IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF KANSAS

UNITED STATES OF AMERICA,

and

STATE OF KANSAS, ex rel.
KANSAS DEPARTMENT OF
HEALTH AND ENVIRONMENT,

Plaintiffs

v.

COFFEYVILLE RESOURCES
REFINING & MARKETING, LLC,

Defendant.

Civ. No. 04-CV-1064-JAR-KGG

CONSENT DECREE

WHEREAS Plaintiffs 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"), and the State of Kansas ("State") by and through the Kansas Department of Health and the Environment ("KDHE") (collectively, "Plaintiffs"), filed a complaint, and amendments thereto (Docket Nos. 32, 90 and 132) ("Complaint"), against Coffeyville Resources Refining & Marketing, LLC ("CRRM") for alleged violations of the Clean Air Act ("CAA"), 42 U.S.C. 7401 et seq., and the Kansas air quality statutes and regulations at its petroleum refinery located at 400 North Linden Street, Coffeyville, Kansas ("the Refinery").

WHEREAS the United States, the State, and CRRM are parties to a Consent Decree entered by this Court on April 19, 2012, in the above-captioned action (Docket No. 14), which has been modified periodically (Docket Nos. 15, 17, and 21) ("2012 Consent Decree").

WHEREAS on June 19, 2020, Plaintiffs alleged that CRRM violated certain requirements of the 2012 Consent Decree and demanded payment of stipulated penalties for those violations.

WHEREAS on March 30, 2022, the Court denied CRRM's petition for review of the stipulated penalties assessed by Plaintiffs and found CRRM liable for $6,817,000 in stipulated penalties for alleged violations of 2012 Consent Decree requirements (Docket No. 95). CRRM filed an appeal of the District Court's decision with the Tenth Circuit Court of Appeals (Appeal No. 22-3088), which is still pending.

WHEREAS from 2004 until July 1, 2022, CRRM owned the real property on which the Refinery is located. On July 1, 2022, CRRM transferred this real property through various related entities to CVR Common Assets CVL, LLC ("CVR Common Assets").

WHEREAS from 2004 until February 1, 2023, CRRM owned certain Refinery assets related to the refining of fossil fuel at the Refinery including but not limited to certain machinery and equipment, vehicles, tractors, aircraft, land improvement, storage tanks, work-in-progress, intellectual property, contracts, accounts receivable, and cash ("Fossil Fuel Assets"). On February 1, 2023, CRRM transferred the Refinery Fossil Fuel Assets through various related entities to CVR Refining CVL, LLC ("CVL").

WHEREAS CRRM has operated the Refinery since 2004 and continues to operate the Refinery under various permits and a February 1, 2023 operating agreement with CVL.

WHEREAS CVL buys certain fossil fuel feedstock from and sells certain fossil fuel products to CVR Supply & Trading, LLC ("CVRFuels").

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WHEREAS CVL, CVR Common Assets and CVRFuels are not Defendants in this action but have agreed to become parties to this Consent Decree subject to its requirements and obligations along with CRRM (collectively "Settling Parties").

WHEREAS CRRM denies that it has violated and/or continues to violate the 2012 Consent Decree, the CAA, or the Kansas Air Quality Act ("KAQA"), and regulations and permits issued thereunder, as alleged in the Complaint, and maintains that it is not liable for stipulated penalties, civil penalties, or injunctive relief under the 2012 Consent Decree.

WHEREAS this Consent Decree requires the Settling Parties to pay a civil penalty to resolve the allegations in the Complaint, a stipulated penalty to resolve the alleged violations of the 2012 Consent Decree, and to implement injunctive relief, mitigation, and a State Supplemental Environmental Project, as set forth herein.

WHEREAS Plaintiffs and the Settling Parties agree that: (i) settlement of the matters set forth in this Consent Decree is in the best interests of the Parties and the public; and (ii) entry of this Consent Decree without litigation is the most appropriate means of resolving this matter.

WHEREAS this Court by entering this Consent Decree finds, that this Consent Decree has been negotiated at arm's length and in good faith and that this Consent Decree is fair, reasonable, and in the public interest.

NOW THEREFORE 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, 1355, and 1367(a). 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. CRRM agrees that the Complaint states a claim upon

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which relief may be granted for injunctive relief and civil penalties against CRRM under the CAA. Authority to bring this suit is vested in the United States Department of Justice ("DOJ") and KDHE. *See, e.g.*, 28 U.S.C. §§ 516 and 519, and Section 305 of the CAA, 42 U.S.C. § 7605; K.S.A. §§ 65-3005, 65-3012 and 75-702.

2. Venue is proper in the District of Kansas 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 Parties consent to the personal jurisdiction of this Court and waive any objections to venue in this District.

3. Notice of the commencement of this action has been given to the State of Kansas in accordance with Section 113(a)(1) of the CAA, 42 U.S.C. § 7413(a)(1), as required by Section 113(b) of the CAA, 42 U.S.C. 7413(b).

II. APPLICABILITY AND BINDING EFFECT

4. The obligations of this Consent Decree apply to and are binding upon the United States, the State of Kansas, and upon Settling Parties and their successors, assigns, and other entities or persons otherwise bound by law.

5. Settling Parties are jointly responsible for complying with the requirements of this Consent Decree including the payment of the stipulated and civil penalties required by this Consent Decree. However, satisfaction of any Consent Decree obligation by one Settling Party shall constitute satisfaction of that obligation on behalf of all Settling Parties.

6. Settling Parties shall provide a copy of this Consent Decree to all officers, employees, and agents whose duties might reasonably include compliance with any provision of this Consent Decree, as well as to any contractor retained to perform work required under this Consent Decree. Settling Parties shall condition any such contract upon performance of the work in conformity with the terms of this Consent Decree.

7. In any action to enforce this Consent Decree, Settling Parties shall not raise as a defense the failure by any of their officers, directors, employees, agents, or contractors to take any actions necessary to comply with the provisions of this Consent Decree.

8. Settling Parties agree not to contest the validity of the Consent Decree in any subsequent proceeding to implement or enforce its terms.

9. Transfer of Ownership and/or Operation of the Refinery. Prior to any transfer, in whole or in part, of ownership of, operation of, or other interest (exclusive of any non-controlling, non-operational shareholder interest) in the Refinery (a "Transfer"), Settling Parties shall comply with the following requirements. The United States, after consultation with KDHE, may at its sole discretion, waive any of the following requirements at the request of Settling Parties.

a. Notice to Transferee and Requirements for Transfer Agreement.

i. Settling Parties shall give written notice of the Consent Decree and shall provide a copy of the Consent Decree to any person or entity to which they propose to transfer ownership and/or operation of the Refinery, in whole or in part (hereinafter a "Transferee").

ii. Settling Parties shall condition any Transfer upon the Transferee's written agreement to execute a modification to the Consent Decree that shall make the Transferee a Settling Party responsible for complying with the terms and conditions of the Consent Decree.

b. Notice to Plaintiffs. Settling Parties shall notify the United States and KDHE, in accordance with the notice provisions set forth in Section XVIII (Notices), of any Transfer at least 45 Days prior to the Transfer. The Notice shall (a) identify the specific parts or

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operations of the Refinery being transferred, (b) provide the draft transfer agreement(s), (c) certify in accordance with Paragraph 53 below that the Transferee has the financial and technical ability to assume the transferred obligations and liabilities of this Consent Decree and detail the basis for this belief, and (d) certify in accordance with Paragraph 53 below, that the Transferee is contractually bound to agree to a modification making it a Settling Party responsible for complying with the terms and conditions of the Consent Decree.

c. Modification of the Consent Decree.

i. By no later than 30 Days after the submission to the United States and KDHE of the notice and certifications required by Paragraph 9.b above, the United States, after consultation with KDHE, shall notify Settling Parties as to whether the United States agrees to modify the Consent Decree to make the Transferee a Settling Party responsible for complying with the terms and conditions of the Consent Decree. The United States shall not unreasonably withhold or delay consent to the modification of the Consent Decree and if it does not agree to the modification, it shall detail the basis for its non-agreement in writing.

ii. If the United States agrees to modify the Consent Decree to make the Transferee a Settling Party responsible for complying with the terms and conditions of the Consent Decree, the United States, Settling Parties, and the Transferee shall file with the Court a joint motion requesting the Court to approve a modification in accordance with Section XXI (Modification of this Consent Decree) that makes the Transferee a Settling Party responsible for complying with the terms and conditions of the Consent Decree effective as of the date of the Transfer.

iii. If the United States does not agree to a modification to make the Transferee a Settling Party responsible for complying with the terms and conditions of the

Consent Decree, and the Settling Parties continue to desire to effectuate the Transfer, the Settling Parties and Transferee shall file, without the agreement of the United States, a motion demonstrating that the Transferee has the financial and technical ability to assume the obligations and liabilities of the Consent Decree and requesting that the Court approve modifying the Consent Decree to make the Transferee a Settling Party responsible for complying with the terms and conditions of the Consent Decree. If the United States continues to oppose the modification, it shall file an opposition to the motion in accordance with the local rules of the Court.

III. OBJECTIVES

10. It is the purpose of the Parties to this Consent Decree to further the objectives of the CAA.

IV. DEFINITIONS

11. Unless otherwise defined herein, terms used in the Consent Decree shall have the meaning given to those terms in the CAA and the implementing regulations promulgated thereunder. The following terms used in this Consent Decree shall be defined, for purposes of the Consent Decree and the reports and documents submitted pursuant hereto, as follows:

a. "2012 Consent Decree" shall mean the Consent Decree entered by this Court on April 19, 2012 (Docket No. 14).

b. "#2 Vacuum Charge Heater" shall mean the heater at the Refinery assigned Emission Unit No. EU-04-FH0017 (H-17).

c. "30-day rolling average" shall mean the average daily emission rate or concentration during the preceding 30 Operating Days.

d. "365-day rolling average" shall mean the average daily emission rate or concentration during the preceding 365 Operating Days.

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e. “Capable of Receiving Flare Sweep Gas, Flare Supplemental Gas and/or Waste Gas” shall mean, for a Refinery Flare, that the flow of Flare Sweep Gas, as defined in 40 C.F.R. § 63.641, Flare Supplemental Gas, as defined in 40 C.F.R. § 63.641, and/or Waste Gas is/are not prevented from being directed to a Refinery Flare by means of closed valves and/or blinds.

f. “CD Emissions Reductions” shall mean any emissions reductions in hydrogen sulfide (“H_2S”), total reduced sulfur, sulfur dioxide (“SO_2”), nitrogen oxides (NO_x”), particulate matter (“PM”) (2.5 and 10), volatile organic compounds (“VOCs”) and greenhouse gases (“GHGs”) (carbon dioxide “CO_2” and methane “CH_4”) that result from any projects conducted, controls utilized, or any other actions taken to comply with this Consent Decree.

g. “CEMS” shall mean continuous emissions monitoring system.

h. “Coker Flare” shall mean the Flare assigned Emission Unit No. EU-00-004 and described in the Refinery’s Flare Management Plan for the Coker Flare.

i. “Cold Pond Flare” shall mean the Flare assigned Emission Unit No. EU-08-102 described in the Refinery’s Flare Management Plan for the Cold Water Pond Flare.

j. “Compressor” shall mean, with respect to a Flare Gas Recovery System, a mechanical device designed and installed to assist in recovering gas from a Flare header.

k. “Consent Decree” or “Decree” shall mean this Consent Decree, including the following appendices attached to the Consent Decree:

Appendix A: #2 Vacuum Charge Heater NOx Source Testing Protocol.

Appendix B: KDHE Bureau of Air *Supplemental Environmental Project (SEP) Policy* dated December 2019 (SEP Policy).

Appendix C: DOJ August 22, 2023 Letter to CRRM Counsel Regarding Additional Stipulated Penalties Not Formally Demanded.

l. “CRRM” shall mean Coffeyville Resources Refining & Marketing, LLC, a Delaware limited liability company, and its successors and assigns.

m. “Crude Unit No. 2 Charge Heater” shall mean the heater at the Refinery assigned Emission Unit ID No. EU-06-FH0035.

n. “CVL” shall mean CVR Refining CVL, LLC, a Delaware limited liability company.

o. “CVR Common Assets” shall mean CVR Common Assets CVL, LLC, a Delaware limited liability company.

p. “CVRFuels” shall mean CVR Supply & Trading, LLC, a Delaware limited liability company.

q. “Date of Lodging” shall mean the date on which this Consent Decree is lodged with the United States District Court for the District of Kansas.

r. “Day” or “Days” (whether or not capitalized) shall mean a calendar day or days, unless “business days” are expressly specified. In computing any period of time in which a report or deliverable is due under this Consent Decree, where the last day would fall on a Saturday, Sunday or federal holiday, the period shall run until the close of business the next business day.

s. “Effective Date” means the date of entry of the Consent Decree by the Court as defined in Section XIX (Effective Date).

t. “EPA” shall mean the United States Environmental Protection Agency and any successor departments or agencies.

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u. "Flare" shall have the meaning in NSPS Subpart Ja, 40 C.F.R. § 60.101a, except when the term is used with respect to requirements in NESHAP Subpart CC, 40 C.F.R. §§ 63.670-671, in which case it shall have the definition set forth in 40 C.F.R. § 63.641.

v. "Flare Gas Recovery System" and "FGRS" shall mean a system of at least one Compressor, piping, and associated water seal, rupture disk, or similar device used to divert gas from a Flare and direct the gas to the fuel gas system or to a fuel gas combustion device other than a Flare where the heat produced is recovered and used.

w. "H_2S" shall mean hydrogen sulfide.

x. "In Operation" with respect to a Flare, shall mean any and all times that any gas (e.g., Waste, vent, Purge, pilot) is or may be vented to a Flare. A Flare that is In Operation is Capable of Receiving Flare Sweep Gas, Flare Supplemental Gas, and/or Waste Gas unless all flow of Flare Sweep Gas, as defined in 40 C.F.R. § 63.641, Flare Supplemental Gas, as defined in 40 C.F.R. § 63.641, and Waste Gas flow is prevented by means of closed valves and/or blinds. A Flare is not In Operation if it is only capable of receiving Non-Recoverable Gases.

y. "Interest" shall mean interest at the rate specified in 28 U.S.C. § 1961 in effect on the date fifteen Days prior to the date that a payment is due.

z. "KDHE" shall mean the Kansas Department of Health and the Environment and any successor agency or department.

aa. "lb/MMBtu" means pound per million British thermal units (Btu) of heat input.

bb. "NESHAP" or "MACT" shall mean the National Emission Standards for Hazardous Air Pollutants promulgated by EPA pursuant to Section 112 of the CAA, 42 U.S.C. § 7412.

cc. "NSPS" shall mean the New Source Performance Standards promulgated by EPA pursuant to Section 111 of the CAA, 42 U.S.C. § 7411.

dd. "NO_x" shall mean nitrogen oxides.

ee. "Non-Recoverable Gases" means pilot gas, total steam, and Purge Gas introduced downstream of the Flare's water seal.

ff. "Operating Day" as to any process unit or equipment shall mean a calendar Day (including Saturday, Sunday, and holidays) when there was any time period during which the unit was operating.

gg. "Paragraph" shall mean a portion of this Consent Decree identified by an Arabic numeral.

hh. "Parties" shall mean the United States, the State of Kansas, and Settling Parties.

ii. "Plaintiffs" shall mean the United States and the State of Kansas.

jj. "ppmv" shall mean parts per million by volume.

kk. "Purge Gas" shall have the meaning set forth in 40 C.F.R. § 63.641 unless the term is used with respect to compliance with NSPS Subpart Ja in which case it shall have the meaning set forth in 40 C.F.R. § 60.101a.

ll. "Refinery" shall mean the refinery owned by CVL and operated by CRRM at 400 North Linden Street, Coffeyville, Kansas.

mm. "Refinery Flares" shall mean the Cold Pond and Coker Flares at the Refinery.

nn. "scf" shall mean standard cubic feet.

oo. "scfh" shall mean standard cubic feet per hour.

pp. "Settling Parties" shall mean CRRM, CVL, CVR Common Assets, and CVRFuels.

qq. "SO_2" shall mean sulfur dioxide.

rr. "SSM Occurrence" shall mean any of the following occurrences:

i. "malfunction," "shutdown," or "startup" within the meaning of NSPS Subpart A, 40 C.F.R. § 60.2; or

ii. "the combustion in a Flare of process upset gases or fuel gas that is released to the Flare as a result of relief valve leakage or other emergency malfunctions" within the meaning of NSPS Subpart Ja, 40 C.F.R. § 60.103a(h); or

iii. "startup, shutdown, or malfunction of an affected facility or control system" within the meaning of NSPS Subpart Ja, 40 C.F.R. § 60.108a(d)(3); or

iv. "malfunction," "shutdown," or "startup" within the meaning of NESHAP Subpart A, 40 C.F.R. § 63.2; or

v. "malfunction," "shutdown," or "startup" within the meaning of K.A.R. § 28-19-11.

ss. "State of Kansas" or "State" shall mean the State of Kansas through the KDHE.

tt. "Subject Flaring Event" shall mean any of the following events:

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i. any exceedance of the prohibition on burning in an affected Flare any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis set forth in NSPS Subpart Ja, 40 C.F.R. § 60.103a(h), that occurs in a calendar month where the total duration of excess emissions is more than 5 percent of the total operating time in that calendar month.

ii. any non-compliance with visible emissions, Flare tip velocity, and combustion zone operating limits in NESHAP Subpart CC, 40 C.F.R. § 63.670, that occurs in a calendar month where the total duration of that type of non-compliance is more than 5 percent of the total operating time in that calendar month.

uu. "Title V Permit" shall mean the in-effect operating permit issued to the Refinery by KDHE pursuant to Subchapter V of the CAA, 42 U.S.C. §§ 7661-7661e and K.A.R. § 28-19-500 including any revisions, modifications, or renewals thereto.

vv. "United States" shall mean the United States of America including all of its departments and agencies.

ww. "Waste Gas" shall mean the mixture of all gases from facility operations that is directed to a Refinery Flare for the purpose of disposing of the gas. "Waste Gas" does not include Pilot Gas, Total Steam, Flare Sweep Gas, Purge Gas, or Flare Supplemental Gas as defined in 40 C.F.R. § 63.641.

V. COMPLIANCE REQUIREMENTS

A. Compliance with NSPS Subparts A and Ja and NESHAP Subparts A and CC at Refinery Flares

12. NSPS Subparts A and Ja. As of November 11, 2015, the Cold Pond Flare and the Coker Flare each has been and shall continue to be an "affected facility" within the meaning of,

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and subject to, Subparts A and Ja of 40 C.F.R. Part 60, and Settling Parties shall comply with all provisions and requirements of Subparts A and Ja applicable to these Flares.

13. NESHAP Subparts A and CC. As of January 30, 2020, the Cold Pond Flare and the Coker Flare are subject to the provisions and requirements of NESHAP Subparts A and CC, 40 C.F.R. §§ 63.1-16, 640-642, 655, and 670-71, and Settling Parties shall comply with all provisions and requirements in Subparts A and CC applicable to these Flares.

B. Subject Flaring Event Reporting

14. Subject Flaring Event Reporting. For each Subject Flaring Event that occurs, Settling Parties shall submit a report to KDHE through the Kansas Environmental Information Management System ("KEIMS"), https://keims.kdhe.ks.gov/nsuite/ncore/external/home, which is available via the KDHE Bureau of Air Compliance and Enforcement website at https://www.kdhe.ks.gov/243/Compliance-Enforcement, and EPA in accordance with Section XVIII (Notices) that complies with the following requirements.

a. Timing of Reports. The reporting period for Subject Flaring Events shall be each calendar month; Settling Parties shall submit a report for each Subject Flaring Event no later than the last Day of the calendar month following the month in which each Subject Flaring Event occurred. For example, the report for Subject Flaring Events occurring in March of a given year shall be due on April 30 of that same year. In the event a Subject Flaring Event also triggers the Root Cause and Corrective Action Reporting requirements in Paragraph 16.a, the information required by Paragraph 14.b. may be included in the root cause and corrective action analysis ("RCA") report, provided the RCA report is submitted with the next monthly Subject Flaring Event report after the RCA report is complete. For example, if the Subject Flaring Event triggering the RCA occurs in March and the RCA report is due to be completed in April (45-days

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after the triggering flaring incident), the RCA report (containing the information required in 14.b.), will be included in the May monthly Subject Flaring Event report.

b. Content of Reports. Settling Parties shall report the following information for each Subject Flaring Event.

i. For Subject Flaring Events that Settling Parties do not attribute to an SSM Occurrence, the Subject Flaring Event Report shall: (1) describe the cause of the Subject Flaring Event; (2) describe measures implemented or to be implemented in response to the Subject Flaring Event including measures to prevent recurrence of Subject Flaring Events due to the same cause; (3) estimate emissions caused by the Subject Flaring Event by weight and in the unit of the limit exceeded, if applicable; and (4) provide information on the timing of the investigation of the Subject Flaring Event if not complete.

ii. If Settling Parties claim that the Subject Flaring Event is due to an SSM Occurrence, the Subject Flaring Event Report shall include the following information: (1) identify the process unit(s) and the emissions unit(s) at which the SSM Occurrence took place and the specific areas of the process unit, emissions unit, or other equipment at which the SSM Occurrence took place (including, if applicable, the relief valve found to be leaking); (2) provide the feed rate (on an hourly basis) to both the process unit and the emissions unit (in excel format) 72 hours prior to and through the duration of the SSM Occurrence; (3) provide information as to the specific cause of the SSM Occurrence; (4) provide the date, start and end time, and duration of the SSM Occurrence; (5) estimate emissions caused by the Subject Flaring Event by weight and in the unit of the limit exceeded, if applicable; (6) describe any measures taken or to be taken in response to the SSM Occurrence including measures to minimize emissions during the SSM Occurrence and measures to prevent recurrence due to the same cause; and (7) provide

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information on the timing of the investigation of the Subject Flaring Event and SSM Occurrence if not complete.

iii. To the extent that any of the above information is not known or is preliminary at the time the report is submitted, Settling Parties shall provide final data and updates of such information as soon as it is available.

iv. Upon request from EPA or KDHE, after the submission of the Subject Flaring Event Report, Settling Parties shall also identify the titles of the participants on investigation team within 30 Days of the request.

15. In the excess emissions reports for the Refinery Flares submitted with the semi-annual reports for NSPS Subpart Ja (prepared pursuant to 40 C.F.R. § 60.7 and submitted pursuant to 40 C.F.R. § 60.108a other than summary reports submitted under 40 CF.R. § 60.7(d)), Settling Parties shall include the following information:

a. the “Emission Source” column will designate the process unit/area that is the cause of the flaring;

b. for Cause Type “A,” Settling Parties shall separate into two Cause Types: “A1” (Startup) and “A2” (Shutdown);

c. for Cause Type “A2,” Settling Parties shall describe the cause of the shutdown in the “Cause/Corrective Action” column;

d. for Cause Type “D,” Settling Parties shall specify the “other known causes;” and

e. for Cause Type “E,” Settling Parties shall update the underlying Cause Type for the event in subsequent semi-annual reports, if it later determines the cause(s) of the event.

16. Root Cause and Corrective Action Reporting.

a. Until a Flare Gas Recovery System is installed and commences operation pursuant to Section VI (Mitigation), in the root cause and corrective action analysis ("RCA") reports created and submitted pursuant to NSPS Subpart Ja, 40 C.F.R. § 60.103a(c)(1) and § 60.108a(c)(6), Settling Parties shall include the following information for the Refinery Flares:

i. the process area, process unit, and/or equipment that is the cause of the event described in the RCA;

ii. the title of the official who reviewed and approved the RCA;

iii. the date that the RCA was completed;

iv. whether the event that is the subject of the RCA occurred during an SSM Occurrence;

v. a description of the specific steps, if any, that Settling Parties took to limit emissions during the event that is the subject of the RCA; and

vi. for any RCA for which corrective action(s) are required in 40 C.F.R. § 60.103a(e), a description of the root cause(s) of the event that is the subject of the RCA and the status of any corrective action(s).

b. Settling Parties shall use an electronic system to track RCA investigations and reporting.

c. No later than 90 Days after the Effective Date, Settling Parties shall provide root cause and corrective action analysis training to all employees who investigate or analyze data or investigate or analyze potential corrective actions in the course of an RCA investigation or prepare the RCA reports and thereafter to new employees who perform these functions. Settling Parties shall provide refresher training for such employees and contractors at a minimum, every two years.

17. Nothing in this Consent Decree shall be construed to relieve Settling Parties of any obligation under any federal, state, or local law, regulation, or permit to report information concerning excess emissions or information concerning SSM Occurrences, or to comply with emissions limits applicable during periods of SSM Occurrences, or to report information required to claim exemption due to an SSM Occurrence including that required by KAR 28-19-11.

C. NO_x Emissions from Crude Unit No. 2 Charge Heater and #2 Vacuum Charge Heater

18. No later than October 14, 2022, Settling Parties shall not emit NO_x in excess of 0.032 lb/MMBtu from the Crude Unit No. 2 Charge Heater based on a 365-day rolling average. Settling Parties shall monitor and demonstrate compliance with this limit by continuing to operate CEMS.

19. Beginning on April 12, 2023, Settling Parties shall not emit NO_x in excess of 0.046 lbs/MMBtu from the #2 Vacuum Charge Heater based on a three (3)-hour average. Settling Parties may convert a three (3)-hour average limit to the same limit expressed as a 365-day rolling average limit if such demonstration of compliance is based upon CEMS.

20. <u>Compliance Demonstration.</u>

a. To demonstrate compliance with the NO_x emission limit set forth in Paragraph 19 above, no later than October 12, 2023, Settling Parties shall conduct an initial performance test on the #2 Vacuum Charge Heater in accordance with the approved protocol attached hereto as Appendix A.

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b. Settling Parties shall thereafter conduct annual performance tests on the #2 Vacuum Charge Heater in accordance with the approved protocol attached hereto as Appendix A until $G \leq H$, where:

$G = 14.33$ tons NO_x
H = Total tons NO_x mitigated for all 6-month periods that the #2 Vacuum Charge Heater operated = $\sum [A_i \times B_i \times (C-D) / E]$

where:

A_i = Total #2 Vacuum Charge Heater Fuel Gas Flow rate for 6-month period [Mscf]
B_i = Average HHV of Refinery Fuel Gas Burned for 6-month period [Btu/scf]
C = Original #2 Vacuum Charge Heater NO_x Emission Factor = 0.098 [lb/MMBtu]
D = New #2 Vacuum Charge Heater LNB NO_x Emission Factor = determined by the most recent performance test [lb/MMBtu]
E = Unit Conversion = 2,000,000 [lb x Mscf x Btu / ton x scf x MMBtu]

c. After the above equation has been satisfied, Settling Parties shall continue to conduct performance tests in accordance with the protocol attached as Appendix A, or any subsequent protocol submitted to and approved by KDHE, at the following frequencies.

i. If the last performance test indicates that the heater is emitting NO_x at or above 80% of the limit, Settling Parties shall conduct another performance test no later than three years after the previous performance test.

ii. If the last performance test indicates that the heater is emitting NO_x below 80% of the limit, Settling Parties shall conduct another performance test again no later than five years after the previous performance test.

d. During the term of the Consent Decree, KDHE approval of any subsequent protocol or amendment of Appendix A shall be after consultation with EPA.

21. Settling Parties shall give EPA and KDHE at least 30 Days notice before each performance test in accordance with Section XVIII (Notices).

22. Settling Parties shall submit to EPA and KDHE in accordance with Section XVIII (Notices) a written report of the results of each performance test within 60 Days of each test.

D. Compliance with NESHAP Subpart CC for Certain Process Vents

23. Settling Parties shall comply with the provisions and requirements of NESHAP Subpart CC, 40 C.F.R. § 63.643(c)(1), applicable to any miscellaneous process vents designated as maintenance vents at the Refinery.

E. Compliance with NSPS Subpart Ja at Refinery Process Heaters

24. Settling Parties shall comply with all provisions and requirements of NSPS Subpart Ja, 40 C.F.R. § 60.107a(c)(1), applicable to process heaters subject to NSPS Subpart Ja at the Refinery.

F. Compliance with NESHAP Subpart CC at Refinery Gas Loading Rack(s)

25. Settling Parties shall comply with all applicable requirements in NESHAP Subpart CC, 40 C.F.R. §§ 63.640-671, pertaining to the gasoline loading rack at the Refinery (EU-96-900).

G. Compliance with NESHAP Subpart CC Requirements for Open-Ended Lines

26. Settling Parties shall comply with all applicable requirements in NESHAP Subpart CC, 40 C.F.R. §§ 63.640-671, and NSPS Subpart GGG, 40 C.F.R. §§ 60.590-593, pertaining to open-ended lines ("OELs") at the Refinery.

27. No later than one year after the Effective Date, Settling Parties shall submit to EPA in accordance with Section XVIII (Notices) a list of all OELs at the Refinery that includes the process unit and identification number for each OEL.

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28.e Settling Parties shall paint up to 12 inches of piping on all OELs and theire corresponding plugs at the Refinery a conspicuous color in accordance with the following deadlines:

Percent of OELs at Refinery	**Deadline for OEL Painting**
33%	No later than 1 year from the Date of Lodging
66%	No later than 2 years from the Date of Lodging
100%	No later than 3 years from the Date of Lodging

H. Emissions Monitoring Requirements.

29.e Settling Parties shall certify, calibrate, maintain, and operate all CEMS requirede by this Consent Decree in accordance with NSPS Subpart A, 40 C.F.R.§ 60.13, and Part 60 Appendices A and F, and the applicable performance specification test of 40 C.F.R. Part 60 Appendix B. However, unless Appendix F is required by the NSPS, state law or regulation, or a permit or approval, in lieu of the requirements of 40 C.F.R. Part 60, Appendix F §§ 5.1.1, 5.1.3, and 5.1.4, Settling Parties may conduct: (1) either a Relative Accuracy Audit ("RAA") or a Relative Accuracy Test Audit ("RATA") once every three (3) years; and (2) a Cylinder Gas Audit ("CGA") each calendar quarter in which a RAA or RATA is not performed. If a CEMS component must be moved because of the installation of control equipment, Settling Parties shall promptly reinstall, recalibrate, and re-certify the CEMS.

30.e For all CEMS required by this Consent Decree, monitoring is required duringe SSM Occurrences unless exempted by 40 C.F.R. § 60.107a(a)(3).

31.e <u>CEMS Technician Training.</u> No later than 180 Days after the Effective Date,e Settling Parties shall train all CEMS technicians, i.e., Refinery employees with responsibilities for CEMS operations, alarms, validation, and QA/QC procedures, under the applicable NSPS, NESHAP, and Consent Decree CEMS requirements. Settling Parties shall conduct refresher training of all CEMS technicians every three years.

32. Maintenance of Data Acquisition and Handling System ("DAHS") Configuration. For purposes of tracking at the Cold Pond and Coker Flare compliance with applicable regulations and permits, beginning no later than the Date of Lodging, Settling Parties shall maintain the DAHS configuration so that: (1) calculation of 30-day rolling averages consist of 30 Operating Days; (2) calculation of hourly averages is in accordance with the definition in 40 C.F.R. § 60.13(h)(2)(iii) for hours where required maintenance or quality-assurance activities are performed; and (3) excessive calibration drifts data are categorized in accordance with the criteria set forth in 40 C.F.R. Part 60, Appendix F.

VI. MITIGATION

33. Settling Parties shall comply with the following requirements to mitigate excess emissions associated with the violations alleged in the Complaint.

a. No later than three years from the Effective Date, Settling Parties shall complete installation and commence operation of a Flare Gas Recovery System on the header of the Cold Pond Flare. Settling Parties may elect to comply with the FGRS requirements in Paragraphs 33-37 earlier than three years from the Effective Date. If Settling Parties elect to comply with the FGRS requirements in Paragraphs 33-37 earlier than three years from the Effective Date, they will provide notice of the earlier election date ("Earlier Election Date") to KDHE and EPA in accordance with the notice requirements in Section XVIII (Notices).

b. The FGRS shall have an operating design capacity of at least 62,500 scfh.

c. The FGRS shall be operated in a manner to minimize Waste Gas to the Cold Pond Flare while ensuring safe refinery operations.

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d. The FGRS shall be operated consistent with good engineering and maintenance practices and in accordance with the manufacturer's specifications.

e. No later than three years from the Effective Date or by the Earlier Election Date, whichever is applicable, Settling Parties shall operate the FGRS at least 95% of the time the Cold Pond Flare is In Operation based on a 8,760-hour rolling sum, summed hourly, except during periods described in Paragraph 33.e.i-ii below. In the event that all gases that were previously combusted in the Cold Pond Flare are diverted to the Coker or another Flare, Settling Parties shall continue to operate the FGRS and recover these gases from the Cold Pond Flare header, subject to the same requirements and exceptions as if they were routed to the Cold Pond Flare.

i. The requirements of this Paragraph 33.e shall not apply during periods of maintenance on equipment within the FGRS up to 450 hours based on a five-year rolling sum, summed for each Day. Settling Parties will make best efforts to schedule these maintenance activities during process unit turnarounds and to minimize the generation of Waste Gas during such periods of maintenance.

ii. The requirements of this Paragraph 33.e shall not apply during periods when the Compressor is shut down consistent with the Compressor manufacturer's specifications for safety-instrumented systems shutdowns to preserve the mechanical integrity of the Compressor (for example, as a result of high pressure or temperature or air ingress into the Cold Pond Flare header).

34. Settling Parties shall monitor the time the Compressor is operating by tracking whether the electrical switchgear is open or closed for the Compressor when any portion of the Refinery is operating (or by any other tracking method that EPA approves in advance of use).

35. No later than thirty-nine months after the Effective Date or three months after the Earlier Election Date, whichever is earlier, Settling Parties shall revise the Flare Management Plan for the Cold Pond Flare as required by NSPS Subpart Ja, 40 C.F.R. § 60.103a(a), to reflect the installation and operation of the FGRS including updating the following elements of the Flare Management Plan and submitting a copy of the updated plan to EPA and KDHE in accordance with Section XVIII (Notices):

a. the assessment of whether discharges to the Cold Pond Flare from these process units, ancillary equipment, and fuel gas systems can be minimized (40 C.F.R. § 60.103a(a)(2));

b. the description of the Flare Gas Recovery System (40 C.F.R. § 60.103a(a)(3)(vii));

c. the evaluation of baseline flow to the Cold Pond Flare (40 C.F.R. § 60.103a(a)(4));

d. the procedures to minimize or eliminate discharges to the Cold Pond Flare during the planned startup and shutdown of the Refinery process units and ancillary equipment that are connected to the Cold Pond Flare, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the revision of the Flare Management Plan (40 C.F.R. § 60.103a(a)(5)); and

e. procedures to minimize the frequency and duration of outages of the Flare Gas Recovery System and procedures to minimize the volume of gas flared during such outages, together with a schedule for the prompt implementation of any procedures that cannot reasonably be implemented as of the date of the revision of the Flare Management Plan (40 C.F.R. § 60.103a(a)(7)).

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36.o Settling Parties shall compile and include the following information relating too compliance with the requirements of Section VI (Mitigation) in the semi-annual reports submitted pursuant to Section VIII (Reporting) beginning with the first semi-annual report after installation of the FGRS, unless the installation occurs 90 Days or less before the first reporting date, in which case the first semi-annual report shall be due on the next reporting due date:

a.o a list of the hours during the reporting period that the Cold Pond Flare waso In Operation;

b.o a list of the hours during the reporting period that the FGRS waso operating;

c.o a list of the hours excluded as periods of maintenance shutdowns or foro safety and mechanical integrity under Paragraphs 33.e.i-ii above and description of the maintenance performed or safety/mechanical integrity issues in each excluded hour; and

d.o For each hour in the reporting period, the result of the calculation of theo percent of time the FGRS operated while the Cold Pond Flare was In Operation as required by Paragraph 33.e above using the following calculation methodology:

$$\text{FGRS Operation \%} = \frac{A + B + C}{D} \times 100$$

where:
A = FGRS uptime hours during the previous 8760 hours
B = Maintenance shutdown hours excluded during the previous 8760 hours as capped in Paragraph 33.e.i.
C = Safety/mechanical integrity shutdown hours excluded during the previous 8760 hours pursuant to Paragraph 33.e.ii.
D = Cold Pond Flare In Operation hours during the previous 8760 hours

e.o an estimate of the reductions in SO_2, NO_x, and GHGs (CO_2 and CH_4)o associated with operation of the FGRS; and

f. a certification in accordance with Paragraph 53 that the requirements of this Section VI (Mitigation) have been fully implemented during the reporting period pursuant to the provisions of this Decree.

37. Mitigation Project Certification. With regard to the requirements of this Section VI (Mitigation), CRRM certifies in accordance with Paragraph 53 the truth and accuracy of each of the following:

a. that, as of the date of executing this Decree, Settling Parties are not required to implement the requirements of this Section VI (Mitigation) by any federal, state, or local law or regulation or by agreement, grant, or as injunctive relief awarded in any other action in any forum;

b. that the Settling Parties were not planning or intending to construct, perform, or implement the requirements of this Section VI (Mitigation) other than in settlement of the claims resolved in this Decree;

c. that Settling Parties have not received and will not receive credit for implementing the requirements of this Section VI (Mitigation) in any other enforcement action; and

d. that Settling Parties shall neither generate nor use any pollutant reductions from complying with the requirements of this Section VI (Mitigation) as netting reductions, pollutant offsets, or to apply for, obtain, trade, or sell any pollutant reduction credits.

VII. STATE SUPPLEMENTAL ENVIRONMENTAL PROJECT

38. Settling Parties shall generate no less than one million dollars ($1,000,000) in penalty offset credits by funding one or more Supplemental Environmental Project(s) (SEP(s)) pursuant to the KDHE Bureau of Air *Supplemental Environmental Project (SEP) Policy* dated

December 2019 or later issued policy ("SEP Policy"). The SEP Policy is attached hereto as Appendix B.

39. No later than 60 Days after the Effective Date, Settling Parties shall design and provide SEP project proposals to KDHE for approval that include the following information:

a. The schedule for each SEP's intermediate progress and completion consistent with Paragraph 42 below;

b. A calculation of the total amount that Settling Parties shall spend on each SEP as set forth on Table 2, Page 4, of the SEP Policy. Settling Parties are "For-Profit;" and,

c. The schedule for progress reports and submission of final documentation.

40. Settling Parties shall not make expenditures on any SEP project until they receive written approval of the SEP proposal from KDHE. KDHE shall not withhold or unreasonably delay approval of any project that meets the criteria for an acceptable SEP under Section III of the SEP Policy. If KDHE does not approve a proposed SEP project, it shall detail the basis for its non-approval in writing.

41. Settling Parties shall design and implement each SEP in accordance with the project proposals approved by KDHE.

42. Deadlines for SEP completion.

a. If a SEP project is a financial contribution to a pre-approved project, as set forth in page 5 of the SEP Policy, it shall be completed within 60 Days of the KDHE approval of the SEP.

b. Settling Parties shall complete any other SEP(s) within three years of the Effective Date.

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VIII. REPORTING

43.a Settling Parties shall submit to EPA and KDHE semi-annual reports no later thana August 31 of each year (covering a reporting period of January 1 to June 30) and February 28 of each year (covering a reporting period from July 1 to December 31). The first semi-annual report shall be due on the first reporting date (August 31 or February 28) after the Effective Date, unless the Effective Date falls 90 Days or less before the first reporting date, in which case the first semi-annual report shall be due on the next reporting due date.

44.a Method of Submission for Semi-Annual Reports.a

a.a To the United States: Settling Parties shall submit semi-annual reports toa the United States in accordance with Section XVIII (Notices).

b.a To the State: Settling Parties shall submit semi-annual reports to KDHEa via KEIMS.

45.a Content of Reports. Settling Parties' semi-annual reports shall each contain, at aa minimum, the following information:

a.a a progress report on the implementation of the requirements of Section Va (Compliance Requirements), Section VI (Mitigation), and Section VII (State Supplemental Environmental Project) that includes a description of any problems encountered in implementing the requirements and solutions thereto;

b.a documentation of RCA training provided pursuant to Paragraph 16.c;a

c.a a list of all the OELs which were painted during the reporting perioda pursuant to Paragraph 28;

d.a documentation of the CEMs training that occurred in the reporting perioda pursuant to Paragraph 31;

e.o if not reported elsewhere in the semi-annual report, a description of anyo non-compliance with the requirements of this Consent Decree and an explanation of the violation's likely cause and of the remedial steps taken, or to be taken, to prevent or minimize such violation. If the cause of a violation cannot be fully explained at the time the report is due, Settling Parties shall so state in the report. Settling Parties shall investigate the cause of the violation and shall then submit an amendment to the report, including a full explanation of the cause of the violation, within 30 Days of the Day Settling Parties become aware of the cause of the violation;

f.o information specified in Paragraph 36 pertaining to the FGRS;o

g.o the following data, in Excel format, for the Coker and Cold Pond Flareso for the six (6) month period covered by the report;

i.o Hourly and 3-hour rolling average H_2S continuous monitoringo concentration data in units of ppmv;

ii.o Hourly and daily Total Sulfur continuous monitoring concentrationo data in units of ppmv;

iii. Hourly and daily (standard cubic feet per hour/day) continuouso monitoring flow data, corrected to standard conditions (as defined in 40 C.F.R. § 60.2), of the flowrate of the gas discharged to each Refinery;

iv. Sulfix or other H_2S scavenger use data; and

v.o any such additional matters that Settling Parties believe should beo brought to the attention of EPA and the KDHE.

46. Emissions Data. Settling Parties shall include in the semi-annual report required to be submitted on August 31 of each year, a summary of annual emissions data for the prior calendar year including:

a. NO_x emissions in tons per year for the #2 Vacuum Charge Heater and the Crude Unit No. 2 Charge Heater;

b. GHGs (CO_2 and CH_4), SO_2, and NO_x emissions in tons per year for each Refinery Flare;

c. NO_x, SO_2, PM, and CO emissions in tons per year as a sum for the Refinery for all emissions units not identified in Paragraphs 46.a and b above, or a copy of the Refinery's annual emissions summary required pursuant to K.A.R. § 28-19-517; and

d. for each of the estimates in Paragraphs 46.a through c above, the basis for the emissions estimate or calculation (i.e., stack tests, CEMS, emission factor, etc.).

47. To the extent that the required emissions summary data is available in other reports generated by the Refinery, such other reports can be attached, or the appropriate information can be extracted from such other reports and attached to the semi-annual report to satisfy the requirements in Paragraph 46.

48. Exceedances of Emissions Limits. In all semi-annual reports, Settling Parties shall identify each exceedance of an emission limit required or established by this Consent Decree that occurred during the previous semi-annual period. The report shall, at a minimum, include the following information:

a. for emissions units monitored with CEMS:

i. total period where the emissions limit was exceeded, if applicable, expressed as a percentage of operating time for each calendar quarter;

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ii. where an emissions unit has exceeded the emissions limit more than 1% of the unit's total operating time of the calendar quarter, an identification of each averaging period for the emissions unit that exceeded the limit by time and date, the actual emissions of that averaging period (in the units of the limit), and any identified cause for the exceedance (including startup, shutdown, maintenance, or malfunction), and, if it was a malfunction, an explanation of the malfunction and corrective actions taken;

iii. total downtime of the CEMS, if applicable, expressed as a percentage of operating time for the calendar quarter;

iv. where the CEMS downtime is greater than 5% of the total operating time in a calendar quarter for a unit, an identification of the periods of downtime by time and date, and any cause or causes of the downtime (including maintenance or malfunction), and if downtime was caused by a malfunction, an explanation of any corrective actions taken; and

v. if one or more reports submitted pursuant to another applicable legal requirement contains all of the information required by this Paragraph 48.a in the same or a similar format, the requirements of this Paragraph 48.a may be satisfied by attaching a copy of such report, or the appropriate information can be extracted from such report and attached, to the semi-annual report.

b. for emissions limits monitored by stack testing:

i. a copy of the full stack test report in which the emissions exceedance occurred; and

ii. if the stack test results already have been submitted, Settling Parties need not resubmit them, but may instead reference the prior submission in the semi-annual report (e.g., date, sender, addressee, reason for submission).

49. Settling Parties shall comply with the emissions inventory reporting requirements in the Refinery's Title V Permit Section VIII.E and such reports shall account for all reduced sulfur compounds in the Refinery fuel gas based on the annual average H_2S concentration in the Refinery fuel gas adjusted to account for all non-H_2S reduced sulfur compounds in accordance the best representative information available to Settling Parties.

50. Whenever any violation of this Consent Decree or any other event affecting a Settling Party's performance under this Decree may pose an immediate threat to the public health or welfare or the environment, Settling Parties shall notify EPA and the State in accordance with Section XVIII (Notices) as soon as possible, but no later than 24 hours after Settling Parties first knew of the violation or event. This procedure is in addition to the reporting requirements set forth in the preceding Paragraphs 43-49.

51. Nothing in this Section relieves Settling Parties of their reporting obligation under applicable federal or state law or to provide the notice required by Section XIII (Force Majeure).

52. Each semi-annual report shall be certified with the language set forth in Paragraph 53 below by (i) the person responsible for environmental management and compliance for the Refinery or (ii) a person or persons responsible for overseeing implementation of this Decree for Settling Parties.

53. Whenever this Consent Decree requires that a report or submission be certified, the following language shall be included on such report or submissions:

> I certify under penalty of law that this information related to the Refinery 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 persons who manage the system, or the persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete.

IX. SURVIVAL OF CONSENT DECREE REQUIREMENTS

54. Surviving Consent Decree Obligations. The following Consent Decree limits, requirements, and standards shall constitute Surviving Consent Decree Obligations:

a. The following definitions, as applicable, to the surviving emissions limits and standards.

i. Definition of "356-day rolling average" (Paragraph 11.d)

ii. Definition of "Capable of Receiving Flare Sweep Gas, Flare Supplemental Gas, and/or Waste Gas" (Paragraph 11.e)

iii. Definition of "CD Emissions Reductions" (Paragraph 11.f)

iv. Definition of "CEMS" (Paragraph 11.g)

v. Definition of "Compressor" (Paragraph 11.j)

vi. Definition of "Flare" (Paragraph 11.u)

vii. Definition of "Flare Gas Recovery System" (Paragraph 11.v)

viii. Definition of "In Operation" (Paragraph 11.x)

ix. Definition of "Non-Recoverable Gases" (Paragraph 11.ee)

x. Definition of "Operating Day" (Paragraph 11.ff)

xi. Definition of "Purge Gas" (Paragraph 11.kk)

xii. Definition of "Refinery" (Paragraph 11.ll)

xiii. Definition of "Refinery Flares" (Paragraph 11.mm)

xiv. Definition of "SSM Occurrence" (Paragraph 11.rr)

xv. Definition of "Waste Gas" (Paragraph 11.ww)

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b. Surviving emission limits and standards

i. NSPS Ja Applicability Flares (Paragraph 12)

ii. NESHAP CC Applicability Flares (Paragraph 13)

iii. Crude Unit No. 2 Charge Heater NO_x Emission Limit and CEMS Requirement (Paragraph 18)

iv. #2 Vacuum Charge Heater NO_x Emission Limit (Paragraph 19)

v. #2 Vacuum Charge Heater Performance Testing (Paragraph 20.c and Appendix A)

vi. Requirement to calibrate, maintain, and operate CEMS for Flares, Crude Unit No. 2 Charge Heater, and #2 Vacuum Charge Heater (if CEMS is installed prior to CD termination) (Paragraph 29)

vii. Requirement to operate CEMS during SSM Occurrences (Flares, Crude Unit No. 2 Heater) (Paragraph 30)

viii. FGRS Operational and Reporting Requirements

(a) Paragraph 33.b (62,500 scfh requirement)

(b) Paragraph 33.c (minimize Waste Gas while ensuring safe refinery operations)

(c) Paragraph 33.d (operate consistent with good engineering and maintenance practices and in accordance with manufacturer specifications)

(d) Paragraph 33.e (95% operational requirement)

(e) Paragraph 34 (Compressor Monitoring)

(f) Paragraph 36.a-d. (FGRS Reporting)

ix. Prohibition on Netting Credits or Offsets (Paragraphs 61-62).

55. Obtaining Permits for Consent Decree Limits and Standards. No later than 180 Days after the Effective Date, Settling Parties shall submit applications, amendments, and/or supplements to the KDHE SIP-approved permitting program to incorporate the Surviving Consent Decree Obligations, that are effective as of the Effective Date into minor or major new source review permits or other permits (other than Title V permits) that are federally enforceable. Following submission of the applications, amendments, or supplements, Settling Parties shall cooperate with KDHE by promptly submitting to KDHE all available information that KDHE seeks following its receipt of the permit materials. Promptly upon issuance of such permits or in conjunction with such permitting, Settling Parties shall file any applications necessary to incorporate the Surviving Consent Decree Obligations into the Title V Permit for the Refinery.

56. Future Emission Limits and Standards. For any Surviving Consent Decree Obligation that becomes effective after the Effective Date, as soon as practicable, but in no event later than 180 Days after such Surviving Consent Decree Obligation becomes effective, Settling Parties shall submit applications, amendments and/or supplements to the KDHE SIP-approved permitting program to incorporate those Surviving Consent Decree Obligations into minor or major new source review permits or other permits (other than Title V permits) that are federally enforceable.

57. Following submission of the applications, amendments, or supplements, Settling Parties shall cooperate with KDHE by promptly submitting to KDHE all available information that KDHE seeks following its receipt of the permit materials. Promptly upon issuance of such permits or in conjunction with such permitting, Settling Parties shall file any applications necessary to incorporate Surviving Consent Decree Obligations into the Title V Permit for the Refinery.

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58. Obtaining Construction Permits. Settling Parties agree to use their best efforts 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 compliance requirements and mitigation project set forth in Sections V (Compliance Requirements) and VI (Mitigation). To the extent that Settling Parties must submit permit applications for construction or installation to KDHE, Settling Parties shall cooperate with KDHE by promptly submitting to KDHE all available information that KDHE seeks following its receipt of the permit application.

59. Title V Incorporation of Surviving Consent Decree Obligations. The Parties agree that the incorporation of the requirements of this Consent Decree into Title V permits shall be in accordance with State Title V regulations.

60. The Surviving Consent Decree Obligations shall survive Termination of this Consent Decree under Section XXIII (Termination of this Consent Decree) regardless of State permitting actions purporting to change them unless such changes thereto are made in adherence with an analysis consistent with applicable EPA regulations and policies.

X. PROHIBITION ON NETTING CREDITS OR OFFSETS

61. General Prohibition. Settling Parties shall not use any emissions reductions that result from actions required by this Consent Decree for the purposes of obtaining project decreases, netting reductions, or emission offset credits, including, but not limited to, applying for, obtaining, trading, or selling any emission reductions credits.

62. Outside the Scope of the General Prohibition. Nothing in this Consent Decree is intended to prohibit Settling Parties from:

a. using or generating netting reductions or emission offset credits from Refinery units that are covered by this Consent Decree to the extent that the proposed netting reductions or emission offset credits represent the difference between the emissions limitations set forth in or established pursuant to this Consent Decree for these Refinery units and the more stringent emissions limitations that Settling Parties may elect to accept for these Refinery units in a permitting process;

b.a using or generating netting reductions or emission offset credits fora emissions reductions not required by this Consent Decree; or

c.a using CD Emissions Reductions for the Refinery's compliance with anya rules or regulations designed to address regional haze or the non-attainment status of any area (excluding PSD and Non-Attainment New Source Review rules) that apply to the Refinery; provided, however, that Settling Parties shall not be allowed to trade or sell any CD Emissions Reductions.

d.a For purposes of Paragraph 62.a, where an emissions limitation establisheda or required by this Consent Decree is expressed in terms of a numeric limit on a Refinery unit's emissions (e.g., in pounds per million Btu or parts per million), Settling Parties may utilize the difference between the numeric emissions limitation set forth in or required by this Consent Decree and the more stringent numeric emissions limitation Settling Parties have elected to accept under a permitting process for the Refinery unit. Where an emissions limitation set forth or required by this Consent Decree is not expressed in terms of a numeric limit on the Refinery unit, Settling Parties may not so utilize or generate emissions credits from the project or control required by this Consent Decree.

XI. PAYMENT OF CIVIL AND STIPULATED PENALTIES

63.a By no later than 30 Days after the Effective Date of this Consent Decree, Settlinga Parties shall pay the total sum of $13,250,000 in civil penalties and stipulated penalties to the United States and State, together with Interest as specified below.

64.a Payments to the United States.a

a.t Payment of Civil Penalty. Settling Parties shall pay the United Statest $3,625,000 in civil penalties plus Interest accruing from the date that this Consent Decree is executed by Settling Parties.

b.t Payment of Stipulated Penalties. Settling Parties shall pay the Unitedt States stipulated penalties for alleged violations of the 2012 Consent Decree as follows.

i.t $3,408,500 plus one half of the interest that accumulated on thist amount in the escrow account ("Escrow Account") that CRRM established pursuant to Paragraph 201 of the 2012 Consent Decree at Security 1st Title, LLC, 727 N. Waco Avenue, Suite 300 Wichita, Kansas 67203, which reflects one half of the stipulated penalties awarded by the Court (Docket No. 95) plus one half of the interest that has accumulated on that amount.

ii. $91,500 in stipulated penalties for other alleged violations of thet 2012 Consent Decree, which reflects one half of stipulated penalties that accrued but were not formally demanded.

c.t Method of Payment. Settling Parties shall pay the above penalties to thet United States, together with required Interest by FedWire Electronic Funds Transfer ("EFT") to the DOJ account, in accordance with instructions provided to Settling Parties by the Financial Litigation Unit ("FLU") of the United States Attorney's Office for the District of Kansas after the Effective Date. The payment instructions provided by the FLU will include a Consolidated Debt Collection System ("CDCS") number, which Settling Parties shall use to identify all payments required to be made in accordance with this Consent Decree. The FLU will provide the payment instructions to:

Brent Traxel
Vice President and General Manager Coffeyville Refinery
Coffeyville Resources Refining & Marketing, LLC
P.O. Box 1566

400 N. Linden
Coffeyville KS 67337-0945
bxtraxel@CVREnergy.com

with a copy to:

Melissa M. Buhrig, Esq.
Executive Vice President, General Counsel and Secretary
Coffeyville Resources Refining & Marketing, LLC
2277 Plaza Drive Suite 500
Sugar Land, TX 77479
LegalServices@CVREnergy.com

and

LeAnn Johnson Koch, Esq.
Perkins Coie LLP
700 13th Street, NW
Suite 800
Washington, DC 20005
leannjohnson@perkinscoie.com

on behalf of Settling Parties. Settling Parties may change the individual to receive payment instructions on their behalf by providing written notice of such change to DOJ and EPA in accordance with Section XVIII (Notices).

d. At the time of payment, Settling Parties shall send notice that payment has been made and a documentation of the balance in the Escrow Account at the time payment was made: (i) to EPA via email at cinwd_acctsreceivable@epa.gov or via regular mail at EPA Cincinnati Finance Office, 26 W. Martin Luther King Drive, Cincinnati, Ohio 45268; (ii) to DOJ via email or regular mail in accordance with Section XVIII (Notices); and (iii) to EPA in accordance with Section XVIII (Notices). Such notice shall state that the payment is for the civil penalty owed pursuant to the Consent Decree in United States and State of Kansas v. Coffeyville Resources Refining & Marketing, and shall reference the civil action number, CDCS Number and DOJ case number 90-5-2-1-07459/5.

65. Payments to the State of Kansas.

a. Payment of Civil Penalties. Settling Parties shall pay the State $2,625,000 in civil penalties.

b. Payment of Stipulated Penalties. Settling Parties shall pay the State stipulated penalties for alleged violations of the 2012 Consent Decree as follows.

i. $3,408,500 plus one half of the interest that accumulated on this amount in the Escrow Account, which reflects one half of the stipulated penalties awarded by the Court (Docket No. 95) plus one half of the interest that has accumulated on that amount.

ii. $91,500 in stipulated penalties for additional alleged violations of the 2012 Consent Decree, which reflects one half of stipulated penalties that accrued but were not formally demanded.

c. Method of Payment to the State. Settling Parties shall pay the civil and stipulated penalties due to the State of Kansas by (i) electronic transfer in accordance with instructions Settling Parties may obtain from KDHE via kdhe.accountsreceivable@ks.gov after the Effective Date or (ii) check sent by certified mail to KDHE and submitted to: Kansas Department of Health and Environment, Office of Legal Services, Suite 560, 1000 SW Jackson, Topeka, Kansas 66612-1371.

d. Notice of Payment to the State. At the time of payment, Settling Parties shall provide notice of the payment by e-mail pursuant to Section XVIII (Notices) which shall state the method of payment, that the payment is for the civil and/or stipulated penalties owed pursuant to the Consent Decree in *United States and Kansas v. Coffeyville Resources Refining &Marketing, LLC*, and shall reference the civil action number.

XII. STIPULATED PENALTIES

66. General Provisions Regarding Stipulated Penalties.

a. Settling Parties shall be liable for stipulated penalties to the United States and the State for each failure by Settling Parties to comply with the terms of this Consent Decree as specified below, unless excused under Section XIII (Force Majeure) or waived under Paragraph 81.

b. All penalties paid shall be split evenly between the United States and the State.

c. For those provisions where a stipulated penalty of either a fixed amount or 1.2 times the economic benefit of non-compliance is available, the decision as to which alternative will be sought rests exclusively within the discretion of the United States after consultation with KDHE and is not subject to dispute resolution. In no event shall any stipulated penalty assessed against Settling Parties exceed the maximum civil penalty that may be assessed under the Clean Air Act (42 U.S.C. § 7413), as adjusted by the Civil Penalties Inflation Adjustment Act of 1990, 28 U.S.C. § 2461, as amended by 31 U.S.C. § 3701, and EPA regulations codified at 40 C.F.R. Part 19, for any violation of this Consent Decree in effect at the time of the violation.

67. Requirements to Pay Civil Penalties. For failure to timely make a civil penalty or stipulated penalty payment required by Section XI (Payment of Civil and Stipulated Penalties) of this Consent Decree, Settling Parties shall be liable for $10,000 per day, plus Interest on the amount overdue.

68. Sections V.A and V.B Related to NSPS and NESHAP Compliance at Refinery Flares.

a. For each failure to comply with the NSPS Subpart Ja H_2S concentration limit at the Coker and Cold Pond Flares as required by Paragraph 12:

i. Prior to three years from the Effective Date or the Earlier Election Date defined in Paragraph 33, whichever occurs earlier:

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$1,500
Days 31-60	$2,500
Days 61 and Beyond	$3,500 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

ii. After three years from the Effective Date or the Earlier Election Date defined in Paragraph 33, whichever occurs earlier:

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$1,500
Days 31-60	$3,500
Days 61 and Beyond	$6,500 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

b. For failure to comply with any requirement set forth in NESHAP Subpart CC, 40 C.F.R. §§ 63.670(b) (pilot flame presence), (c) (visible emissions), (d) (flare tip velocity) and (e) (combustion zone operating limits), as required by Paragraph 13:

i. Prior to three years from the Effective Date or the Earlier Election Date defined in Paragraph 33, whichever occurs earlier:

Hours of Noncompliance Per Quarter	Penalty Per Hour Per Requirement Violated
0.25-50	$50
50.25-100	$100
100.25+	$300

ii. After three years from the Effective Date or the Earlier Election Date defined in Paragraph 33, whichever occurs earlier:

Hours of Noncompliance Per Quarter	Penalty Per Hour Per Requirement Violated
0.25-100	$300
100.25-200	$700
200.25+	$1,000

c. For failure to comply with any monitoring requirement applicable to the Coker and Cold Pond Flare set forth in NSPS Subpart A (including but not limited to 40 C.F.R. §§ 60.11(d); 60.13; 60.18(d)), Subpart Ja (40 C.F.R. § 60.107a)), or NESHAP Subpart A (including but not limited to 40 C.F.R. § 63.8) or Subpart CC (including but not limited to 40 C.F.R. §§ 63.670; 63.671), as required by Paragraphs 12 or 13:

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$1,000
Days 31-60	$2,000
Days 61 and Beyond	$4,000

d. For failure to comply with Paragraphs 12 or 13 for any violation of an NSPS Subpart A, Ja or MACT CC requirement applicable to the Coker and Cold Pond Flares except those requirements for which a stipulated penalty has been assessed pursuant to Paragraphs 68.a-c above:

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$750
Days 31-60	$1,500
Days 61 and Beyond	$2,500

69. Section V.C Related to NO_x Emissions from the #2 Vacuum Charge Heater and the Crude Unit No. 2 Charge Heater.

a. For violation of any requirement in Paragraphs 18 or 19 (NO_x limits for the Crude Unit No. 2 Charge Heater and the #2 Vacuum Charge Heater):

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$1,000
Days 31-60	$2,500
Days 61 and Beyond	$4,500 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

b. For violation of the requirement in Paragraph 18 to monitor compliance at the Crude Unit No. 2 Charge Heater by continuing to operate the CEMS and the requirement in Paragraph 20 and Appendix A to conduct initial and continuing performance tests at the #2 Vacuum Charge Heater:

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$1,000
Days 31-60	$2,000
Days 61 and Beyond	$4,000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

70. Section V.D Related to NESHAP Subpart CC Compliance Applicable to Miscellaneous Process Vents. For violation of any requirement in Paragraph 23 (provisions and requirements of NESHAP Subpart CC applicable to any miscellaneous process vents designated

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as maintenance vents at the Refinery), Settling Parties shall pay a stipulated penalty of $400 per vent per day.

71. Section V.E Related to NSPS Subpart Ja Compliance at Refinery Process Heaters. For violation of any requirement in Paragraph 24 (provisions and requirements of NSPS Subpart Ja, 40 C.F.R. § 60.107a(c)(1) applicable to process heaters at the Refinery):

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$1,000
Days 31-60	$2,000
Days 61 and Beyond	$4,000 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

72. Section V.F Related to NESHAP Subpart CC Compliance at Refinery Gasoline Loading Racks.

a. For any violation of the applicable operating parameter value for the Refinery gas loading rack, as required by Paragraph 25:

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$1,000
Days 31-60	$2,500
Days 61 and Beyond	$4,500 or an amount equal to 1.2 times the economic benefit of delayed compliance, whichever is greater.

b. For violation of any monitoring requirement applicable to the Refinery gasoline loading rack set forth in NESHAP Subpart CC, 40 C.F.R. §§ 63.427(a) and (b), as required by Paragraph 25:

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$1,000
Days 31-60	$2,000
Days 61 and Beyond	$4,000

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c. For violation of any NESHAP Subpart CC requirement applicable to the Refinery gasoline loading rack except those requirements for which a stipulated penalty has been assessed pursuant to Paragraph 72.a-b above, as required by Paragraph 25:

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$750
Days 31-60	$1,500
Days 61 and Beyond	$2,500

73. Section V.G Related to NESHAP Subpart CC Compliance Related to Open-Ended Lines.

a. For violation of any requirement in Paragraph 26 (requirements in NESHAP Subpart CC and NSPS Subpart GGG relating to open ended lines during each Semi-Annual Consent Decree reporting period):

Number of OELs	Penalty per OEL Per Requirement Violated Per Day
1-25 OELs	$100
26-50 OELs	$250
> 50 OELs	$500

Stipulated penalties under this Paragraph 73.a per Semi-Annual Consent Decree reporting period shall be capped at $20,000.

b. For failure to timely submit the list of OELs as required by Paragraph 27:

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$750
Days 31-60	$1,500
Days 61 and Beyond	$2,500

c. For violation of any requirement in Paragraph 28 (requirement to paint OELs at the Refinery):

Number of OELs	Penalty per OEL
1-100 OELs	$100
> 100 OELs	$400

74. Section V.H Related to Emissions Monitoring and Performance Testing.

a. For violation of any requirement in Paragraphs 29-30 (requirements to certify, calibrate, maintain, and operate all CEMS required by this Consent Decree):

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$1,000
Days 31-60	$2,000
Days 61 and Beyond	$4,000

b. For violation of any requirement to conduct CEMS technician training as specified in Paragraph 31:

Penalty Per Individual Per Semi-Annual Reporting Period
$5,000

c. For violation of any requirement in Paragraph 32 (DAHS configuration):

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$750
Days 31-60	$1,500
Days 61 and Beyond	$2,500

75. Section VI Related to Installation and Operation of FGRS.

a. For violations of Paragraph 33 (requirements related to installation and operation of FGRS):

i. Failure to install FGRS in compliance with Paragraphs 33.a-b:

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-14	$2,000
Days 15-30	$5,000
Days 31 and Beyond	$10,000

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ii. Failure to operate FGRS as required by Paragraph 33.e

Percentage of FGRS Operating Time when Flare is In Operation	Days of Non-Compliance	Penalty Per Day
90-94.5%	Days 1-14	$750
	Days 15-30	$2,500
	Days 31 and Beyond	$4,500
Below 90%	Days 1-14	$2,000
	Days 15-30	$5,000
	Days 31 and Beyond	$10,000

iii. Failure to operate FGRS as required by Paragraphs 33.c-d: $200 penalty per requirement violated per Day.

iv. If Settling Parties fail to install and/or operate the FGRS because the Cold Pond Flare is not In Operation due to a long-term Refinery shutdown (defined as a shutdown of more than four consecutive months not due to a Force Majeure event), Settling Parties shall pay a stipulated penalty of $3,653 per day for each day less than three years that the FGRS did not operate.

b. For violation of any requirement in Paragraph 34 (FGRS Monitoring):

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$1,000
Days 31-60	$2,000
Days 61 and Beyond	$4,000

c. For violation of any requirement in Paragraph 35 (revision of Flare Management Plan) or Paragraph 36 (FGRS information collection and reporting requirements):

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$750
Days 31-60	$1,500
Days 61 and Beyond	$2,500

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76.e Recordkeeping and Reporting Violations. For failure to timely submit any reporte required by Section V.B (Subject Flaring Event Reporting) or Section VIII (Reporting), or for submitting any of the above reports that does not substantially conform to the applicable requirements:

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$750
Days 31-60	$1,500
Days 61 and Beyond	$2,500

*Accrual of these stipulated penalties ceases when a substantially-conforming report covering the same time period for which the prior report was missing or delinquent is filed.

77.e Section VII Related to State Supplemental Environmental Project.e

a.e For failure to comply with any KDHE-approved SEP deadline as specifiede in Paragraph 41:

Period of Noncompliance	Penalty Per Requirement Violated Per Day
Days 1-30	$500
Days 31-60	$1,000
Days 61 and Beyond	$2,000

b.e If Settling Parties fail to complete a KDHE-approved SEP as required bye Paragraph 41, Settling Parties shall pay a stipulated penalty of 1.5 times the difference between $1,000,000 and the amount expended in compliance with the KDHE-approved SEP, less any stipulated penalties paid in Paragraph 77.a.

78.e Noncompliance with any Consent Decree Requirement Not Specifically Identifiede in this Section. Settling Parties shall pay a stipulated penalty of $400 per day for each violation of any term, condition, or requirement of this Consent Decree for which a specific stipulated penalty is not provided in this Section.

79.e Accrual of Stipulated Penalties.e

a. Stipulated penalties under this Section shall begin to accrue on the Day after performance is due or on the Day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases, including during any period of dispute resolution. Stipulated penalties shall accrue simultaneously for separate violations of this Consent Decree. However, where Settling Parties' violation of a particular Consent Decree requirement triggers more than one stipulated penalty provision in this Consent Decree, Settling Parties shall be liable for stipulated penalties calculated under only one stipulated penalty provision as determined by the United States in consultation with KDHE, the choice of which is not subject to dispute resolution.

b. The number of Days of a particular violation is calculated as the total Days (including non-contiguous Days) on which a violation occurred. However, in calculating the number of Days of violation comprised of two or more non-contiguous periods of violation (i.e., where Settling Parties achieve compliance between non-contiguous periods of violation), the calculation shall reset to Day 1 on the first Day of any non-contiguous period of violation if Settling Parties demonstrate that such subsequent non-contiguous period of violation is due to a different cause than the previous non-contiguous period of violation. For example, in the case of a violation that occurs for 34 Days, ceases for several Days, and then resumes for a further 10 Days, if Settling Parties demonstrate that the second period of violation is due to a different cause than the first period of violation, the stipulated penalty shall be calculated as one violation lasting 34 Days and a second violation lasting 10 Days. In contrast, in this example, if Settling Parties do not demonstrate that the second period of violation is due to a different cause than the first period of violation, then the stipulated penalty shall be calculated as a single violation lasting 44 Days.

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80. Settling Parties shall pay stipulated penalties upon written demand by the United States or State no later than 60 Days after Settling Parties receive such demand. A demand for the payment of stipulated penalties will identify the particular violations to which the stipulated penalty relates, the stipulated penalty amount Plaintiffs have demanded for each violation (as can be best estimated), the calculation method underlying the demand, and the grounds upon which the demand is based.

81. The United States, after consultation with the State, may, in its unreviewable discretion, waive payment of any portion of stipulated penalties that may accrue under this Consent Decree.

82. Stipulated penalties shall be paid to the United States in the manner set forth in Paragraph 64.c of this Consent Decree. Stipulated penalties shall be paid to the State in the manner set forth in Paragraph 65.c of this Consent Decree.

83. Requirement to Pay Stipulated Penalties. If Settling Parties fail to pay stipulated penalties accruing pursuant to and in accordance with this Section XII (Stipulated Penalties), Settling Parties shall be liable for Interest on such penalties accruing as of the date payment became due.

84. If Settling Parties invoke dispute resolution as to the United States' or State's demand for all or part of a stipulated penalty, by no later than 60 Days after the Settling Parties receive such demand, they shall place the disputed amount demanded in a commercial interest-bearing escrow account pending resolution of the matter in dispute and invoke dispute resolution in accordance with the provisions of Section XIV (Dispute Resolution).

85. Stipulated Penalties Dispute. Stipulated penalties shall continue to accrue in accordance with Paragraph 79, but payment shall be stayed pending resolution of the dispute. If Settling Parties do not prevail on the disputed issue, stipulated penalties shall be paid as follows:

a. If the dispute is resolved by agreement of the Parties or by a decision of the United States or the State that is not appealed to the Court, Settling Parties shall pay accrued penalties determined to be owing or agreed upon through settlement, together with accrued Interest, to the United States or the State within 60 Days of the date of the agreement or the receipt of the United States' or the State's decision or order.

b. If the dispute is not resolved as provided in Paragraph 85.a, and is appealed to the Court and the United States or the State prevails in whole or in part, Settling Parties shall pay all accrued penalties determined by the Court to be owing, together with accrued Interest, within 60 Days of receiving the Court's decision or order, except as provided in Paragraph 85.c, below.

c. If any Party appeals the District Court's decision, Settling Parties shall pay all accrued penalties determined to be owing, together with Interest, within sixty (60) Days of receiving the final appellate court decision.

d. Should the amount determined to be owing under Paragraphs 85.a-c exceed the amount in the escrow account, Settling Parties shall, in addition, pay the difference within the time limit provided in Paragraphs 85.a-c.

86. The payment of penalties and interest, if any, shall not alter in any way Settling Parties' obligation to complete the performance of the requirements of this Consent Decree.

87. Non-Exclusivity of Remedy. Stipulated penalties are not the United States and State's exclusive remedy for violations of this Consent Decree. Subject to the provisions of

Section XVI (Effect of Settlement/Reservation of Rights), the United States and State expressly reserve the right to seek any other legal and equitable remedies they deem appropriate for Settling Parties' violation of this Decree or applicable law, including but not limited to, an action against Settling Parties for statutory penalties, additional injunctive relief, mitigation or offset measures, and/or contempt. However, the amount of any statutory penalty assessed for a violation of this Consent Decree shall be reduced by an amount equal to the amount of any stipulated penalty assessed and paid pursuant to this Consent Decree.

88. Pre-Entry Obligations. Upon the Effective Date, the stipulated penalty provisions of this Decree shall be retroactively enforceable with regard to any and all violations of Paragraphs 12-13, 18-26, 29-30, and 32 that have occurred prior to the Effective Date, provided that stipulated penalties that may have accrued prior to the Effective Date may not be collected unless and until this Consent Decree is entered by the Court. However, stipulated penalties shall not accrue for any violations resolved pursuant to Section XVI (Effect of Settlement/Reservations of Rights) that occurred prior to the Date of Lodging.

XIII. FORCE MAJEURE

89. "Force majeure," for purposes of this Consent Decree, means any event arising from causes beyond the control of Settling Parties, of any entity controlled by Settling Parties, or of Settling Parties' contractors, that delays or prevents the performance of any obligation under this Consent Decree despite Settling Parties' best efforts to fulfill the obligation. The requirement that Settling Parties exercise "best efforts to fulfill the obligation" includes using best efforts to anticipate any potential force majeure and best efforts to address the effects of any potential force majeure (a) as it is occurring and (b) following the potential force majeure, such that any delay or non-performance is, and any adverse effects of the delay or non-performance are,

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minimized to the greatest extent possible. "Force majeure" does not include financial inability to perform any obligation under this Consent Decree.

90. If any event occurs or has occurred that may delay the performance of any obligation under this Consent Decree for which Settling Parties will or may claim a force majeure, Settling Parties shall provide notice to the United States and State in accordance with Section XVIII (Notices). The deadline for the initial notice is seven (7) Days after Settling Parties first knew that the event would likely delay or prevent performance. Settling Parties shall be deemed to know of any circumstance of which any contractor or entity controlled by Settling Parties knew or should have known.

91. If Settling Parties seek to assert a claim of force majeure concerning the event, within fourteen (14) Days after the notice under Paragraph 90, Settling Parties shall submit a further notice to the United States and the State that includes (a) an explanation and description of the event and its effect on Settling Parties' completion of the requirements of the Consent Decree; (b) a description and schedule of all actions taken or to be taken to prevent or minimize the delay and/or other adverse effects of the event; (c) if applicable, the proposed extension of time for Settling Parties to complete the requirements of the Consent Decree; (d) Settling Parties' rationale for attributing such delay to a force majeure; (e) a statement as to whether, in the opinion of Settling Parties, such event may cause or contribute to an endangerment to public health or welfare or the environment; and (f) all available proof supporting the claim that the delay was attributable to a force majeure event.

92. Failure to submit a timely or complete notice or claim under Paragraph 90 and 91 regarding an event precludes Settling Parties from asserting any claim of force majeure regarding that event, provided, however, that the United States may, in its unreviewable discretion, excuse

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such failure if it is able to assess to its satisfaction whether the event is a force majeure, and whether Settling Parties have exercised their best efforts, under Paragraph 89.

93. If EPA 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 will be extended by EPA 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. EPA will notify Settling Parties in writing of the length of the extension, if any, for performance of the obligations affected by the force majeure event. Settling Parties may elect to invoke the dispute resolution procedures set forth in Section XIV (Dispute Resolution) to challenge the length of the extension provided in EPA's notification. If EPA does not agree that the delay or anticipated delay has been or will be caused by a force majeure event, EPA will notify Settling Parties in writing of its decision.

94. If Settling Parties elect to invoke the dispute resolution procedures set forth in Section XIV (Dispute Resolution), they shall do so no later than 30 Days after receipt of the United States' notice under Paragraph 93. In any such proceeding, Settling Parties have the burden of demonstrating by a preponderance of the evidence that they are entitled to relief under Paragraph 89, that their proposed excuse or extension was or will be warranted under the circumstances, and that it complied with the requirements of Paragraphs 89-91. If Settling Parties carry this burden, the delay or non-performance at issue shall be deemed not to be a violation by Settling Parties of the affected obligation of this Consent Decree identified to the United States, State, and the Court.

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95. With respect to any compliance obligation under this Consent Decree that requires a Settling Party to obtain a federal, state, or local permit or approval, a delay in the performance of such obligation by a Settling Party resulting from a failure to obtain, or a delay in obtaining, any permit or approval required to fulfill such obligation, may form the basis for a claim of force majeure, provided that Settling Parties have submitted timely and complete applications and taken other actions necessary to obtain such permits or approvals.

XIV. DISPUTE RESOLUTION

96. 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. Settling Parties' failure to seek resolution of a dispute under this Section concerning an issue of which it had notice and an opportunity to dispute under this Section prior to an action by the United States or State to enforce any obligation of Settling Parties arising under this Decree precludes Settling Parties from raising any such issue as a defense to any such enforcement action.

97. Informal Dispute Resolution. Any dispute subject to dispute resolution under this Consent Decree shall first be the subject of informal negotiations between the Parties. The dispute shall be considered to have arisen when Settling Parties send the United States and the State a written Notice of Dispute. Such Notice of Dispute shall clearly state the matter in dispute. The period of informal negotiations shall not exceed 60 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 30 Days after the conclusion of the informal negotiation period, Settling Parties invoke formal dispute resolution procedures as set forth below.

98. Formal Dispute Resolution. Settling Parties shall invoke formal dispute resolution procedures, within the time period provided in the preceding Paragraph 97, by sending the United States and the State 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 Settling Parties position and any supporting documentation relied upon by Settling Parties.

99. The United States and State will send Settling Parties their Statement of Position within 45 Days of receipt of Settling Parties' Statement of Position. The United States' and State's 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' and State's Statement of Position is binding on Settling Parties, unless Settling Parties file a motion for judicial review of the dispute in accordance with the following Paragraph.

100. Judicial Dispute Resolution. Settling Parties may seek judicial review of the dispute by filing with the Court and serving on the United States and State a motion requesting judicial resolution of the dispute. The motion (a) must be filed within 30 Days of receipt of the United States' and State's Statement of Position pursuant to the preceding Paragraph 99; (b) may not raise any issue not raised in informal or formal dispute resolution pursuant to Paragraphs 97-98, unless the Plaintiffs raise a new issue of law or fact in the Statement of Position; (c) shall contain a written statement of Settling Parties' position on the matter in dispute, including any supporting factual data, analysis, opinion, or documentation, and (d) shall set forth the relief requested and any schedule within which the dispute must be resolved for orderly implementation of the Consent Decree.

101. The United States and State shall respond to Settling Parties' motion within the time period allowed by the Local Rules of this Court. Settling Parties may file a reply memorandum, to the extent permitted by the Local Rules.

102. Standard of Review. In a formal dispute proceeding under this Section, Settling Parties shall bear the burden of demonstrating that its position complies with this Consent Decree and the CAA, and that they are entitled to relief under applicable principles of law. The United States reserves the right to argue that its position is reviewable only on the administrative record and must be upheld unless arbitrary and capricious or otherwise not in accordance with law, and Settling Parties reserve the right to argue to the contrary.

103. The invocation of dispute resolution procedures under this Section shall not, by itself, extend, postpone, or affect in any way any obligation of Settling Parties under this Consent Decree, unless and until the Court or the final resolution of the dispute so provides. Stipulated penalties with respect to the disputed matter shall continue to accrue from the first Day of noncompliance, but payment shall be stayed pending resolution of the dispute as provided in Paragraph 85. If Settling Parties do not prevail on the disputed issue, stipulated penalties shall be assessed and paid as provided in Section XII (Stipulated Penalties).

104. As part of the resolution of any dispute submitted to dispute resolution, the Parties, by agreement, or this Court, by order, may, in appropriate circumstances, extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of the time it took for the issue to be resolved under dispute resolution. Settling Parties shall be liable for stipulated penalties for their failure thereafter to complete the work in accordance with the extended or modified schedule.

XV. INFORMATION COLLECTION AND RETENTION

105. The United States, the State, and their authorized representatives, including attorneys, contractors, and consultants, shall have the right of entry into the Refinery, at all reasonable times, upon presentation of credentials, to:

a. monitor the progress of activities required under this Consent Decree;

b. verify any data or information submitted to the United States or the State in accordance with the terms of this Consent Decree;

c. obtain samples and, upon request, splits of any samples taken by Settling Parties or their representatives, contractors, or consultants related to the requirements in this Consent Decree;

d. obtain documentary evidence, including photographs and similar data related to the requirements in this Consent Decree; and

e. assess Settling Parties' compliance with this Consent Decree.

106. Upon request, Settling Parties shall provide EPA and the State or their authorized representatives splits of any samples taken by Settling Parties related to the requirements of this Consent Decree. Upon request, EPA and the State shall provide Settling Parties splits of any samples taken by EPA or the State related to the requirements of this Consent Decree.

107. Settling Parties shall retain, and shall instruct their contractors and agents to preserve, all non-identical copies of all documents, records, or other information (including documents, records, or other information in electronic form) (hereinafter referred to as "Records") in their or their contractors' or agents' possession or control, or that come into their or their contractors' or agents' possession or control, and that relate in any manner to Settling Parties' performance of their obligations under this Consent Decree for a period of two years after termination of this Consent Decree. This information-retention requirement shall apply

regardless of any contrary corporate or institutional policies or procedures. This retention requirement does not apply to voicemail messages or text messages. Nor does this retention requirement apply to Settling Parties' outside counsel, provided an exact copy of any Records in outside counsel's possession or control is maintained by Settling Parties.

108. At any time during this information-retention period, upon request by the United States or the State, Settling Parties shall provide copies of any Records required to be maintained under the preceding Paragraph 107.

a. Settling Parties may assert that certain Records are privileged under the attorney-client privilege or any other privilege recognized by federal law. If Settling Parties assert such a privilege, it shall comply with Federal Rule of Civil Procedure 26(b)(5) regarding claims of privilege. However, no Records created or generated pursuant to the requirements of this Consent Decree shall be withheld on grounds of privilege.

b. Settling Parties may also assert that information required to be provided under this Section is protected as Confidential Business Information ("CBI") under 40 C.F.R. Part 2. As to any information that Settling Parties seek to protect as CBI, Settling Parties shall follow the procedures set forth in 40 C.F.R. Part 2.

109. At the conclusion of the information-retention period provided in Paragraph 108, Settling Parties shall notify the United States and the State at least 60 Days prior to the destruction of Records subject to the requirements of Paragraph 107 above and, upon request by the United States or the State, Settling Parties shall deliver any Records to EPA or KDHE.

110. This Consent Decree in no way limits or affects any right of entry and inspection, or any right to obtain information, held by the United States or the State pursuant to applicable federal or state laws, regulations, or permits, nor does it limit or affect any duty or obligation of

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Settling Parties to maintain documents, records, or other information imposed by applicable federal or state laws, regulations, or permits.

XVI. EFFECT OF SETTLEMENT/RESERVATION OF RIGHTS

111. This Consent Decree resolves only civil claims (for civil penalties and injunctive relief) of the United States and the State for violations that occurred through the Date of Lodging and are alleged in the Complaint filed in this action and in the Notices of Violation issued by EPA and KDHE on August 30, 2023.

112. The United States and the State 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 the State to obtain penalties or injunctive relief under the CAA or implementing regulations or permits, or under other federal or state laws, regulations, or permit conditions, except as expressly specified in Paragraph 111 above. Nothing in this Consent Decree shall be construed to limit the United States and the State from pursuing legal and equitable remedies to address any conditions if there is or may be an imminent and substantial endangerment to the public health or welfare or the environment arising at, or posed by, the Refinery.

113. Entry of this Consent Decree resolves the United States' and KDHE's claims for stipulated penalties that the Court awarded (Docket No. 95) and Settling Parties' appeal of that award, which is pending before the Court of Appeals for the Tenth Circuit (Appeal No. 22-3088). No later than 15 Days after the Effective Date, Settling Parties shall file in the Tenth Circuit a Motion to Dismiss with Prejudice the pending appeal. Entry of this Consent Decree also resolves the United States' and KDHE's claims for additional stipulated penalties that were not

formally demanded or litigated which are described in an August 22, 2023, letter from DOJ to Counsel for CRRM, attached hereto as Appendix C.

114. In any subsequent administrative or judicial proceeding initiated by the United States or the State for injunctive relief, civil penalties, or other appropriate relief relating to the Refinery or Settling Parties' CAA violations resolved through this Consent Decree, Settling Parties shall not assert, and may not maintain, any defense or claim based upon the principles of waiver, claim preclusion (res judicata), issue preclusion (collateral estoppel), claim-splitting, or other defenses based upon any contention that the claims raised by the United States or the State 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 111 and 113 above.

115. This Consent Decree is not a permit, or a modification of any permit, under any federal, State, or local laws or regulations. Settling Parties are responsible for achieving and maintaining compliance with all applicable federal, State, and local laws, regulations, and permits; and Settling Parties' 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.

116. The United States and the State do not, by their consent to the entry of this Consent Decree, warrant or aver in any manner that Settling Parties' compliance with any aspect of this Consent Decree will result in compliance with provisions of the CAA, or with any other provisions of federal, State, or local laws, regulations, or permits.

117. This Consent Decree does not limit or affect the rights of Settling Parties or of the United States or the State against any third parties, not party to this Consent Decree, nor does it limit the rights of third parties, not party to this Consent Decree, against Settling Parties, except as otherwise provided by law.

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118. 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.

XVII. COSTS

119. The Parties shall bear their own costs of this action, including attorneys' fees, except that the United States and the State shall be entitled to collect the costs (including attorneys' fees) incurred in any action necessary to collect any portion of the civil penalty or any stipulated penalties due but not paid.

XVIII. NOTICES

120. Unless otherwise specified in this Consent Decree, whenever notifications, submissions, or communications are required by this Consent Decree, they shall be made in writing and sent by mail or email, with a preference for email, addressed as follows. Where this Consent Decree requires notice to the "United States" such notice shall be sent to both DOJ and EPA. Where this Consent Decree requires notice to the "State of Kansas" such notice shall be sent to KDHE. 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.

As to the United States

As to DOJ:
Submit electronically to:
EENRDb9cl@ENRD.USDOJ.GOV

If unable to submit electronically, then submit to:
The Department of Justice
Case No. DJ: 90-5-2-1-07459/5
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
150 M. Street N.E.
Washington, D.C. 20002

As to EPA:

EPA Headquarters

Submit electronically to:
argentieri.sabrina@epa.gov,
foley.patrick@epa.gov, and
refinerycd@erg.com

If unable to submit electronically, then submit to:

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

EPA Region 7

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Grant Harse, Esq.
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2345 Grand Boulevard, Suite 2200
Kansas City, MO 64108
Grant.Harse@lathropgpm.com

As to Settling Parties:

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Manager, Environmental
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jdditmore@CVREnergy.com

LeAnn Johnson Koch, Esquire
Perkins Coie, LLP
700 13th Street N.W.
Washington, D.C. 20005
leannjohnson@perkinscoie.com

XIX. EFFECTIVE DATE

121. The Effective Date of this Consent Decree shall be the date upon which this Consent Decree is entered by the Court or a motion to enter this Consent Decree is granted, whichever occurs first, as recorded on the Court's docket, provided, however, that Settling Parties hereby agree that they shall be bound to perform duties scheduled to occur prior to the

Effective Date. In the event the United States withdraws or withholds consent to this Consent Decree before entry, or the Court declines to enter this Consent Decree, then the preceding requirement to perform duties scheduled to occur before the Effective Date shall terminate.

XX. RETENTION OF JURISDICTION

122. The Court shall retain jurisdiction over this case until termination of this Consent Decree, for the purpose of resolving disputes arising under this Consent Decree or entering orders modifying this Consent Decree, pursuant to Section XIV (Dispute Resolution) and Section XXI (Modification of this Consent Decree), or effectuating or enforcing compliance with the terms of this Consent Decree.

XXI. MODIFICATION OF THIS CONSENT DECREE

123. The terms of this Consent Decree, including any attached appendices, may be modified only by a subsequent written agreement signed by all the Parties. Where the modification constitutes a material change to this Consent Decree, it shall be effective only upon approval by the Court.

124. The nature and frequency of reports required by this Consent Decree may be modified by mutual agreement of the Parties. The agreement of the United States and the State to such modification must be communicated in the form of a written notification (via e-mail) from EPA and KDHE but need not be filed with the Court to be effective.

125. Except as otherwise set forth in Paragraph 9, any disputes concerning modification of this Decree shall be resolved pursuant to Section XIV (Dispute Resolution), provided, however, that, instead of the standard of review provided by Paragraph 102, the Party seeking the modification bears the burden of demonstrating that it is entitled to the requested modification in accordance with Federal Rule of Civil Procedure 60(b).

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XXII. TERMINATION OF CERTAIN SECTIONS OF THE 2012 CONSENT DECREE

126. Upon the Effective Date, the following Sections, Subsections, and Paragraphs of the 2012 Consent Decree are hereby terminated:

Section V (Affirmative Relief):

Paragraphs 16, 17, and 18 (FCCU NO_x)
Paragraphs 19, 20.b, 21, 22, 23, and 24 (FCCU SO_2)
Paragraphs 25-26 (FCCU PM)
Paragraphs 28-29 (FCCU CO)
Paragraph 30 (FCCU CEMS)
Paragraphs 31-36 and 38-51 (Heater Boiler NO_x)
Paragraph 37 (NOx Emissions Limitations only for the Coker DHR3, the Radco Crude Unit Heater, #2 Vacuum Charge Heater, and Crude Unit No. 2 Charge Heater)
Paragraph 52 (NSPS Applicability to Fuel Gas Combustion Devices but excluding the Alkylation Hot Oil Heater, Alkylation Olefin Feed Drying Tower Heater, Isom. Charge Heater, FCCU Startup Heater, and Unifier Charge Heater B-101)
Paragraph 53 (Elimination of Fuel Oil Burning)
Paragraph 54 (Elimination of Coal Burning)
Paragraphs 55, 56.a, b, and c, and 57 (SRP)

Section V.J (Flaring Devices)

Section V.K (Control of Acid Gas Flaring and Tail Gas Incidents)

Section V.L (Hydrocarbon Flaring Incidents)

Section V.M (Continuous Emissions Monitors and General Provisions)

Section V.N. (Benzene Waste Operations NESHAP)

Section V.O (Leak Detection and Repair Requirements)

Section V.Q (CERCLA/EPCRA)

Section VI (Emission Credit Generation)

Section VII (Supplemental Environmental Project)

127. The remaining provisions of the 2012 Consent Decree shall be terminated when both of the following events have occurred:

a. CRRM provides the United States and KDHE with copies of final and effective construction and operating (Title V) permits that correctly incorporate the 2012 Consent Decree limits, standards, and requirements set forth in Paragraph 151 of the 2012 Consent Decree; and

b. submission of a certification by CRRM in accordance with Paragraph 53 above to the United States and KDHE that since June 30, 2023, CRRM has maintained substantial and material compliance with remaining 2012 Consent Decree requirements and that CRRM has paid all penalties and other monetary obligations due under the 2012 Consent Decree through the date of the last permit issuance in Paragraph 127.a above.

128. Termination under Paragraph 127 above shall be effective 45 Days after the occurrence of the events set forth in Paragraph 127.a and b above unless prior to that time the United States, after consultation with KDHE, disagrees that the conditions for termination in Paragraph 127.a and b have occurred and invokes dispute resolution pursuant to Section XIV (Dispute Resolution) of this Consent Decree.

XXIII. TERMINATION OF THIS CONSENT DECREE

129. This Consent Decree may be terminated when all of the following conditions have been satisfied.

a. The requirements of Section V (Compliance Requirements), Section VI (Mitigation) and Section VII (State Supplemental Environmental Project) of this Consent Decree have been completed;

b. The FGRS has been operated as required by Section VI (Mitigation) for a period of two years and thereafter Settling Parties have maintained substantial and material

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compliance with each term of this Consent Decree (including FGRS requirements) for at least one additional year;

c. Settling Parties have paid the stipulated penalties and civil penalties as required by Section XI (Payment of Civil and Stipulated Penalties) of this Consent Decree, and any accrued stipulated penalties and Interest as required by Section XII (Stipulated Penalties) of this Consent Decree, and

d. the Surviving Consent Decree Obligations specified in Paragraph 54 above have been correctly incorporated into final and effective federally enforceable construction and operating (Title V) permits.

130. Upon satisfaction of the conditions set forth in Paragraph 129.a-d above, Settling Parties may serve upon the United States and the State a Request for Termination, stating that Settling Parties have satisfied those requirements, together with all necessary supporting documentation.

131. Following receipt by the United States and the State of Settling Parties' Request for Termination, the Parties shall confer informally concerning the Request. If the United States after consultation with the State agrees that this Consent Decree may be terminated, the Parties shall submit, for the Court's approval, a joint stipulation terminating the Decree.

132. If the United States after consultation with the State does not agree that this Consent Decree may be terminated, the United States shall provide written notice to Settling Parties within 120 Days of receiving Settling Parties' Request for Termination that explains why it does not agree. Upon receipt of the written notice or if no notice is provided within the 120 Day time-period set forth above, Settling Parties may invoke dispute resolution under Section XIV (Dispute Resolution).

XXIV. PUBLIC PARTICIPATION

133. This Consent Decree shall be lodged with the Court for a period of not less than thirty (30) Days for public notice and comment in accordance with 28 C.F.R. § 50.7. The United States reserves the right to withdraw or withhold its consent if the comments regarding the Consent Decree disclose facts or considerations indicating that the Consent Decree is inappropriate, improper, or inadequate. Settling Parties consent to entry of this Consent Decree without further notice and agree not to withdraw from or oppose entry of this Consent Decree by the Court or to challenge any provision of the Decree, unless the United States has notified Settling Parties in writing that it no longer supports entry of the Decree.

XXV. SIGNATORIES/SERVICE

134. Each undersigned representative of a Settling Party, the Assistant Attorney General for the Environment and Natural Resources Division of the Department of Justice, and the Secretary of KDHE 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 that person represents to this document.

135. This Consent Decree may be signed in counterparts, and its validity shall not be challenged on that basis.

136. Settling Parties 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 Rules 4 and 5 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons.

XXVI. INTEGRATION

137.o This Consent Decree, including deliverables that are subsequently approvedo pursuant to this Decree, constitutes the entire agreement among the Parties regarding the subject matter of the Decree and supersedes all prior representations, agreements and understandings, whether oral or written, concerning the subject matter of the Decree herein.

XXVII. 26 U.S.C. SECTION 162(f)(2)(A)(ii) IDENTIFICATION

138.o For purposes of the identification requirement in Section 162(f)(2)(A)(ii) of theo Internal Revenue Code, 26 U.S.C. § 162(f)(2)(A)(ii), and 26 C.F.R. § 1.162-21(b)(2), performance of the requirements of this Consent Decree is restitution, remediation, or required to come into compliance with law: Section II (Applicability) Paragraph 6, Section V (Compliance Requirements) Paragraphs 12- 32, Section VI (Mitigation) Paragraphs 33-37, Section VIII (Reporting) Paragraphs 43-53 (except Paragraph 45.e), Section XV (Information Collection and Retention) Paragraphs 105-107 and Paragraph 109, and Appendix A.

XXVIII. HEADINGS

139.o Headings to the Sections and Subsections of this Consent Decree are provided foro convenience and do not affect the meaning or interpretation of the provisions of this Consent Decree.

XXIX. FINAL JUDGMENT

140.o Upon approval and entry of this Consent Decree by the Court, this Consento Decree shall constitute a final judgment of the Court as to the United States, the State, and Settling Parties. The Court finds that there is no just reason for delay and therefore enters this judgment as a final judgment under Federal Rules of Civil Procedure 54 and 58.

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XXX. APPENDICES

141. The following Appendices are attached to and part of this Consent Decree:

"Appendix A" is the #2 Vacuum Charge Heater NOx Source Testing Protocol.

"Appendix B" is the KDHE Bureau of Air *Supplemental Environmental Project (SEP) Policy* dated December 2019 (SEP Policy).

"Appendix C" is the August 22, 2023, letter from DOJ to CRRM counsel regarding additional stipulated penalties not formally demanded by Plaintiffs.

Dated and entered this __ day of __________, 2023

UNITED STATES DISTRICT JUDGE

WE HEREBY CONSENT to the entry of this Consent Decree subject to the public notice and comment provisions of 28 C.F.R. § 50.7:

FOR PLAINTIFF THE UNITED STATES OF AMERICA

TODD KIM
Assistant Attorney General
United States Department of Justice
Environment and Natural Resources Division

Date: November 20, 2023

Elizabeth Loeb
ELIZABETH L. LOEB
Senior Attorney
JOANNA CITRON DAY
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KATE E. BRUBACHER
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Date: November 17, 2023

DAVID M. ULHMANN
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Office of Enforcement and Compliance Assurance
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ROSEMARIE A. KELLEY
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SABRINA ARGENTIERI
Attorney-Advisor, Air Enforcement Division
Office of Civil Enforcement
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Date: 11-14-2023

MEGHAN A. MCCOLLISTER
Regional Administrator
U.S. Environmental Protection Agency, Region 7
11201 Renner Boulevard
Lenexa, Kansas 66219

Date: 11-13-2023

Leslie Humphrey

LESLIE HUMPHREY
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ANTONETTE PALUMBO
Attorney-Advisor
U.S. Environmental Protection Agency, Region 7
11201 Renner Boulevard
Lenexa, Kansas 66219

WE HEREBY CONSENT to the entry of this Consent Decree:

FOR THE STATE OF KANSAS, ex rel KANSAS DEPARTMENT OF HEALTH AND ENVIRONMENT

Date: 09/29/2023 Janet Stanek ag
JANET STANEK
Secretary
Kansas Department of Health and Environment

Date: 9/25/23
BRIAN VAZQUEZ
General Counsel
Kansas Department of Health and Environment
1000 SW Jackson, Suite 560
Topeka, KS 66612
(785) 296-5334

WE HEREBY CONSENT to the entry of this Consent Decree:

FOR DEFENDANT COFFEYVILLE RESOURCES REFINING & MARKETING, LLC,

Date:

BRENT E. TRAXEL
Vice President and General Manager
400 N. Linden
Coffeyville, KS 67337
(602)7251-40007
bxtraxel@cvrenergy.com7

FOR CVR REFINING CVL, LLC,

Date:

MICHAEL H. WRIGHT, JR.
Executive Vice President and Chief Operating Officer
2277 Plaza Drive, Suite 500
Sugar Land, TX 77479

FOR CVR COMMON ASSETS CVL, LLC

Date:

MELISSA M. BUHRIG
Executive Vice President, General Counsel and Secretary
2277 Plaza Drive, Suite 500
Sugar Land, TX 77479
(281)7207-32007
LegalServices@cvrenergy.com7

FOR CVR SUPPLY & TRADING, LLC

Date:

CHARLES DOUGLAS JOHNSON
Executive Vice President and Chief Commercial Officer
2277 Plaza Drive, Suite 500
Sugar Land, TX 77479

APPENDIX A
OF CONSENT DECREE

DENOVO

#2 VACUUM CHARGE HEATER
NO_X SOURCE TESTING PROTOCOL

COFFEYVILLE RESOURCES REFINING & MARKETING, LLC. FACILITY, COFFEYVILLE, KANSAS

July 27, 2023

Project No.: 5281.01.095

Prepared for:
Coffeyville Resources Refining & Marketing, LLC.
400 North Linden
Coffeyville, Kansas 67337

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PREFACE

Coffeyville Resources Refining & Marketing, LLC. (CRRM) is preparing to conduct a stack test to determine compliance with the NO_X lb. / MMBtu emission rate on the #2 Vacuum Charge Heater (#2 Vac Chg. Htr) the CRRM petroleum refinery located in Coffeyville, Kansas. This document outlines the testing protocol for this test.

GENERAL INFORMATION

CRRM has contracted DeNovo Global Technologies, Inc. (DeNovo) to perform the above-referenced stack test. DeNovo will be performing the stack test for the measurement of oxides of nitrogen (NO_X), excess oxygen (O_2), stack gas flow (EPA Method 19) and flue gas analysis.

#2 VACUUM CHARGE HEATER

I.D No.:	IA-04-FH0017
Fuel Source:	Refinery Fuel Gas
Rated capacity:	80.0 MMBtu/hr
NOx limit:	0.046 lb./MMBtu

Plant and Process Description

Coffeyville Resources Refining and Marketing, LLC (CRRM) is located at 400 North Linden, Coffeyville, Kansas in Montgomery County. CRRM processes crude oil into refined petroleum products including but not limited to propane, gasoline, distillates, and coke, and is composed of process operating units and associated utilities.

Testing Summary

Facility Contact Information:

Mr. John Ditmore
Coffeyville Resources Refining & Marketing, LLC.
P.O. Box 1566
400 North Linden
Coffeyville, Kansas 67337
(620)-252-4542

Site Information

Coffeyville Resources Refining & Marketing, LLC. (CRRM) owns and operates a petroleum refinery facility located at 400 North Linden, Coffeyville, Kansas

Testing Organization

DeNovo Global Technologies, Inc
Louis M. Esposito
17902 East Strack Drive
Spring, Texas 77379
(281) 292-0636 ext. 14
lou.esposito@denovogt.com

Test Schedule

The current test schedule is initiate testing during the week of August 14 2023, beginning at approximately 10:00 am.

Equipment and Procedures

Process heaters associated with the CRRM facility includes the #2 Vacuum Charge Heater. The following is a brief description of the equipment specifics:

Process Equipment:

#2 Vacuum Charge Heater
I.D No. IA-04-FH0017
Fuel Source: Refinery Fuel Gas
Rated capacity: 80.0 MMBtu/hr

The units will be tested according to USEPA 40 CFR 60 Appendix A utilizing the following test methods:

SAMPLE FREQUENCY FOR EACH RUN	***SAMPLING METHOD***	***ANALYTICAL PARAMETER***	***ANALYTICAL METHOD***
3 x 60 Min Runs	EPA Method 1	Port Location	Manual Method
	EPA Method 3A	O_2,	Paramagnetic Analyzer
	EPA Method 7E	NO_x	Chemiluminescent Analyzer
	EPA Method 19	Flows, Moisture and Mass Emissions	N/A
	Grab Sampling	Fuel Analysis	Gas Chromatography

EPA Method 1
Determination of port sampling location will be performed as outlined by the procedures in EPA Method 1 and 2 in 40 CFR, Part 60. There are no modifications to this method.

EPA Method 3A
Sampling of the flue gas for O_2 will be performed as outlined by the procedures in EPA Method 3A, in 40 CFR, Part 60, Appendix A, and in accordance with Performance Specification 3 in 40 CFR, Part 60, and Appendix B. There are no modifications to this method.

EPA Method 7E
Sampling of the flue gas for NO_X will be performed as outlined by the procedures in EPA Method 7E, in 40 CFR, Part 60, Appendix A, and in accordance with Performance Specification 2 in 40 CFR, Part 60, and Appendix B. There are no modifications to this method.

EPA Method 19
Determination of mass emissions (NOx lb./MMBtu), stack flow and moisture will be performed as outlined by the procedures in EPA Method 19, in 40 CFR, Part 60, Appendix A. There are no modifications to this method.

RM Instrumentation

The compounds to be calibrated are NO_x and O_2. The NO_x analysis will be performed utilizing a California Analytical Model 600 Chemiluminescent analyzer. O_2 will be detected using a California Analytical model 601 Paramagnetic O_2 analyzer.

RM Calibration Procedure

The NO_x and O_2 analyzers will be calibrated using EPA protocol gas mixtures. The sensitivity of the analyzers is less than 1% of the range and response time is typically less than one minute, depending on the length of heated line used. The analyzers will be zeroed with ultra-pure nitrogen, followed by a mid and high range calibration standard, corresponding to approximately 40 % - 60 % and 100 % of the analyzer full span value. The calibration range for each component will vary dependent on the unit specifics for NO_x and O_2.

A system bias check will be performed before and after each test run using the mid-range gas mixture through the entire sampling system to check for line contamination and leaks. Calibration correction factors will be determined and used to correct the raw RM concentrations.

RM Sampling Procedure

The flue gas samples present in the exhaust stack gas will be sampled and measured according to the requirements and procedures of EPA Reference Method 3A (O_2) and Method 7E (NO_X). Samples are drawn from three points, 16.7%, 50%, and 83.3% of the stack diameter. From the stack, the sample is transferred through a heated line to the mobile laboratory. Upon entering the lab, the sample passed through a one-micron filter assembly to remove particulate and then through the system sampling pump. Moisture is then removed using a universal analyzer model 1090 chiller. The dried sample is distributed via a manifold and independent control flow to the various analyzers. Sample concentrations are recorded eight times each second using Dasylab data acquisition software and averaged at one-minute intervals. The data is saved to a personal computer and test runs averaged and corrected for bias and drift.

RM Sampling Locations

Samples will be withdrawn from the outlet location, consistent with the requirements in EPA Method 1 found in 40 CFR Part 60 Appendix A. A stack diagram is provided in appendix A below. The sample ports are > 2.5 stack diameters downstream and >11 stack diameters upstream of any disturbances. The stack has 42" outside diameter. Actual measurements will be performed prior to compliance testing.

Operational Parameters

During the performance test series, the unit will be running at a production rate greater than or equal to 90% of the permitted load. In the event that process conditions do not allow for a minimum operating rate of 90%, the unit will be operated at maximum achievable load. The heater load is determined by the fired duty of the heater, which is calculated based on the flow rate of the fuel gas to the heater and the higher heating value of the fuel gas. The fuel gas flow is measured using an orifice plate flow meter that is situated in the upstream piping accounting for all fuel gas flow to the burners. The higher heating value is determined from the latest fuel gas sample. The flow and heating value data will be obtained from the refinery data acquisition system. Plant personnel will be responsible for gathering operations data necessary for determining load conditions.

Possible Complications

No complications are expected for these test series. Should it become necessary to change the testing schedule, the KDHE Regional and/or State office will be notified as soon as practicable.

The test crew will consist of Messrs. B. Cox and J. Chatman. Mr. Esposito will be the team leader and has over 30 years of emissions testing experience as well as air/water/waste permitting. Mr. Cox and Chatman will be acting as the field technicians and will be assisting in the compliance determination.

APPENDIX A - SAMPLE TRAIN DRAWINGS

APPENDIX B – EPA TEST METHODS

DENOVO

#2 VACUUM CHARGE HEATER
NO$_X$ SOURCE TESTING PROTOCOL

COFFEYVILLE RESOURCES REFINING & MARKETING, LLC. FACILITY, COFFEYVILLE, KANSAS

July 07, 2023

Project No.: 5281.01.095

Prepared for:
Coffeyville Resources Refining & Marketing, LLC.
400 North Linden
Coffeyville, Kansas 67337

\\wtxsbs1\ATD\Clients - Active\CVR Energy -5281\Coffeyville RR&M\5281.01.095 - Vac Htr #2 (July 2023)\Pre-Test DOCs\5281.01.095 CVR Vac 2 Heater Performance Test PROTOCOL July23 Rev 0.3.docx

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PREFACE

Coffeyville Resources Refining & Marketing, LLC. (CRRM) is preparing to conduct a source performance test to determine the NO_X lb. / MMBtu emission rate on the #2 Vacuum Charge Heater (#2 Vac Chg. Htr) serving operations at the CRRM petroleum refinery located in Coffeyville, Kansas. This document outlines the testing protocol for this test.

GENERAL INFORMATION

CRRM has contracted DeNovo Global Technologies, Inc. (DeNovo) to provide a unit Performance Test for the #2 Vacuum Charge Heater associated with plant operations at the CRRM petroleum refinery located in Coffeyville, Kansas. Testing will include performance determination of NO_X lb. / MMBtu emission factor associated with the #2 Vacuum Charge Heater, as required under Paragraph 42.c. of Civ. No. 04-CV-1064-MLB. DeNovo will be performing the performance test for the measurement of oxides of nitrogen (NO_X , excess oxygen (O_2), stack gas flow (EPA Method 19) and flue gas analysis.

#2 VACUUM CHARGE HEATER

I.D No.:	IA-04-FH0017
Fuel Source:	Refinery Fuel Gas
Rated capacity:	80.0 MMBtu/hr
NOx limit:	0.046 lb./MMBtu

Testing will include performance testing requirements for the respective unit as governed under Federal regulations associated with NSPS 40 CFR Part 60, Subpart Ja along with the state operating permit requirements.

Plant and Process Description

Coffeyville Resources Refining and Marketing, LLC CRRM) is located at 400 North Linden, Coffeyville, Kansas in Montgomery County. CRRM processes crude oil into refined petroleum products including but not limited to propane, gasoline, distillates, and coke, and is composed of process operating units and associated utilities. Sources are required by operating permit provisions to be continuously monitored; CRRM currently utilizes CEMS technology and hardware for this purpose.

Testing Summary

Facility Contact Information:

Mr. John Ditmore
Coffeyville Resources Refining & Marketing, LLC.
P.O. Box 1566
400 North Linden
Coffeyville, Kansas 67337
620)-252-4542

Site Information

Coffeyville Resources Refining & Marketing, LLC. (CRRM) owns and operates a petroleum refinery facility located at 400 North Linden, Coffeyville, Kansas

Testing Organization

DeNovo Global Technologies, Inc
Louis M. Esposito
17902 East Strack Drive
Spring, Texas 77379
(281) 251-0399 ext. 14
lou.esposito@denovogt.com

Test Schedule

The current test schedule is initiate testing during the week of August 14, 2023, beginning at 10:00 am.

Equipment and Procedures

Process heaters associated with the CRRM facility includes the #2 Vacuum Charge Heater. The following is a brief description of the equipment specifics:

Process Equipment:

#2 Vacuum Charge Heater
I.D No. IA-04-FH0017
Fuel Source: Refinery Fuel Gas
Rated capacity: 80.0 MMBtu/hr

The units will be tested according to USEPA 40 CFR 60 Appendix A utilizing the following test methods:

SAMPLE FREQUENCY FOR EACH RUN	*SAMPLING METHOD*	*ANALYTICAL PARAMETER*	*ANALYTICAL METHOD*
3 x 60 Min Runs	EPA Method 1	Port Location	Manual Method
	EPA Method 3A	O_2,	Paramagnetic Analyzer
	EPA Method 7E	NO_x	Chemiluminescent Analyzer
	EPA Method 19	Flows, Moisture and Mass Emissions	N/A
	Grab Sampling	Fuel Analysis	Gas Chromatography

EPA Method 1
Determination of port sampling location will be performed as outlined by the procedures in EPA Method 1 and 2 in 40 CFR, Part 60. There are no modifications to this method.

EPA Method 3A
Sampling of the flue gas for O_2 will be performed as outlined by the procedures in EPA Method 3A, in 40 CFR, Part 60, Appendix A, and in accordance with Performance Specification 3 in 40 CFR, Part 60, and Appendix B. There are no modifications to this method.

EPA Method 7E
Sampling of the flue gas for NO_X will be performed as outlined by the procedures in EPA Method 7E, in 40 CFR, Part 60, Appendix A, and in accordance with Performance Specification 2 in 40 CFR, Part 60, and Appendix B. There are no modifications to this method.

EPA Method 19
Determination of mass emissions (NOx lb./MMBtu), stack flow and moisture will be performed as outlined by the procedures in EPA Method 19, in 40 CFR, Part 60, Appendix A. There are no modifications to this method.

RM Instrumentation

The compounds to be calibrated are NO_x and O_2. The NO_x analysis will be performed utilizing a California Analytical Model 600 Chemiluminescent analyzer. O_2 will be detected using a California Analytical model 601 Paramagnetic O_2 analyzer.

RM Calibration Procedure

The NO_x and O_2 analyzers will be calibrated using EPA protocol gas mixtures. The sensitivity of the analyzers is less than 1% of the range and response time is typically less than one minute, depending on the length of heated line used. The analyzers will be zeroed with ultra-pure nitrogen, followed by a mid and high range calibration standard, corresponding to approximately 40 % - 60 % and 100 % of the analyzer full span value. The calibration range for each component will vary dependent on the unit specifics for NO_x and O_2.

A system bias check will be performed before and after each test run using the mid-range gas mixture through the entire sampling system to check for line contamination and leaks. Calibration correction factors will be determined and used to correct the raw RM concentrations.

RM Sampling Procedure

The flue gas samples present in the exhaust stack gas will be sampled and measured according to the requirements and procedures of EPA Reference Method 3A (O_2) and Method 7E (NO_X). Samples are drawn from three points, 16.7%, 50%, and 83.3% of the stack diameter. From the stack, the sample is transferred through a heated line to the mobile laboratory. Upon entering the lab, the sample passed through a one-micron filter assembly to remove particulate and then through the system sampling pump. Moisture is then removed using a universal analyzer model 1090 chiller. The dried sample is distributed via a manifold and independent control flow to the various analyzers. Sample concentrations are recorded eight times each second using Dasylab data acquisition software and averaged at one-minute intervals. The data is saved to a personal computer and test runs averaged and corrected for bias and drift.

RM Sampling Locations

Samples will be withdrawn from the outlet location, consistent with the requirements in EPA Method 1 found in 40 CFR Part 60 Appendix A. A stack diagram is provided in appendix A below. The sample ports are > 2.5 stack diameters downstream and >11 stack diameters upstream of any disturbances. The stack has 42" outside diameter. Actual measurements will be performed prior to compliance testing.

Operational Parameters

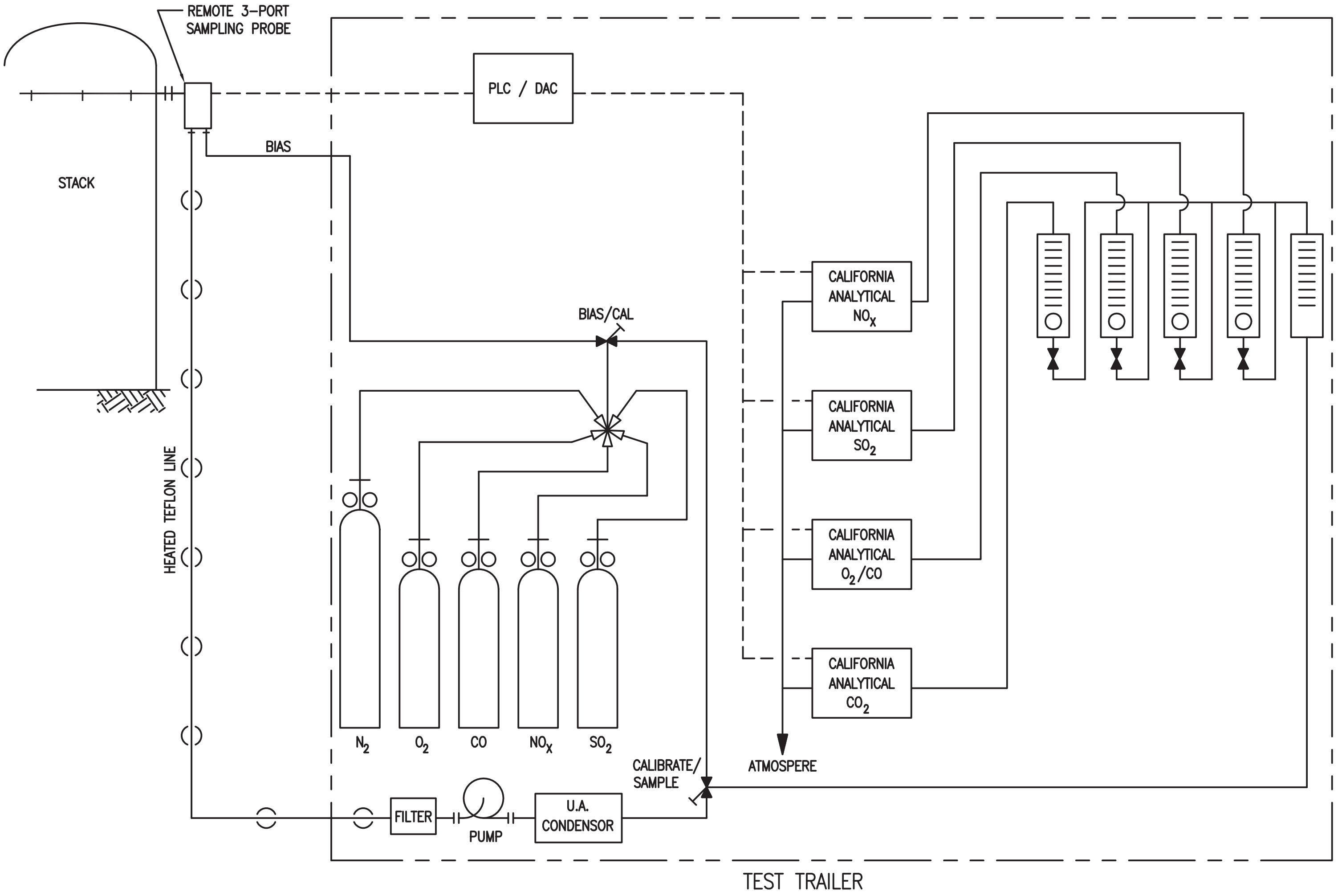
During the performance test series, the unit will be running at a production rate greater than or equal to 90% of the permitted load. In the event that process conditions do not allow for a minimum operating rate of 90%, the unit will be operated at maximum achievable load. The heater load is determined by the fired duty of the heater, which is calculated based on the flow rate of the fuel gas to the heater and the higher heating value of the fuel gas. The fuel gas flow is measured using an orifice plate flow meter that is situated in the upstream piping accounting for all fuel gas flow to the burners. The higher heating value is determined from the latest fuel gas sample. The flow and heating value data will be obtained from the refinery data historian. Plant personnel will be responsible for gathering operations data necessary for determining load conditions.

Possible Complications

No complications are expected for these test series. Should it become necessary to change the testing schedule, the KDHE Regional and/or State office will be notified as soon as practicable.

The test crew will consist of Messrs. B. Cox and J. Chatman. Mr. Esposito will be the team leader and has over 30 years of emissions testing experience as well as air/water/waste permitting. Mr. Cox and Chatman will be acting as the field technicians and will be assisting in the compliance determination.

APPENDIX A - SAMPLE TRAIN DRAWINGS



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Facility Audit / Permitting / Design / Project Liaison

17902 EAST STRACK, SPRING TEXAS 77379
PH:(281) 251–0399 FAX:(281) 251–1301 www.denovogt.com

NON VOC TRAILER SCHEMATIC

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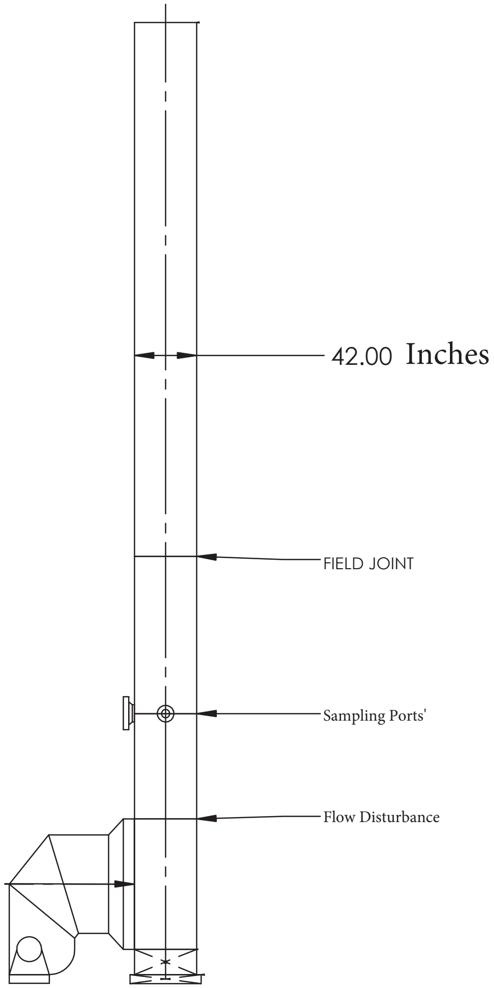

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CVR Energy - Coffeyville, KS - Air Preheater

7/10/2023

APPENDIX B – EPA TEST METHODS

METHOD 3A DETERMINATION OF OXYGEN AND CARBON DIOXIDE CONCENTRATIONS IN EMISSIONS FROM STATIONARY SOURCES (INSTRUMENTAL ANALYZER PROCEDURE)	**Revision 0 12/11/2013**	DENOVO

1.0 Scope and Application

What is Method 3A?

Method 3A is a procedure for measuring oxygen (O_2) and carbon dioxide (CO_2) in stationary source emissions using a continuous instrumental analyzer. Quality assurance and quality control requirements are included to assure that you, the tester, collect data of known quality. You must document your adherence to these specific requirements for equipment, supplies, sample collection and analysis, calculations, and data analysis.

This method does not completely describe all equipment, supplies, and sampling and analytical procedures you will need but refers to other methods for some of the details. Therefore, to obtain reliable results, you should also have a thorough knowledge of these additional test methods which are found in appendix A to this part:

(a) Method 1—Sample and Velocity Traverses for Stationary Sources.
(b) Method 3—Gas Analysis for the Determination of Molecular Weight.
(c) Method 4—Determination of Moisture Content in Stack Gases.
(d) Method 7E—Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure).

1.1 Analytes. What does this method determine? This method measures the concentration of oxygen and carbon dioxide.

Analyte	CAS No.	Sensitivity
Oxygen (O_2)	7782–44–7	Typically <2% of Calibration Span.
Carbon dioxide (CO_2)	124–38–9	Typically <2% of Calibration Span.

1.2 Applicability. When is this method required? The use of Method 3A may be required by specific New Source Performance Standards, Clean Air Marketing rules, State Implementation Plans and permits, where measurements of O_2 and CO_2 concentrations in stationary source emissions must be made, either to determine compliance with an applicable emission standard or to conduct performance testing of a continuous emission monitoring system (CEMS). Other regulations may also require the use of Method 3A.

1.3 Data Quality Objectives. How good must my collected data be? Refer to Section 1.3 of Method 7E.

2.0 Summary of Method

In this method, you continuously or intermittently sample the effluent gas and convey the sample to an analyzer that measures the concentration of O_2 or CO_2. You must meet the performance requirements of this method to validate your data.

3.0 Definitions

Refer to Section 3.0 of Method 7E for the applicable definitions.

4.0 Interferences [Reserved]

5.0 Safety

Refer to Section 5.0 of Method 7E.

6.0 Equipment and Supplies

Figure 7E–1 in Method 7E is a schematic diagram of an acceptable measurement system.

6.1 What do I need for the measurement system? The components of the measurement system are described (as applicable) in Sections 6.1 and 6.2 of Method 7E, except that the analyzer described in Section 6.2 of this method must be used instead of the analyzer described in Method 7E. You must follow the noted specifications in Section 6.1 of Method 7E except that the requirements to use stainless steel, Teflon, or non-reactive glass filters do not apply. Also, a heated sample line is not required to transport dry gases or for systems that measure the O_2 or CO_2 concentration on a dry basis, provided that the system is not also being used to concurrently measure SO_2 and/or NO_X.

6.2 What analyzer must I use? You must use an analyzer that continuously measures O_2 or CO_2 in the gas stream and meets the specifications in Section 13.0.

7.0 Reagents and Standards

7.1 Calibration Gas. What calibration gasses do I need? Refer to Section 7.1 of Method 7E for the calibration gas requirements. Example calibration gas mixtures are listed below. Precleaned or scrubbed air may be used for the O_2 high-calibration gas provided it does not contain other gases that interfere with the O_2 measurement.

(a) CO_2 in nitrogen (N_2).
(b) CO_2 in air.
(c) CO_2/SO_2 gas mixture in N_2.
(d) O_2/SO_2 gas mixture in N_2.
(e) $O_2/CO_2/SO_2$ gas mixture in N_2.
(f) CO_2/NO_X gas mixture in N_2.
(g) $CO_2/SO_2/NO_X$ gas mixture in N_2.

The tests for analyzer calibration error and system bias require high-, mid-, and low-level gases.

7.2 Interference Check. What reagents do I need for the interference check? Potential interferences may vary among available analyzers. Table 7E–3 of Method 7E lists a number of gases that should be considered in conducting the interference test.

8.0 Sample Collection, Preservation, Storage, and Transport

8.1 Sampling Site and Sampling Points. You must follow the procedures of Section 8.1 of Method 7E to determine the appropriate sampling points, unless you are using Method 3A only to determine the stack gas molecular weight and for no other purpose. In that case, you may use single-point integrated sampling as described in Section 8.2.1 of Method 3. If the stratification test provisions in Section 8.1.2 of Method 7E are used to reduce the number of required sampling points, the alternative acceptance criterion for 3-point sampling will be ± 0.5 percent CO_2 or O_2, and the alternative acceptance criterion for single-point sampling will be ± 0.3 percent CO_2 or O_2. In that case, you may use single-point integrated sampling as described in Section 8.2.1 of Method 3.

8.2 Initial Measurement System Performance Tests. You must follow the procedures in Section 8.2 of Method 7E. If a dilution-type measurement system is used, the special considerations in Section 8.3 of Method 7E apply.

8.3 Interference Check. The O_2 or CO_2 analyzer must be documented to show that interference effects to not exceed 2.5 percent of the calibration span. The interference test in Section 8.2.7 of Method 7E is a procedure that may be used to show this. The effects of all potential interferences at the concentrations encountered during testing must be addressed and documented. This testing and documentation may be done by the instrument manufacturer.

8.4 Sample Collection. You must follow the procedures in Section 8.4 of Method 7E.

8.5 Post-Run System Bias Check and Drift Assessment. You must follow the procedures in Section 8.5 of Method 7E.

9.0 Quality Control

Follow quality control procedures in Section 9.0 of Method 7E.

10.0 Calibration and Standardization

Follow the procedures for calibration and standardization in Section 10.0 of Method 7E.

11.0 Analytical Procedures

Because sample collection and analysis are performed together (see Section 8), additional discussion of the analytical procedure is not necessary.

12.0 Calculations and Data Analysis

You must follow the applicable procedures for calculations and data analysis in Section 12.0 of Method 7E, substituting percent O_2 and percent CO_2 for ppmv of NO_X as appropriate.

13.0 Method Performance

The specifications for the applicable performance checks are the same as in Section 13.0 of Method 7E except for the alternative specifications for system bias, drift, and calibration error. In these alternative specifications, replace the term “0.5 ppmv” with the term “0.5 percent O_2” or “0.5 percent CO_2” (as applicable).

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 Alternative Procedures [Reserved]

17.0 References

17.1 “EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards” September 1997 as amended, EPA–600/R–97/121.

18.0 Tables, Diagrams, Flowcharts, and Validation Data

Refer to Section 18.0 of Method 7E.

METHOD 7E **DETERMINATION OF NITROGEN OXIDES EMISSIONS FROM STATIONARY SOURCES (INSTRUMENTAL ANALYZER PROCEDURE)**	**Revision 0** **12/11/2013**	DENOVO

1.0 Scope and Application

What is Method 7E?

Method 7E is a procedure for measuring nitrogen oxides (NO_X) in stationary source emissions using a continuous instrumental analyzer. Quality assurance and quality control requirements are included to assure that you, the tester, collect data of known quality. You must document your adherence to these specific requirements for equipment, supplies, sample collection and analysis, calculations, and data analysis. This method does not completely describe all equipment, supplies, and sampling and analytical procedures you will need but refers to other methods for some of the details. Therefore, to obtain reliable results, you should also have a thorough knowledge of these additional test methods which are found in appendix A to this part:

(a) Method 1—Sample and Velocity Traverses for Stationary Sources.
(b) Method 4—Determination of Moisture Content in Stack Gases.

1.1 Analytes. What does this method determine? This method measures the concentration of nitrogen oxides as NO_2.

Analyte	CAS No.	Sensitivity
Nitric oxide (NO)	10102–43–9	Typically <2% of Calibration Span.
Nitrogen dioxide (NO_2)	10102–44–0	

1.2 Applicability. When is this method required? The use of Method 7E may be required by specific New Source Performance Standards, Clean Air Marketing rules, State Implementation Plans, and permits where measurement of NO_X concentrations in stationary source emissions is required, either to determine compliance with an applicable emissions standard or to conduct performance testing of a continuous monitoring system (CEMS). Other regulations may also require the use of Method 7E.

1.3 Data Quality Objectives (DQO). How good must my collected data be? Method 7E is designed to provide high-quality data for determining compliance with Federal and State emission standards and for relative accuracy testing of CEMS. In these and other applications, the principal objective is to ensure the accuracy of the data at the actual emission levels encountered. To meet this objective, the use of EPA traceability protocol calibration gases and measurement system performance tests are required.

1.4 Data Quality Assessment for Low Emitters. Is performance relief granted when testing low-emission units? Yes. For low-emitting sources, there are alternative performance specifications for analyzer calibration error, system bias, drift, and response time. Also, the alternative dynamic spiking procedure in Section 16 may provide performance relief for certain low-emitting units.

2.0 Summary of Method

In this method, a sample of the effluent gas is continuously sampled and conveyed to the analyzer for measuring the concentration of NO_X. You may measure NO and NO_2 separately or simultaneously together but, for the purposes of this method, NO_X is the sum of NO and NO_2. You must meet the performance requirements of this method to validate your data.

3.0 Definitions

3.1 Analyzer Calibration Error, for non-dilution systems, means the difference between the manufacturer certified concentration of a calibration gas and the measured concentration of the same gas when it is introduced into the analyzer in direct calibration mode.

3.2 Calibration Curve means the relationship between an analyzer's response to the injection of a series of calibration gases and the actual concentrations of those gases.

3.3 Calibration Gas means the gas mixture containing NO_X at a known concentration and produced and certified in accordance with “EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,” September 1997, as amended August 25, 1999, EPA–600/R–97/121 or more recent updates. The tests for analyzer calibration error, drift, and system bias require the use of calibration gas prepared according to this protocol. If a zero gas is used for the low-level gas, it must meet the requirements under the definition for “zero air material” in 40 CFR 72.2 in place of being prepared by the traceability protocol.

3.3.1 Low-Level Gas means a calibration gas with a concentration that is less than 20 percent of the calibration span and may be a zero gas.

3.3.2 Mid-Level Gas means a calibration gas with a concentration that is 40 to 60 percent of the calibration span.

3.3.3 High-Level Gas means a calibration gas with a concentration that is equal to the calibration span.

3.4 Calibration Span means the upper limit of the analyzer's calibration that is set by the choice of high-level calibration gas. No valid run average concentration may exceed the calibration span. To the extent practicable, the measured emissions should be between 20 to 100 percent of the selected calibration span. This may not be practicable in some cases of low-concentration measurements or testing for compliance with an emission limit when emissions are substantially less than the limit. In such cases, calibration spans that are practicable to achieving the data quality objectives without being excessively high should be chosen.

3.5 Centroidal Area means the central area of the stack or duct that is no greater than 1 percent of the stack or duct cross section. This area has the same geometric shape as the stack or duct.

3.6 Converter Efficiency Gas means a calibration gas with a known NO or NO_2 concentration and of Traceability Protocol quality.

3.7 Data Recorder means the equipment that permanently records the concentrations reported by the analyzer.

3.8 Direct Calibration Mode means introducing the calibration gases directly into the analyzer (or into the assembled measurement system at a point downstream of all sample conditioning equipment) according to manufacturer's recommended calibration procedure. This mode of calibration applies to non-dilution-type measurement systems.

3.9 Drift means the difference between the pre- and post-run system bias (or system calibration error) checks at a specific calibration gas concentration level (i.e. low-, mid- or high-).

3.10 Gas Analyzer means the equipment that senses the gas being measured and generates an output proportional to its concentration.

3.11 Interference Check means the test to detect analyzer responses to compounds other than the compound of interest, usually a gas present in the measured gas stream, that is not adequately accounted for in the calibration procedure and may cause measurement bias.

3.12 Low-Concentration Analyzer means any analyzer that operates with a calibration span of 20 ppm NO_X or lower. Each analyzer model used routinely to measure low NO_X concentrations must pass a manufacturer's stability test (MST). An MST subjects the analyzer to a range of line voltages and temperatures that reflect potential field conditions to demonstrate its stability following procedures similar to those provided in 40 CFR 53.23. Ambient-level analyzers are exempt from the MST requirements of Section 16.3. A copy of this information must be included in each test report. Table 7E–5 lists the criteria to be met.

3.13 Measurement System means all of the equipment used to determine the NO_X concentration. The measurement system comprises six major subsystems: Sample acquisition, sample transport, sample conditioning, calibration gas manifold, gas analyzer, and data recorder.

3.14 Response Time means the time it takes the measurement system to respond to a change in gas concentration occurring at the sampling point when the system is operating normally at its target sample flow rate or dilution ratio.

3.15 Run means a series of gas samples taken successively from the stack or duct. A test normally consists of a specific number of runs.

3.16 System Bias means the difference between a calibration gas measured in direct calibration mode and in system calibration mode. System bias is determined before and after each run at the low- and mid- or high-concentration levels. For dilution-type systems, pre- and post-run system calibration error is measured rather than system bias.

3.17 System Calibration Error applies to dilution-type systems and means the difference between the measured concentration of low-, mid-, or high-level calibration gas and the certified concentration for each gas when introduced in system calibration mode. For dilution-type systems, a 3-point system calibration error test is conducted in lieu of the analyzer calibration error test, and 2-point system calibration error tests are conducted in lieu of system bias tests.

3.18 System Calibration Mode means introducing the calibration gases into the measurement system at the probe, upstream of the filter and all sample conditioning components.

3.19 Test refers to the series of runs required by the applicable regulation.

4.0 Interferences

Note that interferences may vary among instruments and that instrument-specific interferences must be evaluated through the interference test.

5.0 Safety

What safety measures should I consider when using this method? This method may require you to work with hazardous materials and in hazardous conditions. We encourage you to establish safety procedures before using the method. Among other precautions, you should become familiar with the safety recommendations in the gas analyzer user's manual. Occupational Safety and Health Administration (OSHA) regulations concerning cylinder and noxious gases may apply. Nitric oxide and NO_2 are toxic and dangerous gases. Nitric oxide is immediately converted to NO_2 upon reaction with air. Nitrogen dioxide is a highly poisonous and insidious gas. Inflammation of the lungs from exposure may cause only slight pain or pass unnoticed, but the resulting edema several days later may cause death. A concentration of 100 ppm is dangerous for even a short exposure, and 200 ppm may be fatal. Calibration gases must be handled with utmost care and with adequate ventilation. Emission-level exposure to these gases should be avoided.

6.0 Equipment and Supplies

The performance criteria in this method will be met or exceeded if you are properly using equipment designed for this application.

6.1 What do I need for the measurement system? You may use any equipment and supplies meeting the following specifications.

(1) Sampling system components that are not evaluated in the system bias or system calibration error test must be glass, Teflon, or stainless steel. Other materials are potentially acceptable, subject to approval by the Administrator.

(2) The interference, calibration error, and system bias criteria must be met.

(3) Sample flow rate must be maintained within 10 percent of the flow rate at which the system response time was measured.

(4) All system components (excluding sample conditioning components, if used) must maintain the sample temperature above the moisture dew point.

Section 6.2 provides example equipment specifications for a NO_X measurement system. Figure 7E–1 is a diagram of an example dry basis measurement system that is likely to meet the method requirements and is provided as guidance. For wet-basis systems, you may use alternative equipment and supplies as needed (some of which are described in Section 6.2), provided that the measurement system meets the applicable performance specifications of this method.

6.2 Measurement System Components

6.2.1 Sample Probe. Glass, stainless steel, or other approved material, of sufficient length to traverse the sample points.

6.2.2 Particulate Filter. An in-stack or out-of-stack filter. The filter must be made of material that is non-reactive to the gas being sampled. The filter media for out-of-stack filters must be included in the system bias test. The particulate filter requirement may be waived in applications where no significant particulate matter is expected (e.g., for emission testing of a combustion turbine firing natural gas).

6.2.3 Sample Line. The sample line from the probe to the conditioning system/sample pump should be made of Teflon or other material that does not absorb or otherwise alter the sample gas. For a dry-basis measurement system (as shown in Figure 7E–1), the temperature of the sample line must be maintained at a sufficiently high level to prevent condensation before the sample conditioning components. For wet-basis measurement systems, the temperature of the sample line must be maintained at a sufficiently high level to prevent condensation before the analyzer.

6.2.4 Conditioning Equipment. For dry basis measurements, a condenser, dryer or other suitable device is required to remove moisture continuously from the sample gas. Any equipment needed to heat the probe or sample line to avoid condensation prior to the sample conditioning component is also required.

For wet basis systems, you must keep the sample above its dew point either by: (1) Heating the sample line and all sample transport components up to the inlet of the analyzer (and, for hot-wet extractive systems, also heating the analyzer) or (2) by diluting the sample prior to analysis using a dilution probe system. The components required to do either of the above are considered to be conditioning equipment.

6.2.5 Sampling Pump. For systems similar to the one shown in Figure 7E–1, a leak-free pump is needed to pull the sample gas through the system at a flow rate sufficient to minimize the response time of the measurement system. The pump may be constructed of any material that is non-reactive to the gas being sampled. For dilution-type measurement systems, an ejector pump (eductor) is used to create a vacuum that draws the sample through a critical orifice at a constant rate.

6.2.6 Calibration Gas Manifold. Prepare a system to allow the introduction of calibration gases either directly to the gas analyzer in direct calibration mode or into the measurement system, at the probe, in system calibration mode, or both, depending upon the type of system used. In system calibration mode, the system should be able to flood the sampling probe and vent excess gas. Alternatively, calibration gases may be introduced at the calibration valve following the probe. Maintain a constant pressure in the gas manifold. For in-stack dilution-type systems, a gas dilution subsystem is required to transport large volumes of purified air to the sample probe and a probe controller is needed to maintain the proper dilution ratio.

6.2.7 Sample Gas Manifold. For the type of system shown in Figure 7E–1, the sample gas manifold diverts a portion of the sample to the analyzer, delivering the remainder to the by-pass discharge vent. The manifold should also be able to introduce calibration gases directly to the analyzer (except for dilution-type systems). The manifold must be made of material that is non-reactive to the gas sampled or the calibration gas and be configured to safely discharge the bypass gas.

6.2.8 NO_X Analyzer. An instrument that continuously measures NO_X in the gas stream and meets the applicable specifications in Section 13.0. An analyzer that operates on the principle of chemiluminescence with an NO_2 to NO converter is one example of an analyzer that has been used successfully in the past. Analyzers operating on other principles may also be used provided the performance criteria in Section 13.0 are met.

6.2.8.1 Dual Range Analyzers. For certain applications, a wide range of gas concentrations may be encountered, necessitating the use of two measurement ranges. Dual-range analyzers are readily available for these applications. These analyzers are often equipped with automated range-switching capability, so that when readings exceed the full-scale of the low measurement range, they are recorded on the high range. As an alternative to using a dual-range analyzer, you may use two segments of a single, large measurement scale to serve as the low and high ranges. In all cases, when two ranges are used, you must quality-assure both ranges using the proper sets of calibration gases. You must also meet the interference, calibration error, system bias, and drift checks. However, we caution that when you use two segments of a large measurement scale for dual range purposes, it may be difficult to meet the performance specifications on the low range due to signal=to-noise ratio considerations.

6.2.8.2 Low Concentration Analyzer. When an analyzer is routinely calibrated with a calibration span of 20 ppmv or less, the manufacturer's stability test (MST) is required. See Table 7E–5 for test parameters.

6.2.9 Data Recording. A strip chart recorder, computerized data acquisition system, digital recorder, or data logger for recording measurement data may be used.

7.0 Reagents and Standards

7.1 Calibration Gas. What calibration gases do I need? Your calibration gas must be NO in N_2 and certified (or recertified) within an uncertainty of 2.0 percent in accordance with “EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards” September 1997, as amended August 25, 1999, EPA–600/R–97/121. Blended gases meeting the Traceability Protocol are allowed if the additional gas components are shown not to interfere with the analysis. If a zero gas is used for the low-level gas, it must meet the requirements under the definition for “zero air material” in 40 CFR 72.2. The calibration gas must not be used after its expiration date. Except for applications under part 75 of this chapter, it is acceptable to prepare calibration gas mixtures from EPA Traceability Protocol gases in accordance with Method 205 in appendix M to part 51 of this chapter. For part 75 applications, the use of Method 205 is subject to the approval of the Administrator. The goal and recommendation for selecting calibration gases is to bracket the sample concentrations. The following calibration gas concentrations are required:

7.1.1 High-Level Gas. This concentration sets the calibration span and results in measurements being 20 to 100 percent of the calibration span.

7.1.2 Mid-Level Gas. 40 to 60 percent of the calibration span.

7.1.3 Low-Level Gas. Less than 20 percent of the calibration span.

7.1.4 Converter Efficiency Gas. What reagents do I need for the converter efficiency test? The converter efficiency gas is a manufacturer-certified gas with a concentration sufficient to show NO_2 conversion at the concentrations encountered in the source. A test gas concentration in the 40 to 60 ppm range is suggested, but other concentrations may be more appropriate to specific sources. For the test described in Section 8.2.4.1, NO_2 is required. For the alternative converter efficiency tests in Section 16.2, NO is required.

7.2 Interference Check. What reagents do I need for the interference check? Use the appropriate test gases listed in Table 7E–3 or others not listed that can potentially interfere (as indicated by the test facility type, instrument manufacturer, etc.) to conduct the interference check. These gases should be manufacturer certified but do not have to be prepared by the EPA traceability protocol.

8.0 Sample Collection, Preservation, Storage, and Transport

Emission Test Procedure

Since you are allowed to choose different options to comply with some of the performance criteria, it is your responsibility to identify the specific options you have chosen, to document that the performance criteria for that option have been met, and to identify any deviations from the method.

8.1 What sampling site and sampling points do I select?

8.1.1 Unless otherwise specified in an applicable regulation or by the Administrator, when this method is used to determine compliance with an emission standard, conduct a stratification test as described in Section 8.1.2 to determine the sampling traverse points to be used. For performance testing of continuous emission monitoring systems, follow the sampling site selection and traverse point layout procedures described in the appropriate performance specification or applicable regulation (e.g., Performance Specification 2 in appendix B to this part).

8.1.2 Determination of Stratification. Perform a stratification test at each test site to determine the appropriate number of sample traverse points. If testing for multiple pollutants or diluents at the same site, a stratification test using only one pollutant or diluent satisfies this requirement. A stratification test is not required for small stacks that are less than 4 inches in diameter. To test for stratification, use a probe of appropriate length to measure the NO_X (or pollutant of interest) c.oncentration at twelve traverse points located according to Table 1–1 or Table 1–2 of Method 1. Alternatively, you may measure at three points on a line passing through the centroidal area. Space the three points at 16.7, 50.0, and 83.3 percent of the measurement line. Sample for a minimum of twice the system response time (see Section 8.2.6) at each traverse point. Calculate the individual point and mean NO_X concentrations. If the concentration at each traverse point differs from the mean concentration for all traverse points by no more than: (a) ±5.0 percent of the mean concentration; or (b) ±0.5 ppm (whichever is less restrictive), the gas stream is considered unstratified and you may collect samples from a single point that most closely matches the mean. If the 5.0 percent or 0.5 ppm criterion is not met, but the concentration at each traverse point differs from the mean concentration for all traverse points by no more than: (a) ±10.0 percent of the mean; or (b) ±1.0 ppm (whichever is less restrictive), the gas stream is considered to be minimally stratified, and you may take samples from three points. Space the three points at 16.7, 50.0, and 83.3 percent of the measurement line. Alternatively, if a twelve-point stratification test was performed and the emissions were shown to be minimally stratified (all points within ±10.0 percent of their mean or within ±1.0 ppm), and if the stack diameter (or equivalent diameter, for a rectangular stack or duct) is greater than 2.4 meters (7.8 ft), then you may use 3-point sampling and locate the three points along the measurement line exhibiting the highest average concentration during the stratification test, at 0.4, 1.0 and 2.0 meters from the stack or duct wall. If the gas stream is found to be stratified because the 10.0 percent or 1.0 ppm criterion for a 3-point test is not met, locate twelve traverse points for the test in accordance with Table 1–1 or Table 1–2 of Method 1.

8.2 Initial Measurement System Performance Tests. What initial performance criteria must my system meet before I begin collecting samples? Before measuring emissions, perform the following procedures:

(a) Calibration gas verification,
(b) Measurement system preparation,
(c) Calibration error test,
(d) NO_2 to NO conversion efficiency test, if applicable,
(e) System bias check,
(f) System response time test, and
(g) Interference check

8.2.1 Calibration Gas Verification. How must I verify the concentrations of my calibration gases? Obtain a certificate from the gas manufacturer documenting the quality of the gas. Confirm that the manufacturer certification is complete and current. Ensure that your calibration gas certifications have not expired. This documentation should be available on-site for inspection. To the extent practicable, select a high-level gas concentration that will result in the measured emissions being between 20 and 100 percent of the calibration span.

8.2.2 Measurement System Preparation. How do I prepare my measurement system? Assemble, prepare, and precondition the measurement system according to your standard operating procedure. Adjust the system to achieve the correct sampling rate or dilution ratio (as applicable).

8.2.3 Calibration Error Test. How do I confirm my analyzer calibration is correct? After you have assembled, prepared and calibrated your sampling system and analyzer, you must conduct a 3-point analyzer calibration error test (or a 3-point system calibration error test for dilution systems) before the first run and again after any failed system bias test (or 2-point system calibration error test for dilution systems) or failed drift test. Introduce the low-, mid-, and high-level calibration gases sequentially. For non-dilution-type measurement systems, introduce the gases in direct calibration mode. For dilution-type measurement systems, introduce the gases in system calibration mode.

(1) For non-dilution systems, you may adjust the system to maintain the correct flow rate at the analyzer during the test, but you may not make adjustments for any other purpose. For dilution systems, you must operate the measurement system at the appropriate dilution ratio during all system calibration error checks, and may make only the adjustments necessary to maintain the proper ratio.

(2) Record the analyzer's response to each calibration gas on a form similar to Table 7E–1. For each calibration gas, calculate the analyzer calibration error using Equation 7E– 1 in Section 12.2 or the system calibration error using Equation 7E–3 in Section 12.4 (as applicable). The calibration error specification in Section 13.1 must be met for the low-

, mid-, and high-level gases. If the calibration error specification is not met, take corrective action and repeat the test until an acceptable 3-point calibration is achieved.

8.2.4 NO_2 to NO Conversion Efficiency Test. Before or after each field test, you must conduct an NO_2 to NO conversion efficiency test if your system converts NO_2 to NO before analyzing for NO_X. You may risk testing multiple facilities before performing this test provided you pass this test at the conclusion of the final facility test. A failed final conversion efficiency test in this case will invalidate all tests performed subsequent to the test in which the converter efficiency test was passed. Follow the procedures in Section 8.2.4.1, or 8.2.4.2. If desired, the converter efficiency factor derived from this test may be used to correct the test results for converter efficiency if the NO_2 fraction in the measured test gas is known. Use Equation 7E–8 in Section 12.8 for this correction.

8.2.4.1 Introduce NO_2 converter efficiency gas to the analyzer in direct calibration mode and record the NO_X concentration displayed by the analyzer. Calculate the converter efficiency using Equation 7E–7 in Section 12.7. The specification for converter efficiency in Section 13.5 must be met. The user is cautioned that state-of-the-art NO_2 calibration gases may have limited shelf lives, and this could affect the ability to pass the 90-percent conversion efficiency requirement.

8.2.4.2 Alternatively, either of the procedures for determining conversion efficiency using NO in Section 16.2 may be used.

8.2.5 Initial System Bias and System Calibration Error Checks. Before sampling begins, determine whether the high-level or mid-level calibration gas best approximates the emissions and use it as the upscale gas. Introduce the upscale gas at the probe upstream of all sample conditioning components in system calibration mode. Record the time it takes for the measured concentration to increase to a value that is within 95 percent or 0.5 ppm (whichever is less restrictive) of the certified gas concentration. Continue to observe the gas concentration reading until it has reached a final, stable value. Record this value on a form similar to Table 7E–2.

(1) Next, introduce the low-level gas in system calibration mode and record the time required for the concentration response to decrease to a value that is within 5.0 percent or 0.5 ppm (whichever is less restrictive) of the certified low-range gas concentration. If the low-level gas is a zero gas, use the procedures described above and observe the change in concentration until the response is 0.5 ppm or 5.0 percent of the upscale gas concentration (whichever is less restrictive).

(2) Continue to observe the low-level gas reading until it has reached a final, stable value and record the result on a form similar to Table 7E–2. Operate the measurement system at the normal sampling rate during all system bias checks. Make only the adjustments necessary to achieve proper calibration gas flow rates at the analyzer.

(3) From these data, calculate the measurement system response time (see Section 8.2.6) and then calculate the initial system bias using Equation 7E–2 in Section 12.3. For dilution systems, calculate the system calibration error in lieu of system bias using

equation 7E–3 in Section 12.4. See Section 13.2 for acceptable performance criteria for system bias and system calibration error. If the initial system bias (or system calibration error) specification is not met, take corrective action. Then, you must repeat the applicable calibration error test from Section 8.2.3 and the initial system bias (or 2-point system calibration error) check until acceptable results are achieved, after which you may begin sampling.

(Note: For dilution-type systems, data from the 3-point system calibration error test described in Section 8.2.3 may be used to meet the initial 2-point system calibration error test requirement of this section, if the calibration gases were injected as described in this section, and if response time data were recorded).

8.2.6 Measurement System Response Time. As described in section 8.2.5, you must determine the measurement system response time during the initial system bias (or 2-point system calibration error) check. Observe the times required to achieve 95 percent of a stable response for both the low-level and upscale gases. The longer interval is the response time.

8.2.7 Interference Check. Conduct an interference response test of the gas analyzer prior to its initial use in the field. If you have multiple analyzers of the same make and model, you need only perform this alternative interference check on one analyzer. You may also meet the interference check requirement if the instrument manufacturer performs this or similar check on the same make and model of analyzer that you use and provides you with documented results.

(1) You may introduce the appropriate interference test gases (that are potentially encountered during a test, see examples in Table 7E–3) into the analyzer separately or as mixtures. Test the analyzer with the interference gas alone at the highest concentration expected at a test source and again with the interference gas and NO_X at a representative NO_X test concentration. For analyzers measuring NO_X greater than 20 ppm, use a calibration gas with an NO_X concentration of 80 to 100 ppm and set this concentration equal to the calibration span. For analyzers measuring less than 20 ppm NO_X, select an NO concentration for the calibration span that reflects the emission levels at the sources to be tested, and perform the interference check at that level. Measure the total interference response of the analyzer to these gases in ppmv. Record the responses and determine the interference using Table 7E–4. The specification in Section 13.4 must be met.

(2) A copy of this data, including the date completed and signed certification, must be available for inspection at the test site and included with each test report. This interference test is valid for the life of the instrument unless major analytical components (e.g., the detector) are replaced with different model parts. If major components are replaced with different model parts, the interference gas check must be repeated before returning the analyzer to service. If major components are replaced, the interference gas check must be repeated before returning the analyzer to service.

The tester must ensure that any specific technology, equipment, or procedures that are intended to remove interference effects are operating properly during testing.

8.3 Dilution-Type Systems—Special Considerations. When a dilution-type measurement system is used, there are three important considerations that must be taken into account to ensure the quality of the emissions data. First, the critical orifice size and dilution ratio must be selected properly so that the sample dew point will be below the sample line and analyzer temperatures. Second, a high-quality, accurate probe controller must be used to maintain the dilution ratio during the test. The probe controller should be capable of monitoring the dilution air pressure, eductor vacuum, and sample flow rates. Third, differences between the molecular weight of calibration gas mixtures and the stack gas molecular weight must be addressed because these can affect the dilution ratio and introduce measurement bias.

8.4 Sample Collection.

(1) Position the probe at the first sampling point. Purge the system for at least two times the response time before recording any data. Then, traverse all required sampling points, sampling at each point for an equal length of time and maintaining the appropriate sample flow rate or dilution ratio (as applicable). You must record at least one valid data point per minute during the test run.

(2) Each time the probe is removed from the stack and replaced, you must recondition the sampling system for at least two times the system response time prior to your next recording. If the average of any run exceeds the calibration span value, that run is invalid.

(3) You may satisfy the multipoint traverse requirement by sampling sequentially using a single-hole probe or a multi-hole probe designed to sample at the prescribed points with a flow within 10 percent of mean flow rate. Notwithstanding, for applications under part 75 of this chapter, the use of multi-hole probes is subject to the approval of the Administrator.

8.5 Post-Run System Bias Check and Drift Assessment.

How do I confirm that each sample I collect is valid? After each run, repeat the system bias check or 2-point system calibration error check (for dilution systems) to validate the run. Do not make adjustments to the measurement system (other than to maintain the target sampling rate or dilution ratio) between the end of the run and the completion of the post-run system bias or system calibration error check. Note that for all post-run system bias or 2-point system calibration error checks, you may inject the low-level gas first and the upscale gas last, or vice-versa. You may risk sampling for multiple runs before performing the post-run bias or system calibration error check provided you pass this test at the conclusion of the group of runs. A failed final test in this case will invalidate all runs subsequent to the last passed test.

(1) If you do not pass the post-run system bias (or system calibration error) check, then the run is invalid. You must diagnose and fix the problem and pass another calibration error test (Section 8.2.3) and system bias (or 2-point system calibration error) check (Section 8.2.5) before repeating the run. Record the system bias (or system calibration error) results on a form similar to Table 7E–2.

(2) After each run, calculate the low-level and upscale drift, using Equation 7E–4 in Section 12.5. If the post-run low- and upscale bias (or 2-point system calibration error) checks are passed, but the low-or upscale drift exceeds the specification in Section 13.3, the run data are valid, but a 3-point calibration error test and a system bias (or 2-point system calibration error) check must be performed and passed before any more test runs are done.

(3) For dilution systems, data from a 3-point system calibration error test may be used to meet the pre-run 2-point system calibration error requirement for the first run in a test sequence. Also, the post-run bias (or 2-point calibration error) check data may be used as the pre-run data for the next run in the test sequence at the discretion of the tester.

8.6 Alternative Interference and System Bias Checks (Dynamic Spike Procedure). If I want to use the dynamic spike procedure to validate my data, what procedure should I follow? Except for applications under part 75 of this chapter, you may use the dynamic spiking procedure and requirements provided in Section 16.1 during each test as an alternative to the interference check and the pre- and post-run system bias checks. The calibration error test is still required under this option. Use of the dynamic spiking procedure for Part 75 applications is subject to the approval of the Administrator.

8.7 Moisture correction. You must determine the moisture content of the flue gas and correct the measured gas concentrations to a dry basis using Method 4 or other appropriate methods, subject to the approval of the Administrator, when the moisture basis (wet or dry) of the measurements made with this method is different from the moisture basis of either: (1) the applicable emissions limit; or (2) the CEMS being evaluated for relative accuracy. Moisture correction is also required if the applicable limit is in lb/mm Btu and the moisture basis of the Method 7E NO_X analyzer is different from the moisture basis of the Method 3A diluent gas (CO_2 or O_2) analyzer.

9.0 Quality Control

What quality control measures must I take?

The following table is a summary of the mandatory, suggested, and alternative quality assurance and quality control measures and the associated frequency and acceptance criteria. All of the QC data, along with the sample run data, must be documented and included in the test report.

Summary Table of QA/QC

Status	Process or element	QA/QC specification	Acceptance criteria	Checking frequency
S	Identify Data User		Regulatory Agency or other primary end user of data	Before designing test.
S	Analyzer Design	Analyzer resolution or sensitivity	< 2.0% of full-scale range	Manufacturer design.
M		Interference gas check	Sum of responses ≤ 2.5% of calibration span Alternatively, sum of responses:	

Status	Process or element	QA/QC specification	Acceptance criteria	Checking frequency
			≤ 0.5 ppmv for calibration spans of 5 to 10 ppmv	
			≤ 0.2 ppmv for calibration spans < 5 ppmv	
			See Table 7E-3	
M	Calibration Gases	Traceability protocol (G1, G2)	Valid certificate required Uncertainty ≤ 2.0% of tag value	
M		High-level gas	Equal to the calibration span	Each test.
M		Mid-level gas	40 to 60% of calibration span	Each test.
M		Low-level gas	< 20% of calibration span	Each test.
S	Data Recorder Design	Data resolution	≤ 0.5% of full-scale range	Manufacturer design.
S	Sample Extraction	Probe material	SS or quartz if stack > 500 °F	East test.
M	Sample Extraction	Probe, filter and sample line temperature	For dry-basis analyzers, keep sample above the dew point by heating, prior to sample conditioning	Each run.
			For wet-basis analyzers, keep sample above dew point at all times, by heating or dilution	
S	Sample Extraction	Calibration valve material	SS	Each test.
S	Sample Extraction	Sample pump material	Inert to sample constituents	Each test.
S	Sample Extraction	Manifolding material	Inert to sample constituents	Each test.
S	Moisture Removal	Equipment efficiency	< 5% target compound removal	Verified through system bias check.
S	Particulate Removal	Filter inertness	Pass system bias check	Each bias check.
M	Analyzer & Calibration Gas Performance	Analyzer calibration error (of 3-point system calibration error for dilution systems)	Within ±2.0 percent of the calibration span of the analyzer for the low-, mid-, and high-level calibration gases	Before initial run and after a failed system bias test or drift test.
			Alternative specification: ≤ 0.5 ppmv absolute difference	
M	System Performance	System bias (or pre- and post-run 2-point system calibration error for dilution (Systems)	Within ±5.0% of the analyzer calibration span for low-scale and upscale calibration gases	Before and after each run.

Status	Process or element	QA/QC specification	Acceptance criteria	Checking frequency
			Alternative specification: ≤ 0.5 ppmv absolute difference	
M	System Performance	System response time	Determines minimum sampling time per point	During initial sampling system bias test.
M	System Performance	Drift	≤ 3.0% of calibration span for low-level and mid- or high-level gases	After each test run.
			Alternative specification: ≤ 0.5 ppmv absolute difference	
M	System Performance	NO_2-NO conversion efficiency	≥ 90% of certified test gas concentration	Before or after each test.
M	System Performance	Purge time	≥ 2 times system response time	Before starting the first run and when probe is removed from and re-inserted into the stack.
M	System Performance	Minimum sample time at each point	Two times the system response time	Each sample point.
M	System Performance	Stable sample flow rate (surrogate for maintaining system response time)	Within 10% of flow rate established during system response time check	Each run.
M	Sample Point Selection	Stratification test	All points within:	Prior to first run.
			±5% of mean for 1-point sampling	
			±10% of mean for 3-point	
			Alternatively, all points within:	
			±0.5 ppm of mean for 1-point sampling	
			±1.0 ppm of mean for 3-point sampling	
A	Multiple sample points simultaneously	No. of openings in probe	Multi-hole probe with verifiable constant flow through all holes within 10% of mean flow rate (requires Administrative approval for Part 75)	Each run.
M	Data Recording	Frequency	≤ 1 minute average	During run.
S	Data Parameters	Sample concentration range	All 1-minute averages within calibration span	Each run.

Status	Process or element	QA/QC specification	Acceptance criteria	Checking frequency
M	Date Parameters	Average concentration for the run	Run average ≤ calibration span	Each run.

S = Suggest.

M = Mandatory.

A = Alternative.

Agency.

10.0 Calibration and Standardization

What measurement system calibrations are required?

(1) The initial 3-point calibration error test as described in Section 8.2.3 and the system bias (or system calibration error) checks described in Section 8.2.5 are required and must meet the specifications in Section 13 before you start the test. Make all necessary adjustments to calibrate the gas analyzer and data recorder. Then, after the test commences, the system bias or system calibration error checks described in Section 8.5 are required before and after each run. Your analyzer must be calibrated for all species of NO_X that it detects. Analyzers that measure NO and NO_2 separately without using a converter must be calibrated with both NO and NO_2.

(2) You must include a copy of the manufacturer's certification of the calibration gases used in the testing as part of the test report. This certification must include the 13 documentation requirements in the EPA Traceability Protocol For Assay and Certification of Gaseous Calibration Standards, September 1997, as amended August 25, 1999. When Method 205 is used to produce diluted calibration gases, you must document that the specifications for the gas dilution system are met for the test. You must also include the date of the most recent dilution system calibration against flow standards and the name of the person or manufacturer who carried out the calibration in the test report.

11.0 Analytical Procedures

Because sample collection and analysis are performed together (see Section 8), additional discussion of the analytical procedure is not necessary.

12.0 Calculations and Data Analysis

You must follow the procedures for calculations and data analysis listed in this section.

12.1 Nomenclature. The terms used in the equations are defined as follows:

ACE = Analyzer calibration error, percent of calibration span.

B_{WS} = Moisture content of sample gas as measured by Method 4 or other approved method, percent/100.

C_{Avg} = Average unadjusted gas concentration indicated by data recorder for the test run, ppmv.

C_D = Pollutant concentration adjusted to dry conditions, ppmv.

C_{Dir} = Measured concentration of a calibration gas (low, mid, or high) when introduced in direct calibration mode, ppmv.

C_{Gas} = Average effluent gas concentration adjusted for bias, ppmv.

C_M = Average of initial and final system calibration bias (or 2-point system calibration error) check responses for the upscale calibration gas, ppmv.

C_{MA} = Actual concentration of the upscale calibration gas, ppmv.

C_{Native} = NO_X concentration in the stack gas as calculated in Section 12.6, ppmv.

C_O = Average of the initial and final system calibration bias (or 2-point system calibration error) check responses from the low-level (or zero) calibration gas, ppmv.

C_{OA} = Actual concentration of the low-level calibration gas, ppmv.

C_S = Measured concentration of a calibration gas (low, mid, or high) when introduced in system calibration mode, ppmv.

C_{SS} = Concentration of NO_X measured in the spiked sample, ppmv.

C_{Spike} = Concentration of NO_X in the undiluted spike gas, ppmv.

C_{Calc} = Calculated concentration of NO_X in the spike gas diluted in the sample, ppmv.

C_V = Manufacturer certified concentration of a calibration gas (low, mid, or high), ppmv.

C_W = Pollutant concentration measured under moist sample conditions, wet basis, ppmv.

CS = Calibration span, ppmv.

D = Drift assessment, percent of calibration span.

DF = Dilution system dilution factor or spike gas dilution factor, dimensionless.

Eff_{NO2} = $NO_2$to NO converter efficiency, percent.

NO_{XCorr} = The NO_X concentration corrected for the converter efficiency, ppmv.

NO_{XFinal} = The final NO_X concentration observed during the converter efficiency test in Section 16.2.2, ppmv.

NO_{XPeak} = The highest NO_X concentration observed during the converter efficiency test in Section 16.2.2, ppmv.

Q_{Spike} = Flow rate of spike gas introduced in system calibration mode, L/min.

Q_{Total} = Total sample flow rate during the spike test, L/min.

R = Spike recovery, percent.

SB = System bias, percent of calibration span.

SB_i = Pre-run system bias, percent of calibration span.

SB_{final} = Post-run system bias, percent of calibration span.

SCE = System calibration error, percent of calibration span.

SCE_i = Pre-run system calibration error, percent of calibration span.

SCE_{Final} = Post-run system calibration error, percent of calibration span.

12.2 Analyzer Calibration Error. For non-dilution systems, use Equation 7E–1 to calculate the analyzer calibration error for the low-, mid-, and high-level calibration gases.

$$ACE = \frac{C_{Dir} - C_V}{CS} \times 100 \quad Eq. 7E - 1$$

12.3 System Bias. For non-dilution systems, use Equation 7E–2 to calculate the system bias separately for the low-level and upscale calibration gases.

$$SB = \frac{C_S - C_{Dir}}{CS} \times 100 \quad Eq. 7E - 2$$

12.4 System Calibration Error. Use Equation 7E–3 to calculate the system calibration error for dilution systems. Equation 7E–3 applies to both the initial 3-point system calibration error test and the subsequent 2-point calibration error checks between test runs. In this equation, the term "C_s" refers to the diluted calibration gas concentration measured by the analyzer.

$$SCE = \frac{(C_S \times DF) - C_V}{CS} \times 100 \quad Eq.7E-3$$

12.5 Drift Assessment. Use Equation 7E–4 to separately calculate the low-level and upscale drift over each test run. For dilution systems, replace "SB_{final}" and "SB_i" with "SCE_{Final}" and "SCE_i", respectively, to calculate and evaluate drift.

$$D = \left|SB_{final} - SB_i\right| \quad Eq.7E-4$$

12.6 Effluent Gas Concentration. For each test run, calculate C_{Avg}, the arithmetic average of all valid NO_X concentration values (e.g., 1-minute averages). Then adjust the value of C_{Avg} for bias using Equation 7E–5a if you use a non-zero gas as your low-level calibration gas, or Equation 7E–5b if you use a zero gas as your low-level calibration gas.

$$C_{Gas} = (C_{Avg} - C_M)\frac{C_{MA} - C_{OA}}{C_M - C_O} + C_{MA} \quad Eq.7E-5a$$

$$C_{Gas} = (C_{Avg} - C_O)\frac{C_{MA}}{C_M - C_O} \quad Eq.7E-5b$$

12.7 NO_2—NO Conversion Efficiency. If the NO_X converter efficiency test described in Section 8.2.4.1 is performed, calculate the efficiency using Equation 7E–7.

$$Eff_{NO2} = \frac{C_{Dir}}{C_V} \times 100 \quad Eq.7E-7$$

12.8 NO_2—NO Conversion Efficiency Correction. If desired, calculate the total NO_X concentration with a correction for converter efficiency using Equation 7E–8.

$$NO_{XCorr} = NO + \frac{NO_X - NO}{Eff_{NO2}} \times 100 \quad Eq.7E-8$$

12.9 Alternative NO_2 Converter Efficiency. If the alternative procedure of Section 16.2.2 is used, determine the NO_X concentration decrease from NO_{XPeak} after the minimum 30-minute test interval using Equation 7E–9. This decrease from NO_{XPeak} must meet the requirement in Section 13.5 for the converter to be acceptable.

$$\%Decrease = \frac{NO_{XPeak} - NO_{XFinal}}{NO_{XPeak}} \times 100 \quad Eq.7E-9$$

12.10 Moisture Correction. Use Equation 7E–10 if your measurements need to be corrected to a dry basis.

$$C_D = \frac{C_W}{1 - B_{WS}} \quad Eq.7E-10$$

12.11 Calculated Spike Gas Concentration and Spike Recovery for the Example Alternative Dynamic Spiking Procedure in Section 16.1.3. Use Equation 7E–11 to determine the calculated spike gas concentration. Use Equation 7E–12 to calculate the spike recovery.

$$C_{Calc} = \frac{C_{Spike}Q_{Spike}}{Q_{Total}} \quad Eq. 7E-11$$

$$R = \frac{DF(C_{SS} - C_{Native}) + C_{Native}}{C_{Spike}} \times 100 \quad Eq. 7E-12$$

13.0 Method Performance

13.1 Calibration Error. This specification is applicable to both the analyzer calibration error and the 3-point system calibration error tests described in Section 8.2.3. At each calibration gas level (low, mid, and high) the calibration error must either be within ± 2.0 percent of the calibration span. Alternatively, the results are acceptable if $|C_{dir} - C_v|$ or $|C_s - C_v|$ (as applicable) is ≤0.5 ppmv.

13.2 System Bias. This specification is applicable to both the system bias and 2-point system calibration error tests described in Section 8.2.5 and 8.5. The pre- and post-run system bias (or system calibration error) must be within ± 5.0 percent of the calibration span for the low-level and upscale calibration gases. Alternatively, the results are acceptable if $|C_s - C_{dir}|$ is ≤ 0.5 ppmv or if $|C_s - C_v|$ is ≤ 0.5 ppmv (as applicable).

13.3 Drift. For each run, the low-level and upscale drift must be less than or equal to 3.0 percent of the calibration span. The drift is also acceptable if the pre- and post-run bias (or the pre- and post-run system calibration error) responses do not differ by more than 0.5 ppmv at each gas concentration (i.e. $|C_{s\ post\text{-}run} - C_{s\ pre\text{-}run}| \leq 0.5$ ppmv).

13.4 Interference Check. The total interference response (i.e., the sum of the interference responses of all tested gaseous components) must not be greater than 2.50 percent of the calibration span for the analyzer tested. In summing the interferences, use the larger of the absolute values obtained for the interferent tested with and without the pollutant present. The results are also acceptable if the sum of the responses does not exceed 0.5 ppmv for a calibration span of 5 to 10 ppmv, or 0.2 ppmv for a calibration span < 5 ppmv.

13.5 NO_2 to NO Conversion Efficiency Test (as applicable). The NO_2 to NO conversion efficiency, calculated according to Equation 7E–7, must be greater than or equal to 90 percent. The alternative conversion efficiency check, described in Section 16.2.2 and calculated according to Equation 7E–9, must not result in a decrease from NO_{XPeak} by more than 2.0 percent.

13.6 Alternative Dynamic Spike Procedure. Recoveries of both pre-test spikes and post-test spikes must be within 100 ± 10 percent. If the absolute difference between the calculated spike value and measured spike value is equal to or less than 0.20 ppmv, then the requirements of the ADSC are met.

14.0 Pollution Prevention [Reserved]

15.0 Waste Management [Reserved]

16.0 Alternative Procedures

16.1 Dynamic Spike Procedure. Except for applications under part 75 of this chapter, you may use a dynamic spiking procedure to validate your test data for a specific test matrix in place of the interference check and pre- and post-run system bias checks. For part 75 applications, use of this procedure is subject to the approval of the Administrator. Best results are obtained for this procedure when source emissions are steady and not varying. Fluctuating emissions may render this alternative procedure difficult to pass. To use this alternative, you must meet the following requirements.

16.1.1 Procedure Documentation. You must detail the procedure you followed in the test report, including how the spike was measured, added, verified during the run, and calculated after the test.

16.1.2 Spiking Procedure Requirements. The spikes must be prepared from EPA Traceability Protocol gases. Your procedure must be designed to spike field samples at two target levels both before and after the test. Your target spike levels should bracket the average sample NO_X concentrations. The higher target concentration must be less than the calibration span. You must collect at least 5 data points for each target concentration. The spiking procedure must be performed before the first run and repeated after the last run of the test program.

16.1.3 Example Spiking Procedure. Determine the NO concentration needed to generate concentrations that are 50 and 150 percent of the anticipated NO_X concentration in the stack at the total sampling flow rate while keeping the spike flow rate at or below 10 percent of this total. Use a mass flow meter (accurate within 2.0 percent) to generate these NO spike gas concentrations at a constant flow rate. Use Equation 7E–11 in Section 12.11 to determine the calculated spike concentration in the collected sample.

(1) Prepare the measurement system and conduct the analyzer calibration error test as described in Sections 8.2.2 and 8.2.3. Following the sampling procedures in Section 8.1, determine the stack NO_X concentration and use this concentration as the average stack concentration (C_{avg}) for the first spike level, or if desired, for both pre-test spike levels. Introduce the first level spike gas into the system in system calibration mode and begin sample collection. Wait for at least two times the system response time before measuring the spiked sample concentration. Then record at least five successive 1-minute averages of the spiked sample gas. Monitor the spike gas flow rate and maintain at the determined addition rate. Average the five 1-minute averages and determine the spike recovery using Equation 7E–12. Repeat this procedure for the other pre-test spike level. The recovery at each level must be within the limits in Section 13.6 before proceeding with the test.

(2) Conduct the number of runs required for the test. Then repeat the above procedure for the post-test spike evaluation. The last run of the test may serve as the average stack concentration for the post-test spike test calculations. The results of the post-test spikes must meet the limits in Section 13.6.

16.2 Alternative NO_2 to NO Conversion Efficiency Procedures. You may use either of the following procedures to determine converter efficiency in place of the procedure in Section 8.2.4.1.

16.2.1 The procedure for determining conversion efficiency using NO in 40 CFR 86.123–78.

16.2.2 Tedlar Bag Procedure. Perform the analyzer calibration error test to document the calibration (both NO and NO_X modes, as applicable). Fill a Tedlar bag approximately half full with either ambient air, pure oxygen, or an oxygen standard gas with at least 19.5 percent by volume oxygen content. Fill the remainder of the bag with mid- to high-level NO in N_2 (or other appropriate concentration) calibration gas. (Note that the concentration of the NO standard should be sufficiently high enough for the diluted concentration to be easily and accurately measured on the scale used. The size of the bag should be large enough to accommodate the procedure and time required.)

(1) Immediately attach the bag to the inlet of the NO_X analyzer (or external converter if used). In the case of a dilution-system, introduce the gas at a point upstream of the dilution assembly. Measure the NO_X concentration for a period of 30 minutes. If the NO_X concentration drops more than 2 percent absolute from the peak value observed, then the NO_2 converter has failed to meet the criteria of this test. Take corrective action. The highest NO_X value observed is considered to be NO_{XPeak}. The final NO_X value observed is considered to be NO_{Xfinal}.

(2) [Reserved]

16.3 Manufacturer's Stability Test. A manufacturer's stability test is required for all analyzers that routinely measure emissions below 20 ppmv and is optional but recommended for other analyzers. This test evaluates each analyzer model by subjecting it to the tests listed in Table 7E–5 following procedures similar to those in 40 CFR 53.23 for thermal stability and insensitivity to supply voltage variations. If the analyzer will be used under temperature conditions that are outside the test conditions in Table B–4 of Part 53.23, alternative test temperatures that better reflect the analyzer field environment should be used. Alternative procedures or documentation that establish the analyzer's stability over the appropriate line voltages and temperatures are acceptable.

17.0 References

17.1 “EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards” September 1997 as amended, EPA–600/R–97/121.

18.0 Tables, Diagrams, Flowcharts, and Validation Data

METHOD 19 **DETERMINATION OF SULFUR DIOXIDE REMOVAL EFFICIENCY AND PARTICULATE MATTER, SULFUR DIOXIDE, AND NITROGEN OXIDE EMISSION RATES**	**Revision 0** **12/11/2013**	DENOVO

1.0 Scope and Application

1.1 Analytes. This method provides data reduction procedures relating to the following pollutants, but does not include any sample collection or analysis procedures.

Analyte	**CAS No.**	**Sensitivity**
Nitrogen oxides (NO_X), including		
Nitric oxide (NO)	10102-43-9	N/A
Nitrogen dioxide (NO_2)	10102-44-0	
Particulate matter (PM)	None assigned	N/A
Sulfur dioxide (SO_2)	7499-09-05	N/A

1.2 Applicability. Where specified by an applicable subpart of the regulations, this method is applicable for the determination of (a) PM, SO_2, and NO_X emission rates; (b) sulfur removal efficiencies of fuel pretreatment and SO_2 control devices; and (c) overall reduction of potential SO_2 emissions.

2.0 Summary of Method.

2.1 Emission Rates. Oxygen (O_2) or carbon dioxide (CO_2) concentrations and appropriate F factors (ratios of combustion gas volumes to heat inputs) are used to calculate pollutant emission rates from pollutant concentrations.

2.2 Sulfur Reduction Efficiency and SO_2 Removal Efficiency. An overall SO_2 emission reduction efficiency is computed from the efficiency of fuel pretreatment systems, where applicable, and the efficiency of SO_2 control devices.

2.2.1 The sulfur removal efficiency of a fuel pretreatment system is determined by fuel sampling and analysis of the sulfur and heat contents of the fuel before and after the pretreatment system.

2.2.2 The SO_2 removal efficiency of a control device is determined by measuring the SO_2 rates before and after the control device.

2.2.2.1 The inlet rates to SO_2 control systems (or, when SO_2 control systems are not used, SO_2 emission rates to the atmosphere) are determined by fuel sampling and analysis.

3.0 Definitions. [Reserved]

4.0 Interferences. [Reserved]

5.0 Safety. [Reserved]

6.0 Equipment and Supplies. [Reserved]

7.0 Reagents and Standards. [Reserved]

8.0 Sample Collection, Preservation, Storage, and Transport. [Reserved]

9.0 Quality Control. [Reserved]

10.0 Calibration and Standardization. [Reserved]

11.0 Analytical Procedures. [Reserved]

12.0 Data Analysis and Calculations.

12.1 Nomenclature.

B_{wa} = Moisture fraction of ambient air, percent.

B_{ws} = Moisture fraction of effluent gas, percent.

%C = Concentration of carbon from an ultimate analysis of fuel, weight percent.

C_d = Pollutant concentration, dry basis, ng/scm (lb/scf).

$\%CO_{2d}$, $\%CO_{2w}$ = Concentration of carbon dioxide on a dry and wet basis, respectively, percent.

C_w = Pollutant concentration, wet basis, ng/scm (lb/scf).

D = Number of sampling periods during the performance test period.

E = Pollutant emission rate, ng/J (lb/million Btu).

E_a = Average pollutant rate for the specified performance test period, ng/J (lb/million Btu).

E_{ao}, E_{ai} = Average pollutant rate of the control device, outlet and inlet, respectively, for the performance test period, ng/J (lb/million Btu).

E_{bi} = Pollutant rate from the steam generating unit, ng/J (lb/million Btu)

E_{bo} = Pollutant emission rate from the steam generating unit, ng/J (lb/million Btu).

E_{ci} = Pollutant rate in combined effluent, ng/J (lb/million Btu).

E_{co} = Pollutant emission rate in combined effluent, ng/J (lb/million Btu).

E_d = Average pollutant rate for each sampling period (e.g., 24-hr Method 6B sample or 24-hr fuel sample) or for each fuel lot (e.g., amount of fuel bunkered), ng/J (lb/million Btu).

E_{di} = Average inlet SO_2 rate for each sampling period d, ng/J (lb/million Btu)

E_g = Pollutant rate from gas turbine, ng/J (lb/million Btu).

E_{ga} = Daily geometric average pollutant rate, ng/J (lbs/million Btu) or ppm corrected to 7 percent O_2.

E_{jo},E_{ji} = Matched pair hourly arithmetic average pollutant rate, outlet and inlet, respectively, ng/J (lb/million Btu) or ppm corrected to 7 percent O_2.

E_h = Hourly average pollutant, ng/J (lb/million Btu).

E_{hj} = Hourly arithmetic average pollutant rate for hour "j," ng/J (lb/million Btu) or ppm corrected to 7 percent O_2.

EXP = Natural logarithmic base (2.718) raised to the value enclosed by brackets.

F_d, F_w, F_c = Volumes of combustion components per unit of heat content, scm/J (scf/million Btu).

GCV = Gross calorific value of the fuel consistent with the ultimate analysis, kJ/kg (Btu/lb).

GCV_p, GCV_r = Gross calorific value for the product and raw fuel lots, respectively, dry basis, kJ/kg (Btu/lb).

%H = Concentration of hydrogen from an ultimate analysis of fuel, weight percent.

H = Total number of operating hours for which pollutant rates are determined in the performance test period.

H_b = Heat input rate to the steam generating unit from fuels fired in the steam generating unit, J/hr (million Btu/hr).

H_g = Heat input rate to gas turbine from all fuels fired in the gas turbine, J/hr (million Btu/hr).

$\%H_2O$= Concentration of water from an ultimate analysis of fuel, weight percent.

H_r = Total numbers of hours in the performance test period (e.g., 720 hours for 30-day performance test period).

K = Conversion factor, 10^{-5} (kJ/J)/(%) [106 Btu/million Btu].

K_c = (9.57 scm/kg)/% [(1.53 scf/lb)/%].

K_{cc} = (2.0 scm/kg)/% [(0.321 scf/lb)/%].

K_{hd} = (22.7 scm/kg)/% [(3.64 scf/lb)/%].

K_{hw} = (34.74 scm/kg)/% [(5.57 scf/lb)/%].

K_n = (0.86 scm/kg)/% [(0.14 scf/lb)/%].

K_o = (2.85 scm/kg)/% [(0.46 scf/lb)/%].

K_s = (3.54 scm/kg)/% [(0.57 scf/lb)/%].

K_w = (1.30 scm/kg)/% [(0.21 scf/lb)/%].

ln = Natural log of indicated value.

L_p, L_r = Weight of the product and raw fuel lots, respectively, metric ton (ton).

%N = Concentration of nitrogen from an ultimate analysis of fuel, weight percent.

N = Number of fuel lots during the averaging period.

n = Number of fuels being burned in combination.

n_d = Number of operating hours of the affected facility within the performance test period for each E_d determined.

n_t = Total number of hourly averages for which paired inlet and outlet pollutant rates are available within the 24-hr midnight to midnight daily period.

%O = Concentration of oxygen from an ultimate analysis of fuel, weight percent.

$\%O_{2d}$, $\%O2_w$ = Concentration of oxygen on a dry and wet basis, respectively, percent.

P_s = Potential SO_2 emissions, percent.

$\%R_f$ = SO_2 removal efficiency from fuel pretreatment, percent.

$\%R_g$ = SO_2 removal efficiency of the control device, percent.

$\%R_{ga}$ = Daily geometric average percent reduction.

$\%R_o$ = Overall SO_2 reduction, percent.

%S = Sulfur content of as-fired fuel lot, dry basis, weight percent.

S_e = Standard deviation of the hourly average pollutant rates for each performance test period, ng/J (lb/million Btu).

$\%S_f$ = Concentration of sulfur from an ultimate analysis of fuel, weight percent.

S_i = Standard deviation of the hourly average inlet pollutant rates for each performance test period, ng/J (lb/million Btu).

S_o = Standard deviation of the hourly average emission rates for each performance test period, ng/J (lb/million Btu).

%S_p, %S_r = Sulfur content of the product and raw fuel lots respectively, dry basis, weight percent.

$t_{0.95}$ = Values shown in Table 19-3 for the indicated number of data points n.

X_k = Fraction of total heat input from each type of fuel k.

12.2 Emission Rates of PM, SO_2, and NO_X. Select from the following sections the applicable procedure to compute the PM, SO_2, or NO_X emission rate (E) in ng/J (lb/million Btu). The pollutant concentration must be in ng/scm (lb/scf) and the F factor must be in scm/J (scf/million Btu). If the pollutant concentration (C) is not in the appropriate units, use Table 19-1 in Section 17.0 to make the proper conversion. An F factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel. The dry F factor (F_d) includes all components of combustion less water, the wet F factor (F_w) includes all components of combustion, and the carbon F factor (F_c) includes only carbon dioxide.

NOTE: Since F_w factors include water resulting only from the combustion of hydrogen in the fuel, the procedures using F_w factors are not applicable for computing E from steam generating units with wet scrubbers or with other processes that add water (e.g., steam injection).

12.2.1 Oxygen-Based F Factor, Dry Basis. When measurements are on a dry basis for both O (%O_{2d}) and pollutant (C_d) concentrations, use the following equation:

$$E = C_d F_d \frac{20.9}{(20.9 - \%O_{2d})} \quad Eq. 19-1$$

12.2.2 Oxygen-Based F Factor, Wet Basis. When measurements are on a wet basis for both O_2 (%O_{2w}) and pollutant (C_w) concentrations, use either of the following:

12.2.2.1 If the moisture fraction of ambient air (B_{wa}) is measured:

Instead of actual measurement, B_{wa} may be estimated according to the procedure below.

$$E = C_w F_w \frac{20.9}{[20.9(1 - B_{wa}) - \%O_{2w}]} \quad Eq. 19-2$$

NOTE: The estimates are selected to ensure that negative errors will not be larger than -1.5 percent. However, positive errors, or over-estimation of emissions by as much as 5 percent may be introduced depending upon the geographic location of the facility and the associated range of ambient moisture.

12.2.2.1.1 B_{wa} = 0.027. This value may be used at any location at all times.

12.2.2.1.2 B_{wa} = Highest monthly average of B_{wa} that occurred within the previous calendar year at the nearest Weather Service Station. This value shall be determined annually and may be used as an estimate for the entire current calendar year.

12.2.2.1.3 B_{wa} = Highest daily average of B_{wa} that occurred within a calendar month at the nearest Weather Service Station, calculated from the data from the past 3 years.

This value shall be computed for each month and may be used as an estimate for the current respective calendar month.

12.2.2.2 If the moisture fraction (B_{ws}) of the effluent gas is measured:

$$E = C_w F_d \frac{20.9}{[20.9(1 - B_{ws}) - \%O_{2w}]} \qquad Eq. 19-3$$

12.2.3 Oxygen-Based F Factor, Dry/Wet Basis.

12.2.3.1 When the pollutant concentration is measured on a wet basis (C_w) and O_2 concentration is measured on a dry basis ($\%O_{2d}$), use the following equation:

$$E = \frac{(C_w F_d)(20.9)}{(1 - B_{ws})(20.9 - \%O_{2d})} \qquad Eq. 19-4$$

12.2.3.2 When the pollutant concentration is measured on a dry basis (C_d) and the O_2 concentration is measured on a wet basis ($\%O_{2w}$), use the following equation:

$$E = \frac{C_d F_d 20.9}{\frac{(20.9 - \%O_{2w})}{(1 - B_{ws})}} \qquad Eq. 19-5$$

12.2.4 Carbon Dioxide-Based F Factor, Dry Basis. When measurements are on a dry basis for both CO_2 ($\%CO_{2d}$) and pollutant (C_d) concentrations, use the following equation:

$$E = C_d F_c \frac{100}{\%CO_{2d}} \qquad Eq. 19-6$$

12.2.5 Carbon Dioxide-Based F Factor, Wet Basis. When measurements are on a wet basis for both CO_2 ($\%CO_{2w}$) and pollutant (C_w) concentrations, use the following equation:

$$E = C_w F_c \frac{100}{\%CO_{2w}} \qquad Eq. 19-7$$

12.2.6 Carbon Dioxide-Based F Factor, Dry/Wet Basis.

12.2.6.1 When the pollutant concentration is measured on a wet basis (C_w) and CO_2 concentration is measured on a dry basis ($\%CO_{2d}$), use the following equation:

$$E = \frac{C_w F_c}{(1 - B_{ws})} \frac{100}{\%CO_{2d}} \qquad Eq. 19-8$$

12.2.6.2 When the pollutant concentration is measured on a dry basis (C_d) and CO_2 concentration is measured on a wet basis ($\%CO_{2w}$), use the following equation:

$$E = C_d F_c (1 - B_{ws}) \frac{100}{\%CO_{2w}} \qquad Eq. 19-9$$

12.2.7 Direct-Fired Reheat Fuel Burning. The effect of direct-fired reheat fuel burning (for the purpose of raising the temperature of the exhaust effluent from wet scrubbers to above the moisture dew-point) on emission rates will be less than 1.0 percent and, therefore, may be ignored.

12.2.8 Combined Cycle-Gas Turbine Systems. For gas turbine-steam generator combined cycle systems, determine the emissions from the steam generating unit or the percent reduction in potential SO_2 emissions as follows:

12.2.8.1 Compute the emission rate from the steam generating unit using the following equation:

$$E_{bo} = E_{co} + \frac{H_g}{H_b}(E_{co} - E_g) \quad Eq. 19-10$$

12.2.8.1.1 Use the test methods and procedures section of 40 CFR Part 60, Subpart GG to obtain E_{co} and E_g. Do not use F_w factors for determining E_g or E_{co}. If an SO_2 control device is used, measure E_{co} after the control device.

12.2.8.1.2 Suitable methods shall be used to determine the heat input rates to the steam generating units (H_b) and the gas turbine (H_g).

12.2.8.2 If a control device is used, compute the percent of potential SO_2 emissions (P_s) using the following equations:

$$E_{bi} = E_{ci} + \frac{H_g}{H_b}(E_{ci} - E_g) \quad Eq. 19-11$$

$$P_s = 100\left(1 - \frac{E_{bo}}{E_{bi}}\right) \quad Eq. 19-12$$

NOTE: Use the test methods and procedures section of Subpart GG to obtain E_{ci} and E_g. Do not use F_w factors for determining E_g or E_{ci}.

12.3 F Factors. Use an average F factor according to Section 12.3.1 or determine an applicable F factor according to Section 12.3.2. If combined fuels are fired, prorate the applicable F factors using the procedure in Section 12.3.3.

12.3.1 Average F Factors. Average F factors (F_d, F_w, or F_c) from Table 19-2 in Section 17.0 may be used.

12.3.2 Determined F Factors. If the fuel burned is not listed in Table 19-2 or if the owner or operator chooses to determine an F factor rather than use the values in Table 19-2, use the procedure below:

12.3.2.1 Equations. Use the equations below, as appropriate, to compute the F factors:

$$F_d = \frac{K(K_{hd}\%H + K_c\%C + K_s\%S + K_n\%N - K_o\%O)}{GCV} \quad Eq. 19-13$$

$$F_d = \frac{K(K_{hw}\%H + K_c\%C + K_s\%S + K_n\%N - K_o\%O + K_w\%H_2O)}{GCV_w} \quad Eq. 19-14$$

$$F_c = \frac{K(K_{cc}\%C)}{GCV} \quad Eq. 19-15$$

NOTE: Omit the $\%H_2O$ term in the equations for F_w if %H and %O include the unavailable hydrogen and oxygen in the form of H_2O.)

12.3.2.2 Use applicable sampling procedures in Section 12.5.2.1 or 12.5.2.2 to obtain samples for analyses.

12.3.2.3 Use ASTM D 3176-74 or 89 (all cited ASTM standards are incorporated by reference-see §60.17) for ultimate analysis of the fuel.

12.3.2.4 Use applicable methods in Section 12.5.2.1 or 12.5.2.2 to determine the heat content of solid or liquid fuels. For gaseous fuels, use ASTM D 1826-77 or 94 (incorporated by reference-see §60.17) to determine the heat content.

12.3.3 F Factors for Combination of Fuels. If combinations of fuels are burned, use the following equations, as applicable unless otherwise specified in an applicable subpart:

$$F_d = \sum_{k=1}^{n} (X_k F_{dk}) \quad Eq. 19-16$$

$$F_w = \sum_{k=1}^{n} (X_k F_{wk}) \quad Eq. 19-17$$

$$F_c = \sum_{k=1}^{n} (X_k F_{ck}) \quad Eq. 19-18$$

12.4 Determination of Average Pollutant Rates.

12.4.1 Average Pollutant Rates from Hourly Values. When hourly average pollutant rates (E_h), inlet or outlet, are obtained (e.g., CEMS values), compute the average pollutant rate (E_a) for the performance test period (e.g., 30 days) specified in the applicable regulation using the following equation:

$$E_a = \frac{1}{H} \sum_{j=1}^{n} E_{hj} \quad Eq. 19-19$$

12.4.2 Average Pollutant Rates from Other than Hourly Averages. When pollutant rates are determined from measured values representing longer than 1-hour periods (e.g., daily fuel sampling and analyses or Method 6B values), or when pollutant rates are determined from combinations of 1-hour and longer than 1-hour periods (e.g., CEMS and Method 6B values), compute the average pollutant rate (E_a) for the performance test period (e.g., 30 days) specified in the applicable regulation using the following equation:

$$E_a = \frac{\sum_{j=1}^{D} (n_d E_d)_j}{\sum_{j=1}^{D} n_{dj}} \quad Eq. 19-20$$

12.4.3 Daily Geometric Average Pollutant Rates from Hourly Values. The geometric average pollutant rate (E_{ga}) is computed using the following equation:

$$E_{ga} = exp\left[\frac{1}{n_t} \sum_{j=1}^{n_t} [ln(E_{hj})]\right] \quad Eq. 19-21$$

12.5 Determination of Overall Reduction in Potential Sulfur Dioxide Emission.

12.5.1 Overall Percent Reduction. Compute the overall percent SO_2 reduction ($\%R_o$) using the following equation:

$$\%R_o = 100\left[1.0 - \left(1.0 - \frac{\%R_f}{100}\right)\left(1.0 - \frac{\%R_g}{100}\right)\right] \qquad Eq. 19-22$$

12.5.2 Pretreatment Removal Efficiency (Optional). Compute the SO_2 removal efficiency from fuel pretreatment ($\%R_f$) for the averaging period (e.g., 90 days) as specified in the applicable regulation using the following equation:

$$\%R_f = 100\left[1.0 - \frac{\sum_{j=1}^{N}\left(\frac{\%S_{pj}}{GCV_{pj}}\right)L_{pj}}{\sum_{j=1}^{N}\left(\frac{\%S_{rj}}{GCV_{rj}}\right)L_{rj}}\right] \qquad Eq. 19-23$$

NOTE: In calculating $\%R_f$, include %S and GCV values for all fuel lots that are not pretreated and are used during the averaging period.

12.5.2.1 Solid Fossil (Including Waste) Fuel-Sampling and Analysis.

NOTE: For the purposes of this method, raw fuel (coal or oil) is the fuel delivered to the desulfurization (pretreatment) facility. For oil, the input oil to the oil desulfurization process (e.g., hydrotreatment) is considered to be the raw fuel.

12.5.2.1.1 Sample Increment Collection. Use ASTM D 2234-76, 96, 97a, or 98 (incorporated by reference-see §60.17), Type I, Conditions A, B, or C, and systematic spacing. As used in this method, systematic spacing is intended to include evenly spaced increments in time or increments based on equal weights of coal passing the collection area. As a minimum, determine the number and weight of increments required per gross sample representing each coal lot according to Table 2 or Paragraph 7.1.5.2 of ASTM D 2234. Collect one gross sample for each lot of raw coal and one gross sample for each lot of product coal.

12.5.2.1.2 ASTM Lot Size. For the purpose of Section 12.5.2 (fuel pretreatment), the lot size of product coal is the weight of product coal from one type of raw coal. The lot size of raw coal is the weight of raw coal used to produce one lot of product coal. Typically, the lot size is the weight of coal processed in a 1-day (24-hour) period. If more than one type of coal is treated and produced in 1 day, then gross samples must be collected and analyzed for each type of coal. A coal lot size equaling the 90-day quarterly fuel quantity for a steam generating unit may be used if representative sampling can be conducted for each raw coal and product coal.

NOTE: Alternative definitions of lot sizes may be used, subject to prior approval of the Administrator.

12.5.2.1.3 Gross Sample Analysis. Use ASTM D 2013-72 or 86 to prepare the sample, ASTM D 3177-75 or 89 or ASTM D 4239-85, 94, or 97 to determine sulfur content

(%S), ASTM D 3173-73 or 87 to determine moisture content, and ASTM D 2015-77 (Reapproved 1978) or 96, D 3286-85 or 96, or D 5865-98 or 10 to determine gross calorific value (GCV) (all standards cited are incorporated by reference-see §60.17 for acceptable versions of the standards) on a dry basis for each gross sample.

12.5.2.2 Liquid Fossil Fuel-Sampling and Analysis. See Note under Section 12.5.2.1.

12.5.2.2.1 Sample Collection. Follow the procedures for continuous sampling in ASTM D 270 or D 4177-95 (incorporated by reference-see §60.17) for each gross sample from each fuel lot.

12.5.2.2.2 Lot Size. For the purpose of Section 12.5.2 (fuel pretreatment), the lot size of a product oil is the weight of product oil from one pretreatment facility and intended as one shipment (ship load, barge load, etc.). The lot size of raw oil is the weight of each crude liquid fuel type used to produce a lot of product oil.

NOTE: Alternative definitions of lot sizes may be used, subject to prior approval of the Administrator.

12.5.2.2.3 Sample Analysis. Use ASTM D 129-64, 78, or 95, ASTM D 1552-83 or 95, or ASTM D 4057-81 or 95 to determine the sulfur content (%S) and ASTM D 240-76 or 92 (all standards cited are incorporated by reference-see §60.17) to determine the GCV of each gross sample. These values may be assumed to be on a dry basis. The owner or operator of an affected facility may elect to determine the GCV by sampling the oil combusted on the first steam generating unit operating day of each calendar month and then using the lowest GCV value of the three GCV values per quarter for the GCV of all oil combusted in that calendar quarter.

12.5.2.3 Use appropriate procedures, subject to the approval of the Administrator, to determine the fraction of total mass input derived from each type of fuel.

12.5.3 Control Device Removal Efficiency. Compute the percent removal efficiency ($\%R_g$) of the control device using the following equation:

$$\%R_g = 100\left(1.0 - \frac{E_{ao}}{E_{ai}}\right) \qquad Eq. 19-24$$

12.5.3.1 Use continuous emission monitoring systems or test methods, as appropriate, to determine the outlet SO_2 rates and, if appropriate, the inlet SO_2 rates. The rates may be determined as hourly (E_h) or other sampling period averages (E_d). Then, compute the average pollutant rates for the performance test period (E_{ao} and E_{ai}) using the procedures in Section 12.4.

12.5.3.2 As an alternative, as-fired fuel sampling and analysis may be used to determine inlet SO_2 rates as follows:

12.5.3.2.1 Compute the average inlet SO_2 rate (E_{di}) for each sampling period using the following equation:

$$E_{di} = K \frac{\%S}{GCV} \quad Eq. 19-25$$

Where:

$$K = 2 \times 10^7 \left(\frac{ng\ SO_2}{\%S_f}\right)\left(\frac{(kJ)}{J}\right)\left(\frac{1}{kg\ coal}\right)$$

$$\left[2 \times 10^4 \left(\frac{lb\ SO_2}{\%S}\right)\left(\frac{Btu}{million\ Btu}\right)\left(\frac{1}{lb\ coal}\right)\right]$$

After calculating E_{di}, use the procedures in Section 12.4 to determine the average inlet SO_2 rate for the performance test period (E_{ai}).

12.5.3.2.2 Collect the fuel samples from a location in the fuel handling system that provides a sample representative of the fuel bunkered or consumed during a steam generating unit operating day. For the purpose of as-fired fuel sampling under Section 12.5.3.2 or Section 12.6, the lot size for coal is the weight of coal bunkered or consumed during each steam generating unit operating day. The lot size for oil is the weight of oil supplied to the "day" tank or consumed during each steam generating unit operating day. For reporting and calculation purposes, the gross sample shall be identified with the calendar day on which sampling began. For steam generating unit operating days when a coal-fired steam generating unit is operated without coal being added to the bunkers, the coal analysis from the previous "as bunkered" coal sample shall be used until coal is bunkered again. For steam generating unit operating days when an oil-fired steam generating unit is operated without oil being added to the oil "day" tank, the oil analysis from the previous day shall be used until the "day" tank is filled again. Alternative definitions of fuel lot size may be used, subject to prior approval of the Administrator.

12.5.3.2.3 Use ASTM procedures specified in Section 12.5.2.1 or 12.5.2.2 to determine %S and GCV.

12.5.4 Daily Geometric Average Percent Reduction from Hourly Values. The geometric average percent reduction ($\%R_{ga}$) is computed using the following equation:

$$\%R_{ga} = 100\left[1 - EXP\left(\frac{1}{n_t}\sum_{j=1}^{n_t} ln \frac{E_{jo}}{E_{ji}}\right)\right] \quad Eq. 19-26$$

NOTE: The calculation includes only paired data sets (hourly average) for the inlet and outlet pollutant measurements.

12.6 Sulfur Retention Credit for Compliance Fuel. If fuel sampling and analysis procedures in Section 12.5.2.1 are being used to determine average SO_2 emission rates (E_{as}) to the atmosphere from a coal-fired steam generating unit when there is no SO_2 control device, the following equation may be used to adjust the emission rate for sulfur retention credits (no credits are allowed for oil-fired systems) (E_{di}) for each sampling period using the following equation:

$$E_{di} = 0.97K\frac{\%S}{GDV} \quad Eq. 19-27$$

Where:

$$K = 2 \times 10^{7}\left(\frac{ng\ SO_2}{\%S}\right)\left(\frac{kJ}{J}\right)\left(\frac{1}{kg\ coal}\right)$$

$$\left[2 \times 10^{4}\left(\frac{lb\ SO_2}{\%S}\right)\left(\frac{Btu}{million\ Btu}\right)\left(\frac{1}{lb\ coal}\right)\right]$$

After calculating E_{di}, use the procedures in Section 12.4.2 to determine the average SO_2 emission rate to the atmosphere for the performance test period (E_{ao}).

12.7 Determination of Compliance When Minimum Data Requirement Is Not Met.

12.7.1 Adjusted Emission Rates and Control Device Removal Efficiency. When the minimum data requirement is not met, the Administrator may use the following adjusted emission rates or control device removal efficiencies to determine compliance with the applicable standards.

12.7.1.1 Emission Rate. Compliance with the emission rate standard may be determined by using the lower confidence limit of the emission rate (E_{ao}^{*}) as follows:

$$E_{ao}^{*} = E_{ao} - t_{0.95}S_o \quad Eq. 19-28$$

12.7.1.2 Control Device Removal Efficiency. Compliance with the overall emission reduction ($\%R_o$) may be determined by using the lower confidence limit of the emission rate (E_{ao}^{*}) and the upper confidence limit of the inlet pollutant rate (E_{ai}^{*}) in calculating the control device removal efficiency ($\%R_g$) as follows:

$$\%R_g = 100\left(1.0 - \frac{E_{ao}^{*}}{E_{ai}^{*}}\right) \quad Eq. 19-29$$

$$E_{ai}^{*} = E_{ai} + t_{0.95}S_i \quad Eq. 19-30$$

12.7.2 Standard Deviation of Hourly Average Pollutant Rates. Compute the standard deviation (S_e) of the hourly average pollutant rates using the following equation:

$$S_e = \sqrt{\frac{1}{H} - \frac{1}{H_r}}\sqrt{\frac{\sum_{j=1}^{H}\left(E_{hj} - E_a\right)^2}{H-1}} \quad Eq. 19-31$$

Equation 19-19 through 19-31 may be used to compute the standard deviation for both the outlet (S_o) and, if applicable, inlet (S_i) pollutant rates.

13.0 Method Performance. [Reserved]

14.0 Pollution Prevention. [Reserved]

15.0 Waste Management. [Reserved]

16.0 References. [Reserved]

17.0 Tables, Diagrams, Flowcharts, and Validation Data.

From	To	Multiply by
g/scm	ng/scm	10^9
mg/scm	ng/scm	10^6
lb/scf	ng/scm	1.602×10^{13}
ppm SO_2	ng/scm	2.66×10^6
ppm NO_X	ng/scm	1.912×10^6
ppm SO_2	lb/scf	1.660×10^{-7}
ppm NO_X	lb/scf	1.194×10^{-7}

Table 19-1—Conversion Factors for Concentration

Fuel Type	F_d		F_w		F_c	
	dscm/J	dscf/10^6 Btu	wscm/J	wscf/10^6 Btu	scm/J	scf/10^6 Btu
Coal:						
Anthracite[2]	2.71×10^{-7}	10,100	2.83×10^{-7}	10,540	0.530×10^{-7}	1,970
Bituminous[2]	2.63×10^{-7}	9,780	2.86×10^{-7}	10,640	0.484×10^{-7}	1,800
Lignite	2.65×10^{-7}	9,860	3.21×10^{-7}	11,950	0.513×10^{-7}	1,910
Oil[3]	2.47×10^{-7}	9,190	2.77×10^{-7}	10,320	0.383×10^{-7}	1,420
Gas:						
Natural	2.34×10^{-7}	8,710	2.85×10^{-7}	10,610	0.287×10^{-7}	1,040
Propane	2.34×10^{-7}	8,710	2.74×10^{-7}	10,200	0.321×10^{-7}	1,190
Butane	2.34×10^{-7}	8,710	2.79×10^{-7}	10,390	0.337×10^{-7}	1,250
Wood	2.48×10^{-7}	9,240			0.492×10^{-7}	1,830
Wood Bark	2.58×10^{-7}	9,600			0.516×10^{-7}	1,920
Municipal	2.57×10^{-7}	9,570			0.488×10^{-7}	1,820
Solid Waste						

Table 19-2—F Factors for Various Fuels[1]

[1] Determined at standard conditions: 20 °C (68 °F) and 760 mm Hg (29.92 in Hg)

[2] As classified according to ASTM D 388.

[3] Crude, residual, or distillate.

n[1]	$t_{0.95}$	n[1]	$t_{0.95}$	n[1]	$t_{0.95}$
2	6.31	8	1.89	22-26	1.71
3	2.42	9	1.86	27-31	1.70
4	2.35	10	1.83	32-51	1.68
5	2.13	11	1.81	52-91	1.67
6	2.02	12-16	1.77	92-151	1.66
7	1.94	17-21	1.73	152 or more	1.65

Table 19-3—Values for $T_{0.95}$*

[1] The values of this table are corrected for n-1 degrees of freedom. Use n equal to the number (H) of hourly average data points.

APPENDIX B
OF CONSENT DECREE

Version 1.1
December 2019

Supplemental Environmental Project (SEP) Policy

Kansas Department of Health and Environment
Division of Environment
Bureau of Air

I. Introduction

As part of an enforcement action settlement, an alleged violator of the Kansas Air Quality Statutes and Regulations may agree to participate in a Supplemental Environmental Project ("SEP") to offset a portion of a civil penalty associated with the enforcement action. SEPs are an opportunity to improve the community and environment through projects; educate and raise awareness of environmental concerns; and prevent, remediate, or reduce emissions of pollutants that adversely impact public health or the environment. SEPs are beneficial to alleged violators because they are an opportunity to improve relations with the local community and may qualify as a tax exemption. SEPs, which the Bureau of Air ("BOA") will propose to the Kansas Department of Health and Environment ("KDHE") management for approval, will be related to air quality and air pollution prevention or reduction. However, KDHE may also consider SEPs that benefit other environmental media. SEPs are environmentally beneficial projects that an alleged violator agrees to undertake as part of an enforcement action, but that the alleged violator is not otherwise legally required to perform. All SEPs must result in improvements to the environment or public health. KDHE and BOA follow certain criteria in consideration of what constitutes an acceptable SEP, the value of SEPs, and civil penalty offset. This document describes these criteria and how SEPs are carried out. Each proposed enforcement action and/or SEP must be approved by the Director of BOA, the Director of the Division of Environment, and the Secretary of KDHE before becoming final. During the process of negotiating and proposing enforcement actions and/or SEPs, agency management may revise the proposed action at any time. This policy is intended for guidance purposes only, with final decisions made by KDHE management.

II. SEP Approval Process

A. Enforcement Action

Once enforcement by KDHE has begun, the alleged violator will generally have the opportunity to resolve the case through a settlement agreement with KDHE. The settlement will be in the form of a Consent Agreement and Final Order of the Secretary ("CAO") for the resolution of the enforcement action; and will include an agreed civil penalty to be paid by the alleged violator. Mutually agreeable SEPs may be a component of the proposed CAO and offset a portion of the civil penalty.

B. Selection of Proposed Projects

Possible SEPs may be proposed by the alleged violator or from a suggested list provided in Section V of this document. Ultimately, one or more acceptable SEPs may be determined to be mutually acceptable to all participants, and implementing details related to the SEPs are developed and mutually agreed upon. BOA consideration of a proposal is based on the criteria described in Section III, and offsetting of penalties is described in Section IV. After review by the Air Compliance and Enforcement Section, the proposed SEP must be approved by the BOA director.

C. Approval Process

The mutually agreeable SEPs are incorporated into the proposed CAO, drafted by the BOA. Within this draft CAO, the amount of civil penalty offset and conditions of the SEP are stated. The implementation requirements of the SEP will be set forth in the Schedule of Compliance section of the CAO. Progress reports and progress deadlines are usually included as requirements. The CAO will be sent to the BOA Director, the Director of the Division of Environment, and the KDHE Legal office for review and approval, or suggested revisions. If the alleged violator is agreeable to all components and requirements of the proposed CAO, a responsible official of the organization will sign the agreement and return it to KDHE Legal office. The responsible official will also sign an affidavit under penalty of perjury attesting to the SEP's compliance with this policy. Upon the final signature by the Secretary of KDHE, the CAO is executed.

D. Implementation of Approved SEP

With the execution of the CAO, the progress of the SEP will be monitored by KDHE-BOA until completion. Failure to complete the SEP, submit required progress reports, or meet conditions contained therein will be a violation of the CAO. Violations will have the potential for additional enforcement action, including civil penalties. The agreement will contain provisions for emergency and unforeseen circumstances that cause a delay or failure in completion of the SEP or the CAO, such as *force majeure* at a facility (i.e., severe weather, fires, explosions, etc.). The alleged violator is responsible for presenting acceptable cause and effect statements related to force majeure or other delay in progress. A *force majeure* event may result in agreement by KDHE to amend the CAO to extend deadlines or modify SEP plans. Regardless of a *force majeure* event, failure to complete a SEP will require full payment of the assessed civil penalty. The CAO also has provisions for Dispute Resolution between all parties. The CAO will be terminated when all requirements contained in the agreement have been met, as determined by KDHE.

III. Criteria for an Acceptable SEP

The following criteria are evaluated and serve as guidance by BOA when considering a SEP as a component to resolve enforcement actions:

A. Requirements

- The SEP must be environmentally beneficial to the State of Kansas and its residents; it must improve and protect the environment as well as reduce environmental risks to the public.
- The SEP is undertaken in conjunction with the settlement of a CAO action only. An environmental project which has already been completed, for which a commitment has been made, or has been budgeted for by the violator is generally not acceptable for consideration as a SEP.
- The SEP must go beyond the minimum compliance with the law, whether air quality, other environmental or any other state or federal law.
- SEPs must not adversely affect another environmental concern in the process of implementation.

- The CAO may require the source to have, or develop, an Environmental Management System ("EMS") as a consideration for a SEP within a CAO.
- The review, oversight, or monitoring of SEPs must be within the resources and capabilities of BOA and must provide enough environmental benefit to justify oversight.

B. Other Considerations

- Creating a SEP that will benefit the communities affected by the violation
- Utilizing public input on community improvement projects
- Creating a SEP that involves the same environmental media as the violation
- The contributions of the SEP toward the environmental priorities of BOA
- The direct, indirect, or mixed benefits of the SEP

IV. Allowable Penalty Offset and Offset Credits

The following criteria are evaluated and serve as guidance by BOA when considering allowable penalty offsets and offset credits for a SEP.

A. Allowable Penalty Offset

After BOA staff has reviewed a SEP proposal for the criteria list in Section III, the allowable penalty offset will be determined by BOA as a percentage of the overall penalty. The allowable penalty offset is the maximum percentage of the overall penalty that can be reduced through a SEP. The table below lists the allowable penalty offset as a percentage of the overall penalty. Example calculations can be found in Section IV (C).

	Maximum	**Minimum**
Government / Non-Profit	100%	$2,000
For-Profit	50%	$4,000

Table 1. Maximum allowable penalty offset as a percentage and minimum allowable penalty offset as a dollar amount. Under certain circumstances, KDHE may increase the maximum allowable penalty offset.

1. Local Government:

Applicable local governments may be eligible to apply the cost of correcting a violation toward a SEP. To qualify, the local government must have not committed a violation at the same site with the same underlying cause within the last five years and have not agreed to perform the project before the date of agreeing to enter into a consent agreement. If there is no cost to correcting the violation, a SEP may include environmentally focused upgrades of their own property.

B. Offset Credits

Next, BOA calculates the number of offset credits earned per dollar spent on a SEP. For each offset credit earned, one dollar is removed from penalty. The number of offset credits earned per dollar spent are calculated using the conversion table below. Example calculations can be found in Section IV (C).

	Direct Local	**Direct Non-local**	**Mixed Local**	**Mixed Non-local**	**Indirect Local**	**Green Schools**
Government / Non-Profit	1.00	0.50	0.75	0.50	0.50	1.00
For-Profit	0.75	0.50	0.75	0.50	0.50	1.00

Table 2. Number of offset credits earned per dollar spent on a SEP.

Direct Benefit SEPs are defined by benefits that directly impact the environment in a quantifiable manner. Direct Benefit SEPs do this through projects that prevent, remediate, or reduce emissions of pollutants that adversely impact public health or the environment.

Indirect Benefit SEPs are defined by benefits that do not directly impact the environment. These SEPs include part beautification projects and enhancement to local community.

Mixed Benefit SEPs are those that include both direct and indirect impacts.

Local Benefit* SEPs are defined as those taking place in communities within 50 miles of the alleged violator's facility.

Non-local Benefit* SEPs are defined as those taking place in communities further than 50 miles from the alleged violator's facility.

* All SEPs, whether local or non-local, must provide their benefits primarily in the State of Kansas.

C. Examples Calculations

1. A facility has a CAO penalty of $50,000 and they are planning to fund an air pollution awareness class, which costs $10,000 to fund, at the local library as part of their SEP. According to Table 1, they are eligible for a 50% allowable penalty offset, which is $25,000. At a minimum, they are required to meet a $4,000 penalty offset. The local awareness would classify as an indirect local SEP and the facility is a for-profit business. According to Table 2, they would receive 0.50 offset credits per dollar spent. This would amount to 5,000 offset credits, which is above the minimum $4,000 penalty offset. The penalty value after the SEP would be $45,000.

2. A county government has a CAO penalty of $5,000 and they are planning on planting $3,000 worth of trees along the edge of the local baseball field for their SEP. According to Table 1, they are eligible for a 100% allowable penalty offset. At a minimum, they are required to meet a $2,000 penalty offset. The SEP would qualify as a direct local project. According to Table 2, they would receive 1.00 offset credits per dollar spent. This would amount to 3,000 offset credits, which is above the minimum $2,000 penalty offset. The penalty value after the SEP would be $2,000.

V. Preapproved and Example Projects

Listed below are projects preapproved by KDHE for use as a SEP, as well as example projects.

Preapproved Projects

- Kansas Green Schools (www.kansasgreenschools.org)
- Nature Conservancy (www.nature.org/en-us/about-us/where-we-work/united-states/kansas/)

Example Projects

- Fugitive dust control (paving parking lots, roads)
- Solar panel or wind turbine project
- Park beautification projects (pollinator gardens, etc.)
- Retrofit local school bus diesel engines
- Purchasing more fuel efficient or electric vehicles for local school fleet
- Assist in or implement a recycling program in a local school or community
- Purchase land for parks and natural areas
- Conduct a household hazardous waste collection event
- Purchase and retirement of emission credits
- Wood stove changeout program

VI. Contact Information

If you would like additional information, contact the Bureau of Air:

Bureau of Air
Air Compliance and Enforcement Section
Curtis State Office Building
1000 SW Jackson, Suite 310
Topeka, KS 66612-1366
785-296-6024

VII. Approval of SEP Policy

Director, Bureau of Air

12/17/2019

Date

APPENDIX C
OF CONSENT DECREE

U.S. Department of Justice
Environment and Natural Resources
Division

90-5-2-1-07459/5

August 22, 2023

LeAnn Johnson Koch, Esq.
Perkins Coie LLP
700 Thirteenth Street NW, Suite 800
Washington, D.C. 20005-3960

Dear Ms. Johnson Koch,

Re. United States v. CRRM, Case No. 6:04-cv-01064 (D. Kan.)

As you know, Plaintiffs in the above-captioned action allege that stipulated penalties have accrued for the following CRRM violations of the 2012 Consent Decree that are in addition to those subject to the Court's Order dated March 30, 2022 (Dkt. 95). Plaintiffs have not formally demanded these stipulated penalties.

- Violations of Paragraphs 34 and 37 (for failure to put heater limits into a permit by 12/31/2016 and annual inventory updates); and

- Violations of Paragraphs 15.a., 30 and 78 (for FCCU CEMS downtime and downtime reporting).

CRRM has agreed to pay a total amount of $183,000 (split evenly between the United States and KDHE) as part of the larger settlement of the claims in the Second Amended Supplemental Complaint (Dkt No. 132) and Court ordered (Dkt. No. 95) stipulated penalties to resolve these claims.

As with the other aspects of this settlement, resolution of these stipulated penalty claims is subject to execution of a Consent Decree by CRRM, the review and approval of officials at EPA, DOJ, and KDHE with the authority to compromise such claims, and Court entry of the Consent Decree.

Sincerely,

/s/ Elizabeth L. Loeb
Elizabeth L. Loeb
Senior Attorney

Cc: Counsel of Record