period (*e.g.*, an instrument is down), only the remaining value(s) in the Block Average Period are to be used in measuring or calculating the Block Average. For clarity, values that are excluded or do not exist are ***not*** given the number "0." They should not have any value assigned to them. The Block Average is the arithmetic mean of the non-excluded, existing values.

G. When All Values in a Block Average Period May Be Excluded and/or Do(es) Not Exist.

2.2.27. If, for any reason, the value(s) of a parameter either: (i) may be excluded during the entirety of a Block Average Period; and/or (ii) do(es) not exist for the entirety of a Block Average Period (*e.g.*, an instrument is down), then there is ***no*** Block Average for that Block Average Period. (For clarity, the number "0" is *not* the Block Average value in this circumstance.) Under this circumstance, there will be a gap in the Block Average Periods that have values (sometimes referred to as a "gap in the data").

III. WHEN COMPLIANCE FIRST CAN BE DEMONSTRATED

2.2.29. For both Rolling Sums and Rolling Averages, compliance cannot be demonstrated until the first Rolling Sum Period or Rolling Average Period is completed.

> *Example 11. For a standard that is applicable on a 365-day rolling average, rolled daily, where the initial compliance date is January 1, 2014, values must start to be recorded at midnight on January 1, 2014. The first daily Block Average that can be calculated is at midnight on January 2, 2014. Then, assuming there are no gaps in the data, the first Rolling Average that can be calculated is at midnight on January 1, 2015. The first Rolling Average would be the arithmetic mean of the 365 Block Averages calculated for January 1, 2014, through December 31, 2014.*

APPENDIX C-2.1

	A	B	D	E	F	G	H	I	J	K	L
1	**Appendix 2.1 - Covered Flares and Applicability Dates for Certain Consent Decree Requirements**										
2	**CD Paragraph No.**	**CD Requirement (N/A Requirement Does Not Apply)**	**Kenai Refinery Flare (AA)**	**Kapolei Refinery Flare**	**ANR Vertical Flare (X 813)**	**ANR Horizontal Flare (X 814) (GF)**	**SLC North flare**	**SLC South flare**	**MAN Alky flare**	**MAN GHT flare**	**MAN Combo flare**
3		Flare Assist Type (SA = Steam Assisted; AA = Air Aissisted; UA = Unassisted)	AA	SA	SA	SA	SA	SA	SA	SA	SA
4	113.a	Complete installation of visual image of S/VG ratio	N/A	10/1/2015	10/1/2015	10/1/2015	10/1/2015	10/1/2015	10/1/2015	10/1/2015	10/1/2015
5	113.b	Complete Training on Steam Control	N/A	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015
6	113.c	Operate Covered Flares to minimize *S/VG* ratio to extent practicable	N/A	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015	12/1/2015
7	114	Evaluate Meters Measuring Sweep and Purge Gas Flow Rates	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016
8	115	Minimize Sweep and Purge Gas Flow Rates	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016
9	116	Minimize Leaking PRVs	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016
10	117	Install Vent Gas, Steam Assist, and Air Assist Flow Monitoring System	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017
11	118	Install Vent Gas Composition Monitoring System	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017
12	119	Install Video Camera	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017
13	127	Initial Flare Management Plan	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017
14	128	Updated Flare Management Plan	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018

	A	B	D	E	F	G	H	I	J	K	L
15	**CD Paragraph No.**	**CD Requirement (N/A Requirement Does Not Apply)**	**Kenai Refinery Flare (AA)**	**Kapolei Refinery Flare**	**ANR Vertical Flare (X 813)**	**ANR Horizontal Flare (X 814) (GF)**	**SLC North flare**	**SLC South flare**	**MAN Alky flare**	**MAN GHT flare**	**MAN Combo flare**
16		Flare Assist Type (SA = Steam Assisted; AA = Air Aissisted; UA = Unassisted)	AA	SA	SA	SA	SA	SA	SA	SA	SA
17	130	Flare Gas Recovery System Start-Up	10/1/2016	7/1/2017	6/1/2016	6/1/2016	2/1/2016	2/1/2016	N/A	7/1/2016	7/1/2016
18	132	Limitations On Flaring - Begin collecting data for compliance	4/1/2017	1/1/2018	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017
19	132	Limitations On Flaring - 30-Day Limit Compliance	5/1/2017	1/31/2018	5/1/2017	5/1/2017	5/1/2017	5/1/2017	5/1/2017	5/1/2017	5/1/2017
20	132	Limitations On Flaring - 365-Day Limit Compliance	4/1/2018	1/1/2019	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018
21	135.a and 135.f.	Emission Standards and Work Practices - Operation During Waste Gas Venting, Good Air Pollution Control Practices	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016
22	135.b and 136.c	Visible Emissions, Flame Presence	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019
23	135.d	Flare Tip Velocity	N/A	7/1/2017	7/1/2017	7/1/2017	7/1/2017	7/1/2017	7/1/2017	7/1/2017	7/1/2017
24	137	Automate Supplemental Gas Flow Rate	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017
25	138	Operation According to Design	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016
26	139	Net Heating Value Standards for NHVcz (combustion zone)	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017
27	140	96.5% Combustion Efficiency	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017
28	142	Recordkeeping	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017	10/1/2017
29	144	Air Assisted Flare Requirements - Instrumentation and Monitoring Systems	10/1/2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
30	145	Dilution Operating Limits for Flares with Perimeter Assist Air	10/1/2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
31	146	Kenai Passive PFTIR Testing	11/29/2015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
32	151	NSPS Subparts A and Ja Applicability	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015

	A	B	D	E	F	G	H	I	J	K	L
33	**CD Paragraph No.A50**	**CD Requirement (N/A Requirement Does Not Apply)**	**Martinez Unit 50 flare**	**Martinez DCU flare**	**Martinez East Air flare**	**Martinez West Air flare**	**Martinez Emergency flare**	**Martinez North Steam flare**	**Martinez South Steam flare**	**Martinez Tank 691 flare**	
34		Flare Assist Type (SA = Steam Assisted; AA = Air Aissisted; UA = Unassisted)	SA	SA	AA	AA	UA	SA	SA	SA	
35	113.a	Complete installation of visual image of S/VG ratio	NA	10/1/2015	N/A	N/A	N/A	10/1/2015	10/1/2015	N/A	
36	113.b	Complete Training on Steam Control	NA	12/1/2015	N/A	N/A	N/A	12/1/2015	12/1/2015	N/A	
37	113.c	Operate Covered Flares to minimize *S/VG* ratio to extent practicable	NA	12/1/2015	N/A	N/A	N/A	12/1/2015	12/1/2015	N/A	
38	114	Evaluate Meters Measuring Sweep and Purge Gas Flow Rates	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	
39	115	Minimize Sweep and Purge Gas Flow Rates	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	
40	116	Minimize Leaking PRVs	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	
41	117	Install Vent Gas, Steam Assist, and Air Assist Flow Monitoring System	NA	4/1/2017	1/30/2019	1/30/2019	N/A	4/1/2017	4/1/2017	N/A	
42	118	Install Vent Gas Composition Monitoring System	N/A	1/30/2019	1/30/2019	1/30/2019	N/A	4/1/2017	4/1/2017	N/A	
43	119	Install Video Camera	N/A	N/A	N/A	N/A	N/A	4/1/2017	4/1/2017	N/A	
44	127	Initial Flare Management Plan	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	
45	128	Updated Flare Management Plan	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	

	A	B	D	E	F	G	H	I	J	K	L
46	**CD Paragraph No.**	**CD Requirement (N/A Requirement Does Not Apply)**	**Martinez Unit 50 flare**	**Martinez DCU flare**	**Martinez East Air flare**	**Martinez West Air flare**	**Martinez Emergency flare**	**Martinez North Steam flare**	**Martinez South Steam flare**	**Martinez Tank 691 flare**	
47		Flare Assist Type (SA = Steam Assisted; AA = Air Aissisted; UA = Unassisted)	SA	SA	AA	AA	UA	SA	SA	SA	
48	130	Flare Gas Recovery System Start-Up	4/1/2015	4/1/2015	4/1/2015	4/1/2015	4/1/2015	4/1/2015	4/1/2015	N/A	
49	132	Limitations On Flaring - Begin collecting data for compliance	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	4/1/2017	
50	132	Limitations On Flaring - 30-Day Limit Compliance	5/1/2017	5/1/2017	5/1/2017	5/1/2017	5/1/2017	5/1/2017	5/1/2017	5/1/2017	
51	132	Limitations On Flaring - 365-Day Limit Compliance	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	4/1/2018	
52	135.a and 135.f	Emission Standards and Work Practices - Operation During Waste Gas Venting, Good Air Pollution Control Practices	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	
53	135.b and 135.c	Visible Emissions, Flame Presence	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	1/30/2019	
54	135.d	Flare Tip Velocity	NA	7/1/2017	1/30/2019	1/30/2019	N/A	7/1/2017	7/1/2017	N/A	
55	137	Automate Supplemental Gas Flow Rate	N/A	1/30/2019	1/30/2019	1/30/2019	N/A	4/1/2017	4/1/2017	N/A	
56	138	Operation According to Design	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	4/1/2016	
57	139	Net Heating Value Standards for NHVcz (combustion zone)	N/A	1/30/2019	1/30/2019	1/30/2019	N/A	10/1/2017	10/1/2017	N/A	
58	140	96.5% Combustion Efficiency	N/A	1/30/2019	1/30/2019	1/30/2019	N/A	10/1/2017	10/1/2017	N/A	
59	142	Recordkeeping	10/1/2017	1/30/2019	1/30/2019	1/30/2019	10/1/2017	10/1/2017	10/1/2017	10/1/2017	
60	144	Air Assisted Flare Requirements - Instrumentation and Monitoring Systems	N/A	N/A	1/30/2019	1/30/2019	N/A	N/A	N/A	N/A	
61	145	Dilution Operating Limits for Flares with Perimeter Assist Air	N/A	N/A	1/30/2019	1/30/2019	N/A	N/A	N/A	N/A	
62	146	Kenai Passive PFTIR Testing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
63	151	NSPS Subparts A and Ja Applicability	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015	11/11/2015	Has Not Been Triggered	

APPENDIX C-2.2

Appendix C-2.2

Large, High Pressure Relief Valves

Refinery	Process Unit	Relief Valve Description	Inlet / Outlet Size, inches	Pressure Set Point, psig
ANA	Alky	PSV-0942	4x6	310
ANA	Bensat	PSV-6716	4x6	730
ANA	Bensat	PSV-6714	3x4	630
ANA	Butamer	PSV-0775	4x6	350
ANA	CFH	PSV-1012-1	3x4	960
ANA	CFH	PSV-7180-1	3x4	350
ANA	CR	PSV-6684-1	3x4	775
ANA	DHT	PSV-7109	3x4	850
ANA	DHT	PSV-6809	3x4	750
ANA	NHT	PSV-6601-1	3x4	585
ANA	NHT	PSV-6688-1	3x4	550
ANA	NHT	PSV-6651	4x6	330
ANA	ROSE	PSV-5513	4x6	787
ANA	ROSE	PSV-5514	4x6	787
ANA	ROSE	PSV-5502	3x4	750
ANA	ROSE	PSV-5503	3x4	750
ANA	Treaters	PSV-5000	4x6	323
KAP	ATU	14-PSV-107	3x4	440
KAP	ATU	PSV-1306	3x4	325
KAP	ATU	PSV-A109	3x4	325
KAP	ATU	PSV-1305	3x4	324
KAP	ATU	PSV-1308	3x4	323
KAP	ATU	PSV-1307	3x4	320
KAP	CRU	PSV-R570	3x4	330
KAP	CRU	14-PSV-424	3x4	319
KAP	DHC	PSV-H13-1	3x6	1810
KAP	DHC	PSV-H13-2	3x6	1810
KAP	VDU	PSV-V3	4x6	500
KEN	Crude	PSV-1703	4x6	350
KEN	Crude	PSV-1704	4x6	350
KEN	Crude	PSV-1705	4x6	350
KEN	Crude	PSV-1710	3x4	425
KEN	DHC	PSE-4802	4x6	325
KEN	DHC	PSV-4068	4x6	385
KEN	DHC	PSV-4802	4x6	325
KEN	H2	PSV-10604	3x6	435
KEN	H2	PSV-10607	4x6	315

Appendix C-2.2

Large, High Pressure Relief Valves

Refinery	Process Unit	Relief Valve Description	Inlet / Outlet Size, inches	Pressure Set Point, psig
KEN	PRIP	PSV-12606	3x4	340
KEN	PRIP	PSV-12609	3x4	340
KEN	Vacuum	PSV-17400	3x4	310
MAN	ALKY	PSV-A-011 T-1 Deprop	4x6	330
MAN	ALKY	PSV-A-011S T-1 Deprop	4x6	330
MAN	GHT	PSV-G-101 C-75S Comp. Discharge	3x4	331
MAN	GHT	PSV-G-107 PSA Feed KO D-97	3x4	340
MAN	ULTRA	PSV-500 D-101 Desulfurizer	4x6	319
MAN	ULTRA	PSV-904 F-200 Furnace	3x4	447
MAN	ULTRA	PSV-905 F-200 Furnance	3x4	450
MAN	ULTRA	PSV-926 F-200 Reactor Charge	3x4	455
MAN	ULTRA	PSV-961 E-3A Shell Side	4x6	461
MTZ	1 HDA	A010PSV0025	3x4	750
MTZ	1 HDS	A005PSV0189	4x6	631
MTZ	2 HDS	A004PSV0009	4x6	720
MTZ	2 HDS	A004PSV0098	4x6	720
MTZ	2 HDS	A004PSV0088	3x4	1000
MTZ	2 HDS	A004PSV0093	3x4	980
MTZ	3 Crude	A048PSV0047	4x6	343
MTZ	3 Crude	A048PSV1047	4x6	361
MTZ	3 HDS	A076PSV1007	3x4	500
MTZ	3 HDS	A076PSV1538	6x8	525
MTZ	3 HDS	A076PSV1539	6x8	525
MTZ	3 HDS	A076PSV1021	3x4	1925
MTZ	3 HDS	A076PSV1022	3x4	1935
MTZ	3 HDS	A076PSV1023	3x4	1985
MTZ	3 HDS	A076PSV1024	3x4	2015
MTZ	3 HDS	A076PSV1026	4x6	481
MTZ	3 HDS	A076PSV1132	4x6	505
MTZ	3 HDS	A076PSV1133	3x4	675
MTZ	4 HDS	A092PSV0007	4x6	340
MTZ	5 Gas	A003PSV0036	4x6	360
MTZ	5 Gas	A003PSV0002	4x6	320
MTZ	5 Gas	A003PSV0003	4x6	320
MTZ	50 Crude	A016PSV0077	4x6	350
MTZ	Ben Sat	A091PSV0004	4x6	450
MTZ	Ben Sat	A091PSV0005	4x6	330

Appendix C-2.2

Large, High Pressure Relief Valves

Refinery	Process Unit	Relief Valve Description	Inlet / Outlet Size, inches	Pressure Set Point, psig
MTZ	Ben Sat	A091PSV0015	4x6	300
MTZ	DHC Stg 2	A068PSV0017	4x6	424
MTZ	DHC Stg 2	A068PSV0037	3x4	1590
MTZ	DHC Stg 2	A068PSV0091	6x10	305
MTZ	DHC Stg 2	A068PSV0071	3x4	460
MTZ	DHC Stg 2	A068PSV0021	6x8	450
MTZ	DHC Stg 1	A067PSV0014	3x6	1780
MTZ	DHC Stg 1	A067PSV0024	4x6	400
MTZ	DHC Stg 1	A067PSV0615	6x8	420
MTZ	DHC Stg 1	A067PSV0020	6x8	450
MTZ	DHC Stg 1	A067PSV0016	6x8	450
MTZ	DHC Stg 2	A068PSV0036	3x4	1590
MTZ	DHC Stg 2	A068PSV0092	6x10	310
MTZ	DHC Stg 2	A068PSV0080	6x8	450
MTZ	H2	A069PSV0011	3x4	461
MTZ	Reformate Frac	A006PSV0040	3x4	750
MTZ	Reformate Frac	A006PSV0033	4x6	480
SLC	Alky	F-446 Caustic Drum	3x4	335
SLC	Alky	F-447 Water Wash Drum	3x4	325
SLC	BSU	R-501 - BSU Rx	3x5	570
SLC	DDU	D-621 High Pressure Separator	3x4	1360
SLC	UFU	F-1A/B/C/D Feed Preheat Furnace	4x6	330
SLC	UFU	E-77 Reactor EFF/ DESULF Feed	4x6	320
SLC	VRU	C-116	3x4	600

APPENDIX C-2.3

COMBUSTION EFFICENCY TEST DESCRIPTION FOR KENAI AIR ASSISTED FLARE

1.0 Introduction

This appendix describes the approach for conducting a combustion efficiency performance test on the main refinery Flare at the Kenai Refinery. This Flare is air-assisted. More specific information describing how the testing will be performed will be included in the test protocol required to be submitted for agency approval per Paragraph 146 of the Consent Decree.

2.0 Test Objective and Boundary Conditions

Tesoro will conduct a combustion efficiency performance test on the air-assisted main refinery Flare at the Kenai Refinery. The primary objective of the Flare's performance test is to measure combustion efficiency over a range of Flare operating conditions.

While the Flare operating conditions will be purposefully varied between test runs, each individual test run will be conducted under stable conditions as defined by the approved test protocol. Meteorological conditions will be monitored to ensure that test runs are conducted under conditions that ensure the presence of a consistent plume cross-section during each test run.

3.0 Flare Performance Test Description

A Passive Fourier Transform Infrared (PFTIR) instrument will be used to measure combustion efficiency of the Flare. The testing will be conducted during weather conditions conducive to this testing technology.

During the testing, the Vent Gas composition, calorific value, and flow rate will be required to remain relatively stable and the Assist-Air rate will be varied to provide a performance curve of optimal stoichiometric air ratio ($\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$). Each operating scenario necessary to establish a stoichiometric air ratio to measured combustion efficiency is defined as a "test run." During each test run, the PFTIR analyzer will remotely analyze the combustion gases in the Flare plume to determine combustion efficiency. The result will be a defined Flare operating envelope as a function of Combustion Zone Gas Net Heating Value bounded by the incipient smoke point on one side and over-assisting on the other. The testing will not include evaluating combustion efficiency on plumes having visible emissions.

The anticipated total time for the test (data acquisition time only) is about 12 to 16 hours or more depending on the number of Assist Air flow conditions to be tested and atmospheric conditions. The duration of each test run will be approximately 15 minutes and will be synchronized to the gas chromatograph ("GC") analysis cycle.

The following compounds in Table 1 will be measured in the GC:

Table 1

Compound	Mol. Wt.	Range	Units
Hydrogen	2.02	0 - 100	mole %
Nitrogen	28.01	0 - 100	mole %
Oxygen	32.00	0 - 100	mole %
Carbon Dioxide	44.01	0 - 100	mole %
Carbon Monoxide	28.01	0 - 100	mole %
Methane	16.04	0 - 100	mole %
Ethane	30.07	0 - 100	mole %
Ethylene	28.05	0 - 100	mole %
Propane	44.10	0 - 100	mole %
Propylene	42.08	0 - 100	mole %
Iso-Butane	58.12	0 - 100	mole %
Butane	58.12	0 - 100	mole %
Butenes + 1,3 Butadiene	54.09	0 - 100	mole %
Pentane-Plus (C5+)	72.15	0 - 100	mole %
Hydrogen Sulfide	34.08	0 - 100	Mole %

During the testing the Flare gas may vary significantly in both flow and composition. During the test the Flare gas flow rates will be measured continuously with the existing ultrasonic flow monitor. The Assist Air rate will be monitored by supply-air fan curve calculations or flow meter. Determination of molecular weight of the Flare gas will also be provided for every test run via the GC. This data should allow operators to hold a steady $\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$ ratio even as flow rates and composition varies.

Both thermal and visual video recordings will be collected and stored. A timestamp for each image will saved with the video so the video can be referenced to each test run.
One aiming camera mounted to the PFTIR will record the point at which the PFTIR is pointed. One high definition visual color camera will be beside the PFTIR to record the overall Flare flame and plume. One infrared camera will be beside each PFTIR to record the thermal image of the Flare plume.

The following additional elements of the testing approach will be presented in the test protocol:

- Expected location of the PFTIR relative to Flare location
- Data collection approaches
- PFTIR operation and calibration details
- Thermal and video camera operation and calibration details

4.0 Data Collection

Process data will be provided by plant operations and include process data, Vent Gas composition data, and meteorological data. Table 2 lists the parameters and time interval that will be recorded and delivered by plant operations. The GC) used for measuring Flare gas composition will report the compounds listed in Table 1.

Table 2

Parameter	Unit	Frequency
Flare Gas Volumetric Flow	scfh	1 minute
Flare Gas Mass Flow Rate	lb/hr	1 minute
Flare Gas Molecular Weight	lb/lb-mole	1 minute
Flare Gas Composition	vol. %	15 minutes
Estimated Pilot Gas Flow Rate	lb/hr	N/A
Assist Air Mass Flow Rate	lb/hr	1 minute
Assist Air Temperature at Flow Measurement Point	°F	1 minute
Flare Gas Combustion Zone Net Heating Value	BTU/scf	15 minutes
Vent Gas Net Heating Value	BTU/scf	15 minutes
Actual Total Assist Air to Vent Gas Ratio	--	1 minute
Hydrocarbon Mass Flow Rate	lb/hr	15 minutes
Flare Exit Velocity	fps	1 minute
Wind Direction	°	1 minute
Wind Speed	mph	1 minute
Ambient Barometric Pressure	in. Hg	1 minute
Ambient Temperature	°F	1 minute
Ambient Humidity	%	1 minute

APPENDIX C-2.4

APPENDIX 2.4

Refinery	Calculation Basis	Refinery Crude Capacity (b/cd)	Refinery Complexity[2]	US Complexity[2]	Refinery/US Complexity	30-Day Rolling Average SCFD	365-Day Rolling Average SCFD
Anacortes	EIA/O&GJ (b/cd)[1]	120,000	8.24	11.19	0.736	662,670	441,780
Kapolei	EIA/O&GJ (b/cd)[1]	93,500	4.69	11.19	0.419	293,681	195,787
Kenai	EIA/O&GJ (b/cd)[1]	65,000	5.31	11.19	0.475	231,354	154,236
Mandan	EIA/O&GJ (b/cd)[1]	70,000	6.68	11.19	0.596	313,139	208,759
Martinez	EIA/O&GJ (b/cd)[1]	166,000	13.63	11.19	1.218	1,516,353	1,010,902
Salt Lake	EIA/O&GJ (b/cd)[1]	57,500	7.05	11.19	0.630	271,505	181,003

Notes:

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

2) Nelson Complexity factors are shown on the next page, and are specified in Appendix C-1.14

Anacortes 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 Distillation	1	120,000	Part 5, Tesoro's 2014 EIA-820, b/cd	17,924,630	EIA Website 2014 Data, b/cd
Vacuum Distillation	1.3	44,650	Part 6, Tesoro's 2014 EIA-820, b/sd*0.95	8,538,071	EIA Website 2014 Data, b/sd*0.95
Coking	7.5		Part 5, Tesoro's 2014 EIA-820, b/cd	2,686,917	EIA Website 2014 Data, b/cd
Catalytic Cracking - Fresh Feed	6	50,700	Part 5, Tesoro's 2014 EIA-820, b/cd	5,616,015	EIA Website 2014 Data, b/cd
Catalytic Cracking - Recycle Fe	6	2,700	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	68,301	EIA Website 2014 Data, b/sd*0.9
Reforming	5	23,400	Part 5, Tesoro's 2014 EIA-820, b/cd	3,419,407	EIA Website 2014 Data, b/cd
Hydrocracking	8		Part 5, Tesoro's 2014 EIA-820, b/cd	2,034,689	EIA Website 2014 Data, b/cd
Hydrotreating	2.5	88,200	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	15,385,086	EIA Website 2014 Data, b/sd*0.9
Alkylates	10	12,420	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	1,139,717	EIA Website 2014 Data, b/sd*0.9
Hydrogen (mmcfd)	1000		Part 7, Tesoro's 2014 EIA-820, mmscf/sd*0.9	2,785	EIA Website 2014 Data, mmcfd)*0.9
Sulfur (short tons/day)	240	49	Part 7, Tesoro's 2014 EIA-820, t/sd *0.9	37,238	EIA Website 2014 Data, t/sd*0.9
Thermal Processes (Visbreakin	2.75		Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	14,400	EIA Website 2014 Data, b/sd*0.9
Polymerization	10		O&GJ (12/5/2013), b/cd	71,870	O&GJ (12/5/2013), b/cd
Aromatics	20		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	266,860	EIA Website 2014 Data, b/sd*0.9
Isomerization	3	3,240	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	664,722	EIA Website 2014 Data, b/sd*0.9
Oxygenates	10		O&GJ (12/5/2013), b/cd	32,250	O&GJ (12/5/2013), b/cd
Lubes	60		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	216,216	EIA Website 2014 Data, b/sd*0.9
Asphalt	1.5	4,950	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	669,588	EIA Website 2014 Data, b/sd*0.9
Refinery / US Complexity		**8.24**		**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.

Kapolei Capacities and Factors

Process	Nelson Complexity Factors	Capacity (b/cd, except H2 and S)	Source (Note 1) for Prior	US Capacity (b/cd, except H2 and S)	Source (Note 1)	EPA Capacity (b/cd, except H2 and S)	EPA Source (Note 1)	EPA US Capacity (b/cd, except H2 and S)	EPA Source (Note 1)
Atmospheric Distillation	1	93,500	Part 5, Tesoro's 2014 EIA-820, b/cd	17,924,630	EIA Website 2014 Data, b/cd	93,500	EIA 2014 Data, b/cd	17,924,630	EIA Website 2014 Data, b/cd
Vacuum Distillation	1.3	38,000	Part 6, Tesoro's 2014 EIA-820, b/sd*0.95	8,538,071	EIA Website 2014 Data, b/sd*0.95	38,000	EIA 2014 Data, b/sd*0.95	8,538,071	EIA Website 2014 Data, b/sd*0.95
Coking	7.5	0	There is no coker at the Kaoplei Refinery.Part 5, Tesoro's 2014 EIA-820, b/cd	2,686,917	EIA Website 2014 Data, b/cd	0	There is no coker at the Kaoplei Refinery.	2,686,917	EIA Website 2014 Data, b/cd
Catalytic Cracking - Fresh Feed	6	0	There is no FCC at the Kapolei Refinery. Part 5, Tesoro's 2014 EIA-820, b/cd	5,616,015	EIA Website 2014 Data, b/cd	0	There is no FCC at the Kapolei Refinery.	5,616,015	EIA Website 2014 Data, b/cd
Catalytic Cracking - Recycle Feed	6	0	There is no FCC at the Kapolei Refinery. Part 6, Tesoro's 2014 EIA-820, b/cd	68,301	EIA Website 2014 Data, b/sd*0.9	0	There is no FCC at the Kapolei Refinery.	68,301	EIA Website 2014 Data, b/sd*0.9
Reforming	5	12,500	Part 5, Tesoro's 2014 EIA-820, b/cd. The capacity on a stream day basis is listed as 13,000 BPD and calendar basis as 12,500	3,419,407	EIA Website 2014 Data, b/cd	12,500	EIA 2014 Data, b/cd	3,419,407	EIA Website 2014 Data, b/cd
Hydrocracking	8	19,000	Part 5, 2014 EIA-820, b/cd includes 17500 gas oil and 1500 distillate	2,034,689	EIA Website 2014 Data, b/cd	19,000	EIA 2014 Data, b/cd	2,034,689	EIA Website 2014 Data, b/cd
Hydrotreating	2.5	12,500	Naphtha/Refomer Feed Hydrotreating was listed 13,000 BSD on EIA. Set barrels per calendar to aligned with 12,500 BCD specified for Reformer as set forth in the EIA report	15,385,086	EIA Website 2014 Data, b/sd*0.9	11,700	EIA 2014 Data, b/sd*0.9	15,385,086	EIA Website 2014 Data, b/sd*0.9
Alkylates	10	0	There is no Alkylate Unit at the Kapolei refinery.	1,164,521	O&GJ (12/5/2013), b/cd	0	There is no alky at the Kapolei Refinery.	1,139,717	EIA Website 2014 Data, b/sd*0.9
Hydrogen (mmcfd)	1000	18	The capacity of the H2 plant is 18 MMSCF/D. Tesoro's EIA -820	4,104	O&GJ (12/5/2013), b/cd	16	EIA 2014 Data, b/sd*0.9	2,785	EIA Website 2014 Data, mmcfd)*0.9
Sulfur (short tons/day)	240	38	The Kapolei refinery has 2 SRUs which are described on the Title V permit as 14 and 20 LTPD (total 24 LTPD) or approximately 38 short tons per day and this is consistent with EIA-820. The O&GJ (12/5/2013),incorrectly lists zero(0) t/cd .	32,693	O&GJ (12/5/2013), b/cd	34	EIA 2014 Data, b/sd*0.9	37,238	EIA Website 2014 Data, t/sd*0.9
Thermal Processes (Visbreaking)	2.75	9,900	Part 6, Tesoro's 2013 EIA-820, 11,000 b/sd	16,000	EIA Website 2014 Data, b/sd*0.9	9,900	EIA 2014 Data, b/sd*0.9	14,400	EIA Website 2014 Data, b/sd*0.9
Polymerization	10	0	There is no Polymerization Unit at the Kapolei Refinery. The O&GJ (12/5/2013),incorrectly lists 1,000 b/cd	71,870	O&GJ (12/5/2013), b/cd	0	There is no poly at the Kapolei Refinery.	71,870	O&GJ (12/5/2013), b/cd
Aromatics	20	0	O&GJ (12/5/2013), b/cd	366,869	O&GJ (12/5/2013), b/cd	0	There is no aromatics at the Kapolei Refiner	266,860	EIA Website 2014 Data, b/sd*0.9
Isomerization	3	0	There is no isomeration unit at the Kapolie refinery. The O&GJ (12/5/2013),incorrectly listed 1200 b/cd	661,815	O&GJ (12/5/2013), b/cd	0	There is no isom at the Kapolei Refinery.	664,722	EIA Website 2014 Data, b/sd*0.9
Oxygenates	10	0	O&GJ (12/5/2013), b/cd	32,250	O&GJ (12/5/2013), b/cd	0	There is no oxygenates at the Kapolei Refine	32,250	O&GJ (12/5/2013), b/cd
Lubes	60	0	O&GJ (12/5/2013), b/cd	193,300	O&GJ (12/5/2013), b/cd	0	There is no lubes at the Kapolei Refinery.	216,216	EIA Website 2014 Data, b/sd*0.9
Asphalt	1.5	0	Although the Kapolei refinery previously operated an air blown asphalt plant, that method of producing asphalt was suspended in 2006. The O&GJ (12/5/2013), incorrectly lists 1,300 b/cd	486,117	O&GJ (12/5/2013), b/cd	0	There is no asphalt at the Kapolei Refinery.	669,588	EIA Website 2014 Data, b/sd*0.9
Refinery / US Complexity		4.74		11.23869157		4.69		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"

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 Distillation	1	65,000	Part 5, Tesoro's 2014 EIA-820, b/cd	17,924,630	EIA Website 2014 Data, b/cd
Vacuum Distillation	1.3	24,700	Part 6, Tesoro's 2014 EIA-820, b/sd*0.95	8,538,071	EIA Website 2014 Data, b/sd*0.95
Coking	7.5		Part 5, Tesoro's 2014 EIA-820, b/cd	2,686,917	EIA Website 2014 Data, b/cd
Catalytic Cracking - Fresh Feed	6		Part 5, Tesoro's 2014 EIA-820, b/cd	5,616,015	EIA Website 2014 Data, b/cd
Catalytic Cracking - Recycle Feed	6		Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	68,301	EIA Website 2014 Data, b/sd*0.9
Reforming	5	10,500	Part 5, Tesoro's 2014 EIA-820, b/cd	3,419,407	EIA Website 2014 Data, b/cd
Hydrocracking	8	12,000	Part 5, Tesoro's 2014 EIA-820, b/cd	2,034,689	EIA Website 2014 Data, b/cd
Hydrotreating	2.5	22,050	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	15,385,086	EIA Website 2014 Data, b/sd*0.9
Alkylates	10		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	1,139,717	EIA Website 2014 Data, b/sd*0.9
Hydrogen (mmcfd)	1000	12	Part 7, Tesoro's 2014 EIA-820, mmscf/sd*0.9	2,785	EIA Website 2014 Data, mmcfd)*0.9
Sulfur (short tons/day)	240	24	Part 7, Tesoro's 2014 EIA-820, t/sd *0.9	37,238	EIA Website 2014 Data, t/sd*0.9
Thermal Processes (Visbreaking)	2.75		Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	14,400	EIA Website 2014 Data, b/sd*0.9
Polymerization	10		O&GJ (12/5/2013), b/cd	71,870	O&GJ (12/5/2013), b/cd
Aromatics	20		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	266,860	EIA Website 2014 Data, b/sd*0.9
Isomerization	3	4,500	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	664,722	EIA Website 2014 Data, b/sd*0.9
Oxygenates	10		O&GJ (12/5/2013), b/cd	32,250	O&GJ (12/5/2013), b/cd
Lubes	60		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	216,216	EIA Website 2014 Data, b/sd*0.9
Asphalt	1.5	9,000	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	669,588	EIA Website 2014 Data, b/sd*0.9
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.

Mandan 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 Distillation	1	70,000	Part 5, Tesoro's 2014 EIA-820, b/cd	17,924,630	EIA Website 2014 Data, b/cd
Vacuum Distillation	1.3		Part 6, Tesoro's 2014 EIA-820, b/sd*0.95	8,538,071	EIA Website 2014 Data, b/sd*0.95
Coking	7.5		Part 5, Tesoro's 2014 EIA-820, b/cd	2,686,917	EIA Website 2014 Data, b/cd
Catalytic Cracking - Fresh Feed	6	26,460	Part 5, Tesoro's 2014 EIA-820, b/cd	5,616,015	EIA Website 2014 Data, b/cd
Catalytic Cracking - Recycle Feed	6	3,240	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	68,301	EIA Website 2014 Data, b/sd*0.9
Reforming	5	12,000	Part 5, Tesoro's 2014 EIA-820, b/cd	3,419,407	EIA Website 2014 Data, b/cd
Hydrocracking	8		Part 5, Tesoro's 2014 EIA-820, b/cd	2,034,689	EIA Website 2014 Data, b/cd
Hydrotreating	2.5	36,180	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	15,385,086	EIA Website 2014 Data, b/sd*0.9
Alkylates	10	3,960	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	1,139,717	EIA Website 2014 Data, b/sd*0.9
Hydrogen (mmcfd)	1000		Part 7, Tesoro's 2014 EIA-820, mmscf/sd*0.9	2,785	EIA Website 2014 Data, mmcfd)*0.9
Sulfur (short tons/day)	240	15	Part 7, Tesoro's 2014 EIA-820, t/sd *0.9	37,238	EIA Website 2014 Data, t/sd*0.9
Thermal Processes (Visbreaking)	2.75		Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	14,400	EIA Website 2014 Data, b/sd*0.9
Polymerization	10	1,100	O&GJ (12/5/2013), b/cd	71,870	O&GJ (12/5/2013), b/cd
Aromatics	20		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	266,860	EIA Website 2014 Data, b/sd*0.9
Isomerization	3	4,800	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	664,722	EIA Website 2014 Data, b/sd*0.9
Oxygenates	10		O&GJ (12/5/2013), b/cd	32,250	O&GJ (12/5/2013), b/cd
Lubes	60		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	216,216	EIA Website 2014 Data, b/sd*0.9
Asphalt	1.5		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	669,588	EIA Website 2014 Data, b/sd*0.9
Refinery / US Complexity		**6.68**		**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.

Martinez 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 Distillation	1	166,000	Part 5, Tesoro's 2014 EIA-820, b/cd	17,924,630	EIA Website 2014 Data, b/cd
Vacuum Distillation	1.3	149,055	Part 6, Tesoro's 2014 EIA-820, b/sd*0.95	8,538,071	EIA Website 2014 Data, b/sd*0.95
Coking	7.5	50,000	Part 5, Tesoro's 2014 EIA-820, b/cd	2,686,917	EIA Website 2014 Data, b/cd
Catalytic Cracking - Fresh Feed	6	70,000	Part 5, Tesoro's 2014 EIA-820, b/cd	5,616,015	EIA Website 2014 Data, b/cd
Catalytic Cracking - Recycle Feed	6	900	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	68,301	EIA Website 2014 Data, b/sd*0.9
Reforming	5	22,900	Part 5, Tesoro's 2014 EIA-820, b/cd	3,419,407	EIA Website 2014 Data, b/cd
Hydrocracking	8	35,900	Part 5, Tesoro's 2014 EIA-820, b/cd	2,034,689	EIA Website 2014 Data, b/cd
Hydrotreating	2.5	178,200	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	15,385,086	EIA Website 2014 Data, b/sd*0.9
Alkylates	10	13,860	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	1,139,717	EIA Website 2014 Data, b/sd*0.9
Hydrogen (mmcfd)	1000	74	Part 7, Tesoro's 2014 EIA-820, mmscf/sd*0.9	2,785	EIA Website 2014 Data, mmcfd)*0.9
Sulfur (short tons/day)	240	180	Part 7, Tesoro's 2014 EIA-820, t/sd *0.9	37,238	EIA Website 2014 Data, t/sd*0.9
Thermal Processes (Visbreaking)	2.75		Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	14,400	EIA Website 2014 Data, b/sd*0.9
Polymerization	10		O&GJ (12/5/2013), b/cd	71,870	O&GJ (12/5/2013), b/cd
Aromatics	20		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	266,860	EIA Website 2014 Data, b/sd*0.9
Isomerization	3		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	664,722	EIA Website 2014 Data, b/sd*0.9
Oxygenates	10		O&GJ (12/5/2013), b/cd	32,250	O&GJ (12/5/2013), b/cd
Lubes	60		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	216,216	EIA Website 2014 Data, b/sd*0.9
Asphalt	1.5		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	669,588	EIA Website 2014 Data, b/sd*0.9
Refinery / US Complexity		**13.63**		**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.

Salt Lake City 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 Distillation	1	57,500	Part 5, Tesoro's 2014 EIA-820, b/cd	17,924,630	EIA Website 2014 Data, b/cd
Vacuum Distillation	1.3		Part 6, Tesoro's 2014 EIA-820, b/sd*0.95	8,538,071	EIA Website 2014 Data, b/sd*0.95
Coking	7.5		Part 5, Tesoro's 2014 EIA-820, b/cd	2,686,917	EIA Website 2014 Data, b/cd
Catalytic Cracking - Fresh Feed	6	22,400	Part 5, Tesoro's 2014 EIA-820, b/cd	5,616,015	EIA Website 2014 Data, b/cd
Catalytic Cracking - Recycle Feed	6	2,700	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	68,301	EIA Website 2014 Data, b/sd*0.9
Reforming	5	11,100	Part 5, Tesoro's 2014 EIA-820, b/cd	3,419,407	EIA Website 2014 Data, b/cd
Hydrocracking	8		Part 5, Tesoro's 2014 EIA-820, b/cd	2,034,689	EIA Website 2014 Data, b/cd
Hydrotreating	2.5	31,320	Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	15,385,086	EIA Website 2014 Data, b/sd*0.9
Alkylates	10	5,940	Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	1,139,717	EIA Website 2014 Data, b/sd*0.9
Hydrogen (mmcfd)	1000		Part 7, Tesoro's 2014 EIA-820, mmscf/sd*0.9	2,785	EIA Website 2014 Data, mmcfd)*0.9
Sulfur (short tons/day)	240	16	Part 7, Tesoro's 2014 EIA-820, t/sd *0.9	37,238	EIA Website 2014 Data, t/sd*0.9
Thermal Processes (Visbreaking)	2.75		Part 6, Tesoro's 2014 EIA-820, b/sd*0.9	14,400	EIA Website 2014 Data, b/sd*0.9
Polymerization	10		O&GJ (12/5/2013), b/cd	71,870	O&GJ (12/5/2013), b/cd
Aromatics	20		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	266,860	EIA Website 2014 Data, b/sd*0.9
Isomerization	3		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	664,722	EIA Website 2014 Data, b/sd*0.9
Oxygenates	10		O&GJ (12/5/2013), b/cd	32,250	O&GJ (12/5/2013), b/cd
Lubes	60		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	216,216	EIA Website 2014 Data, b/sd*0.9
Asphalt	1.5		Part 7, Tesoro's 2014 EIA-820, b/sd*0.9	669,588	EIA Website 2014 Data, b/sd*0.9
Refinery / US Complexity		**7.05**		**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.

APPENDIX C-2.5

CONTENTS OF REPORTS FOR EMISSIONS AND FLARE COMBUSTION EFFICIENCY TESTING

APPENDIX D

Environmental Mitigation Projects

Tesoro shall implement the Environmental Mitigation Projects in this Appendix consistent with the requirements in Section IX (Environmental Mitigation Projects) of the Consent Decree and this Appendix.

I. School Bus Replacement

Tesoro has selected the Mount Diablo Unified School District in Contra Costa County, California to implement the School Bus Replacement Mitigation Project. Tesoro will contribute funds to the Mount Diablo Unified School District sufficient to cover the difference in cost of purchasing a minimum of 4 new compressed natural gas (CNG) school buses rather than new petroleum diesel fueled buses. Tesoro may satisfy this obligation by contributing the total cost of the school buses. Tesoro plans to satisfy this obligation by contributing $1,000,000 to the Mount Diablo Unified School District.

A. Purpose

Replacing existing school buses that run on diesel with vehicles that are powered by CNG decreases emissions of NO_x, SO_2, PM, greenhouse gases, and other air pollutants.

B. Project Requirements

1. Consistent with the requirements of this Consent Decree, Tesoro shall contribute funds to replace a minimum of 4 diesel powered school buses serving the Mount Diablo Unified School District in Contra Costa County, California, with a minimum of 4 CNG buses (Replacement Project School Buses). Replacement Project School Buses shall meet all applicable engine standards, certifications, and/or verifications derived from environmental laws.

2. School buses that are being replaced shall be permanently retired from use by the Mount Diablo Unified School District and shall be disposed of in accordance with all applicable environmental laws. A copy of the California Department of Motor Vehicles (DMV) Dismantlers Notice of Acquisition/Report of Vehicle to be Dismantled (REG42), a copy of the DMV registration indicating the bus was dismantled or similar evidence shall be one form of acceptable evidence that the school buses were disposed of in accordance with all applicable environmental laws.

In addition to the information required to be included in periodic reports submitted pursuant to Paragraphs 170 – 171 of this Consent Decree, for the School Bus Replacement Project,

Tesoro shall include the following information (unless such information has already been submitted in a prior report or plan): (a) identification of the school buses replaced during the period covered by the periodic report with bus age, manufacturer, engine model, mileage, and condition; and (b) the per bus expenditure spent during the period covered by the periodic report.

C. Project Completion

1. If EPA concludes based on the Mitigation Project completion report required in Paragraph 171 of the Consent Decree or subsequent information provided by Tesoro that the School Bus Replacement Project has been performed and completed in accordance with the Consent Decree, then EPA will approve completion of the Project for purposes of the Consent Decree.

2. If Tesoro is unable to complete the School Bus Replacement Project in accordance with the Consent Decree and this Appendix due to the Mount Diablo Unified School District's failure to fulfill its obligation, and that failure is not caused by Tesoro and is beyond the control of Tesoro despite Tesoro's best efforts to fulfill its obligations regarding the Project as set out in the Consent Decree and this Appendix, then EPA and Tesoro may agree to cancel the Project and redirect any unspent funds to a mutually-agreed upon Project.

D. Environmental Benefits

Replacement of older diesel fueled school buses with new CNG buses will reduce emissions of NO_x, SO_2, PM, and greenhouse gases and reduce students' in-cabin exposure to diesel pollutants.

E. Schedule

Within 12 months after the Date of Entry of this Consent Decree, Tesoro must contribute funds sufficient to cover the incremental cost difference of purchasing a minimum of 4 Replacement Project School Buses instead of new petroleum diesel buses. Tesoro plans to satisfy this obligation by contributing a total of $1,000,000 to the Mount Diablo Unified School District to cover the full cost of a minimum of 4 Replacement Project School Buses. Tesoro will submit a Mitigation Project completion report to the United States within 60 days after completion of the School Bus Replacement Project. Tesoro will obtain written confirmation of the purchase of a minimum of 4 new CNG school buses from the Mount Diablo Unified School District and the retirement of 4 petroleum diesel school buses. Tesoro shall include the written confirmation in the Mitigation Project completion report required under Paragraph 171 of the Consent Decree.

II. Infrared Gas-Imaging Cameras

Tesoro shall purchase and employ one infrared gas-imaging camera (such as a FLIR camera or its equivalent) at each of the following refineries: Anacortes, Kenai, Mandan, and Salt Lake City.

A. Purpose

Enhancing workers' safety and supplementing Tesoro's Enhanced LDAR program by employing infrared gas-imaging technology to locate Volatile Organic Compound fugitive emissions that may not be otherwise detected by EPA Method 21 and to take corrective action to address fugitive emissions identified by the infrared gas-imaging camera.

B. Project Requirements

1. Tesoro shall purchase one infrared gas-imaging camera (such as a FLIR camera or its equivalent) for each of the following refineries: Anacortes, Kenai, Mandan, and Salt Lake City.

2. Tesoro will develop a protocol (Infrared Gas-Imaging Protocol) designed to effectively utilize the cameras for locating Volatile Organic Compound fugitive emissions. The Infrared Gas-Imaging Protocol will include the corrective action steps that Tesoro will take to address fugitive emissions identified by the infrared gas-imaging camera. The Infrared Gas-Imaging Protocol will, at a minimum address the following operational criteria:

    a) Frequency of using the infrared gas-imaging camera, at a minimum bi-monthly;
    b) Identification of process unit(s) where certified personnel may monitor with an infrared gas-imaging camera;
    c) Calibration procedures;
    d) Startup (i.e., warming-up the infrared gas-imaging camera)/shutdown procedures;
    e) Video recording and retention;
    f) Operational considerations stemming from weather conditions (e.g., wind speed, temperature, and visibility);
    g) Maintenance of the instrument;
    h) Certification of personnel to use the gas-imaging instrument; and
    i) Minimum number of hours of field use under the direction of certified personnel prior to performing monitoring.

3. Tesoro will train personnel who use the infrared gas-imaging camera at the Anacortes, Kenai, Mandan, and Salt Lake City Refineries on infrared gas-imaging camera fundamentals and operation and implementation of the Infrared Gas-Imaging Protocol.

4. Tesoro will implement the Infrared Gas-Imaging Protocol at the Anacortes, Kenai, Mandan, and Salt Lake City Refineries for a minimum of five years following Date of Entry.

C. Project Completion

1. When EPA concludes, based on the Project completion report or subsequent information provided by Tesoro that the Infrared Gas-Imaging Camera Project has been performed and completed in accordance with the Consent Decree, then EPA will approve completion of the Project for purposes of the Consent Decree.

2. If Tesoro is unable to complete the Infrared Gas-Imaging Camera Project in accordance with the Consent Decree and this Appendix and that failure is beyond the control of Tesoro despite Tesoro's best efforts to fulfill its obligations regarding the Project as set out in the Consent Decree and this Appendix, then EPA and Tesoro may agree to cancel the Project and redirect any unspent funds to a mutually-agreed upon Project.

D. Environmental Benefits

Use of infrared gas-imaging camera will enhance worker safety and supplement Tesoro's existing efforts to detect and reduce fugitive emissions.

E. Schedule

Tesoro must purchase the infrared gas-imaging cameras listed in Paragraph II.B above by Date of Entry. Tesoro will submit a copy of its Infrared Gas-Imaging Protocol to the United States and complete training required by this Appendix at each refinery within 180 Days after Date of Entry. Tesoro will implement the Infrared Gas-Imaging Protocol at the Anacortes, Kenai, Mandan, and Salt Lake City Refineries for a minimum of five years following Date of Entry. Tesoro will submit its Mitigation Project completion report to the United States within 60 Days after completion of the Infrared Gas-Imaging Camera Project.

III. Salt Lake City Ultraformer Furnace (F-1) NOx Reductions

Tesoro will install Ultra-Low NOx Burners on the Ultraformer Furnace (F-1) at its Salt Lake City Refinery and, following installation of the Ultra-Low NOx Burners and performance testing, establish a new NOx limit for this unit (Ultraformer Furnace (F-1) Project).

A. Purpose

Installation of Ultra-Low NOx Burners on the Ultraformer Furnace (F-1) decreases NOx emissions.

B. Project Requirements

1. Tesoro shall install and commence operations of Ultra-Low NOx Burners on the Ultraformer Furnace (F-1) at Salt Lake City no later than May 1, 2017. The Ultra-Low NOx Burners in the Ultraformer Furnace (F-1) shall be designed to achieve a NOx concentration of ≤ 0.040 lb NOx/MMBtu.

2. Tesoro will conduct a performance test for NOx emissions on the Ultraformer Furnace (F-1) no later than July 31, 2017, following 40 C.F.R. Part 60, Appendix A, Test Method 7, 7A, 7B, 7C, 7D, or 7E. The test will demonstrate the performance of the Ultra-Low NOx Burners on the Ultraformer Furnace (F-1) and will be the basis for establishing the appropriate NOx emissions rate. Tesoro shall conduct the test under representative operating conditions.

3. No later than ninety (90) days after the completion of the performance test, Tesoro shall report to EPA the results of the testing.

4. If the performance test demonstrates that ≤ 0.035 lb NOx/MMBtu is achievable in practice based on its review of data and information on the actual performance of the Ultraformer Furnace (F-1), the final NOx emissions limit will be 0.040 lb NOx/MMBtu (3-hour average).

5. If the performance test demonstrates that ≤ 0.035 lb NOx/MMBtu is not achievable in practice based on its review of data and information on the actual performance of the Ultraformer Furnace (F-1), the final NOx emissions limit will be 0.065 lb NOx/MMBtu (3-hour average).

6. Tesoro shall apply to amend its permit for the Salt Lake City Refinery to include the final NOx emissions limits (established above) for the Ultraformer Furnace.

C. Project Completion

1. If EPA concludes based on the Mitigation Project completion report required in Paragraph 171 of the Consent Decree or subsequent information provided by Tesoro that the Ultraformer Furnace (F-1) Project has been performed and completed in

accordance with the Consent Decree, then EPA will approve completion of the Project for purposes of the Consent Decree.

2. If Tesoro is unable to complete the Ultraformer Furnace (F-1) Project in accordance with the Consent Decree and this Appendix and that failure is not caused by Tesoro and is beyond the control of Tesoro despite Tesoro's best efforts to fulfill its obligations regarding the Project as set out in the Consent Decree and this Appendix, then EPA and Tesoro may agree to cancel the Project and complete a substitute project with comparable costs and NOx reduction benefits.

D. Environmental Benefits

Installation of Ultra-Low NOx Burners on the Ultraformer Furnace (F-1) decreases NO_x emissions.

E. Schedule

Tesoro will submit a Mitigation Project completion report to the United States within 60 days after completion of the Ultraformer Furnace (F-1) Project. Completion of the Ultraformer Furnace (F-1) Project occurs after the Ultra-Low NOx Burners are installed and operated, the performance test report is submitted to the EPA, and the final NOx emissions limit is established and included in the permit for the Salt Lake City Refinery.