Certified Mail No.

Activity No. PER20220007
Agency Interest (AI) No. 194165

Mr. Josh Wiggins
VP of Manufacturing & Plant Manager
Koch Methanol St. James, LLC
5181 Wildcat St.
St. James, LA 70086

RE: Prevention of Significant Deterioration (PSD) Permit, PSD-LA-851
Koch Methanol St. James, LLC - Koch Methanol Plant
St James, St. James Parish, Louisiana

Dear Mr. Wiggins:

Enclosed is your permit, PSD-LA-851. Construction of the proposed project is not allowed until such time as the corresponding Part 70 Operating Permit is issued.

Please be advised that pursuant to provisions of the Environmental Quality Act and the Administrative Procedure Act, the Department may initiate review of a permit during its term. However, before it takes any action to modify, suspend or revoke a permit, the Department shall, in accordance with applicable statutes and regulations, notify the permittee by mail of the facts or operational conduct that warrant the intended action and provide the permittee with the opportunity to demonstrate compliance with all lawful requirements for the retention of the effective permit.

Should you have any questions, contact Anthony Randall of the Air Permits Division at (225) 219-3494.

Sincerely,

Bliss M. Higgins
Assistant Secretary

____
Date

BMH:alr

c: US EPA Region VI

Agency Interest No. 194165

PSD-LA-851

AUTHORIZATION TO CONSTRUCT THE PROPOSED PROJECT AND OPERATE A MAJOR STATIONARY SOURCE PURSUANT TO THE PREVENTION OF SIGNIFICANT DETERIORATION REGULATIONS IN LOUISIANA ENVIRONMENTAL REGULATORY CODE, LAC 33:III.509

In accordance with the provisions of the Louisiana Environmental Regulatory Code, LAC 33:III.509,

Koch Methanol St. James, LLC
5181 Wildcat Street
St. James, LA 70086

is authorized to construct the Koch Methanol (KMe) Optimization Project at the Koch Methanol Facility located at

5181 Wildcat St.
St. James, Louisiana 70086

subject to the emissions limitations, monitoring requirements, and other conditions set forth hereinafter.

This permit and authorization to construct shall expire at midnight on ________________, 2025, unless physical on site construction has begun by such date, or binding agreements or contractual obligations to undertake a program of construction of the source are entered into by such date.

Signed this ________ day of __________________, 2023.

Bliss M. Higgins
Assistant Secretary
Office of Environmental Services
Louisiana Department of Environmental Quality

BRIEFING SHEET

Koch Methanol Facility
Agency Interest No.: 194165
Koch Methanol St. James, LLC
St. James, St. James Parish, Louisiana
PSD-LA-851

I. APPLICANT

The applicant is:	Koch Methanol St. James, LLC 5181 Wildcat St. St. James, LA 70086
Facility:	Koch Methanol Facility
SIC Code:	2869

II. LOCATION

The facility is located at 5181 Wildcat St., St. James, LA 70086.

III. REVIEWING AGENCY

Louisiana Department of Environmental Quality (LDEQ)
Office of Environmental Services / Air Permits Division
P.O. Box 4313
Baton Rouge, Louisiana 70821-4313

IV. PURPOSE

Koch Methanol St. James, LLC (Koch) has applied for a PSD permit for the KMe Optimization Project.

V. PROJECT DESCRIPTION

Koch Methanol St. James, LLC (Koch) operates the Koch Methanol Plant (KMe Plant) and the adjacent Koch Methanol Terminal (KMe Terminal), collectively known as the KMe Facility, in St. James, St. James Parish, Louisiana. The KMe Plant and the KMe Terminal constitute a single major stationary source under the Part 70 Operating Permits Program. Koch requested to incorporate all permitted KMe Terminal sources from Permit No. 3169-V3 (AI 213599) into the KMe Plant's Title V permit in order to consolidate all emission sources into a single Title V permit for the KMe Facility.

The KMe Optimization Project ("the Project") consists of a number of activities, including a raw material feed upgrade, improvements to plant cooling capability, and other equipment upgrades with the collective primary goal of increasing utilization of existing assets and methanol production. The Project is intended to achieve a 25% increase in the KMe Facility's design production rate from approximately 4,950 MTPD to 6,200 MTPD of refined methanol.

The raw material feed upgrade includes constructing ethane gas piping, a vaporizer, and associated equipment to inject ethane into the process natural gas feed to the steam methane reformer (SMR) (EQT0001). Ethane will be brought into the facility from an existing third-party ethane gas pipeline. Piping, a metering skid, and associated piping components will be constructed, owned, and operated by the third party. KMe will connect to the third-party metering skid at a point of demarcation within the KMe Facility's property. A shell and tube exchanger using low pressure steam, owned and operated by KMe, will be used to vaporize the ethane prior to injection into the process natural gas feed line to the SMR.

To meet the additional cooling needs anticipated for the Project, KMe plans to make upgrades to existing fin fan coolers as well as the existing cooling tower (EQT0007). This work may involve upgrades to or replacement of the fin fans for improved cooling capability at increased production rates. The cooling tower upgrades are anticipated to include addition of a new cooling tower cell and new or upgraded pumps for increased cooling tower circulation rates above current capability.

A modification to the Flare (EQT0003) design may occur as a result of the Project. The flare will either remain a non-assisted flare or may be modified to incorporate a steam-assisted design.

Other equipment upgrades, such as changes to or addition of piping fugitive components (FUG0001) for process safety valve upgrades, improved process monitoring, or new or changed piping configurations or process flows, may be made as part of the Project. Zoloscan technology utilizing advanced combustion monitoring may be installed on the SMR. Additionally, process equipment such as heat exchangers or burners may be replaced, physically modified, or added to accommodate the increased production rates.

VI. APPLICABILITY AND REGULATED POLLUTANTS

Koch Methanol's proposed KMe Optimization Project will be performed at the KMe Facility, which is located in St. James Parish, which is currently designated by EPA as attainment or unclassifiable for all pollutants having National Ambient Air Quality Standards (NAAQS) (40 CFR 81.319). Therefore, Non-Attainment New Source Review (NNSR) regulations are not applicable to the project.

A "major stationary source" under the PSD regulations is defined as any source that emits or has the potential to emit over 250 tons per year (TPY) of at least one criteria pollutant or 100 TPY if the source belongs to one of the 28 specifically listed industrial source categories [40 CFR 52.21(b)(1)]. The major source threshold for the Koch Methanol Facility is 100 TPY.

For existing units, the increase in emissions from the project can be calculated as the post-project potential to emit (PTE) or the projected actual emissions (PAE) minus the baseline actual emissions (BAE). For a new emissions unit, the BAE for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero.

Although not required because the KMe Facility is not an existing major stationary source and because the changes proposed do not themselves constitute construction of a new major stationary source, Koch requested that PSD requirements be applied as if the facility has not yet been built and to all pollutants for which the post-project facility-wide potential to emit will exceed PSD Significant Emission Rates.

Emissions of PM_{10}, $PM_{2.5}$, NO_X, CO, VOC, and greenhouse gases are greater than their corresponding significant emission rates; therefore, PSD review is required for these pollutants.

Permitted emissions for the Koch Methanol Facility (for regulated NSR pollutants) are set forth in the table below. Amounts are listed in TPY.

Pollutant	Project Emission Accounting	Contemporaneous Changes	Net Emissions Increase	PSD de minimis	Review conducted?
PM_{10}	76.30	-	76.30	15	Yes
$PM_{2.5}$	75.32	-	75.32	10	Yes
SO_2	6.16	-	6.16	40	No
NO_X	152.84	-	152.84	40	Yes
CO	181.46	-	181.46	100	Yes
VOC	166.34	-	166.34	40	Yes
CO_2e	1,401,096	-	1,401,096	75,000	Yes
H_2S	9.13	-	9.13	10	No

VII. PRELIMINARY DETERMINATION

LAC 33:III.509.Q.2.a requires LDEQ to "make a preliminary determination whether construction should be approved, approved with conditions, or disapproved." Based on the findings set forth in the Preliminary Determination Summary, the Office of Environmental Services has made a preliminary determination to approve construction of the KMe Optimization Project at the KMe Facility, located in St. James, St. James Parish, subject to the maximum allowable emissions rates and specific conditions established herein.

VIII. PROCESSING TIME

Application Dated:	November 2, 2022
Application Received:	November 2, 2022
Additional Information Dated:	February 1, 2023, February 8, 2023, March 20, 2023, March 22, 2023, March 28, 2023, May 2, 2023, and June 19, 2023
Effective Completeness Date:	March 30, 2023

BRIEFING SHEET

Koch Methanol Facility
Agency Interest No.: 194165
Koch Methanol St. James, LLC
St. James, St. James Parish, Louisiana
PSD-LA-851

IX. PUBLIC NOTICE

In accordance with LAC 33:III.509.Q.2.c, a notice requesting public comment and announcing a public hearing on the proposed permit was published on the department's website on <<Date>>. On <<Date>>, copies of the public notice were mailed to the individuals who have requested to be placed on the mailing list maintained by the Office of Environmental Services (OES). The proposed permit was submitted to EPA on <<Date>>. All comments will be considered prior to a final permit decision.

PRELIMINARY DETERMINATION SUMMARY

Koch Methanol Facility
Agency Interest No.: 194165
Koch Methanol St. James, LLC
St. James, St. James Parish, Louisiana
PSD-LA-851
March 30, 2023

PSD REQUIREMENTS

This Preliminary Determination Summary summarizes the results of the reviews and analyses required by LAC 33:III.509. PSD requirements are outlined below.

A. Control Technology Review[1]

   1. Best Available Control Technology (BACT)
   2. Collateral Environmental Impacts

B. Air Quality Analysis[2]

   1. Preconstruction Monitoring
   2. Background Concentrations

C. Source Impact Analysis[3]

   1. Preliminary Screening
   2. National Ambient Air Quality Standards
   3. PSD Increments[4]
   4. Secondary $PM_{2.5}$ Formation

D. Additional Impact Analyses[5]

   Visibility
   Soils and Vegetation
   Commercial, Residential, Industrial, and Other Growth

E. Additional Requirements for Sources Impacting Class I Areas[6]

In the event of a discrepancy in the provisions found in the application and those in this Preliminary Determination Summary, the Preliminary Determination Summary shall prevail.

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[1] LAC 33:III.509.J
[2] LAC 33:III.509.M
[3] LAC 33:III.509.K
[4] LAC 33:III.509.C
[5] LAC 33:III.509.O
[6] LAC 33:III.509.P

PRELIMINARY DETERMINATION SUMMARY

Koch Methanol Facility
Agency Interest No.: 194165
Koch Methanol St. James, LLC
St. James, St. James Parish, Louisiana
PSD-LA-851
March 30, 2023

A. CONTROL TECHNOLOGY REVIEW

A.1 Best Available Control Technology

Per LAC 33:III.509.J.3, a major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed and modified emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation.

Consistent with EPA guidance, LDEQ utilizes the "top-down" approach to determine BACT.[7] This approach involves determining the most stringent control technique available for a similar or identical source. If it can be shown that this level of control is infeasible based on technical considerations or adverse energy, environmental, or economic impacts, it is rejected, and the next most stringent level of control is determined and similarly evaluated. This process continues until a control level is arrived at which cannot be eliminated due to technical difficulties or environmental, energy, or economic impacts. However, BACT may not result in emissions of any pollutant that would exceed an applicable standard under 40 CFR Part 60, 61, or 63. The five steps in the top-down process are described below.[8]

Step 1

The first step in a "top-down" analysis is to identify all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.

Step 2

In the second step, the technical feasibility of each control option identified in step 1 is evaluated with respect to source-specific (or emissions unit-specific) factors. Technically infeasible control options are then eliminated from further consideration.

Step 3

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[7] Note that it remains EPA's *policy* to use the top-down process to determine BACT. According to EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases":

> EPA has not established the top-down BACT process as a binding requirement through rule. Thus, permitting authorities that implement an EPA-approved PSD permitting program contained in their State Implementation Plans (SIPs) may use another process for determining BACT in permits they issue … so long as that process (and each BACT determination made through that process) complies with the relevant statutory and regulatory requirements. (p. 19, internal citations omitted).

[8] Where the top-down process does not provide meaningful information (e.g., if there is only one available control option), LDEQ may not summarize each of the five steps.

In step 3, all control alternatives not eliminated in step 2 are ranked in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. An applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options.[9]

Step 4

Next, the energy, environmental, and economic impacts of the available and technically feasible control options are considered. Impacts influencing LDEQ's BACT determination are addressed in this Preliminary Determination Summary; those which do not result in the elimination of a control option are detailed in the permit application.

Step 5

The most effective control option not eliminated in step 4 is selected as BACT.

LDEQ's BACT determinations for the emission units located at the Koch Methanol Facility follow.

BACT Analyses for $PM_{2.5}/PM_{10}$

BACT for Steam Methane Reformer and Auxiliary Boiler

EQT0001	**SMR**	**Steam Methane Reformer**
EQT0002	**BLR**	**Auxiliary Boiler**

Step 1 – Identify All Control Technologies

The SMR emits fiterable and condensable PM_{10} and $PM_{2.5}$. A gaseous fuel combustion device can emit PM_{10} and $PM_{2.5}$ due to incomplete combustion of higher molecular weight hydrocarbons in the device's gaseous fuel. However, the SMR will combust pipeline-quality natural gas and process gas primarily composed of hydrogen and relatively low molecular weight hydrocarbons. Therefore, elevated PM_{10} and $PM_{2.5}$ emissions from the SMR due to the incomplete combustion of high molecular weight hydrocarbons are not expected to occur. Additionally the referenced fuels will contain low levels of sulfur, further minimizing the generation of PM_{10} and $PM_{2.5}$ (condensable PM). Note, however, that ammonia addition to control NO_X with selective catalytic reduction (SCR) can result in increased PM_{10} and $PM_{2.5}$ emissions as a result of ammonia slip.

The boiler emits filterable and condensable PM_{10} and $PM_{2.5}$. A gaseous fuel combustion device can emit PM_{10} and $PM_{2.5}$ due to the incomplete combustion of higher molecular weight hydrocarbons present in the device's gaseous fuel. However, the boiler combusts pipeline quality natural gas and process gas composed primarily of hydrogen and relatively

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[9] "New Source Review Workshop Manual" (draft), October 1990 (p. B.8)

low molecular weight hydrocarbons. Therefore, elevated PM_{10} and $PM_{2.5}$ emissions from the boiler due to the incomplete combustion of high molecular weight hydrocarbons are not expected to occur. Additionally, the referenced fuels contain low levels of sulfur, further minimizing the generation of PM_{10} and $PM_{2.5}$ (condensable PM).

Based on a review of RBLC results and available literature, the following technologies were identified as available PM_{10}/$PM_{2.5}$ control technologies:

- Good Combustion Practices
- Electrostatic Precipitator (ESP)
- Wet Scrubber
- Filter
- Cyclone

Good Combustion Practices

Good combustion practices for a gaseous fuel enclosed combustion device entail properly setting and controlling the air-to-fuel ratio and ensuring appropriate combustion zone residence time, temperature, and turbulence parameters essential to achieving low emission levels for all products of combustion, including NO_X, CO, VOC, PM_{10}, and $PM_{2.5}$. Incomplete combustion of fuel hydrocarbons can occur because of improper combustion mechanisms, resulting from poor burner/combustion device design, operation, and/or maintenance. However, combustion devices (e.g., heaters, SMRs, boilers) are designed and typically operated to maximize fuel combustion efficiency so that fuel usage costs are minimized while maximizing process heating performance. Good combustion practices can be achieved by following a combustion device manufacturer's operating procedures and guidelines and by complying with 40 CFR 63 Subpart DDDDD (Boiler MACT) work practice standards, which require a combustion device to undergo regular tune-ups.

ESP

An ESP uses an electric field and collection plates to remove PM from a flowing gaseous stream. The PM in the gaseous stream is given an electric charge by passing the stream through a corona discharge. The resulting negatively charged PM is collected on grounded collection plates, which are periodically cleaned without re-entraining the PM into the flowing gaseous stream that the ESP is treating. In a dry ESP, the collection plate cleaning process is accomplished mechanically by knocking the PM loose from the plates. Alternatively, in a wet ESP, a washing technique is used to remove the collected PM from the collection plates. ESPs can be configured in several ways, including a plate-wire ESP, a flat-plate ESP, and a tubular ESP. As the diameter of the PM decreases, the efficiency of an ESP decreases.

Wet Scrubber

A wet scrubber uses absorption to remove PM from a gaseous stream. Absorption is primarily a physical process, though it can also include a chemical component in which a pollutant in a gas phase contacts a scrubbing liquid and is dissolved in the liquid. A key factor dictating the performance of a wet scrubber is the solubility of the pollutant of concern in the scrubbing liquid. Water is commonly used as the scrubbing liquid in a wet scrubber used for PM emission control, but other liquids can be used depending on the type of PM or other pollutant(s) to be removed from the gaseous stream undergoing treatment. There are several types of wet scrubbers, including packed-bed counter flow scrubbers, packed-bed cross-flow scrubbers, bubble plate scrubbers, and tray scrubbers.

Filter

A filter is a porous media that removes PM from a gaseous stream as the stream passes through the filter. For an emissions unit with an appreciable exhaust rate, the filter system typically contains multiple filter elements. Filters can be used to treat exhaust streams containing dry or liquid PM.

Filters handling dry PM become coated with collected PM during operation, and this coating ("cake") contributes to the filtration mechanism. A dry PM filter system commonly used in industrial scale applications is a "baghouse." A baghouse contains multiple cylindrical bags, and the number of bags is dependent on the flue gas air flow rate requiring treatment, the PM loading of the exhaust stream, and the baghouse design. The two most common baghouse designs today are the reverse-air and pulse-jet designs. These design references indicate the type of bag cleaning system used in the baghouse.

Filters handling liquid PM rely on the impingement of the entrained liquid PM on the surface of the filter media and the retention of these liquid particles on the surface until multiple particles coalesce into particles of sufficient size such that they fall back against the flowing gas stream and collect at a location below the filter. For the high efficiency removal of submicron liquid particles from a gaseous stream, Brownian diffusion filters are used. "Brownian diffusion" is the random movement of submicron particles in a gaseous stream as these particles collide with gas molecules. Liquid PM filter systems can use pad or candle filter elements. These filter elements require little operation and maintenance attention.

Cyclone

A cyclone is the most common type of inertial separator used to collect medium-sized and coarse PM from gaseous streams. The PM contained on a gaseous stream treated in a cyclone moves outward under the influence of centrifugal force until it contacts the wall of the cyclone. The PM is then carried downward by gravity along the wall of the cyclone and collected in a hopper located at the bottom of the cyclone. Although cyclones provide a relatively low cost, mechanically simple option for the removal of larger diameter PM from gaseous streams, alone they do not typically provide adequate PM removal, especially when the gaseous stream contains smaller diameter PM. Instead, these devices are typically used to pre-clean a gaseous stream by removing larger diameter PM upstream of PM emission control devices that are more effective at removing smaller diameter PM.

Step 2 – Eliminate Technically Infeasible Options

ESP

PM emitted by the SMR is estimated to be PM_{10} and $PM_{2.5}$ only, which is a characteristic that would limit the control effectiveness of an ESP. Additionally, the $PM_{2.5}$ and PM_{10} concentrations in the SMR exhaust stream are below the concentration typically seen in an ESP's exhaust stream. Thus, an ESP would not lower the emissions by any appreciable amount. Furthermore, research of emission control technology application data sets indicates an ESP has not been used to control PM emissions from a comparable source. These factors indicate it would not be technically feasible to use an ESP to control PM emissions from the SMR.

Filter

The PM_{10} and $PM_{2.5}$ concentrations in the SMR exhaust stream are below the concentration typically seen in a filter's exhaust stream. Thus, a filter would not lower the emissions by any appreciable amount. Furthermore, research of emission control technology application data sets indicates a filter has not been used to control PM emissions from a comparable source. These factors indicate it would not be technically feasible to use a filter to control PM emissions from the SMR.

Wet Scrubber

The $PM_{2.5}$ and PM_{10}-only profile of the SMR PM emissions indicates a wet scrubber would require a considerable pressure drop to effectively reduce the SMR's PM emissions. Additionally, the PM_{10} and $PM_{2.5}$ concentration in the SMR exhaust stream is below the concentration typically seen in a wet scrubber's exhaust stream. Furthermore, the liquid carryover in the exhaust stream from a wet scrubber contains dissolved and suspended solids, which would result in a new PM emission mechanism, reducing any negligible PM_{10} and $PM_{2.5}$ control effectiveness of the wet scrubber. Moreover, research of emission control technology application data sets indicates a wet scrubber has not been used to control PM emissions from a comparable source. These factors indicate it would not be technically feasible to use a wet scrubber to control PM emissions from the SMR.

Cyclone

The $PM_{2.5}$ and PM_{10}-only profile of the SMR's PM emissions would limit the control effectiveness of a cyclone. Additionally, the PM_{10} and $PM_{2.5}$ concentration in the SMR exhaust stream is below the concentration typically seen in a cyclone's exhaust stream. Thus, a cyclone would not lower the emissions by any appreciable amount. Furthermore, research of emission control technology application data sets indicates a cyclone has not been used to control PM emissions from a comparable source. These factors indicate it would not be technically feasible to use a cyclone to control PM emissions from the SMR.

The technical feasibility of the $PM_{2.5}$ and PM_{10} emission control methods identified as potential control options for the Auxiliary Boiler is sufficiently similar to that for the SMR system such that the above discussion of technical feasibility also applies to the Auxiliary Boiler.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only remaining available PM$_{10}$/PM$_{2.5}$ emission control technology for the SMR and boiler is good combustion practices.

Step 4 – Evaluate Most Effective Controls

The only remaining available PM$_{10}$/PM$_{2.5}$ emission control technology for the SMR and boiler is good combustion practices.

Step 5 – Select BACT

PM$_{10}$/PM$_{2.5}$ BACT for EQT0001, SMR – Steam Methane Reformer is determined to be the use of good combustion practices to limit PM$_{10}$/PM$_{2.5}$ emissions to 0.00745 lb/MMBtu (3-hour average). Compliance with the limit will be determined with performance testing on a 5-year frequency using EPA Methods 5 or 201A and 202, or alternate method as approved by LDEQ.

PM$_{10}$/PM$_{2.5}$ BACT for EQT0002, BLR – Auxiliary Boiler is determined to be the use of good combustion practices to limit PM$_{10}$/PM$_{2.5}$ emissions to 0.00745 lb/MMBtu (3-hour average). Compliance with the limit will be determined with performance testing on a 5-year frequency using EPA Methods 5 or 201a and 202, or alternate method as approved by LDEQ.

BACT for Emergency Engines

EQT0004	**EGEN**	**Plant Emergency Generator**
EQT0026	**EGEN2**	**Admin Building Emergency Generator**
EQT0005	**FWP-01**	**Firewater Pump Engine No. 1**
EQT0006	**FWP-02**	**Firewater Pump Engine No. 2**
EQT0022	**FWP-03**	**Firewater Pump Engine No. 3**
EQT0033	**E. GEN 01**	**Generac SD 2000**
EQT0034	**E. GEN 02**	**Generac SD 2000**

The Plant Emergency Generator (EPN EGEN, EQT0004) has a rating of 3,634 hp, and the Admin Building Emergency Generator (EPN EGEN2, EQT0026) has a rating of 210 hp. Firewater Pump Engines No. 1 and No. 2 each have a rating of 422 hp, and Firewater Pump Engine No. 3 has a rating of 237 hp. The Generac SD 2000 generator engines are both rated at 2923 hp. All engines are compression ignition (diesel), except for the Admin Building Emergency Generator, which runs on natural gas. The engines are subject to BACT for PM$_{10}$ and PM$_{2.5}$.

The use of these engines is limited to emergency situations, except for up to 100 hours per year, including maintenance testing. Because engine operation is intermittent and operating hours are limited, emissions from the engines are minimal, making most applications of add-on control devices technically and/or economically infeasible. Furthermore, all engines are subject to 40 CFR 60 Subpart IIII standards, except for the Admin Building Emergency

Generator, which is subject to 40 CFR 60 Subpart JJJJ standards.

The PM_{10} and $PM_{2.5}$ control technology options identified based on a review of RBLC results and available literature for similar engines are proper operation, good combustion practices, and compliance with 40 CFR 60 Subpart IIII for diesel-fired engines and 40 CFR 60 Subpart JJJJ for spark-ignited engines.

PM_{10}/$PM_{2.5}$ BACT for EQT0004, EGEN – Plant Emergency Generator; EQT0005, FWP-01 – Firewater Pump Engine No. 1; EQT0006, FWP-02 – Firewater Pump Engine No. 2; EQT0022, FWP-03 – Firewater Pump Engine No. 3; EQT0033, E. GEN 01 – Generac SD 2000; and EQT0034, E. GEN 02 – Generac SD 2000 is determined to be compliance with 40 CFR 60 Subpart IIII.

PM_{10}/$PM_{2.5}$ BACT for EQT0026, EGEN2 – Admin Building Emergency Generator is determined to be compliance with 40 CFR 60 Subpart JJJJ.

Note that Subparts IIII and JJJJ incorporate specific combustion (operational) and maintenance practices.

BACT for Cooling Water Tower

EQT0007	**CWT**	**Cooling Water Tower**

Step 1 – Identify All Control Technologies

Particulate matter emissions from the cooling tower occur as a result of dissolved or suspended particulates from the cooling water being entrained in the mist that drifts from the tower. The particulates in the cooling water are naturally occurring (i.e., they do not derive from the process). The primary particulate matter control method is to minimize drift, thereby minimizing particulate matter emissions.

Based on a review of RBLC results and available literature, the following technologies were identified as potential add-on PM_{10}/$PM_{2.5}$ control technologies:

- Drift Eliminators
- Indirect Contact Tower Exchangers
- Dry Cooling Tower Design

Drift Eliminators

High efficiency drift eliminators can substantially reduce the release of aerosol droplets from cooling towers. These drift eliminators consist of sections utilizing several varieties of structured media with tortuous air pathways. Changes of direction of the air flow passing through the eliminator promotes removal of droplets by coagulation and impaction on the eliminator surfaces. Aerosol generation is reduced with these eliminators to a range of 0.005 – 0.0005 percent of the circulating water flow compared to about 0.02 percent (AP-42 Table

13.4-1) for “uncontrolled” towers.

<u>Indirect Contact Tower Exchangers</u>
An indirect-contact style tower uses a sealed bank of exchanger tubes, bathed in a circulating water cascade, to cool process water. The circulating water side of the exchanger that is cooled by forced draft resembles a conventional wetted-media cooling tower; therefore, drift aerosols as well as $PM_{10}/PM_{2.5}$ emissions are not eliminated.

<u>Dry Cooling Tower Design</u>
Dry cooling towers are increasingly used to reject the heat of condensation from utility steam turbines, which can operate at much higher condensing temperatures (i.e., higher turbine discharge pressure) than the return cooling water temperature required for the KMe Facility’s processes.

Step 2 – Eliminate Technically Infeasible Options

<u>Indirect Contact Tower Exchangers</u>
The circulating water side of the exchanger that is cooled by forced draft resembles a conventional wetted-media cooling tower; therefore, drift aerosols as well as PM_{10} emissions will be generated. Therefore, indirect contact heat exchangers are not feasible for reduction of $PM_{10}/PM_{2.5}$ emissions. Additionally, the determinations in the RBLC for indirect contact cooling towers in other industries include higher drift losses than those of cooling towers with drift eliminators.

<u>Dry Cooling Tower Design</u>
This option is only technically feasible for use during cooler months because the ambient dry bulb temperature must be below the required cooling water supply temperature. Dry cooling could not be used for 4 to 6 months of the year in this location, as its use is limited to when ambient temperature is below 75°F.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only remaining available $PM_{10}/PM_{2.5}$ emission control technology for the Cooling Water Tower is drift eliminators.

Step 4 – Evaluate Most Effective Controls

The only remaining available $PM_{10}/PM_{2.5}$ emission control technology for the Cooling Water Tower is drift eliminators.

Step 5 – Select BACT

$PM_{10}/PM_{2.5}$ BACT for EQT0007, CWT – Cooling Water Tower is the use of drift eliminators with a drift rate of 0.0005%.

<u>BACT Analyses for CO</u>

BACT for Steam Methane Reformer and Auxiliary Boiler

EQT0001	**SMR**	**Steam Methane Reformer**
EQT0002	**BLR**	**Auxiliary Boiler**

Step 1 – Identify All Control Technologies

CO emissions from the SMR and boiler are a result of incomplete combustion. Specifically, CO results when there is insufficient residence time at high temperatures or incomplete mixing in the combustion zone to complete the final step in the oxidation of carbon from CO to CO_2. Further, control technologies for NO_X emissions, such as low-NO_X burners, may increase CO emissions.

Based on a review of RBLC results and available literature, the following technologies were identified as available CO control technologies:

- Good Combustion Practices
- Thermal Oxidation
- Catalytic Oxidation

<u>Thermal Oxidation</u>
Thermal oxidation can reduce CO in a source's exhaust stream by maintaining the stream at a high enough temperature in the presence of oxygen, resulting in the oxidation of CO to CO_2. Thermal oxidation of a CO exhaust stream can be achieved by routing the stream to a flare, afterburner, or regenerative or recuperative thermal oxidizer. The effectiveness of all thermal oxidation processes is influenced by residence time, mixing, and temperature. Auxiliary fuel is typically required to achieve the temperature needed to ensure proper CO exhaust stream oxidation in a thermal oxidation device or process. The necessary amount of auxiliary fuel depends on the CO and hydrocarbon content and temperature of the exhaust stream.

<u>Catalytic Oxidation</u>
Catalytic oxidation uses catalysts, such as platinum, palladium, or rhodium, without adding any chemical reagents, to reduce the temperature at which CO oxidizes to CO_2. The effectiveness of catalytic oxidation is dependent on the exhaust stream temperature and the presence of potentially poisoning contaminants in the exhaust stream. The amount of catalyst volume depends upon the exhaust stream flow rate, CO content, temperature, and desired CO removal efficiency. The catalyst will experience activity loss over time due to physical deterioration and chemical deactivation. Therefore, the catalyst must be periodically replaced. Catalyst life varies from manufacturer to manufacturer, but three- to six-year windows are not uncommon. Periodic testing of the catalyst is necessary to monitor its activity (i.e., oxidation-promoting effectiveness) and predict its remaining life.

Step 2 – Eliminate Technically Infeasible Options

Thermal Oxidation

Thermal oxidation is not technically feasible for controlling CO emissions from the SMR and boiler due to the very low concentration of CO in the exhaust stream. Applying thermal oxidation to reduce the CO emission rate would require the combustion of a considerable amount of fuel to achieve the elevated temperature necessary to promote the oxidation of the small amount of CO present in the exhaust stream. This fuel combustion would generate additional combustion pollutants, including CO. Thus, the CO emission reduction effectiveness of the thermal oxidation system would be reduced, if not negated, because of the CO generated by the thermal oxidation process.

In summary, the addition of a second thermal oxidation process to the SMR system and boiler may not reduce the CO emissions by any appreciable amount, if at all, and this add-on control technology would considerably increase the energy requirements of the SMR system and boiler and the amount of combustion pollutants, such as NO_X and CO_2, emitted into the atmosphere. Furthermore, research of emission control technology application data sets indicates thermal oxidation has not been used to control CO emissions from a comparable SMR or boiler. Based on these factors, it is not technically feasible to use thermal oxidation to control CO emissions from the SMR or boiler.

Good combustion practices and catalytic oxidation are considered technically feasible options for the SMR.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The technically feasible control options are ranked below according to their control effectiveness:

For the Steam Methane Reformer:

Rank	Control Technology	Control Effectiveness	Basis for Ranking
1	Catalytic Oxidation	80-90%	Vendor and Testing Data
2	Good Combustion Practices	Baseline	N/A

For the Auxiliary Boiler:

Rank	Control Technology	Control Effectiveness	Basis for Ranking
1	Catalytic Oxidation	80%	Vendor Data
2	Good Combustion Practices	Baseline	N/A

Step 4 – Evaluate Most Effective Controls

The existing SMR is already equipped with an oxidation catalyst, which is the highest ranked remaining control option.

The existing boiler is already equipped with oxidation catalyst, which is the highest ranked remaining control option. Nonetheless, Koch calculated the cost-effectiveness of oxidation catalyst, as shown in detail in Table II, as approximately $16,819 per ton of CO removed. This demonstrates that oxidation catalyst is not cost-effective for controlling CO emissions.

Additionally, good combustion practices are already an integral component of the design and operation of the SMR system and the boiler.

Step 5 – Select BACT

CO BACT for EQT0001, SMR – Steam Methane Reformer is determined to be the use of oxidation catalyst and good combustion practices to limit CO emissions to 0.0037 lb/MMBtu on a 12-month rolling average, for periods inclusive of normal operation as well as start-up, shutdown, and malfunction. Compliance with the limit will be determined utilizing a CO Continuous Emission Monitoring System (CEMS).

CO BACT for EQT0002, BLR – Auxiliary Boiler is determined to be the use of good combustion practices. The top-ranked control technology, oxidation catalyst, was determined to not be cost-effective. Nevertheless, the boiler is equipped with oxidation catalyst, which exceeds what is required to meet BACT. BACT and the use of oxidation catalyst will limit CO emissions to 0.0046 lb/MMBtu on a 12-month rolling average, for periods inclusive of normal operation as well as start-up, shutdown, and malfunction. Compliance with this limit will be determined utilizing a CO CEMS.

BACT for Fugitive Components

FUG0001	FUG	Fugitive Emissions – KMe Facility

Step 1 – Identify All Control Technologies

Process fugitive components at the KMe Facility, including valves, pumps, compressors, connectors, pressure relief devices, and other miscellaneous related equipment, have the potential to emit CO. Fugitive components that contain or contact CO may be subject to 40 CFR 60 Subpart VVa or 40 CFR 63 Subpart H due to their VOC or HAP content or may not be subject to any Leak Detection and Repair (LDAR) regulations. LDAR programs can be tailored for fugitive CO emission control.

<u>Equipment Design and LDAR</u>
Equipment design examples used to minimize piping components include: (1) a cap, plug, or second valve on an open-ended line; (2) a dual mechanical seal on a pump; and (3) a rupture

disk assembly on a pressure relief valve. These types of design features are reasonably priced and tend to be relatively easy and efficient to operate and maintain.

LDAR programs are used to identify piping components leaking material at a level warranting component repair (or replacement), and the effectiveness of these programs has been well established throughout many different industries over several decades. The primary features of an LDAR program are its leak monitoring frequency, leak detection level, and timely leak repair. A piping component may be checked for leakage by visual, audible, olfactory, or instrument techniques. For example, visual inspections may be used to identify leaks of heavy liquid material from connectors, valves, and pumps. Alternatively, a portable hydrocarbon detection instrument is typically used to identify (and measure) leaks of gases and light liquid materials from piping components. After a leak is detected, it must typically be repaired within a specific time period, followed by a subsequent leak inspection to ensure the leaking component was properly repaired.

For comparison to these practical equipment designs and LDAR practices, the use of a control device (e.g., flare, thermal oxidizer, carbon adsorption device) to control emissions from hundreds or thousands of connectors, valves, and pumps located across a wide area in a process unit is not practical because a substantial amount of piping and ductwork would be required to collect the component leaks, and the positive pressure leak collection piping and ductwork would include its own fugitive components with the potential to leak to the atmosphere. Additionally, potentially substantial amounts of collateral combustion emissions or solid waste would be generated by the control device. Therefore, this type of collection and control scheme is not further evaluated.

Step 2 – Eliminate Technically Infeasible Options

Equipment design and LDAR are currently used for the fugitive components in VOC service, and both are technically feasible for components in CO service.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only remaining available CO emission control technology for the fugitive components is the combination of equipment design and LDAR.

Step 4 – Evaluate Most Effective Controls

The fugitive components in VOC and HAP service at the KMe Facility are already part of an LDAR program. Koch will include components in CO service in the LDAR program for the site.

Step 5 – Select BACT

CO BACT for FUG0001, FUG – Fugitive Emissions – KMe Facility is determined to be a combination of equipment design and LDAR. Koch will implement a CO LDAR program for those components in CO service that are not subject to VVa and that contain >5% CO. The CO LDAR program will include relevant elements from Subpart VVa such as calendar-based leak monitoring, 5/15 day repair requirements, delay of repair (DOR), etc., and will be adjusted to appropriately accommodate requirements for CO. The CO LDAR plan must be submitted to LDEQ within 60 days of permit issuance. The CO LDAR program shall be implemented within 180 days following LDEQ's approval of the plan.

BACT for Emergency Engines

EQT0004	**EGEN**	**Plant Emergency Generator**
EQT0026	**EGEN2**	**Admin Building Emergency Generator**
EQT0005	**FWP-01**	**Firewater Pump Engine No. 1**
EQT0006	**FWP-02**	**Firewater Pump Engine No. 2**
EQT0022	**FWP-03**	**Firewater Pump Engine No. 3**
EQT0033	**E. GEN 01**	**Generac SD 2000**
EQT0034	**E. GEN 02**	**Generac SD 2000**

The Plant Emergency Generator (EPN EGEN, EQT0004) has a rating of 3,634 hp, and the Admin Building Emergency Generator (EPN EGEN2, EQT0026) has a rating of 210 hp. Firewater Pump Engines No. 1 and No. 2 each have a rating of 422 hp, and Firewater Pump Engine No. 3 has a rating of 237 hp. The Generac SD 2000 generator engines are both rated at 2923 hp. All engines are compression ignition (diesel), except for the Admin Building Emergency Generator, which runs on natural gas. The engines are subject to BACT for CO.

The use of these engines is limited to emergency situations, except for up to 100 hours per year, including maintenance testing. Because engine operation is intermittent and operating hours are limited, emissions from the engine are minimal, making most applications of add-on control devices technically and/or economically infeasible. Furthermore, all engines are subject to 40 CFR 60 Subpart IIII standards, except for the Admin Building Emergency Generator, which is subject to 40 CFR 60 Subpart JJJJ standards.

The CO control technology options identified based on a review of RBLC results and available literature for similar engines are proper operation, good combustion practices, and compliance with 40 CFR 60 Subpart IIII for diesel-fired engines and 40 CFR 60 Subpart JJJJ for spark-ignited engines.

CO BACT for EQT0004, EGEN – Plant Emergency Generator; EQT0005, FWP-01 – Firewater Pump Engine No. 1; EQT0006, FWP-02 – Firewater Pump Engine No. 2; EQT0022, FWP-03 – Firewater Pump Engine No. 3; EQT0033 E. GEN 01 – Generac SD 2000; and EQT0034, E. GEN 02 – Generac SD 2000 is determined to be compliance with 40 CFR 60 Subpart IIII.

CO BACT for EQT0026, EGEN2 – Admin Building Emergency Generator is determined to be compliance with 40 CFR 60 Subpart JJJJ.

Note that Subparts IIII and JJJJ incorporate specific combustion (operational) and maintenance practices.

BACT for Cooling Water Tower

EQT0007	**CWT**	**Cooling Water Tower**

Step 1 – Identify All Control Technologies

The KMe Facility includes a direct contact wet Cooling Water Tower (EPN CWT, EQT0007). CO has the potential to be introduced into the cooling water through leaks in plant heat exchangers. Based on current operations, Koch has quantified the potential to emit CO from Hazardous Organic NESHAP (HON)-regulated heat exchanger system leaks. The cooling tower is subject to the HON (40 CFR Part 63, Subpart F).

Based on a review of RBLC results and available literature, the following technologies were identified as available CO control technologies:

- Direct Contact Design with Exchanger Monitoring and Repair
- Indirect Contact Tower Exchangers
- Dry Cooling Tower Design

Direct Contact Design with Exchanger Monitoring and Repair
An effective measure to reduce releases of emissions from cooling towers is to institute a monitoring program for water-cooled heat exchangers.

Emissions from direct contact design cooling towers may occur when heat exchangers leak into cooling tower recirculating water. Water from direct contact cooling towers is circulated through heat exchangers throughout the plant to cool process streams. When a leak occurs in a shell and tube heat exchanger, and the process stream operates at a higher pressure than the cooling water stream pressure, the process stream contents are exposed to the circulated water and eventually contaminate the recirculating water stream. As the contaminated water enters the cooling tower, the contaminants in the process stream may be emitted into the atmosphere.

To reduce the possibility of hydrocarbon emissions, the inlet and outlet of a cooling tower can be sampled and analyzed to determine if a leak is present. Logs can be kept and maintained on site. For instance, the HON (40 CFR Part 63, Subpart F) requires cooling tower/heat exchanger monitoring to minimize HAP emissions. For streams containing a mixture of hydrocarbon and other contaminants, such as CO, the hydrocarbon sample results can be used to indicate presence of a leak not just of hydrocarbons, but also of CO, since CO is not directly measured. In such cases, the monitoring program can be utilized to minimize CO emissions, as well as hydrocarbons.

Indirect Contact Tower Exchangers
An indirect contact heat exchanger can be considered 100% effective. The process water that could contain CO is not exposed to the atmosphere in this type of tower.

Dry Cooling Tower Design
For control of CO emissions, a dry cooling tower can be considered 100% effective.

Step 2 – Eliminate Technically Infeasible Options

Indirect Contact Tower Exchangers
RBLC data indicates only a few instances of nondirect/indirect contact tower exchangers that are used in the metals industry, but do not indicate commercially proven installations in the chemical process industry for this technology. Indirect contact tower exchangers may also increase PM_{10} emissions from drift aerosols. Therefore, the use of indirect contact tower exchangers is eliminated from further evaluation.

Dry Cooling Tower Design
The dry cooling tower design option is only technically feasible for use during cooler months because the ambient dry bulb temperature must be below the required cooling water supply temperature. A dry cooling tower could not be used for 4 to 6 months of the year in this location, as its use is limited to when ambient temperature is below 75°F. Thus, dry cooling tower design is eliminated since not technically feasible in this location.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only remaining technically feasible CO emission control technology for the cooling water tower is a direct contact design with exchanger monitoring and repair.

Step 4 – Evaluate Most Effective Controls

The only remaining technically feasible CO emission control technology for the cooling water tower is a direct contact design with exchanger monitoring and repair.

Step 5 – Select BACT

CO BACT for EQT0007, CWT – Cooling Water Tower is determined to be a direct contact design with exchanger monitoring and repair in accordance with the HON (40 CFR 63, Subpart F).

BACT for Process Condensate Stripper Vent and Condensate Trap Vents

RLP0024	**PCSVENT**	**Process Condensate Stripper Vent**
RLP0025	**CTVENT**	**Condensate Trap Vents**

The KMe Facility includes a process condensate stripper that generates offgas that is routed to the SMR for fuel during normal process unit operations and potentially to the atmosphere during process unit outages and startups. The atmospheric vent is the Process Condensate Stripper Vent (EPN PCSVENT, RLP0024). The facility also includes a transfer line for the process condensate stripper offgas, which is equipped with steam traps. These steam traps, Condensate Trap Vents (EPN CTVENT, RLP0025), vent to the atmosphere.

The Process Condensate Stripper Vent regularly routes to the SMR and is only projected to vent to the atmosphere for a maximum of 100 hours per year. Estimated emissions of CO from venting to atmosphere are minimal (<2 TPY CO). The Condensate Trap Vents emit primarily steam with trace amounts of CO (<0.1 tpy) to the atmosphere. Because of the minimal estimated emissions from the vents, add-on controls are not considered feasible, as they would offer no appreciable decrease in emissions and would not be cost effective. Therefore, all control technologies have been eliminated from consideration, and no add-on controls are required as BACT for CO emissions from the Process Condensate Stripper Vent and Condensate Trap Vents.

BACT Analyses for NO_X

BACT for Steam Methane Reformer and Auxiliary Boiler

EQT0001	**SMR**	**Steam Methane Reformer**
EQT0002	**BLR**	**Auxiliary Boiler**

Step 1 – Identify All Control Technologies

The SMR and boiler emit NO_X primarily due to the thermal and prompt NO_X generation mechanisms because the fuel does not contain appreciable amounts of organo-nitrogen compounds that result in fuel NO_X emissions. Thermal NO_X results from the high-temperature thermal dissociation and subsequent reaction of combustion air molecular nitrogen and oxygen. It tends to be generated in the high-temperature zone near the burner of an external combustion device. The rate of thermal NO_X generation is affected by the following three factors: oxygen concentration, peak flame temperature, and the duration at peak flame temperature. As these three factors increase in value, the rate of thermal NO_X generation increases.

Prompt NO_X is generated at the flame front through the relatively fast reaction between combustion air nitrogen and oxygen molecules and fuel hydrocarbon radicals, which are intermediate species formed during the combustion process. Prompt NO_X may represent a meaningful portion of the NO_X emissions from Low NO_X Burners (LNBs) and Ultra Low NO_X Burners (ULNBs).

The Steam Methane Reformer contains two independent fuel/burner systems – SMR primary burners and SMR auxiliary burners. The primary SMR burners are currently equipped with ULNBs. The SMR auxiliary burners must be located within the SMR flue gas duct to balance the heat requirements of the flue gas waste heat recovery system. Due to these design constraints, the auxiliary burners do not employ LNB or ULNB technology. The SMR system (which includes the SMR and auxiliary burners) is equipped with selective catalytic reduction. The SMR system is not subject to an NSPS NO_X emission standard.

The boiler is currently equipped with LNBs, as well as selective catalytic reduction, and is subject to the NO_X emissions limit of 40 CFR 60 Subpart Db (0.10 lb/MMBTU, 30-day rolling average).

Good combustion practices are assumed to be a baseline work practice. They are not addressed as a BACT option for NOx since additional control levels beyond work practices are typically considered BACT. Based on a review of RBLC results and available literature, the following technologies were identified as available NO_X control technologies:

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- Non-Selective Catalytic Reduction (NSCR)
- Low NO_X Burners (LNB) and Ultra Low NO_X Burners (ULNB)

<u>Selective Catalytic Reduction (SCR)</u>
SCR is a post-combustion treatment technology that promotes the selective catalytic chemical reduction of NO_X (nitric oxide and nitrogen dioxide) to molecular nitrogen and water. SCR technology involves the mixing of a reducing agent (aqueous or anhydrous ammonia or urea) with NO_X-containing combustion gases, and the resulting mixture is passed through a catalyst bed, which serves to lower the activation energy of the NO_X reduction reactions. In the catalyst bed, the NO_X and ammonia contained in the combustion gas-reagent mixture are adsorbed onto the SCR catalyst surface to form an activated complex, and then the catalytic reduction of NO_X occurs, resulting in the production of nitrogen and water from NO_X. An excess amount of reducing agent/ammonia is required to achieve the desired conversion to NO_X, while unreacted ammonia (known as ammonia slip) is minimized. The nitrogen and water products of the SCR reaction are desorbed from the catalyst surface into the combustion exhaust gas passing through the catalyst bed. The treated combustion exhaust gas from the SCR catalyst bed, along with unreacted ammonia, is emitted to the atmosphere. SCR systems can effectively operate at a temperature above 350°F and below 1,100°F, with the specific temperature window dependent on the composition of the catalyst used in the SCR system.

<u>Selective Non-Catalytic Reduction (SNCR)</u>
SNCR is a post-combustion treatment technology that is effectively a partial SCR system. A reducing agent (aqueous or anhydrous ammonia or urea) is mixed with NO_X containing combustion gases, and a portion of the NO_X reacts with the reducing agent to form molecular nitrogen and water. SNCR does not utilize a catalyst to promote chemical reduction of NO_X.

Because a catalyst is not used with SNCR, NO_X reduction reactions occur at high temperatures. SNCR typically requires thorough mixing of the reagents in the combustion chamber of an external combustion device because this technology requires at least 0.5

seconds of residence time at a temperature above 1,600°F and below 2,100°F. A combustion device equipped with SNCR technology may require multiple reagent injection locations because the optimum location (temperature profile) for reagent injection may change depending on the load at which the combustion device is operating. At temperatures below 1,600°F, the desired NO_X reduction reactions will not effectively occur, and much of the injected reagent will be emitted to the atmosphere along with the mostly uncontrolled NO_X emissions. At temperatures above 2,100°F, the desired NO_X reduction reactions will not effectively occur, and the ammonia or urea reagent will begin to react with available oxygen to produce additional NO_X emissions.

Non-Selective Catalytic Reduction (NSCR)
NSCR is a post-combustion treatment technology that promotes the catalytic chemical reduction of NO_X (nitric oxide and nitrogen dioxide) to molecular nitrogen and water. NSCR technology has been applied to nitric acid plants and rich burn internal combustion engines to reduce NO_X emissions. NSCR technology uses a reducing agent (hydrocarbon, hydrogen, or CO), which can be inherently contained in the exhaust gas due to rich combustion conditions or injected into the exhaust gas, to react with a portion of the NO_X contained in the source's exhaust gas in the presence of a catalyst to generate molecular nitrogen and water. NSCR systems can effectively operate at a temperature above 725°F and below 1,200°F, with the specific temperature window dependent on the source type and composition of the catalyst used in the NSCR system.

Low NO_X Burners (LNBs) with Flue Gas Recirculation (FGR) / Ultra Low NO_X Burners (ULNBs)
LNBs/ULNBs are available in various configurations and burner types. They incorporate one or more of the following concepts: lower flame temperatures, fuel rich conditions at the maximum flame temperature, and decreased residence times for oxidation conditions. These burners are often designed so that fuel and air are pre-mixed prior to combustion, resulting in lower and more uniform flame temperatures. Pre-mix burners may require the aid of a blower to mix the fuel with air before combustion takes place.

LNBs may be designed so that a portion of a combustion device's flue gas is recycled back into the burner to reduce the burner's flame temperature, also known as external flue gas recirculation (EFGR). Or, instead of recycled flue gas, steam can also be used to reduce a burner's flame temperature. ULNBs are often designed such that flue gas recirculation is incorporated directly into the burner rather than as additional equipment. The combination of LNBs with flue gas recirculation can achieve a similar amount of NO_X reduction to that of ULNBs. LNBs/ULNBs use staged fuel or air combustion, which involves creating a fuel rich zone to start combustion and stabilize a burner's flame, followed by a fuel lean zone to complete combustion and reduce the burner's peak flame temperature.

Step 2 – Eliminate Technically Infeasible Options

SNCR
SNCR control technology poses design and operational technical difficulties that render its

application technically infeasible for the SMR. In the SNCR process, a reagent is injected into the flue gas stream and reacts with NO_X to form nitrogen and water vapor. SNCR does not utilize a catalyst to promote the chemical reduction of NO_X. The most common reagents used in an SNCR system are urea, aqueous ammonia, and anhydrous ammonia, with the reagents being injected into the flue gas stream within a specific temperature window to ensure optimum reduction of NO_X. Because no catalyst is used, the SNCR process requires extremely high flue gas temperature (1,600 to 2,100°F) to disassociate NO_X to nitrogen and water vapor. The SMR at the KMe Facility has flue gas exit temperatures that are much lower than that required for the SNCR process. Due to the extremely high temperature required for SNCR operation, this option has been considered technically infeasible for other similar sources. Based on these considerations, SNCR is considered technically infeasible for the SMR.

NSCR

NSCR uses a catalyst reaction to reduce NO_X, CO, and VOC to form water, CO_2, and nitrogen. NSCR requires a high flue gas temperature (800 – 1,200°F) and works best with certain windows of inlet concentrations for NO_X (2,000 – 4,000 ppmv), CO (3,000 – 6,000 ppmv), and VOC (1,000 – 2,000 ppmv). These operating windows are necessary because the catalyst was developed to react the NO_X, CO, and VOC with one another, reducing the emissions of each. The low flue gas temperature and component concentrations of the SMR exhaust would make NSCR ineffective; therefore, NSCR is considered technically infeasible for the SMR.

LNBs with FGR/ULNBs

LNBs/ULNBs are considered technically feasible options for the primary SMR burner system. They are not technically feasible options for the SMR auxiliary burners due to the type of design needed for locating the auxiliary burners within the SMR flue gas duct for heat recovery.

The technical feasibility of SNCR and NSCR identified as potential control options for the Auxiliary Boiler is sufficiently similar to that for the SMR system such that the discussion of technical feasibility also applies to the boiler.

SCR and LNBs/ULNBs are considered technically feasible options for the SMR and boiler.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The technically feasible control options are ranked below according to their control effectiveness:

Rank	Control Technology	Control Effectiveness	Basis for Ranking
1	SCR	>90%	EPA Control Cost Manual
2	ULNB/LNB+FGR	55-84%	U.S. Department of Energy Low-Emission Boiler Guidance

Rank	Control Technology	Control Effectiveness	Basis for Ranking
3	LNB	0-71%	U.S. Department of Energy Low-Emission Boiler Guidance

Step 4 – Evaluate Most Effective Controls

The SMR and boiler are already equipped with the top-ranked control option, which is SCR. The primary SMR burners are also equipped with the next highest-ranked control option, ULNBs. The boiler is also equipped with LNBs. Thus, consideration of lesser ranked options does not need to be addressed in this BACT evaluation.

Step 5 – Select BACT

NO_X BACT for EQT0001, SMR – Steam Methane Reformer is determined to be the use of the SCR with an emission limit of 0.01 lb/MMBtu on a 12-month rolling average, for periods inclusive of normal operation as well as start-up, shutdown, and malfunction. This limit is within the range of emission limits in the RBLC from recent BACT determinations, is justified based on the unique characteristics of auxiliary burner design, and balances the emissions of NO_X, ammonia, and $PM_{2.5}$ due to SCR control. Compliance with this BACT emission limit will be determined by utilizing a NO_X continuous emissions monitoring system (CEMS).

NO_X BACT for EQT0002, BLR – Auxiliary Boiler is determined to be the use of the SCR with an emission limit of 0.01 lb/MMBtu on a 12-month rolling average, for periods inclusive of normal operation as well as start-up, shutdown, and malfunction. This limit is within the range of emission limits in the RBLC from recent BACT determinations, is justified based on the unique characteristics of auxiliary burner design, and balances the emissions of NOx, ammonia, and $PM_{2.5}$ due to SCR control. Compliance with this BACT emission limit will be determined by utilizing a NO_X CEMS.

As noted above, minimum temperatures are required to operate the SCR as a control device. During low firing periods, when the SCR is below these minimum temperatures, the SCR will be bypassed. During this time, good combustion practices will be utilized, including ramping up the temperature as quickly as possible within safe operating limits. The NO_X generated during these periods will be subject to the annual NO_X emission limit.

BACT for Emergency Engines

EQT0004	**EGEN**	**Plant Emergency Generator**
EQT0026	**EGEN2**	**Admin Building Emergency Generator**
EQT0005	**FWP-01**	**Firewater Pump Engine No. 1**
EQT0006	**FWP-02**	**Firewater Pump Engine No. 2**
EQT0022	**FWP-03**	**Firewater Pump Engine No. 3**
EQT0033	**E. GEN 01**	**Generac SD 2000**

EQT0034	**E. GEN 02**	**Generac SD 2000**

The Plant Emergency Generator (EPN EGEN, EQT0004) has a rating of 3,634 hp, and the Admin Building Emergency Generator (EPN EGEN2, EQT0026) has a rating of 210 hp. Firewater Pump Engines No. 1 and No. 2 each have a rating of 422 hp, and Firewater Pump Engine No. 3 has a rating of 237 hp. The Generac SD 2000 generator engines are both rated at 2923 hp. All engines are compression ignition (diesel), except for the Admin Building Emergency Generator, which runs on natural gas. The engines are subject to BACT for NO_X.

The use of these engines is limited to emergency situations, except for up to 100 hours per year, including maintenance testing. Because engine operation is intermittent and operating hours are limited, emissions from the engine are minimal, making most applications of add-on control devices technically and/or economically infeasible. Furthermore, all engines are subject to 40 CFR 60 Subpart IIII standards, except for the Admin Building Emergency Generator, which is subject to 40 CFR 60 Subpart JJJJ standards.

The NO_X control technology options identified based on a review of RBLC results and available literature for similar engines are proper operation, good combustion practices, and compliance with 40 CFR 60 Subpart IIII for diesel-fired engines and 40 CFR 60 Subpart JJJJ for spark-ignited engines.

NO_X BACT for EQT0004, EGEN – Plant Emergency Generator; EQT0005, FWP-01 – Firewater Pump Engine No. 1; EQT0006, FWP-02 – Firewater Pump Engine No. 2; EQT0022, FWP-03 – Firewater Pump Engine No. 3; EQT0033 E. GEN 01 – Generac SD 2000; and EQT0034, E. GEN 02 – Generac SD 2000 is determined to be compliance with 40 CFR 60 Subpart IIII.

NO_X BACT for EQT0026, EGEN2 – Admin Building Emergency Generator is determined to be compliance with 40 CFR 60 Subpart JJJJ.

Note that Subparts IIII and JJJJ incorporate specific combustion (operational) and maintenance practices.

BACT Analyses for VOC

BACT for Steam Methane Reformer and Auxiliary Boiler

EQT0001	**SMR**	**Steam Methane Reformer**
EQT0002	**BLR**	**Auxiliary Boiler**

Step 1 – Identify All Control Technologies

The SMR emits VOC due to the incomplete oxidation of hydrocarbons present in the gaseous fuel. However, the low molecular weight characteristic of the hydrocarbons in the fuel promotes low levels of VOC emissions from the SMR.

Based on a review of RBLC results and available literature, the following technologies were identified as available VOC control technologies:

- Good Combustion Practices
- Thermal Oxidation
- Catalytic Oxidation

Thermal Oxidation
Thermal oxidation can be used to reduce VOC contained in a source's exhaust stream by maintaining the stream at a high enough temperature in the presence of oxygen, resulting in the oxidation of VOC. Thermal oxidation of a VOC exhaust stream can be achieved by routing the stream to a flare, afterburner, or regenerative or recuperative thermal oxidizer. The effectiveness of all thermal oxidation processes is influenced by residence time, mixing, and temperature. Auxiliary fuel is typically required to achieve the temperature needed to ensure proper VOC exhaust stream oxidation in a thermal oxidation device or process. The necessary amount of auxiliary fuel is dependent on the VOC content and temperature of the exhaust stream.

Catalytic Oxidation
Catalytic oxidation uses catalysts, such as platinum, palladium, or rhodium, without adding any chemical reagents, to reduce the temperature at which VOC oxidizes. The effectiveness of catalytic oxidation is dependent on the exhaust stream temperature and the presence of potentially poisoning contaminants in the exhaust stream. The amount of catalyst volume depends upon the exhaust stream flow rate, VOC content, and temperature, as well as the desired VOC removal efficiency. The catalyst will experience activity loss over time due to physical deterioration and chemical deactivation. Therefore, the catalyst must be periodically replaced. Catalyst life varies from manufacturer to manufacturer, but three- to six- year windows are not uncommon. Periodic testing of the catalyst is necessary to monitor its activity (i.e., oxidation promoting effectiveness) and predict its remaining life.

Step 2 – Eliminate Technically Infeasible Options

Thermal Oxidation
Thermal oxidation is not technically feasible for the control of VOC emissions from the SMR due to the very low concentration of VOC in the exhaust stream. The application of thermal oxidation to reduce the VOC emission rate would require the combustion of a considerable amount of fuel to achieve the elevated temperature necessary to promote the oxidation of the small amount of VOC that will be present in the exhaust stream. This fuel combustion would generate additional combustion pollutants, including VOC. Thus, the VOC emission reduction effectiveness of the thermal oxidation system would be reduced, if not negated, because of the VOC generated by the thermal oxidation process.

In summary, the addition of a second thermal oxidation process to the SMR system may not reduce the VOC emissions by any appreciable amount, if at all, and this add-on control technology would considerably increase the energy requirements of the SMR system and the amount of combustion pollutants, such as NO_X and CO_2, emitted into the atmosphere. Furthermore, research of emission control technology application data sets indicated thermal oxidation has not been used to control VOC emissions from a comparable source. These factors indicate that it is not technically feasible to use thermal oxidation to control VOC emissions from the SMR.

Good combustion practices and catalytic oxidation are considered technically feasible options for controlling VOC emissions from the SMR.

The technical feasibility of the VOC control methods identified as potential control options for the Auxiliary Boiler is sufficiently similar to that for the SMR system such that the discussion of technical feasibility also applies to the Auxiliary Boiler.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The technically feasible control options are ranked below according to their control effectiveness:

For the Steam Methane Reformer:

Rank	Control Technology	Control Effectiveness	Basis for Ranking
1	Catalytic Oxidation	30-70%	Testing Data
2	Good Combustion Practices	Baseline	N/A

For the Auxiliary Boiler:

Rank	Control Technology	Control Effectiveness	Basis for Ranking
1	Catalytic Oxidation	80%	Vendor Data
2	Good Combustion Practices	Baseline	N/A

Step 4 – Evaluate Most Effective Controls

The existing SMR is already equipped with an oxidation catalyst, which is the highest ranked remaining control option. Nonetheless, Koch calculated the economic feasibility of oxidation catalyst installation. The cost-effectiveness of installing an oxidation catalyst, as shown in detail in Table II, is approximately $125,832 per ton of VOC removed. This demonstrates that oxidation catalyst is not cost-effective for controlling VOC emissions from the SMR system.

The existing boiler is already equipped with oxidation catalyst, which is the highest ranked remaining control option. Nonetheless, Koch calculated the cost-effectiveness of oxidation catalyst installation, as shown in detail in Table II, as approximately $177.762 per ton of VOC removed. This demonstrates that oxidation catalyst is not cost-effective for controlling VOC emissions from the boiler.

Additionally, good combustion practices are already an integral component of the design and operation of the SMR system and the boiler.

Step 5 – Select BACT

VOC BACT for EQT0001, SMR – Steam Methane Reformer is determined to be the use of good combustion practices. The top-ranked control technology, oxidation catalyst, was determined to not be cost-effective. Nevertheless, the SMR is equipped with oxidation catalyst, which exceeds what is required to meet BACT. BACT and the use of oxidation catalyst will limit VOC emissions to 0.00374 lb/MMBtu on a 3-hour average. This is consistent with the emission limit range from recent BACT determinations in the RBLC for steam methane reformers and is justified based on the additional VOC generated by the auxiliary burners. Compliance with this limit will be determined with a performance test every 5 years using Method 25a, or alternate method with prior approval from LDEQ.

VOC BACT for EQT0002, BLR – Auxiliary Boiler is determined to be the use of good combustion practices. The top-ranked control technology, oxidation catalyst, was determined not to be cost-effective. Nevertheless, the boiler is equipped with oxidation catalyst, which exceeds what is required to meet BACT. BACT and the use of oxidation catalyst will limit VOC emissions to 0.0016 lb/MMBtu on a 3-hour average. This limit is consistent with the emission limit range from recent BACT determinations in the RBLC for auxiliary boilers and substantially lower than the most common emission limit. Compliance with this limit will be determined with a performance test every 5 years using Method 25a, or alternate method with prior approval from LDEQ.

BACT for Process Vents – VOC

EQT0003	FLR	Flare

The KMe Facility has numerous process vents, which route process gases containing VOCs to the KMe Facility's Flare for destruction, which is typical for most plants in the chemical industry. Additionally, flares have been widely accepted as control for VOC, achieving 98% control when properly designed and operated.

Routing process vents to the Flare is considered BACT for VOC emissions from process vent streams. The flare will be designed and operated in accordance with 40 CFR 60.18 and 40 CFR 63.11, General Control Device and Work Practice Requirements, to achieve 98% control of VOC emissions routed to it. Both 40 CFR 60.18 and 40 CFR 63.11 include operating specifications (exit velocity, heat content, etc.) and monitoring requirements, as well as a requirement that the flare be operated with a flame present at all times.

Koch considered whether implementation of flare gas recovery would be feasible. The flare header has an estimated VOC content of approximately 1%. Streams that are routinely sent to the flare during normal operation as well as during startup and shutdown activities primarily contain CO, hydrogen, nitrogen, and methane, which are not VOCs. Larger amounts of VOC sent to the flare could occur during a process leak or similar event, which is rare. Due to the low frequency of such events, coupled with the low VOC content of most gas streams sent to the flare, flare gas recovery is not technically feasible. Additionally, a flare gas recovery system is not beneficial if the plant trips, since any recovered gas would not be able to be reprocessed, rendering the flare gas recovery process inoperable, and plant trips account for the majority of flaring emissions.

The flare emits combustion pollutants, including NO_X, CO, PM_{10}, $PM_{2.5}$, VOC, and GHG. The most effective ways to minimize emissions from the flare are to minimize the frequency and duration of start-up and shutdown events when elevated amounts of process gases are routed to the flare, and to operate the flare in accordance with NSPS and MACT work practice standards. Although not a control mechanism, KMe is currently pursuing (apart from this permitting action) two improvements to raw material procurement that should reduce flaring emissions. One of these includes adding an alternate natural gas feed line from a different supplier to limit shutdowns due to loss of natural gas supply from the current supplier. KMe is also working with a separately owned facility that supplies oxygen to the KMe Facility to minimize KMe shutdowns due to loss of oxygen from inadvertent trips of their plant.

BACT for Loading Operations

EQT0028	**RT LOAD**	**Methanol Railcar and Tank Truck Loading Operations**

Step 1 – Identify All Control Technologies

The Methanol Railcar and Tank Truck Loading Operations (EPN RT LOAD, EQT0028) represent the loading of methanol product into trucks and railcars. Loading methanol results in potential VOC emissions to the atmosphere because of the displacement of VOC-containing vapor. Specifically, as methanol is loaded into a truck or railcar vessel, the VOC-laden vapor space in the vessel is displaced and emitted directly to the atmosphere if a vapor collection system is not used during the loading operation. Currently, a Vapor Control Unit (VCU) is used to control captured VOC emissions from railcar and truck loading operations. Based on calculated truck and rail loading emissions to the VCU, and a performance test conducted in March 2021 to determine the total organic carbon (TOC) concentration of the VOC exhaust, the VCU achieves 99% VOC control. Submerged fill loading is integrated into the truck loading, but is not incorporated into the rail loading system.

Based on a review of RBLC results and available literature, the following technologies were identified as potential add-on VOC control technologies:

- Thermal Oxidation
- Catalytic Oxidation
- Vapor Recovery Unit (e.g., Condensation, Carbon Adsorption)
- Submerged Fill Loading

Refer to previous sections within this BACT summary for a discussion of thermal oxidation and catalytic oxidation technology.

Condensation
In principle, a condenser achieves condensation by lowering the temperature of the gas stream containing a condensable to a temperature at which the desired condensate's vapor pressure is lower than its entering partial pressure. Condensation is performed by either a surface noncontact condenser or a direct-contact condenser. A surface condenser is usually a shell-and-tube heat exchanger in which the cooling fluid flows inside the tubes of the exchanger and the gas undergoing condensation treatment flows on the outside of the tubes. A direct-contact condenser is a device in which intimate contact occurs between the cooling fluid and the gas undergoing condensation treatment, usually in a spray or packed tower. Although a direct-contact condenser may also be part of a chemical recovery system, an extra separation step is usually required to separate the cooling liquid from the newly formed condensate. Examples of cooling fluids used in condensers are water, brine cooled to below the freezing point of pure water, and refrigerants.

Carbon Adsorption
Carbon adsorption is used to capture a specific compound, or a range of compounds, present in a gas phase on the surface of granular activated carbon. Carbon adsorption performance depends on the type of activated carbon used; the characteristics of the target compound(s); the concentration of the target compound(s) in the gaseous stream; and the temperature, pressure, and moisture content of the gaseous stream. Carbon adsorbers can be of the fixed-bed or fluidized bed design. A fixed-bed carbon adsorber must be periodically regenerated to desorb the collected compounds from the carbon, while a fluidized-bed carbon adsorber is continuously regenerated. Additionally, portable, easily replaceable carbon adsorption units (e.g., 55-gallon drums) are used in some applications. This type of unit is not regenerated at the facility where it is used. Instead, the portable unit is typically returned to the supplier of the unit, and the supplier regenerates or disposes of the spent carbon.

Submerged Fill Loading
By incorporating submerged fill into the loading activity, the saturation level of the vapor space between the surface of the liquid contained in the cargo vessel and the roof of the vessel can be reduced versus the level that would occur if the liquid were introduced into the vessel under splash loading conditions. By reducing the saturation level of the vapor space, the vapor vented from the cargo vessel during loading contains less VOC, resulting in lower VOC emissions from the vessel.

Step 2 – Eliminate Technically Infeasible Options

All potential VOC emission control technologies are technically feasible for the Methanol Railcar and Tank Truck Loading Operations.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

For the Methanol Railcar and Tank Truck Loading Operations, the available add-on VOC emission control technologies are all effectively the same with respect to VOC emission control capabilities. Submerged fill loading alone is not as effective as the other add-on VOC emission control options, but can provide additional control when combined with other control technologies.

Rank	Control Technology	Control Effectiveness	Basis for Ranking
1	Thermal Oxidation (VCU)	95-98%	EPA Control Cost Manual
	Carbon Adsorption	95-98%	EPA Control Cost Manual
	Wet Scrubber	95-98%	EPA Control Cost Manual
	Condensation	90-98%	EPA Control Cost Manual
	Catalytic Oxidation	80-98%	EPA Control Cost Manual
6	Submerged Fill Loading	33-58%	AP-42 Emission Factors

Step 4 – Evaluate Most Effective Controls

Methanol Railcar and Tank Truck Loading Operations are currently equipped with a VCU for vapor control. Additionally, the truck loading operation is also equipped with submerged fill loading, whereas the rail loading utilizes a dip tube, which is not a fully submerged fill loading system. Routing displaced vapors to a control unit is one of the top-ranked add-on control options, and both truck and rail loading are also equipped with some level of submerged fill loading, which is the only other available control option.

Koch estimates that incorporating submerged fill loading into the original design of the railcar loading rack would have required an additional capital investment of $2,268,000. This is based on 50% of the cost of retrofitting the existing rack with submerged fill loading. Because the railcar loading emissions are controlled by one of the top-ranked control options, a VCU, which reduces emissions from the railcar loading operation by 98%, adding submerged fill loading would not achieve a significant reduction in VOC emissions. As a result, the cost effectiveness of constructing a fully submerged fill for railcar loading is $33,097 per ton of VOC removed. Note that the cost effectiveness calculation includes annual savings that would be realized from the reduction in the methanol concentration of the vapors generated during loading due to the installation of submerged fill (less methanol sent to the VCU thus more methanol loaded into railcars). Due to estimated high capital cost and resulting high cost-effectiveness, it is not cost effective to install submerged fill for railcar loading operations. See Table II for the BACT cost effectiveness calculations that support this conclusion.

Step 5 – Select BACT

VOC BACT for EQT0028, RT LOAD – Methanol Railcar and Tank Truck Loading Operations is determined to be routing displaced vapors to a vapor control unit capable of achieving 98% reduction of VOC emissions. VOC emissions will also be limited to 18.54 lb/hr. This mass emission limit is based on achieving 99% control of the uncontrolled methanol loading emissions, which has been previously demonstrated and exceeds what is required to meet BACT. Compliance with the VOC limit will be determined with a performance test every 5 years using Method 25a, or other approved method as approved by LDEQ.

BACT for Wastewater Treatment

FUG0002	**WWT**	**Wastewater Treatment**

The KMe Facility includes Wastewater Treatment, which consists of typical treatment operations including equalization, biological treatment, clarification, and sludge treatment. The wastewater equipment is currently subject to 40 CFR 63, Subpart G requirements. Higher concentration methanol wastewater streams are routed to the closed methanol slop system for reprocessing; only very dilute methanol wastewater streams are routed to Wastewater Treatment. All streams routed to Wastewater Treatment meet the definition of a "Group 2 wastewater stream" under 40 CFR 63.111. With the increase in production rate, Koch concluded there would be no change in this status. Limited monitoring/recordkeeping requirements under 40 CFR 63, Subpart G apply to Group 2 wastewater streams.

Based on a review of RBLC results and available literature, VOC BACT for FUG0002, WWT – Wastewater Treatment plant is determined to be compliance with applicable HON requirements (i.e., 40 CFR 63 Subpart G).

BACT for Fugitive Components - VOC

FUG0001	**FUG**	**Fugitive Emissions – KMe Facility**

Step 1 – Identify All Control Technologies

Process fugitive components at the KMe Facility, including valves, pumps, compressors, connectors, pressure relief devices, and other miscellaneous related equipment, have the potential to emit VOC. Fugitive components that are in VOC and organic HAP service are subject to the leak detection and repair (LDAR) requirements of 40 CFR 60, Subpart VVa and 40 CFR 63 Subpart H, respectively.

Equipment Design and LDAR

Equipment design examples used to minimize piping components include: (1) a cap, plug, or second valve on an open-ended line; (2) a dual mechanical seal on a pump; and (3) a rupture disk assembly on a pressure relief valve. These types of design features are reasonably priced and tend to be relatively easy and efficient to operate and maintain.

LDAR programs are used to identify piping components leaking material at a level warranting component repair (or replacement), and the effectiveness of these programs has been well established throughout many different industries over several decades. The primary features of an LDAR program are its leak monitoring frequency, leak detection level, and timely leak repair. A piping component may be checked for leakage by visual, audible, olfactory, or instrument techniques. For example, visual inspections may be used to identify leaks of heavy liquid material from connectors, valves, and pumps. Alternatively, a portable hydrocarbon detection instrument is typically used to identify (and measure) leaks of gases and light liquid materials from piping components. After a leak is detected, it must typically be repaired within a specific time period, followed by a subsequent leak inspection to ensure the leaking component was properly repaired.

For comparison to these practical equipment designs and LDAR practices, the use of a control device (e.g., flare, thermal oxidizer, carbon adsorption device) to control emissions from hundreds or thousands of connectors, valves, and pumps located across a wide area in a process unit is not practical because a substantial amount of piping and ductwork would be required to collect the component leaks, and the positive pressure leak collection piping and ductwork would include its own fugitive components with the potential to leak to the atmosphere. Additionally, potentially substantial amounts of collateral combustion emissions or solid waste would be generated by the control device. Therefore, this type of collection and control scheme is not further evaluated.

Step 2 – Eliminate Technically Infeasible Options

Equipment design and LDAR are currently used for the fugitive components. Therefore, both are technically feasible.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only remaining available VOC emission control technology for the fugitive components is the combination of equipment design and LDAR.

Step 4 – Evaluate Most Effective Controls

The fugitive components in VOC service and in organic HAP service at the KMe Facility are already part of an LDAR program.

Step 5 – Select BACT

VOC BACT for FUG0001, FUG – Fugitive Emissions – KMe Facility is determined to be a combination of equipment design and LDAR pursuant to 40 CFR 60, Subpart VVa and 40 CFR 63, Subpart H, as applicable.

BACT for Emergency Engines

EQT0004	**EGEN**	**Plant Emergency Generator**
EQT0026	**EGEN2**	**Admin Building Emergency Generator**
EQT0005	**FWP-01**	**Firewater Pump Engine No. 1**
EQT0006	**FWP-02**	**Firewater Pump Engine No. 2**
EQT0022	**FWP-03**	**Firewater Pump Engine No. 3**
EQT0033	**E. GEN 01**	**Generac SD 2000**
EQT0034	**E. GEN 02**	**Generac SD 2000**

The Plant Emergency Generator (EPN EGEN, EQT0004) has a rating of 3,634 hp, and the Admin Building Emergency Generator (EPN EGEN2, EQT0026) has a rating of 210 hp. Firewater Pump Engines No. 1 and No. 2 each have a rating of 422 hp, and Firewater Pump Engine No. 3 has a rating of 237 hp. The Generac SD 2000 generator engines are both rated at 2923 hp. All engines are compression ignition (diesel), except for the Admin Building Emergency Generator, which runs on natural gas. The engines are subject to BACT for VOC.

The use of these engines is limited to emergency situations, except for up to 100 hours per year, including maintenance testing. Because engine operation is intermittent and operating hours are limited, emissions from the engine are minimal, making most applications of add-on control devices technically and/or economically infeasible. Furthermore, all engines are subject to 40 CFR 60 Subpart IIII standards, except for the Admin Building Emergency Generator, which is subject to 40 CFR 60 Subpart JJJJ standards.

The VOC control technology options identified based on a review of RBLC results and available literature for similar engines are proper operation, good combustion practices, and compliance with 40 CFR 60 Subpart IIII for diesel-fired engines and 40 CFR 60 Subpart JJJJ for spark-ignited engines.

VOC BACT for EQT0004, EGEN – Plant Emergency Generator; EQT0005, FWP-01 – Firewater Pump Engine No. 1; EQT0006, FWP-02 – Firewater Pump Engine No. 2; EQT0022, FWP-03 – Firewater Pump Engine No. 3; EQT0033 E. GEN 01 – Generac SD 2000; and EQT0034, E. GEN 02 – Generac SD 2000 is determined to be compliance with 40 CFR 60 Subpart IIII.

VOC BACT for EQT0026, EGEN2 – Admin Building Emergency Generator is determined to be compliance with 40 CFR 60 Subpart JJJJ.

Note that Subparts IIII and JJJJ incorporate specific combustion (operational) and maintenance practices.

BACT for Cooling Water Tower

EQT0007 CWT Cooling Water Tower

Step 1 – Identify All Control Technologies

The KMe Facility includes a direct contact wet Cooling Water Tower (EPN CWT, EQT0007). VOC and other contaminants have the potential to be introduced into the cooling water through leaks in plant heat exchangers. During direct contact with ambient air, hydrocarbons and other contaminants in the circulating water may be volatilized. This represents a potential source of emissions that is independent of the aerosol drift rate, as it is assumed that volatile hydrocarbons and other contaminants in the water will be stripped into the gas phase to an extent dictated by vapor-liquid equilibrium and mass transfer factors. The cooling tower is subject to HON (40 CFR Part 63, Subpart F).

Based on a review of RBLC results and available literature, the following technologies were identified as available VOC control technologies:

- Direct Contact Design with Exchanger Monitoring and Repair
- Indirect Contact Tower Exchangers
- Dry Cooling Tower Design

Direct Contact Design with Exchanger Monitoring and Repair
One effective measure to reduce releases of hydrocarbons from cooling towers is to institute a periodic monitoring program for water-cooled heat exchangers. Water from the cooling towers will be circulated through heat exchangers throughout the plant to cool process streams. When a leak occurs in a shell and tube heat exchanger, the hydrocarbons from the hydrocarbon side are exposed to the circulating water and eventually contaminate the recirculating water stream. As the contaminated water enters the cooling tower, VOC may be emitted into the atmosphere. To reduce the possibility of VOC emissions, the inlet and outlet of a cooling tower can be sampled and analyzed to determine if a leak is present. Logs can be kept and maintained on site. For instance, the HON (40 CFR Part 63, Subpart F) requires cooling tower/heat exchanger monitoring to minimize HAP emissions.

Indirect Contact Tower Exchangers
For purposes of VOC emissions reduction, an indirect contact heat exchanger can be considered 100% effective. The process water that could contain VOC is not exposed to the atmosphere in this type of tower.

Dry Cooling Tower Design
For control of VOC emissions, a dry cooling tower can be considered 100% effective.

Step 2 – Eliminate Technically Infeasible Options

Indirect Contact Tower Exchangers

RBLC data indicates only a few instances of nondirect/indirect contact tower exchangers that are used in the metals industry, but do not indicate commercially proven installations in the chemical process industry for this technology. Indirect contact tower exchangers may also increase PM_{10} emissions from drift aerosols. Therefore, the use of indirect contact tower exchangers is eliminated from further evaluation.

Dry Cooling Tower Design

The dry cooling tower design option is only technically feasible for use during cooler months because the ambient dry bulb temperature must be below the required cooling water supply temperature. A dry cooling tower could not be used for 4 to 6 months of the year in this location, as its use is limited to when ambient temperature is below 75°F.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only remaining technically feasible VOC emission control technology for the Cooling Water Tower is a direct contact design with exchanger monitoring and repair.

Step 4 – Evaluate Most Effective Controls

The only remaining technically feasible VOC emission control technology for the Cooling Water Tower is a direct contact design with exchanger monitoring and repair.

Step 5 – Select BACT

VOC BACT for EQT0007, CWT – Cooling Water Tower is determined to be a direct contact design with exchanger monitoring and repair in accordance with the HON (40 CFR 63, Subpart F).

BACT for Methanol Plant Storage Tanks

EQT0008	**TK-04001**	**Raw Methanol Tank**
EQT0013	**TK-04002A**	**Pure Methanol Intermediate Tank**
EQT0017	**TK-04002B**	**Pure Methanol Intermediate Tank**

Step 1 – Identify All Control Technologies

The KMe Facility includes one Raw Methanol Tank (EPN TK-04001, EQT0008) and two Pure Methanol Intermediate Tanks (EPN TK-04002A, EQT0013; EPN TK-04002B, EQT0017). Emissions mechanism for all three storage tanks include: (1) the contraction and expansion of the vapor in the vapor space of the tank caused by operating temperature fluctuations; and (2) the hydraulic displacement of vapor caused by cyclic increases in the tank's liquid level. The first mechanism results in breathing emissions, while the second mechanism results in working emissions. A third emissions mechanism occurs in the Raw

Methanol Tank when a stream at elevated pressure enters the atmospheric tank and partially vaporizes due to the reduction in pressure. These tanks are fixed roof, and emissions from the tanks are routed to a chiller and scrubber system with a 98% control efficiency. The tanks are subject to 40 CFR 60, Subpart Kb and 40 CFR 63, Subpart G. Per an overlap provision at 40 CFR 63.110(b)(1), the tanks are only required to comply with Subpart G.

Based on a review of RBLC results and available literature, the following technologies were identified as available VOC control technologies:

- Internal Floating Roof (IFR) with Vapor Collection System and Control Device
- Fixed Roof Storage Tank with Vapor Collection System and Control Device
- IFR Storage Tank
- External Floating Roof (EFR) Storage Tank
- Fixed Roof Storage Tank with Submerged Fill

<u>IFR Storage Tank with Vapor Collection System and Control Device</u>
An IFR storage tank is equipped with two roofs – a fixed roof connected to the top of the storage tank wall and a floating roof (the IFR) that rests on the surface of the liquid contained in the storage tank. In general, a floating roof design effectively eliminates the breathing and working emissions that result from a fixed roof storage tank because the floating roof eliminates the vapor space that would be present in a fixed roof tank by directly contacting nearly all of the liquid surface area. Additionally, certain emissions mechanisms and floating roof operating and maintenance risks that exist for an EFR tank (a tank where the floating roof is exposed to the atmosphere) do not exist for an IFR tank because the IFR tank's floating roof is not directly exposed to the atmosphere since the tank's fixed roof is located above the floating roof.

Because an IFR tank incorporates a fixed roof above a floating roof, the vapor between the floating roof and fixed roof can be collected and routed to a control device to reduce VOC emissions to the atmosphere. The following are examples of the types of control devices that can be used to reduce VOC emissions from the vapor collected from an IFR tank:

1. Scrubber;
2. Condenser;
3. Thermal oxidizer; and
4. Carbon adsorption.

<u>Fixed Roof Storage Tank with Vapor Collection System and Control Device</u>
A fixed roof storage tank contains a vapor space between the surface of the liquid contained in the tank and the roof of the tank, and the vapor in the vapor space is partially composed of the compounds making up the liquid contained in the tank. A portion of the vapor contained in the vapor space of an atmospheric fixed roof storage tank is routinely vented to the atmosphere because of the breathing and working emissions mechanisms described previously.

A fixed roof tank can be equipped with a vapor collection system to collect the vapor vented from the tank. This collected vapor can then be routed to a control device to reduce VOC emissions to the atmosphere. The following are examples of the types of control devices that can be used to reduce VOC emissions from the vapor collected from a fixed roof tank:

1. Scrubber;
2. Condenser;
3. Thermal oxidizer; and
4. Carbon adsorption.

IFR Storage Tank

As discussed previously, an IFR storage tank is equipped with two roof structures – a fixed roof located above a floating roof (the IFR). In general, a floating roof design effectively eliminates the breathing and working emissions that result from a fixed roof storage tank because the floating roof eliminates the vapor space that would be present in a fixed roof tank by directly contacting nearly all of the liquid surface area. Additionally, certain emissions mechanisms and floating roof operating and maintenance risks that exist for an EFR tank do not exist for an IFR tank because the IFR tank's floating roof is not directly exposed to the atmosphere since the tank's fixed roof is located above its floating roof. As a result, emissions from an IFR tank are typically lower than the emissions that would occur from an otherwise identical EFR tank containing the same material at the same storage conditions.

EFR Storage Tank

An EFR storage tank is equipped with a roof structure that rests on the surface of the liquid contained in the storage tank, and this floating roof is exposed to the atmosphere. As discussed above for an IFR tank, a floating roof design effectively eliminates the breathing and working emissions that result from a fixed roof storage tank. However, emissions from an EFR tank tend to be higher than from an IFR tank because the floating roof's seal and appurtenances are directly exposed to the atmosphere and, therefore, emissions from these seals and openings are influenced by wind conditions.

Fixed Roof Storage Tank with Submerged Fill

As discussed previously, there are two primary mechanisms that result in emissions from a fixed roof storage tank. The first mechanism results in breathing emissions, while the second mechanism results in working emissions. By incorporating submerged fill into the design of a fixed roof storage tank, the saturation level of the vapor space between the surface of the liquid contained in the tank and the roof of the tank can be reduced versus the level that would occur if the liquid were introduced into the tank under splash loading conditions. Therefore, by reducing the saturation level of the vapor space, the vapors vented from the storage tank as breathing and working emissions contain less VOC, which means lower VOC emissions to the atmosphere.

Step 2 – Eliminate Technically Infeasible Options

The feed material routed to both the raw and pure tanks has the potential to be at or near the boiling point under certain process conditions. Additionally, these tanks can also have dissolved inert gases that can be released upon entering the tanks. Neither of these conditions is conducive to utilizing a floating roof due to the potential damage to the roof under those circumstances, the potential for sinking a roof, and risks to ancillary components (e.g., seals) that are part of the floating roof. Therefore, the only control options that are technically feasible are the two fixed roof tank options.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The remaining available VOC emission control technologies for the tanks are listed below from the highest to lowest potential emission control.

Rank	Control Technology	Control Effectiveness	Basis for Ranking
1	Fixed Roof Storage Tank with Vapor Collection System and Control Device	98%	Vendor Data
2	Fixed Roof Storage Tank with Submerged Fill	33-58%	AP-42 Emission Factors

Step 4 – Evaluate Most Effective Controls

The current configuration of the methanol storage tanks is a fixed roof tank with a vapor collection system routed to a control device, which is the highest ranked control option. No further evaluation is required for the remaining options.

Step 5 – Select BACT

VOC BACT for EQT0008, TK-04001 – Raw Methanol Tank; EQT0013, TK-04002A – Pure Methanol Intermediate Tank; and, EQT0017, TK-04002B – Pure Methanol Intermediate Tank is determined to be routing displaced vapors from the fixed roof tanks to a vapor collection system and a chiller and scrubber system with 98% efficiency. VOC emissions will be limited to 10.07 TPY, 12-consecutive month maximum, based on achieving 98% control of the methanol storage tank emissions. This control efficiency and emission limit is consistent with recent BACT determinations in the RBLC. Compliance with the VOC limit will be demonstrated by calculating emissions monthly using the calculation methodology utilized in the application, using actual throughput and average daily temperature of the methanol stored each calendar month, and demonstrating the control efficiency of the scrubber by complying with the requirements in 40 CFR 63.120(d)(1)-(7), as applicable.

BACT for Methanol Slop Vessel

EQT0018 F-03007 Slop Vessel

Step 1 – Identify All Control Technologies

The KMe Facility includes one Slop Vessel (EPN F-03007, EQT0018). This tank is a 3,000-gallon horizontal vessel with submerged fill. Emissions from the vessel are routed to the flare, which has a 98% VOC control efficiency. The tank is not subject to any federal regulatory requirements, but is subject to LAC 33:III.2103, which requires a submerged fill pipe.

Based on a review of RBLC results and available literature, the following technologies were identified as potential add-on VOC control technologies:

- Internal Floating Roof (IFR) with Vapor Collection System and Control Device
- Fixed Roof Storage Tank with Vapor Collection System and Control Device
- IFR Storage Tank
- External Floating Roof (EFR) Storage Tank
- Fixed Roof Storage Tank with Submerged Fill

Step 2 – Eliminate Technically Infeasible Options

The feed material routed to the slop tank has the potential to be at or near the boiling point under certain process conditions, which is not conducive to utilizing a floating roof tank. Therefore, the only control options that are technically feasible are the two fixed roof tank options.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The remaining available VOC emission control technologies for the tank are listed below from the highest to lowest potential emission control.

Rank	Control Technology	Control Effectiveness	Basis for Ranking
1	Fixed Roof Storage Tank with Vapor Collection System and Control Device	98%	Vendor Data
2	Fixed Roof Storage Tank with Submerged Fill	33-58%	AP-42 Emission Factors

Step 4 – Evaluate Most Effective Controls

The current configuration of the slop vessel is a fixed roof tank with a vapor collection system routed to a control device, which is the highest ranked control option. No further evaluation is required for the remaining options.

Step 5 – Select BACT

VOC BACT for EQT0018, F-03007 - Slop Vessel is determined to be routing displaced vapors from the vessel to a vapor collection system and flare with 98% VOC control efficiency. The flare will be designed and operated in accordance with 40 CFR 60.18 and 40 CFR 63.11, General Control Device and Work Practice Requirements, to achieve 98% control of VOC emissions routed to it. This control efficiency and emission limit are consistent with recent BACT determination in the RBLC. Both 40 CFR 60.18 and 40 CFR 63.11 include operating specifications (exit velocity, heat content, etc.) and monitoring requirements, as well as a requirement that the flare be operated with a flame present at all times.

BACT for Gasoline Tank

EQT0027 GASTANK Gasoline Storage Tank

Step 1 – Identify All Control Technologies

The existing Gasoline Storage Tank (EPN GASTANK, EQT0027) is an atmospheric fixed roof storage tank storing gasoline. The tank is equipped for submerged fill loading. Emissions from the tank result from breathing and working emissions.

The tank is not subject to any federal regulatory requirements, but is subject to LAC 33:III.2103, which requires a submerged fill pipe.

Based on a review of RBLC results and available literature, the following technologies were identified as available VOC control technologies:

- Internal Floating Roof (IFR) with Vapor Collection System and Control Device
- Fixed Roof Storage Tank with Vapor Collection System and Control Device
- IFR Storage Tank
- External Floating Roof (EFR) Storage Tank
- Fixed Roof Storage Tank with Submerged Fill

Step 2 – Eliminate Technically Infeasible Options

All control options listed above are technically feasible.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The remaining available VOC emission control technologies for the tank are listed below from the highest to lowest potential emission control.

Rank	Control Technology	Control	Basis for Ranking

		Effectiveness	
1	IFR Storage Tank with Vapor Collection System and Control Device	>98%	Vendor Data
2	Fixed Roof Storage Tank with Vapor Collection System and Control Device	98%	Vendor Data
3	IFR Storage Tank	Varies by Tank	Equipment Design
4	EFR Storage Tank	Varies by Tank	Equipment Design
5	Fixed Roof Storage Tank with Submerged Fill	33-58%	AP-42 Emission Factors

Step 4 – Evaluate Most Effective Controls

The existing gasoline storage tank as constructed is a 550-gallon fixed roof tank with a submerged fill pipe. Because of the tank size and the minimal estimated VOC emissions of 0.20 tpy, a floating roof and/or vapor collection system with control device are not considered feasible options, as they offer no appreciable decrease in emissions and would not be cost effective. Therefore, the floating roof and/or a vapor collection system and control device are eliminated from consideration as options for controlling the tank's VOC emissions.

Step 5 – Select BACT

VOC BACT for EQT0027, GASTANK – Gasoline Storage Tank is determined to be the use of a fixed roof with submerged fill, based on a review of the RBLC.

BACT for Methanol Terminal Storage Tanks

EQT0029	**TK-26-202A**	**Methanol Product Tank 2301**
EQT0030	**TK-26-202B**	**Methanol Product Tank 2302**
EQT0031	**TK-26-202C**	**Methanol Product Tank 2303**
EQT0032	**TK-26-202D**	**Methanol Product Tank 2304**

Step 1 – Identify All Control Technologies

The Methanol Terminal includes four (4) existing methanol product tanks, each equipped with an internal floating roof. The tanks are subject to 40 CFR 60, Subpart Kb and 40 CFR 63, Subpart G. Per an overlap provision at 40 CFR 63.110(b)(1), the tanks are only required to comply with Subpart G.

Based on a review of RBLC results and available literature, the following technologies were identified as potential add-on VOC control technologies:

- Internal Floating Roof (IFR) with Vapor Collection System and Control Device

- Fixed Roof Storage Tank with Vapor Collection System and Control Device
- IFR Storage Tank
- External Floating Roof (EFR) Storage Tank
- Fixed Roof Storage Tank with Submerged Fill

Step 2 – Eliminate Technically Infeasible Options

All control options listed above are technically feasible.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The remaining available VOC emission control technologies for the tanks are listed below from the highest to lowest potential emission control.

Rank	Control Technology	Control Effectiveness	Basis for Ranking
1	IFR Storage Tank with Vapor Collection System and Control Device	>98%	Vendor Data
2	Fixed Roof Storage Tank with Vapor Collection System and Control Device	98%	Vendor Data
3	IFR Storage Tank	Varies by Tank	Equipment Design
4	EFR Storage Tank	Varies by Tank	Equipment Design
5	Fixed Roof Storage Tank with Submerged Fill	33-58%	AP-42 Emission Factors

Step 4 – Evaluate Most Effective Controls

Koch estimated that the addition of a vapor control system (e.g., carbon adsorber) to further control VOC emissions from the IFR tanks would require a total capital investment of \$7,108,515. The cost effectiveness of adding a carbon adsorber to the terminal tanks is \$1,504,875 per ton of VOC removed. Adding a thermal oxidizer for control of the terminal tanks would require a total capital investment of \$234,533, resulting in a cost effectiveness of \$51,284 per ton of VOC removed. Finally, routing the terminal tanks to the existing vapor combustion unit would require an incremental total capital investment of \$632,322 with a cost effectiveness of \$11,612 per ton of VOC removed. The cost estimates have not included additional costs for nitrogen, electrical, insulation, blowers, etc., nor any additional fuel requirements for managing this stream. For the thermal oxidizer and the vapor combustion unit options, there is also a secondary impact in the form of increased criteria pollutant and GHG emissions which is not insignificant given the relatively dilute inlet concentrations that enter the combustion control devices. See Table II for the BACT cost-effectiveness calculations.

Due to the secondary emissions, capital cost estimates for the installation of additional add-on controls and the negligible reduction of VOC emissions, it would not be cost effective to install additional controls beyond an internal floating roof on the terminal tanks. Therefore, an IFR storage tank with a vapor collection system and control device and FR storage tank with vapor collection system and control device are eliminated from consideration as control options for the tank's VOC emissions. No further evaluation is required for the remaining options.

Step 5 – Select BACT

VOC BACT for EQT0029, TK-26-202A – Methanol Product Tank 2301; EQT0030, TK-26-202B – Methanol Product Tank 2302; EQT0031, TK-26-202C – Methanol Product Tank 2303; EQT0032, TK-26-202D – Methanol Product Tank 2304 is determined to be the use of an internal floating roof.

BACT Analyses for Greenhouse Gas (CO_2e)

The evaluated control technology options focus on CO_2 emissions due to the insignificant quantities of CH_4 and N_2O. However, most BACT limits will be in the form of CO_2 equivalents (CO_2e) to account for the contribution from CH_4 and N_2O. GHG control technologies are evaluated for the individual GHG emitting units and in the case of carbon capture and sequestration, for the SMR and boiler collectively.

BACT for Steam Methane Reformer and Auxiliary Boiler

EQT0001	SMR	Steam Methane Reformer
EQT0002	BLR	Auxiliary Boiler

Step 1 – Identify All Control Technologies

GHG emissions from the boiler originate from the combustion of natural gas along with purge gas from SMR synthesis loop. The boiler operates at reduced firing rates during routine SMR operating conditions and at higher rates during startups and shutdowns of the SMR.

GHG emissions from the SMR originate from the combustion of natural gas for the production of methanol and combustion of process streams routed to the SMR furnace for energy recovery, including purge gas from the synthesis loop, pressure swing adsorption tail gas, expansion gas, and off gas from distillation. Additionally, the KMe Optimization Project includes injection of ethane into the natural gas feed to the SMR to allow for increased methanol yield. The process converts most of the carbon from the methane/ethane feedstock into methanol; however, conversion is not complete (~90%), and the remaining ~10% carbon (as unconverted methane/ethane or dilute carbon monoxide) that cannot be efficiently converted is utilized as fuel in the SMR.

The KMe Facility includes both an SMR and an auto thermal reformer (ATR), collectively known as "combined reforming." The combination of these two units results in a more thorough conversion of carbon from the feedstock (methane/ethane) into methanol. It is designed to optimize utilization of both the carbon and hydrogen in the feedstock to produce the carbon monoxide and hydrogen molecules that are combined to produce methanol. The process converts nearly 90% of the feed carbon to methanol. Inclusive of the fuel needs, the overall process design is closer to 80% efficient.

Potentially available GHG emission control technologies for the SMR and boiler are listed below:

- Carbon Capture and Sequestration (CCS)
- Energy Efficiency Measures
- Clean Fuels

Carbon Capture and Sequestration (CCS)
Carbon capture systems produce a concentrated CO_2 stream, which is then compressed for transport to a suitable disposal site for deep underground storage in geological formations.

Energy Efficiency Measures
Energy efficiency measures minimize GHG emissions by reducing the amount of fuel burned. Energy efficiency measures may include energy efficient equipment design, minimizing heat loss, waste heat recovery, and work practices.

Clean Fuels
Combustion of low carbon fuel results in lower CO_2 emissions per unit of fuel combusted.

Step 2 – Eliminate Technically Infeasible Options

Carbon Capture and Sequestration (CCS)
CCS must be “available” and “applicable” in order to be considered technically feasible. CCS consists of three stages: (1) capture and concentration of CO_2 from the gas stream, (2) compression and transport to a storage facility via pipeline, and (3) injection and storage of the CO_2 into available underground sequestration sites such as old oil and gas wells or other geological formations.

For this BACT analysis, CCS will be assumed to be technically feasible.

Energy Efficiency Measures
Koch currently utilizes the following energy efficiency measures:

Energy Efficiency Measures	Description
Maintenance Program	Koch performs regular maintenance of the SMR and boiler to maintain efficient operation.
Combustion Tuning & Optimization	The SMR and boiler are subject to 40 CFR 63 Subpart DDDDD, and Koch conducts the required periodic tune ups

Energy Efficiency Measures	**Description**
	to maintain optimal combustion characteristics. Combustion tuning and optimization are incorporated into the SMR maintenance program.
Burner Design	As burners are replaced, Koch will use the latest proven burner designs to maximize combustion efficiency.
Furnace Air/Fuel Control	The boiler and SMR have oxygen sensors in the exhaust to continuously monitor and control the air-to-fuel ratio in the furnaces to ensure optimal combustion efficiency while minimizing excess air.
Waste Heat Recovery	The overall SMR thermal efficiency is optimized through the recovery of heat from the SMR exhaust and from process streams to preheat the SMR combustion air, to preheat the feed to the SMR, and to produce steam for use in the process and elsewhere in the facility. The boiler uses an economizer to preheat the boiler feed water.
Process Integration (Pinch)	Process integration (pinch) means that the process is designed to minimize energy consumption (e.g., air louver controls). The SMR and boiler apply pinch.
Adiabatic Pre-Reformer	The SMR utilizes excess steam with a pre—reformer to reduce energy consumption by converting higher molecular weight hydrocarbons such as ethane and propane in the feed into methane to optimize both operation and reliability of the reforming process.
Cogeneration	Excess process steam can be used to generate electricity via the condensing turbine.
Reduction of Slagging and Fouling of Heat Transfer Surfaces	The boiler and SMR both combust low-carbon gaseous fuels that provide an inherently favorable design for heat exchange without the need for steam-consuming soot blowers to keep transfer surfaces clean.
Insulation	Heat losses from the SMR and boiler are minimized through proper selection and use of refractory and insulation materials.
Utilization of Condensate Return System	The boiler and SMR capture energy from the blowdown system by utilizing a condensate return system as part of the feedwater makeup.

Energy efficiency measures are technically feasible GHG work practices to minimize GHG emissions.

Clean Fuels
Combustion of only clean low-carbon fuels is a technically feasible work practice to minimize GHG emissions. The SMR and boiler already combust clean fuels. The SMR

combusts natural gas and various process off-gases, while the boiler burns natural gas with small amounts of SMR purge gas. Combustion of low-carbon fuels is evidenced by the concentration of CO_2 in the SMR and boiler exhaust of 8% and 9%, respectively.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The control options are ranked below according to their control effectiveness:

1. CCS, Add-on Control, Control Efficiency ~90%
2. Energy Efficiency Measures (inherently lower emissions)
3. Clean Fuels (inherently lower emissions)

Step 4 – Evaluate Most Effective Controls

The use of energy efficiency measures and clean fuels as GHG emissions control technologies for the boiler and SMR have no appreciable adverse energy, environmental, or economic impacts.

For the CCS cost evaluation, Koch assumed that post-combustion capture equipment would be installed on the boiler and SMR exhausts and that a new pipeline connection would be constructed to connect to the Denbury pipeline located approximately 10 miles from the KMe Facility. This approach is extremely conservative because Denbury uses CO_2 for EOR, which is not classified as permanent sequestration, whereas the closest potentially permanent sequestration location (reported under 40 CFR 98 Subpart RR) is in Texas. The equipment sizing is based on capturing 90% of baseline CO_2 emissions from the boiler and SMR, including the additional CO_2 generated from incremental boiler firing needed to operate the capture system. Operating the capture equipment would require significant additional boiler firing, electricity, etc., which Koch accounted for in the annual operating costs. A detailed cost break down is included in Table II.

Control Technology	Total Capital Investment ($)	Total Annualized Cost ($/yr)	Pollution Control Cost ($/ton CO_2)
Carbon Capture and Sequestration	$707 Million	$130.2 Million	$112.10

The CCS costs estimated for the KMe Facility are substantially higher than the costs calculated for other methanol plants where BACT determinations concluded that CCS was not cost-effective. Key distinguishing or contributing causes for the higher cost for the KMe Facility relative to other methanol plants include: 1) high inflation on equipment and labor in recent years, 2) the other methanol plant examples appear to have underestimated the ongoing O&M costs for regenerating amine (natural gas) and compression (electricity) for dilute, post-combustion low pressure streams, and 3) no consideration appears to have been made for capturing CO_2 associated with the increased boiler firing to supply the CCS process with steam for amine regeneration. Based on the estimated costs, CCS is not economically feasible as BACT for the KMe Facility.

Step 5 – Select BACT

CO_2e BACT for EQT0001, SMR – Steam Methane Reformer and EQT0002, BLR – Auxiliary Boiler is determined to be the use of energy efficiency measures and combusting only clean fuels.

A two-tier, facility-wide 12-month rolling average GHG intensity limit reflective of energy efficient operation and low carbon gaseous fuel firing in the boiler and SMR will serve as the BACT emission limitation. A 0.56 metric ton (MT) CO_2e/MT MeOH limit is based on facility-wide potential to emit (1,401,096 short tons/yr converted to metric tons) divided by the maximum post-project targeted production capacity (annualized 6200 MT MeOH/day). This limit will apply when operating in the upper half of the facility's operating range.

A 0.68 MT CO_2e/MT MeOH limit is based on the facility-wide GHG potential to emit divided by the midpoint MeOH production rate (annualized 5100 MT MeOH/day based on a projected operating range of 4000 to 6200 MT/day). This second limit will apply when the KMe Facility is operating below the midpoint of the operating range.

Compliance with the two-tier, facility-wide 12-month rolling average GHG intensity limit will be determined per prescribed methods and recordkeeping noted in 40 CFR Part 98. By the end of each month following each 12-month rolling average period, Koch will determine the applicable daily tier values and the 12-month rolling average of the applicable daily tier values and compare to the actual site-wide GHG intensity during the corresponding 12-month timeframe. Koch will calculate the site-wide GHG intensity as the total CO2e emissions divided by the total MeOH production during the relevant 12-month timeframe. In the event that any global warming potentials listed in Table A-1 to Subpart A of 40 CFR 98 are revised, the CO_2e/MT MeOH daily tier values shall be revised accordingly without the need to revise this permit.

The KMe facility produces its own process steam (rather than purchasing), and thus the proposed limits are inclusive of the steam auxiliary boiler emissions which peak during process startup and are not directly proportional to the production rate. KMe has limited the boiler's annual GHG potential to emit to ~50% of its capacity, which makes these proposed limits more restrictive than if the limit was based on 100% capacity. The proposed higher production facility-wide limit is comparable to other methanol facilities with a combined reforming process; however, at least one other facility does not include boiler emissions in the limit. The RBLC determinations do not provide comparable full-facility GHG BACT determinations because the RBLC is typically a source-by-source limit determination summary, and there are few facilities that utilize a combined reforming SMR for methanol production and steam production. The one exception is a similar methanol combined reforming facility that was permitted and constructed in Texas prior to the KMe Facility; however, no facility-wide intensity limit was established as part of the BACT determination for that facility.

BACT for Fugitive Components

FUG0001 FUG Fugitive Emissions – KMe Facility

Step 1 – Identify All Control Technologies

Some process fugitive components at the KMe Facility, including valves, pumps, compressors, connectors, pressure relief devices, and other miscellaneous related equipment, have the potential to emit GHGs (methane and CO_2). Although components that are in CO_2 service have the potential to directly emit CO_2, they are not included in this analysis (unless included because they are also in VOC, methane, or CO service), because reducing or eliminating fugitive component CO_2 emissions by applying BACT to the fugitive component would result in the CO_2 that is not emitted from the fugitive component instead being emitted from the emissions unit to which the CO_2 is routed, thereby achieving no net decrease in CO_2 emissions. Fugitive components that contain or contact GHGs and are in VOC or organic HAP service are subject to 40 CFR 60 Subpart VVa and 40 CFR 63 Subpart H, respectively. Fugitive components may also contain or contact GHGs, but due to their VOC or HAP content, are not subject to any LDAR regulations. LDAR programs can be tailored for fugitive GHG (methane) emission control.

Equipment Design and LDAR
Equipment design examples used to minimize piping components include: (1) a cap, plug, or second valve on an open-ended line; (2) a dual mechanical seal on a pump; and (3) a rupture disk assembly on a pressure relief valve. These types of design features are reasonably priced and tend to be relatively easy and efficient to operate and maintain.

LDAR programs are used to identify piping components leaking material at a level warranting component repair (or replacement), and the effectiveness of these programs has been well established throughout many different industries over several decades. The primary features of an LDAR program are its leak monitoring frequency, leak detection level, and timely leak repair. A piping component may be checked for leakage by visual, audible, olfactory, or instrument techniques. For example, visual inspections may be used to identify leaks of heavy liquid material from connectors, valves, and pumps. Alternatively, a portable hydrocarbon detection instrument is typically used to identify (and measure) leaks of gases and light liquid materials from piping components. After a leak is detected, it must typically be repaired within a specific time period, followed by a subsequent leak inspection to ensure the leaking component was properly repaired.

For comparison to these practical equipment designs and LDAR practices, the use of a control device (e.g., flare, thermal oxidizer, carbon adsorption device) to control emissions from hundreds or thousands of connectors, valves, and pumps located across a wide area in a process unit is not practical because a substantial amount of piping and ductwork would be required to collect the component leaks, and the positive pressure leak collection piping and ductwork would include its own fugitive components with the potential to leak to the atmosphere. Additionally, potentially substantial amounts of collateral combustion emissions or solid waste would be generated by the control device. Therefore, this type of collection and control scheme is not further evaluated.

Step 2 – Eliminate Technically Infeasible Options

Equipment design and LDAR are currently used for the fugitive components. Therefore, both are technically feasible.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only remaining available GHG (methane) emission control technology for the fugitive components is the combination of equipment design and LDAR.

Step 4 – Evaluate Most Effective Controls

The fugitive components at the KMe Facility are already part of an LDAR program. Koch will include components in methane service in the LDAR program for the site.

Step 5 – Select BACT

CO_2e BACT for FUG0001, FUG – Fugitive Emissions – KMe Facility is determined to be a combination of equipment design and LDAR pursuant to 40 CFR 60, Subpart VVa and 40 CFR 63, Subpart H. Koch will implement a Methane LDAR program for those components in methane service that are not subject to VVa and that contain >10% methane. The Methane LDAR program will include relevant elements from Subpart VVa such as calendar-based leak monitoring, 5/15 day repair requirements, delay of repair (DOR), etc., and will be adjusted to appropriately accommodate requirements for methane. The Methane LDAR plan must be submitted to LDEQ within 60 days of permit issuance. The Methane LDAR program shall be implemented within 180 days following LDEQ's approval of the plan.

BACT for Cooling Water Tower

EQT0007	CWT	Cooling Water Tower

Step 1 – Identify All Control Technologies

The KMe Facility includes a direct contact wet Cooling Water Tower (EPN CWT, EQT0007). VOC and other contaminants, including GHGs, have the potential to be introduced into the cooling water through leaks in plant heat exchangers. Based on current operations, Koch has quantified the potential to emit of GHG leaks from Hazardous Organic NESHAP (HON) regulated heat exchanger systems. The cooling tower is subject to the HON (40 CFR Part 63, Subpart F).

Based on a review of RBLC results and available literature, the following technologies were identified as available GHG control technologies:

- Direct contact design with exchanger monitoring and repair
- Indirect contact tower exchangers
- Dry cooling tower design

Refer to CO BACT for EQT0007, CWT – Cooling Water Tower for a general description of these control technologies.

Step 2 – Eliminate Technically Infeasible Options

Indirect Contact Tower Exchangers
RBLC data indicates only a few instances of nondirect/indirect contact tower exchangers that are used in the metals industry, but do not indicate commercially proven installations in the chemical process industry for this technology. Indirect contact tower exchangers may also increase PM_{10} emissions from drift aerosols. Therefore, the use of indirect contact tower exchangers is eliminated from further evaluation.

Dry Cooling Tower Design
The dry cooling tower design option is only technically feasible for use during cooler months because the ambient dry bulb temperature must be below the required cooling water supply temperature. A dry cooling tower could not be used for 4 to 6 months of the year in this location, as its use is limited to when ambient temperature is below 75°F. Thus, dry cooling tower design is eliminated since not technically feasible in this location.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The only remaining technically feasible CO_2e emission control technology for the Cooling Water Tower is a direct contact design with exchanger monitoring and repair.

Step 4 – Evaluate Most Effective Controls

The only remaining technically feasible CO_2e emission control technology for the Cooling Water Tower is a direct contact design with exchanger monitoring and repair.

Step 5 – Select BACT

CO_2e BACT for EQT0007, CWT – Cooling Water Tower is determined to be a direct contact design with exchanger monitoring and repair in accordance with the HON (40 CFR 63, Subpart F).

BACT for Emergency Engines

EQT0004 EGEN Plant Emergency Generator

EQT0026	**EGEN2**	**Admin Building Emergency Generator**
EQT0005	**FWP-01**	**Firewater Pump Engine No. 1**
EQT0006	**FWP-02**	**Firewater Pump Engine No. 2**
EQT0022	**FWP-03**	**Firewater Pump Engine No. 3**
EQT0033	**E. GEN 01**	**Generac SD 2000**
EQT0034	**E. GEN 02**	**Generac SD 2000**

The Plant Emergency Generator (EPN EGEN, EQT0004) has a rating of 3,634 hp, and the Admin Building Emergency Generator (EPN EGEN2, EQT0026) has a rating of 210 hp. Firewater Pump Engines No. 1 and No. 2 each have a rating of 422 hp, and Firewater Pump Engine No. 3 has a rating of 237 hp. The Generac SD 2000 generator engines are both rated at 2923 hp. All engines are compression ignition (diesel), except for the Admin Building Emergency Generator, which runs on natural gas. The engines are subject to BACT for CO2e.

The use of these engines is limited to emergency situations, except for up to 100 hours per year, including maintenance testing. Because engine operation is intermittent and operating hours are limited, emissions from the engine are minimal, making most applications of add-on control devices technically and/or economically infeasible. Furthermore, all engines are subject to 40 CFR 60 Subpart IIII standards, except for the Admin Building Emergency Generator, which is subject to 40 CFR 60 Subpart JJJJ standards.

The CO2e control technology options identified based on a review of RBLC results and available literature for similar engines are proper operation, good combustion practices, and compliance with 40 CFR 60 Subpart IIII for diesel-fired engines and 40 CFR 60 Subpart JJJJ for spark-ignited engines.

CO2e BACT for EQT0004, EGEN – Plant Emergency Generator; EQT0005, FWP-01 – Firewater Pump Engine No. 1; EQT0006, FWP-02 – Firewater Pump Engine No. 2; EQT0022, FWP-03 – Firewater Pump Engine No. 3; EQT0033 E. GEN 01 – Generac SD 2000; and EQT0034, E. GEN 02 – Generac SD 2000 is determined to be compliance with 40 CFR 60 Subpart IIII.

CO2e BACT for EQT0026, EGEN2 – Admin Building Emergency Generator is determined to be compliance with 40 CFR 60 Subpart JJJJ.

Note that Subparts IIII and JJJJ incorporate specific combustion (operational) and maintenance practices.

B. AIR QUALITY ANALYSIS

LAC 33:III.509.M requires an analysis of ambient air quality in the area that a major modification would affect. Such analysis is required for each pollutant for which the source has the potential to emit in a significant amount. For the KMe Optimization Project, these pollutants include:

- particulate matter (PM_{10}, and $PM_{2.5}$);
- nitrogen oxides (NO_X);
- carbon monoxide (CO);
- volatile organic compounds (VOC); and
- greenhouse gases (CO_2e).

Note that there are no ambient air standards for CO_2e; therefore, this pollutant will not be discussed further in Sections B or C of this Preliminary Determination Summary.

Dispersion Model(s) Used: AERMOD

Pollutant	Time Period	Calculated Maximum Ground Level Concentration ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	National Ambient Air Quality Standard ($\mu g/m^3$)
$PM_{2.5}$*	24-hour	1.01	1.2	35
	Annual	0.11	0.2	12
PM_{10}	24-hour	1.32	5	150
	Annual	0.16	1	50
NO_2	1-hour	182.4**	7.5	188
	Annual	0.40	1	100
CO	1-hour	1453.56	2000	40,000
	8-hour	441.48	500	10,000

*Includes secondary formation of $PM_{2.5}$

**This reflects the results of refined NAAQS modeling since results of the SIL analysis were above the SIL. Tier 3 (OLM) was used for 1-hour modeling.

AERMOD modeling of $PM_{2.5}$, PM_{10}, NO_x, and CO emissions from the proposed project indicates that the maximum offsite ground level concentrations of these pollutants will be below their respective PSD significance impact levels (SILs), except for the 1-hour NO_2 SIL. Therefore, refined NAAQS modeling is only required for the 1-hour NO_2 NAAQS.

C. NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS) ANALYSIS

Because AERMOD modeling analyses indicated concentrations of $PM_{2.5}$, PM_{10}, CO, and annual NO_2 emissions would be below their respective SILs, refined NAAQS modeling was not required.

The only pollutant and averaging period for which modeling indicated that the SIL would be exceeded is 1-hour NO_2. Thus, refined modeling for 1-hour NO_2 was required. Refined modeling, including emissions from nearby sources, was performed to determine compliance with the 1-hour NO_2 NAAQS.

Pollutant	Averaging Period	Modeled Concentration (μg/m^3)	Background Concentration (μg/m^3)	Modeled + Background (μg/m^3)	NAAQS (μg/m^3)
NO_2	1-hour	126.0	56.4	182.4	188

The refined modeling results for 1-hour NO_2 do not exceed the NAAQS; there for the air quality impact analysis demonstrates that emissions from the facility will not cause or contribute to an exceedance of NAAQS.

An ozone impact analysis for VOC and NOx using the EPA's Modeled Emission Rates for Precursors (MERP) guidance was completed and demonstrated that the NOx and VOC emissions will not cause or contribute to any exceedances of the ozone NAAQS.

A summary of the air quality analyses is also presented in Table III.

D. PSD INCREMENT ANALYSIS

Because AERMOD modeling analyses indicated concentrations of $PM_{2.5}$, PM_{10}, CO, and annual NO_2 emissions would be below their respective SILs, PSD increment modeling was not required. There is no PSD increment associated with 1-hour NO_2; therefore, PSD increment analysis is not required for hourly NO_2 emissions.

A summary of the air quality analyses is also presented in Table III.

E. SOURCE RELATED GROWTH IMPACTS

While the KMe Optimization Project will require the employment of 50 to 100 temporary employees at any given time during its construction, no significant increase in long term employment is anticipated (less than 5 additional permanent employees). The project is not expected to have any significant effect on residential growth or industrial/commercial development in the area of the facility. No significant net change in employment, population, or housing will be associated with the project. As a result, there will not be any significant increases in pollutant emissions indirectly associated with the project.

F. SOILS, VEGETATION, AND VISIBILITY IMPACTS

There will be no significant impact on area soils, vegetation, or visibility.

G. CLASS I AREA IMPACTS

Louisiana's Breton Wildlife Refuge, the nearest Class I area, is approximately 185 kilometers from the site, precluding any significant impact.

Q/d refers to the ratio of the sum of the net emissions increase (in tons) of PM_{10}, SO_2, NO_X, and H_2SO_4 to the distance (in kilometers) of the facility from the nearest boundary of the Class I area.

$$Q/d = \frac{PM_{10\,(NEI)} + SO_{2\,(NEI)} + NO_{X\,(NEI)} + H_2SO_{4\,(NEI)}}{\text{Class I km}}$$

Where:

$PM_{10\,(NEI)}$ = net emissions increase of PM_{10}
$SO_{2\,(NEI)}$ = net emissions increase of SO_2
$NO_{X\,(NEI)}$ = net emissions increase of NO_X
$H_2SO_{4\,(NEI)}$ = net emissions increase of H_2SO_4
Class I km = distance to nearest Class I area (in kilometers)

If $Q/d \geq 10$, LDEQ will formally notify the FLM in accordance with LAC 33:III.509.P.1.

In this instance,

$$Q/d = \frac{76.30\text{ tpy} + 6.16\text{ tpy} + 152.84\text{ tpy} + 0.04\text{ tpy}}{185\text{ km}} = 1.27$$

Therefore, LDEQ has determined that formally notifying the FLM is not required and that the KMe Facility will not adversely impact visibility in Breton National Wildlife Refuge, the nearest Class 1 area.

H. TOXIC EMISSIONS IMPACT

Implementing control technology and BACT for pollutants such as VOC, PM_{10}, and $PM_{2.5}$ inherently limits toxics emissions. Toxics modeling demonstrates that the emissions increases will comply with the Louisiana Ambient Air Standards.

V. CONCLUSION

The Air Permits Division has made a preliminary determination to approve the construction of the KMe Optimization Project at Koch Methanol St James LLC's Koch Methanol Facility located near St. James in St. James Parish, Louisiana, subject to the attached specific and general conditions. In the event of a discrepancy in the provisions found in the application and those in this Preliminary Determination Summary, the Preliminary Determination Summary shall prevail.

SPECIFIC CONDITIONS

Koch Methanol Facility
Agency Interest No.: 194165
Koch Methanol St. James, LLC
St. James, St. James Parish, Louisiana
PSD-LA-851

1. Comply with the Louisiana General Conditions as set forth in LAC 33:III.537.

2. The permittee is authorized to operate in conformity with the specifications submitted to the Louisiana Department of Environmental Quality (LDEQ) as analyzed in LDEQ's document entitled "Preliminary Determination Summary" dated March 30, 2023, and subject to the following emissions limitations and other specified conditions. Specifications submitted are contained in the application and Emission Inventory Questionnaire dated November 2, 2022, along with supplemental information dated February 1, 2023, February 8, 2023, March 20, 2023, March 22, 2023, March 28, 2023, May 2, 2023, and June 19, 2023.

Good Combustion Practices

3. Where this permit references "good combustion practices," such practices shall include:
   a. for the SMR and Boiler: monitoring of the flue gas oxygen content, combustion air flow, fuel consumption, and flue gas temperature and complying with NESHAP Subpart DDDDD (Boiler MACT) work practice standards, which requires regular tune-ups.
   b. for Emergency Engines: following manufacturer's operating and maintenance recommendations and complying with 40 CFR 60 Subpart IIII or JJJJ, as applicable, which incorporate specific combustion (operational) and maintenance practices.
   c. These parameters shall be maintained within the manufacturer's recommended operating guidelines or within a range that is otherwise indicative of proper operation of the emissions unit.

Continuous Emissions Monitoring Systems (CEMS)

4. The permittee shall monitor and record emissions from the emissions units identified below using Continuous Emissions Monitoring Systems (CEMS) calibrated, operated, and maintained according to the manufacturer's specifications.

   a. CEMS shall comply with the following performance specifications of 40 CFR Part 60, Appendix B.

      CO: Performance Specification 4/4A
      NO_X: Performance Specification 2

   b. All CEMS shall be evaluated in accordance with Procedure 1 of 40 CFR 60, Appendix F.

   c. Data availability shall be stipulated by Part 70 General Condition V of LAC 33:III.535.A.

   d. Where a NO_X CEMS is required, the permittee shall also determine the NO_2/NO_X in-stack ratio in conjunction with Performance Specification 2.

ID No.	Description		Pollutant(s)
EQT0001	SMR	Steam Methane Reformer	CO, NO_X

SPECIFIC CONDITIONS

Koch Methanol Facility
Agency Interest No.: 194165
Koch Methanol St. James, LLC
St. James, St. James Parish, Louisiana
PSD-LA-851

ID No.	**Description**		**Pollutant(s)**
EQT0002	BLR	Auxiliary Boiler	CO, NO_X

Stack Testing

5. In order to demonstrate compliance with the emissions limitations of this permit, the permittee shall conduct performance tests on the emissions units identified below within 180 days after issuance of Title V Permit No. 2560-00295-V6. Unless otherwise agreed to in writing by the department, conduct each test run within 80 percent of the maximum permitted load or within 10 percent of the maximum achievable load. For the Auxiliary Boiler, VOC testing shall be conducted at two points, one at the lowest operating rate associated with routine operations, and one at the highest achievable operating rate during the performance test. Per LAC 33:III.913.A, provide necessary sampling ports in stacks or ducts and such other safe and proper sampling and testing facilities for proper determination of the emission of air contaminants.

   a. Submit notification to the Office of Environmental Services at least 30 days prior to a performance test in order to provide LDEQ with the opportunity to conduct a pretest meeting and/or observe the test.

   b. Use the following stack test methods from 40 CFR 60, Appendix A (unless otherwise noted). Alternate stack test methods may be used with the prior approval of the Office of Environmental Services.

      PM: Method 5 – Determination of Particulate Matter Emissions from Stationary Sources; or Method 201A - Determination of PM_{10} and $PM_{2.5}$ Emissions from Stationary Sources (Constant Sampling Rate Procedure)

      PM: Method 202 – Dry Impinger Method for Determining Condensable Particulate Emissions from Stationary Sources (40 CFR 51, Appendix M)

      VOC: Method 25a – Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer

   c. Submit performance test results to the Office of Environmental Services within 60 days after completion of the test.

   d. Repeat performance tests every 5 years (plus or minus 6 calendar months).

SPECIFIC CONDITIONS

Koch Methanol Facility
Agency Interest No.: 194165
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St. James, St. James Parish, Louisiana
PSD-LA-851

ID No.	Description		Pollutant(s)
EQT0001	SMR	Steam Methane Reformer	$PM_{10}/PM_{2.5}$, VOC
EQT0002	BLR	Auxiliary Boiler	$PM_{10}/PM_{2.5}$, VOC
EQT0028	RT LOAD	Methanol Railcar and Tank Truck Loading Operations	VOC

Cooling Tower

6. The permittee shall determine and record the concentration of total dissolved solids (TDS) in the cooling water at least once per month using Standard Method 2540C or EPA Method 160.1. Alternate methods may be used with the prior approval of LDEQ. The efficiency of the drift eliminators shall be verified by the manufacturer's certification. The permittee shall average all recorded TDS concentrations and utilize the manufacturer's drift rate and the design recirculation rate of the cooling water pump(s) to determine compliance with the emissions limitations set forth in Table I.

ID No.	Description	
EQT0007	CWT	Cooling Water Tower

Greenhouse Gases

7. The CO_2e facility-wide two-tier limit set forth in Specific Condition 8 of this PSD permit is based on the following global warming potentials (GWPs) listed in Table A-1 to Subpart A of 40 CFR 98.

Pollutant	GWP
Carbon Dioxide	1
Methane	25
Nitrous Oxide	298

In the event any GWP is revised, the CO_2e limits shall be revised accordingly without the need to modify this permit

8. The permittee shall comply with the following two-tier, facility-wide 12-month rolling average GHG intensity limit: 0.56 MT CO2e/MT methanol (MeOH) at daily MeOH production rates above 5100 MT, and 0.68 MT CO2e/MT MeOH at daily MeOH production rates at or below 5100 MT.

Compliance with the two-tier, facility-wide 12-month rolling average GHG intensity limit shall be determined per prescribed methods and recordkeeping noted in 40 CFR Part 98. By the end of each month following each 12-month rolling average period, determine the applicable daily tier values and the 12-month rolling average of the applicable daily tier values and compare to the actual site-wide GHG intensity during the corresponding 12-month timeframe. Calculate the site-wide GHG intensity as the total CO2e emissions divided by the total MeOH production during the relevant 12-month timeframe.

CO and Methane LDAR Programs

9. The Permittee shall implement a CO LDAR program for those components in CO service that are not subject to VVa and that contain >5% CO.
    a. The CO LDAR program shall include relevant elements from Subpart VVa such as calendar-based leak monitoring, 5/15 day repair requirements, delay of repair (DOR), etc., and shall be adjusted to appropriately accommodate requirements for CO.
    b. The CO LDAR plan shall be submitted to LDEQ within 60 days of permit issuance.
    c. The CO LDAR program shall be implemented within 180 days following LDEQ's approval of the plan.

10. The Permittee shall implement a Methane LDAR program for those components in methane service that are not subject to VVa and that contain >10% methane.
    a. The Methane LDAR program shall include relevant elements from Subpart VVa such as calendar-based leak monitoring, 5/15 day repair requirements, delay of repair (DOR), etc., and shall be adjusted to appropriately accommodate requirements for methane.
    b. The Methane LDAR plan shall be submitted to LDEQ within 60 days of permit issuance.
    c. The Methane LDAR program shall be implemented within 180 days following LDEQ's approval of the plan.

TABLE I: MAXIMUM ALLOWABLE EMISSIONS RATES[1]

Koch Methanol Facility
Agency Interest No.: 194165
Koch Methanol St. James, LLC
St. James, St. James Parish, Louisiana
PSD-LA-851

ID No.	Description		Units[2]	PM_{10}	$PM_{2.5}$	NO_X	CO	VOC
EMS0001	D-04001	Methanol Scrubber	TPY					10.07
EQT0001	SMR	Steam Methane Reformer	lb/hr	13.37	13.37	17.25[3]	98.50	6.71
			lb/MMBTU	0.00745	0.00745	0.01	0.0037	0.00374
EQT0002	BLR	Auxiliary Boiler	lb/hr	8.20	8.20	15.00[4]	48.02	5.94
			lb/MMBTU	0.00745	0.00745	0.01	0.0046	0.0016
EQT0003	FLR	Flare	TPY	0.16	0.16	26.92	110.50	9.87
EQT0004	EGEN	Plant Emergency Generator	lb/hr	1.19	1.19	38.24	20.91	2.29
EQT0005	FWP-01	Firewater Pump Engine No. 1	lb/hr	0.20	0.20	3.96	3.44	1.47
EQT0006	FWP-02	Firewater Pump Engine No. 2	lb/hr	0.20	0.20	3.96	3.44	1.47
EQT0007	CWT	Cooling Water Tower	TPY	1.82	0.84		4.69	36.79
EQT0022	FWP-03	Firewater Pump Engine No. 3	lb/hr	0.06	0.06	1.49	0.50	0.61
EQT0026	EGEN2	Admin Building Emergency Generator	lb/hr	0.02	0.02	0.92	1.85	0.46
EQT0027	GASTANK	Gasoline Storage Tank	TPY					0.20
EQT0028	RT LOAD	Methanol Railcar and Tank Truck Loading Operations	lb/hr	0.28	0.28	9.31	3.07	18.54
EQT0033	E. GEN 01	Generac SD 2000	lb/hr	0.84	0.84	28.48	2.90	2.06
EQT0034	E. GEN 02	Generac SD 2000	lb/hr	0.84	0.84	28.48	2.90	2.06
RLP0024	PCSVENT	Process Condensate Stripper Vent	lb/hr				39.38	

TABLE I: MAXIMUM ALLOWABLE EMISSIONS RATES[1]

Koch Methanol Facility
Agency Interest No.: 194165
Koch Methanol St. James, LLC
St. James, St. James Parish, Louisiana
PSD-LA-851

ID No.		Description	Units[2]	PM_{10}	$PM_{2.5}$	NO_X	CO	VOC
RLP0025	CTVENT	Condensate Trap Vent	lb/hr				0.02	
FUG0001	FUG	Fugitive Emissions – KMe Facility	TPY				15.97	43.51
FUG0002	WWT	Wastewater Treatment	TPY					5.53

Notes:

[1] Koch Methanol Facility sitewide PTE GHG emissions are 1,401,096 TPY CO2e. This is provided for information only and does not constitute a limit. Koch shall comply with a two-tier, facility-wide 12-month rolling average GHG intensity limit as BACT as described in the Preliminary Determination Summary and Specific Condition 8 of this permit.

[2] Averaging periods for the lb/MMBTU emission rates are specified in the Preliminary Determination Summary or Specific Conditions of this permit; the averaging period for TPY limits is a 12-month rolling basis.

[3] Maximum hourly emissions of NOx <= 269.10 lb/hr for up to 100 hours of operation (12-month rolling sum) during SCR start up, shut down, or maintenance.

[4] Maximum hourly emissions of NOx <= 108.90 lb/hr for up to 500 hours of operation (12-month rolling sum) including, but not limited to, during SCR start up, shut down, or maintenance.

TABLE II: BACT COST SUMMARY

Koch Methanol Facility
Agency Interest No.: 194165
Koch Methanol St. James, LLC
St. James, St. James Parish, Louisiana
PSD-LA-851

Control Alternatives		Availability/ Technical Feasibility	Negative Impacts (a)	Control Efficiency	Emissions Reduction (TPY)	Capital Cost ($)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Notes
SMR– Steam Methane Reformer (EQT0001)									
VOC	Catalytic Oxidation	Yes/Yes	1, 3	30-70%	12.98	1,627,156	1,633,575	125,832	
CO_2e	Carbon Capture and Sequestration	Yes/No	1, 2, 3	90%	1,161,220[10]	707,093,883	130,176,339	112.10	
BLR – Auxiliary Boiler (EQT0002)									
CO	Catalytic Oxidation	Yes/Yes	1, 3	80%	92.16	1,316,774	1,550,092	16,819	
VOC	Catalytic Oxidation	Yes/Yes	1, 3	80%	8.72	1,316,774	1,550,092	177,762	
CO_2e	Carbon Capture and Sequestration	Yes/No	1, 2, 3	90%	1,161,220[10]	707,093,883	130,176,339	112.10	
RT LOAD – Methanol Railcar and Tank Truck Loading Operations (EQT0028)									
VOC	Submerged Fill Loading	Yes/Yes	1	33-58%	7.72	2,268,000	255,510	33,097	
TK-26-202A – Methanol Product Tank 2301 (EQT0029) **TK-26-202B – Methanol Product Tank 2302 (EQT0030)** **TK-26-202C – Methanol Product Tank 2303 (EQT0031)** **TK-26-202D – Methanol Product Tank 2304 (EQT0032)**									
VOC	IFR to Existing VCU Piping	Yes/Yes	1	>98%	9.18	632,322	106,595	11,611	
	Thermal Oxidizer	Yes/Yes	1	98%	9.1	234,533	464,554	51,284	
	Carbon Absorber	Yes/Yes	1	98%	9.1	7,108,515	13,694,193	1,504,875	
Notes:	a) Negative impacts: 1) economic, 2) environmental, 3) energy, 4) safety								

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[10] Emissions of CO_2e are for the emission cap GRP0002 – SMR, BLR, PCS Vent CAP.

TABLE III: AIR QUALITY ANALYSIS SUMMARY

Koch Methanol Facility
Agency Interest No.: 194165
Koch Methanol St. James, LLC
St. James, St. James Parish, Louisiana
PSD-LA-851

Pollutant	Averaging Period	Preliminary Screening Concentration (μg/m³)	Level of Significant Impact (μg/m³)	Significant Monitoring Concentration (μg/m³)	Background (μg/m³)	Maximum Modeled Concentration (μg/m³)	Modeled + Background Concentration (μg/m³)	NAAQS (μg/m³)	Modeled PSD Increment Consumption (μg/m³)	Allowable Class II PSD Increment (μg/m³)
$PM_{2.5}$	24-hour	1.01*	1.2	-	-	-	-	35	-	9
	Annual	0.11*	0.2	-	-	-	-	12	-	4
PM_{10}	24-hour	1.32	5	10	-	-	-	150	-	30
	Annual	0.16	1	-	-	-	-	-	-	17
NO_2	1-hour	13.47**	7.5		56.4	126.0	182.4	188	-	-
	Annual	0.40	1	14	-	-	-	100	-	25
CO	1-hour	1453.56	2000	-	-	-	-	40,000	-	-
	8-hour	441.48	500	575	-	-	-	10,000	-	-
NR = Not required.										

*Includes secondary formation of $PM_{2.5}$

**Tier 3 (OLM) was used for 1-hour modeling.